Arnold Schwarzenegger
Governor

ANALYSIS OF CALIFORNIA NATURAL GAS MARKET, SUPPLY INFRASTRUCTURE, REGULATORY IMPLICATIONS, AND FUTURE MARKET CONDITIONS

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Preface

The Public Interest Energy Research (PIER) Program supports public interest energy research and development that will help improve the quality of life in California by bringing environmentally safe, affordable, and reliable energy services and products to the marketplace.

The PIER Program, managed by the California Energy Commission (Energy Commission), conducts public interest research, development, and demonstration (RD&D) projects to benefit electricity and natural gas customers.

The PIER program strives to conduct the most promising public interest energy research by partnering with RD&D entities, including individuals, businesses, utilities, and public or private research institutions.

PIER funding efforts are focused on the following RD&D program areas:

- Buildings End-Use Energy Efficiency
- Energy-Related Environmental Research
- Energy Systems Integration
- Environmentally Preferred Advanced Generation
- Industrial/Agricultural/Water End-Use Energy Efficiency
- Renewable Energy Technologies
- Transportation

Analysis of California Natural Gas Market, Supply Infrastructure, Regulatory Implications, and Future Market Conditions is the final report for the California Institute for Energy & Environment project (Subcontract number MNG-07-01) conducted by Black & Veatch Corporation – Enterprise Management Solutions. The information from this project contributes to PIER's Energy Systems Integration Program.

For more information about the PIER Program, please visit the Energy Commission's website at www.energy.ca.gov/pier/ or contact the Energy Commission at 916-654-5164.

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Abstract

This report presents an analysis of the wholesale California natural gas market during the time period from 2008 to 2020 with an emphasis on the role - current and future - of natural gas storage.

Fundamental analysis of the California natural gas market incorporating various supply and demand scenarios and infrastructure assumptions was performed to evaluate the additional need for natural gas supply infrastructure, including storage, in California. The economic merits of storage as well as other assets such as pipelines and liquefied natural gas that can help California meet its supply needs were analyzed. A combination of pipeline and storage assets was found to comprise the most economically optimal portfolio for California to meet its needs for additional natural gas supply.

Fundamental and statistical analysis indicated that key drivers to storage value – seasonal price basis and price volatility – remain strong during the analysis period and support the development of new storage projects. In-state storage alternatives present the most economical option for storage service in California. A review of the regulatory regime in California indicated that the regulatory environment in California does not impede the development of storage in California.

Keywords: Public Interest Energy Research (PIER), natural gas, storage, forecasts, market, demand, supply, infrastructure, liquefied natural gas (LNG), production, prices, pipelines, volatility

Executive Summary

Introduction

Black & Veatch Corporation's Enterprise Management Solutions division (B&V) proposal to analyze the California natural gas market and storage infrastructure was selected by the California Institute for Energy & Environment in response to the PIER Natural Gas Program Research Opportunity Notice CIEE-NG-2006-01.

B&V is a management consulting company advising the energy industry on issues of strategy, markets, regulation, valuation and risk management. B&V services are supported by proprietary software tools, significant business experience and broad consulting experience.

Purpose

B&V's objectives in the study were multi faceted. The study focused on the fundamentals of the California natural gas market with emphasis on the role - current and future - of natural gas storage. Specifically, the objectives of this study were to:

Understand how the natural gas market in California will evolve through time:

- Develop a baseline fundamental view of the natural gas market in California incorporating supply, demand and infrastructure.
- Assess the California natural gas market's responses to various supply and demand scenarios.
- Evaluate California's need for additional infrastructure within the baseline and supply/demand scenarios.
- Assess the economic merits of storage as well as other assets such as pipelines and liquefied natural gas (LNG) that can provide natural gas deliverability to California.

Analyze and understand the role of storage and the viability of storage development in California:

- Assess trends in key drivers of storage value - seasonal basis and price volatility
- Develop an economic comparison of in-state and out-of-state storage alternatives to serve the California market
- Complete an economic viability of new storage development in California
- Review regulatory impediments to storage development in California

Project Objectives

The analysis objectives are subdivided into five main sections. A general overview of each sub component of B&V's analysis efforts is outlined below. The B&V analysis period is from 2008 to 2020.

Review Natural Gas Assets and Infrastructure that can serve the State of California

B&V summarized the natural gas assets that are available to meet natural gas demand in California. This effort provided a background for future analysis components to understand what assets are available and the associated economic cost to utilize the identified assets to meet California demand. This analysis included the description of the existing assets in place, the proposed facilities, and operations overview and other key variables that influence the utilization and economic merits of the particular asset. The natural gas supply assets considered included underground natural gas storage, interstate natural gas transmission, intrastate natural gas transmission, natural gas production, LNG import terminals, and LNG peak-shaving facilities.

Develop an Understanding of the Growth in Natural Gas Demand and Demand Elasticity

B&V analyzed the historical consumption of natural gas in California and demand behaviors to changes in prices. To better understand future trends in consumption, B&V interviewed selected large consumers to understand the potential for change in the demand elasticity for natural gas consumption. The findings from the historical analysis and survey results were incorporated in a fundamental analysis of the California market to understand how the seasonal price basis and demand patterns may change in future years.

Examine the Economic Costs of In-state vs. Out-of-State Storage:

Storage facilities can help manage demand fluctuations for natural gas. Key causes of fluctuations include power generation facilities that burn natural gas and space heating requirements for the residential and commercial sectors. It is critical to identify the most economic solution possible to provide storage capacity to the California market while balancing operational, environmental, and reliability requirements. B&V's analysis addressed alternatives to in-state facilities, and the development of in-state facilities, that included the expansion of traditional storage facilities east of California, on pipelines serving the California market. To understand the trade-off of promoting in-state development, this component of the study analyzed the impacts to storage value from increased costs of utilization from long haul transportation. Additional consideration included the need and viability of storage between northern and southern California and inter- and intrastate constraints.

Determine the Economically Optimal Portfolio to Meet California Peak Natural Gas Demand:

Peak demand for natural gas is driven by many factors which include weather, population growth, economic growth, conservation efforts and price of other fuels, such as oil. The potential for peak demand to grow on a disproportional basis to annual demand creates a challenge for industry and the State of California to balancing supply and demand. Determining the operational and economic feasibility of the various options to meet peak natural gas demand in California requires an understanding of technology, regulatory structure and business practices utilized in the energy industry. This component of the study considered natural gas storage, LNG supply, supply, transmission, LNG peak shaving facilities, and conservation to understand the most economical additions to the natural gas infrastructure service California depending on supply requirements.

Develop an Expectation for Long Term Natural Gas Price Volatility for the California Natural Gas Market:

In general, volatility of prices and ultimately volatility of returns on investment discourage potential investments. However, volatility plays a major role in determining the value and development of natural gas storage. Value can be created by market price arbitragers in two ways: First, they exploit the time spread between summer and winter natural gas prices. Second, they exploit the gyrations of the natural gas market that frequently offer natural gas price combinations beyond summer-winter spread. For many storage facilities that have the ability to charge market based rates, the income stream from arbitraging market prices can be comparable or superior to the income from traditional storage use to meet peak day demand needs. Expectations for volatility will play a major role in determining whether the market will support additional storage facilities independent of a demand driven need. Volatility in natural gas prices depend on the relationship between supply, demand, infrastructure, other commodity prices and the imbalances that can occur between these variables. This component of the study utilized fundamental analysis results to understand the markets sensitivity to various factors. With the main factors identified, an expectation for future volatility was developed which allowed the assessment as to whether the market will support storage development independent of meeting growing natural gas demand.

Evaluate the Regulatory Impediments to the Development of New Underground Gas Storage in California:

In addition to the geological limitations, regulatory requirements can determine whether new facilities are constructed to serve California. While traditional cost-based storage rates may not accurately reflect the value of service in peak periods and may not provide a return to create incentives necessary for the construction of new storage facilities, even if a storage facility could obtain market based rates there may exist other obstacles preventing and stymieing storage development. These obstacles arise from regulations that affect the economic siting of storage, standards issues with gas pipelines, and the permitting process in general. This component of the study assessed whether regulatory impediments exist that could limit the development of additional storage facilities in California.

Project Outcomes and Conclusions

The outcomes and conclusions are a logical compilation of the observations and study results across the different project objectives that incorporate the commonalities between them and are not mapped one-to-one with the description of project objectives defined above.

Expectations for Future Demand for Natural Gas in California

The average annual demand for natural gas in the State of California is projected to grow from 6.2 Bcf/day (Billion cubic feet per day) in 2008 to 7.1 Bcf/day by 2020 under baseline projections. The growth in natural gas demand for the residential and commercial sectors is expected to be 0.7 percent compound annual growth rate (CAGR) or 55 Bcf over the study period. This growth projection is lower than recent estimates by the EIA of 1.1 percent CAGR[1], and the Energy Commission of 2 percent CAGR[2] By 2020, B&V's forecast is 0.6 Bcf/day and 0.4 Bcf/day lower, during peak months, than the EIA and Energy Commission forecasts respectively.

Expectations for Future Natural Gas Supply into California

The main natural gas supply basins serving California include the Rockies production region, San Juan basin in northern New Mexico, Permian Basin in western Texas, WCSB, and in-state California production. Natural gas supply to the state is projected to grow from approximately 5.7 Bcf/day to 6.4 Bcf/day by 2020. This results in a 0.7 percent CAGR increase over the study period.

1. Energy Information Administration AEO 2007

2. California Energy Commission: Integrated Energy Policy Report 2007

Baseline Forecast for California Natural Gas Prices

Based on the B&V baseline assumptions for natural gas supply and demand in North America, natural gas prices in both southern and northern California will remain at relatively high levels over the analysis time period. The price delivered into the Southern California Gas Company (SoCal) is expected to increase from $5.50/MMBtu in 2008 to $7.50/MMBtu by 2020. The Pacific Gas and Electric Company (PG&E) Citygate price is also expected to increase from $5.80/MMBtu in 2008 to $7.80/MMBtu in 2020. Compared to the Energy Commission 2007 forecast[3], the B&V forecast is higher in the 2008-2013 time frame, with both forecasts following an upward trend through 2018.

Relationship of California Prices to Henry Hub

Our findings indicate that the baseline expected prices at the Henry Hub in Louisiana, the main pricing point for the North American gas market, will range from $6.50/MMBtu to $8.00/MMBtu during the study period of 2008 through 2020. The price basis differential expected between northern California at the PG&E Citygate and Henry Hub is $-0.01/MMBtu in 2008 growing to $0.13/MMBtu by 2013, before declining to $0.01/MMbtu by 2020. Similarly B&V expects prices in southern California, delivered into the SoCal system, relative to the Henry Hub, to be relatively flat at $-0.24/MMBtu in 2008 and $-0.23/MMBtu in 2020.

Demand from Gas-Fired Generation and Implications of Meeting the California Renewables Targets for Natural Gas Prices

Natural gas demand from power generation will vary based on load growth and conservation, weather and the generation fleet required to meet electricity demand. If the Renewables Portfolio Standard (RPS)[4] requirement is met, natural gas demand from the power generation sector grows at 1.6 percent from 2008 to 2020 under baseline assumptions. The increase in natural gas demand for power generation when additional gas-fired generation is required, due to the non-compliance with the renewables targets and when California power demand peaks due to weather, is 13 percent greater in 2015 and 32 percent greater in 2020 than the baseline demand forecast. This higher demand, when all other variables are constant, results in an increase in natural gas prices in southern California of $0.60/MMBtu by 2020. Larger increases were seen in northern California where prices could be $1.20/MMBtu greater by 2020.

3. California Energy Commission: Integrated Energy Policy Report DRAFT October 2007

4. 20% of IOU sales are assumed to be from renewables by 2010 with a three-year grace period, under the 2003 Energy Action plan adapted by the Energy Commission and the California Public Utilities Commission (CPUC)

Implications to California Prices from Growing LNG Imports

B&V utilized a B&V based estimate for lower than the expected baseline for LNG imports that resulted in LNG imports of approximately 6 Bcf/day by 2020. For a high import scenario, B&V utilized the baseline LNG import assumptions made by the Energy Commission in its preliminary report[5] where LNG imports grow to approximately 33.2 Bcf/day by 2020. California natural gas prices in 2020 are expected to range from $7.15/MMBtu if LNG imports fall to the lower range of the expectations to approximately $5.34/MMBtu should the flood of LNG into North America occur as assumed by the Energy Commission.

California Peak Day Natural Gas Demand is expected to Grow

Peak day demand in California is projected to grow from 10.1 Bcf/day in 2008 to 11.8 Bcf/day in 2020 under normal operating conditions. With higher demand, peak day needs can reach 16 Bcf/day by 2020 within California. The growth in peak day demand is projected to be slightly different in northern California where peak day needs, in high demand periods, could reach 6.1 Bcf/day by 2020 with a 4 percent CAGR from the 2006 peak-day send-out of 3.5 Bcf/day. In southern California, peak day needs could grow at 4.2 percent CAGR to 9.7 Bcf/day by 2020.

With High Demand, Additional Natural Gas Infrastructure Serving California is Required

If increases in peak load are driven by increases in natural gas demand for power generation, a combination of new interstate transportation or LNG supply coupled with additional intrastate storage is expected to be the optimal asset infrastructure combination. B&V projects that 70 Bcf of additional supplies are needed annually to meet daily demand requirements under a high power generation demand scenario. Depending on the feasibility of acquiring additional interstate transportation capacity or LNG supply, storage development can be used as a supplementary supply source.

Meeting expected weather sensitive natural gas demand requires the addition of storage assets in the State or increased availability of base load LNG. However, additional interstate transportation capacity, or LNG imports into California, will be needed to ensure the availability of sufficient capacity to fill the increased storage working gas capacity.

B&V projects that natural gas supply infrastructure which has the capability to deliver 218 Bcf on an annual basis is required to meet daily demand requirements with the combination of high core and power generation demand.

5. California Energy Commission: Integrated Energy Policy Report DRAFT October 2007

Future Natural Gas Infrastructure Needs could be Higher Depending on the Availability of Assets during Peak Periods

A key element behind these projections for new infrastructure to serve California during extreme demand events, is the 100 percent availability of interstate pipeline capacity, intrastate production and base load imports of natural gas into California from the Costa Azul LNG terminal. If peak day planning incorporates some level of unavailability of these supply infrastructure assets, greater levels of supply assets are required to ensure that sufficient infrastructure is in place to meet demand in California. As an example if in-state production, LNG imports and interstate pipeline capacity are available only 90 percent of the time during peak demand periods, 248 Bcf of additional pipeline capacity and 376 Bcf storage capacity are needed to meet daily requirements from a high power generation demand scenario and a high core and high power generation demand scenario.

Intrastate Storage is more Cost Effective than Storage Located Outside California

In-state storage offers the most economical source of storage service for California. Existing storage in both northern and southern California are less expensive than new build alternatives in the state or the import of storage services, from facilities located east or north of California. The current market value of in-state storage ranges from $150 to $280 per Mcf of deliverability. Of the potential and proposed storage services that could become available to serve California demand, expansions of in-state facilities proposed at Kirby Hills and Wild Goose, as well as the development of new in-state storage such as the facility proposed by Sacramento Storage, offer the most economic alternatives for California with an estimated storage cost range of $150 to $220 per Mcf of deliverability.

Future Expectations for Natural Gas Price and Volatility in California Supports the Market Value of Intrastate Storage

Utilizing statistical methods to analyze historical behaviors of natural gas prices in California allowed B&V to understand the best method to simulate short term price volatility and understand implications on a forward looking basis. B&V coupled the short term analysis with the long term analysis of California prices and the sensitivity to fundamental factors to understand the expect trends in natural gas price volatility. Based on this analysis approach, B&V projects that natural gas volatility in California will increase by 5 percent over the analysis period. This will lead to slight increases in the value of market based storage services. The importance of this projection is that the market conditions will remain supportive for future development of independent storage facilities with market based rates.

Minimal Regulatory Impediments Exist that Limit Development of Market Based Storage Facilities in California

B&V reviewed existing federal and state regulations to understand the requirements for new storage development and did not find any unreasonable regulatory requirements, relative to other locations in the United States, which would prevent additional storage development in California. In addition, B&V completed a survey of independent storage operators and developers to better understand their individual concerns. Again, our findings from the survey indicated that while there are unique requirements to develop storage in California, they are not insurmountable for a developer that has a strong knowledge of the California market and regulatory process.

Recommendations

B&V recommendations for future research relating to the California natural gas market and supporting supply, pipeline and storage infrastructure are summarized below. The B&V developed recommendations are based on the conclusions developed and summarized in this report. The recommendations are not listed in order or priority, they are listed in the same general order as the conclusions.

A summary of the B&V recommendations are as follows:

- Update Estimates of Future Supply Infrastructure Needs on a Regular Basis to Reflect Changes in Supply/Demand and Infrastructure Serving California.
- Expanded Review of Market Uncertainties that Cause Natural Gas Price Volatility.
- Revise Peak Day Planning Analysis and Infrastructure Assessment to Incorporate Utility Peak Day Expectations.
- Understand the Implications of Supply Asset Reliability to Peak Day Needs and Supply Asset Redundancy.

Benefits to California

The benefits to California associated with the analysis and findings of this report are multi faceted. The report conclusions and findings should not be viewed necessarily as a replacement to other analysis completed by the Energy Commission or stakeholders in California. Rather, it should be viewed as an independent assessment that either challenges current thoughts concerning the natural gas infrastructure in California or confirms findings published by other stakeholders in California.

Specific benefits to the State of California from the conclusions developed by B&V in this study are as follows:

- Improve understanding of expected natural gas prices in California under base conditions.

- Increase awareness of the impact of power generation demand for natural gas and the implications to California in meeting renewable portfolio standards.
- Understand the sensitivity of natural gas prices in California to changes in market conditions.
- Highlight issues concerning the availability of natural gas supply infrastructure to California and potential requirements for supply asset redundancy to meet peak day conditions.
- Recognize that a combination of new supply (production or LNG), pipeline capacity and storage are required in the future to meet California supply requirements.
- Highlight that storage is an important asset in meeting California natural gas demand and is projected to have a growing role into the future.
- Recognition that it is more cost effective and reliable to facilitate and allow increased storage development within California.

1.0 Introduction

B&V is a management consulting company advising the energy industry on issues of strategy, markets, regulation, valuation and risk management. B&V services are supported by proprietary software tools, significant business experience and broad consulting experience.

B&V's proposal to analyze the California natural gas market and storage infrastructure was selected by the California Institute for Energy & Environment in response to the PIER Natural Gas Program Research Opportunity Notice CIEE-NG-2006-01.

The study focused on the fundamentals of the California natural gas market with emphasis on the role - current and future - of natural gas storage. Specifically, the objectives of this study were to:

Understand how the natural gas market in California will evolve through time:

- Develop a baseline fundamental view of the natural gas market in California incorporating supply, demand and infrastructure.
- Assess the California natural gas market's responses to various supply and demand scenarios.
- Evaluate California's need for additional infrastructure within the baseline and supply/demand scenarios.
- Assess the economic merits of storage as well as other assets such as pipelines and LNG that can provide natural gas deliverability to California.

Analyze and understand the role of storage and the viability of storage development in California:

- Assess trends in key drivers of storage value - seasonal basis and price volatility.
- Develop economic comparison of in-state and out-of-state storage alternatives to serve the California market.
- Complete economic viability of new storage development in California.
- Review regulatory impediments to storage development in California.

Section 2 of this report provides an overview of the supply and demand for natural gas in California and describes a baseline fundamental analysis of the California natural gas market. This report also analyzes the impact from variations in the key supply and demand drivers of the market on the California natural gas market. B&V provides an overview of the analysis and discussion on the potential infrastructure needs for California under different supply and demand scenarios. A real-options based methodology is outlined to value market based storage assets and presents analysis on the trends related to the major drivers of the storage value. Section 6 reviews the economic comparison of in-state and out of state storage alternatives as a means of serving California's demand. B&V provides a high level assessment of the regulatory environment for storage development in California. Section 8 is a summary of the conclusions reached in this study and recommendations for future research concerning natural gas storage and the California natural gas market.

2.0 Natural Gas Supply/Demand Outlook for California

This section describes the baseline fundamental analysis of the wholesale California natural gas market that was undertaken by B&V. The primary objectives of the fundamental analysis were:

1. Understand the evolution of natural gas prices in southern and northern California.
2. Understand the supply portfolio changes in meeting California demand.
3. Evaluate key infrastructure utilization and identify possible infrastructure needs, such as pipeline and/or storage capacity.

The fundamental analysis study period is from November 2008 to October 2020 and the baseline assumptions are normal weather conditions.

2.1. B&V Methodology Overview

For this study, B&V utilized the North America Regional Gas (NARG) model to forecast prices and basis under various fundamental assumptions. NARG is an economic model that solves network questions using a non-linear algorithm. B&V has significant experience utilizing NARG to address a wide range of natural gas market issues. Findings from the NARG based market analysis were monthly projections of regional pricing points from 2008 to 2020.

NARG is a general equilibrium software tool that forecasts future market conditions based on assumed market fundamentals. The model integrates all elements of the North American natural gas industry, including production, pipelines, market demand, and storage. It simulates the interactions of different market components and solves for an equilibrium that will equate supply and demand at each market hub.

When converged, NARG produces a "zero arbitrage" solution where in all markets are in equilibrium simultaneously across location and time. The following section describes how the NARG algorithm solves to convergence.

2.1.1. Addressing the Supply/Demand Balance Across Locations

First, the NARG model equilibrium eliminates all arbitrage opportunities across locations. Pipeline transmission networks link major production and consumption regions. In equilibrium, either a pipeline is fully utilized or the price differential between two locations does not cover the transportation cost, eliminating incentives to move gas along that pipeline route.

Figure 2-1 illustrates how the equilibrium across space is realized through an iterative process. NARG starts with a low price for the supply region and a high price for the consumption region, as indicated by the blue dots. The price difference between two markets is higher than the transportation cost on the pipeline; therefore markets will be motivated to purchase gas from the supply region and move to the consumption region. Increasing demand in the supply region and increasing supply in the consumption region causes prices to move toward convergence. A general equilibrium is established once the pipeline is full, or the price differential equals the transportation cost.

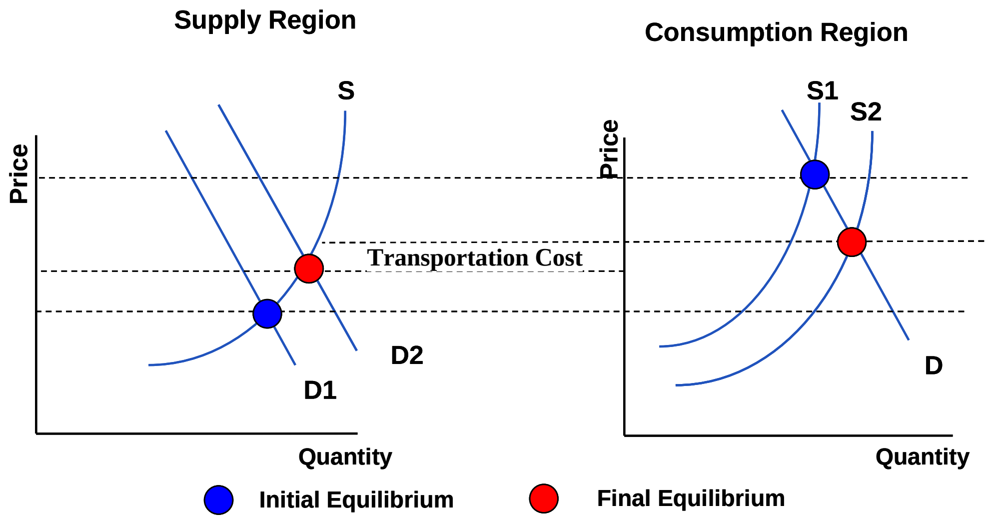


Figure 2-1: NARG Equilibrium Eliminates Locational Arbitrage, Source: B&V

2.1.2. Addressing the Supply/Demand Balance Across Time

NARG equilibrium also eliminates arbitrage opportunities across time. Natural gas demand is highly seasonal due to significant consumption for residential and commercial space heating. Winter demand is typically much higher than summer demand. Natural gas production, however, stays at a relatively constant rate throughout the year. To modulate the seasonal demand and supply balance, storage fields are built to inject gas in the summer, which is then withdrawn for winter consumption.

Storage operators in the model follow market signals to decide storage injection and withdrawal activities. Realizing that the natural gas price is higher in winter than in the summer, the storage operator will store gas to the extent that the seasonal price spread covers the storage cost or until the storage field is full. As illustrated in Figure 2-2, if the winter/summer price spread is higher than the storage cost, the storage operator will be motivated to purchase more gas in the summer and store it to be sold in winter for a profit. As a response, summer prices will rise due to increased demand from storage injections and winter prices will fall because more storage withdrawal constitutes additional supply to the market. In equilibrium, either the storage field is full or the seasonal differential equals the storage cost.

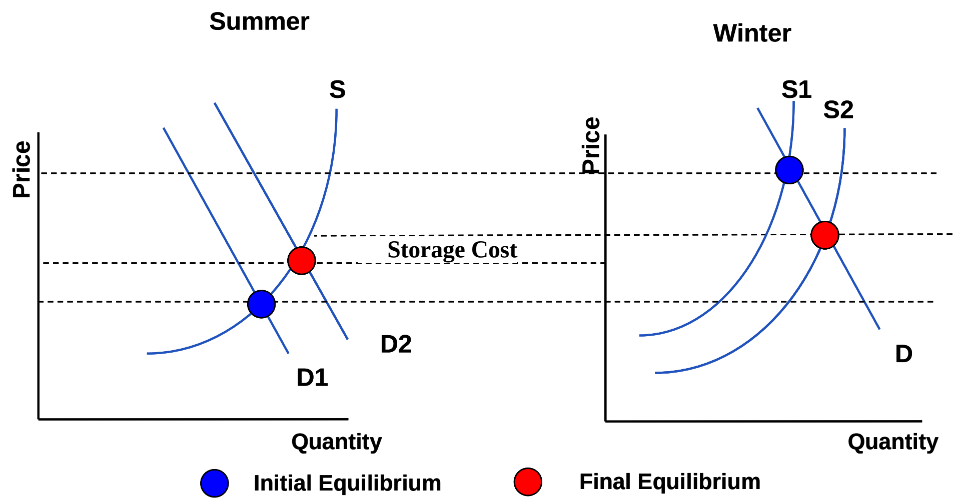


Figure 2-2: NARG Equilibrium Eliminates Seasonal Arbitrage, Source: B&V

2.2. Wholesale Natural Gas Infrastructure in California and Western North America

Natural gas demand in California is met by a combination of interstate pipelines, intrastate pipelines, underground storage facilities, and LNG storage facilities. Interstate pipelines import supply from the Western Canadian Sedimentary Basin (WCSB), Southwest (San Juan basin, Permian basin, Anadarko basin) and Rockies production. Intrastate pipelines comprise mainly of the intrastate transmission systems of the California local distribution companies (LDCs). Storage working gas capacity of almost 264 Bcf (1,000,000,000 cubic feet of natural gas per day) exists within the state with a maximum deliverability of 6.5 Bcf/day. This section discusses the natural gas infrastructure in California and western North America that can serve California.

2.2.1. Storage Facilities

In-State Storage Facilities

Existing underground storage in California consists of depleted reservoirs operated by the LDCs and three independent facilities. Depleted reservoirs typically possess mid to low deliverability capabilities. Figure 2-3 shows the location of the storage facilities within California. Figure 2-4 presents a summary of the total storage capacity within the state of California.

As shown in Figure 2-4, PG&E owns and operates three storage facilities with a total working gas capacity of 42 Bcf. SoCal owns and operates four storage facilities with a total working gas capacity of 120 Bcf. The three independent storage facilities are Lodi, Wild Goose, and Kirby Hills. The total working gas storage capacity in California is almost 264 Bcf with a deliverability of 6.5 Bcf/day.

Expansions of existing facilities at the Lodi and Kirby Hills storage facilities have been proposed, adding 12 Bcf of working gas capacity in the state. In addition, Wild Goose, which currently has a working gas capacity of 24 Bcf is approved for working gas capacity of 29 Bcf. Sacramento Natural Gas will add an additional 7.5 Bcf of working gas capacity in the state.

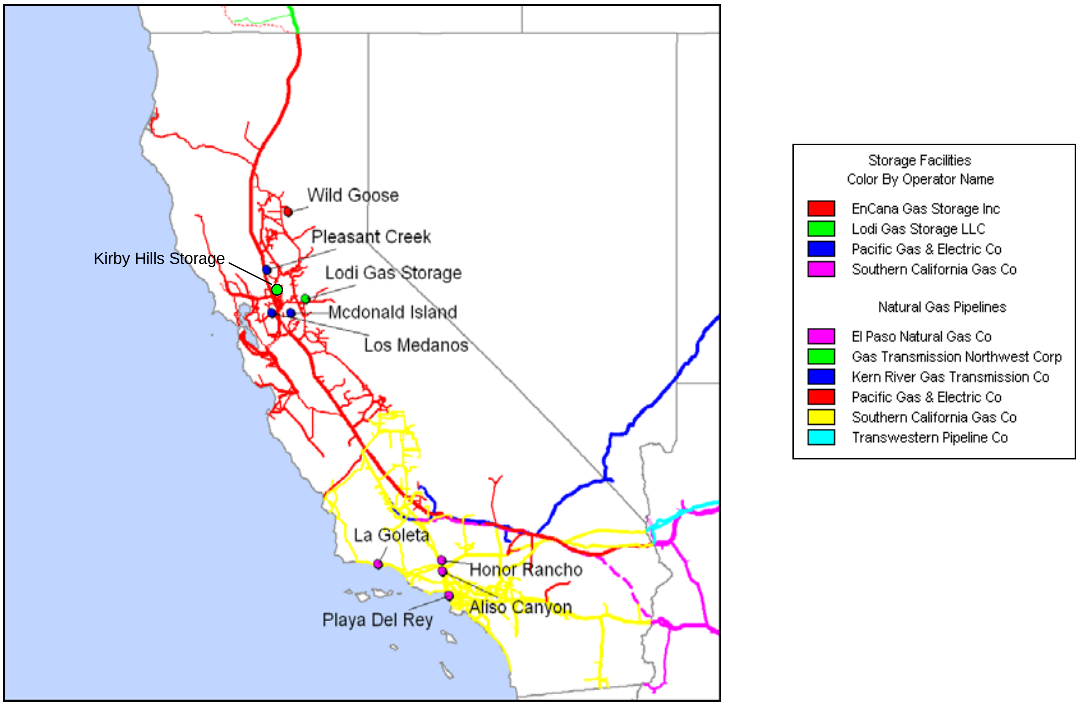


Figure 2-3: Storage Facilities within California, Source: Energy Velocity

Storage Field	Ownership	Working Gas Capacity (Bcf)	Max Deliverability (MMcf/d)	Turns of Service	Pipeline Interconnects	Status
Lodi Gas Storage	Lodi Gas Storage LLC.	12.0	450	7	PG&E	Operating
Kirby Hills Storage	Lodi Gas Storage Co.	5.5	100	3	PG&E	Operating
Wild Goose Storage	Niska Gas Storage - Carlyle/Riverstone	24.0	480	4	PG&E	Operating
Honor Rancho Storage Field	SoCal	20.0	1,000	4	SoCal	Operating
La Goleta	SoCal	20.5	420	2	SoCal	Operating
Playa del Rey	SoCal	2.6	480	9	SoCal	Operating
Aliso Canyon	SoCal	77.0	1,860	1	SoCal	Operating
Los Medanos	PG&E	17.5	350	1	PG&E	Operating
McDonald Island	PG&E	82.0	1,300	1	PG&E	Operating
Pleasant Creek	PG&E	2.3	70	1	PG&E	Operating
Sacramento Natural Gas Facility	Sacramento Natural Gas Storage Co.	7.5	200	3	Sacramento Municipal Utility District, PG&E	Proposed - Expected In Service 2008
Kirby Hills Area Expansion	Lodi Gas Storage Co.	12.0	200	2	PG&E	Proposed - Expected In Service 2008
Wild Goose Expansion	Niska Gas Storage - Carlyle/Riverstone	5.0	TBD	TBD	PG&E	Proposed
Gill Ranch Storage[5]	Gill Ranch Storage, LLC	15.0	485	3	PG&E	Proposed - Expected In Service 2010

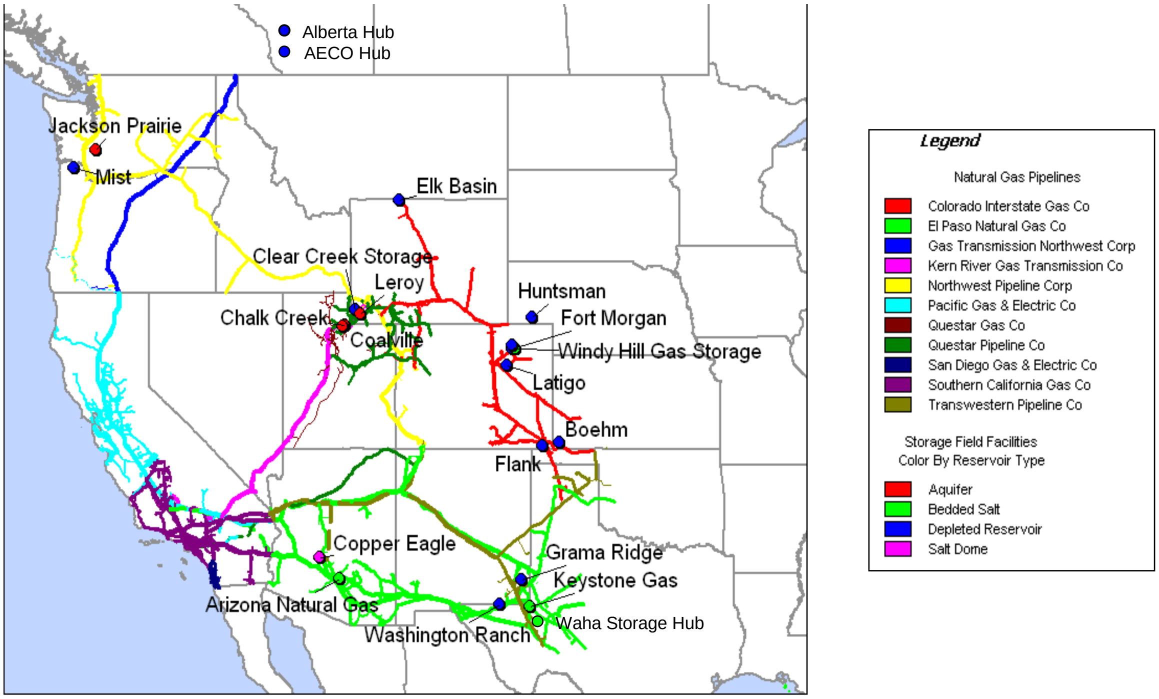
[5] Open Season Announced Oct 15.

Figure 2-4: Summary of Storage Facilities in California, Source: Energy Velocity, Energy Information Administration (EIA) Natural Gas Annual 2005, Natural Gas Intelligence (NGI) Storage Database 2003, B&V Research[6]

Out-of-State Storage Facilities

In addition to in-state storage facilities, out of state storage facilities were identified based upon the available pipeline network and their potential for serving California. As the distance to the storage facility from the California market increases, the transportation costs required to move the gas into the market generally increase. Out-of-state storage alternatives have been identified based on the economic viability of transportation costs to access the storage facilities. The identified facilities generally require only one pipeline transportation leg to access utility systems that serve California and are located in the Rockies region, Southwest, Northwest and Canada. Figure 2-5 shows the location of the selected facilities while Figure 2-6 summarizes the capabilities of the storage facilities.

6. The Gill Ranch Storage project was announced on October 15, 2007 in an open season notice for potential customers. The analysis in this report was completed prior to the announcement and does not incorporate this facility.



Source: Energy Velocity; B&V Research

Figure 2-5: Out-of-State Storage Facilities

Several projects have been proposed to expand storage capacity in the out-of-state regions selected for their potential to serve California demand. Figure 2-6 also summarizes the proposed storage facilities in these regions.

Storage Field	Ownership	Working Gas Capacity (Bcf)	Max Deliverability (MMcf/d)	Turns of Service	Pipeline Interconnects	Status
Washington Ranch	El Paso Corp	44.0	250	1	El Paso Pipeline	Operating
Grama Ridge	ENSTOR - Grama Ridge Storage & Transportation	6.0	125	3	El Paso Pipeline, Transwestern, Northern Natural, NGPL	Operating
Keystone Gas Storage	Unocal Corp	5.0	400	10	El Paso Pipeline	Operating
Mist Storage Field	NW Natural	14.4	380	3	Northwest Pipeline	Operating
AECO Hub	Niska Gas Storage - Carlyle/Riverstone	125.0	3,050	4	Northwest Pipeline	Operating
Alberta Hub	ENSTOR – Scottish Power	40.0	450	2	TransCanada Pipeline	Operating
Huntsman Storage Facility	Kinder Morgan	16.0	168	1	Kinder Morgan	Operating
Clear Creek Storage	Questar Energy Trading, Montana Power	6.0	85	2	Kern River, Questar Pipeline	Operating
Coalville Storage	Questar Corp.	0.7	60	11	Questar Pipeline	Operating
Chalk Creek Storage	Questar Corp.	0.3	35	17	Questar Pipeline	Operating
Leroy Storage	Questar Corp.	0.8	80	12	Questar Pipeline	Operating
Latigo Storage Field	El Paso Natural Gas	9.0	139	2	Colorado Interstate Pipeline	Operating
Flank Storage Field	El Paso Natural Gas	7.2	164	3	Colorado Interstate Pipeline	Operating
Boehm Storage Field	El Paso Natural Gas	5.2	124	3	Colorado Interstate Pipeline	Operating
Young Gas Storage	Young Gas Storage Co.	5.8	199	4	Colorado Interstate Pipeline	Operating
Fort Morgan Compression Station Expansion Project	Colorado Interstate Gas Co.	8.5	450	6	Colorado Interstate Pipeline	Operating
Elk Basin Storage	Williston Basin Interstate	16.0	135	1	Colorado Interstate Pipeline	Operating
Arizona Natural Gas Storage	El Paso Corp.	3.5	350	12	El Paso Pipeline	Proposed - Expected In Service 2010
Copper Eagle Storage (AZ)	El Paso Corp	3.2	320	12	El Paso Pipeline	Proposed
Jackson Prairie Storage - Puget Sound	Puget Sound Energy, Inc.	24.3	1,150	6	Northwest Interstate Pipeline	Proposed - Expected In Service 2008
Windy Hill Gas Storage - Phase I	Chevron	3.0	200	3	Colorado Interstate Pipeline	Proposed - Expected In Service 2008
Windy Hill Gas Storage - Phase II	Chevron	6.0	400	3	Colorado Interstate Pipeline	Proposed - Expected In Service 2010
Waha Storage Hub	ENSTOR	9.5	800	10	El Paso Pipeline, Transwestern	Proposed - Expected In Service 2007
Keystone Gas Storage Expansion	Chevron	8.0	400	6	El Paso Pipeline	Proposed
Mist Storage Expansion	NW Natural	TBD	TBD	TBD	Northwest Interstate Pipeline	Proposed - Expected In Service 2008
Totem Storage Field Project	El Paso Natural Gas	7.0	250	4	Colorado Interstate Pipeline	Proposed - Expected In Service 2009

Figure 2-6: Out of State Operating and Proposed Storage Facilities that can also Serve California Demand, Source: Energy Velocity, EIA Natural Gas Annual 2005, NGI Storage Database 2003, B&V Research

2.2.2. Interstate Natural Gas Pipelines

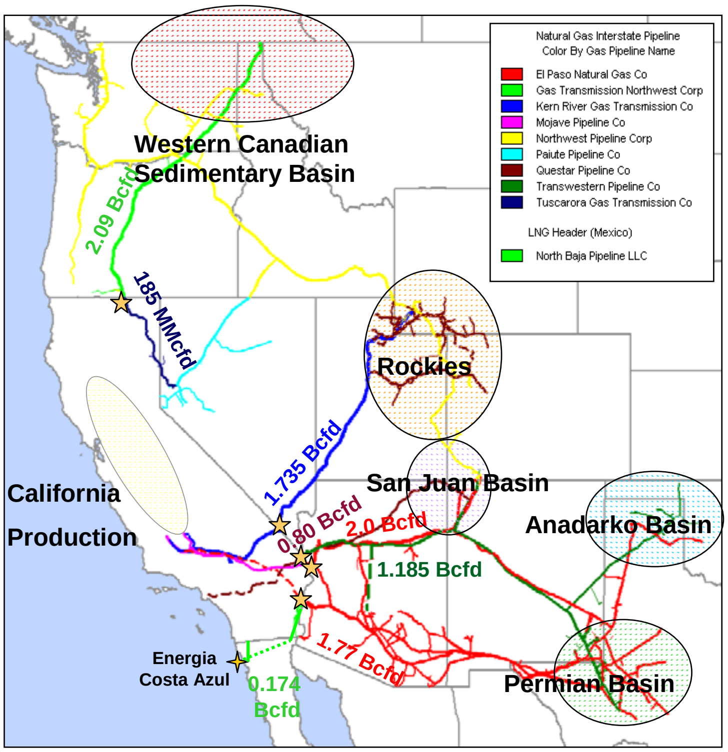
Interstate pipelines link the California market to supply sources in the WCSB, Southwest production in the San Juan basin, Permian and Anadarko basins, and Rockies production as shown in Figure 2-7.

El Paso Natural Gas (El Paso) and Transwestern Pipeline (Transwestern) transport production from the San Juan, Anadarko and Permian basins. They have a combined delivery capacity of 4.955 Bcf/day at the California border as shown in Figure 2-7. Declines in the production in the Southwest basins have caused the throughput on these pipelines to drop over time. In addition, Questar's Southern Trail pipeline links San Juan basin production to California with a delivery capacity of 80 MMcf/day (1,000,000 cubic feet of natural gas per day).

Kern River Gas Transmission (Kern) connects supply in the Rockies to the California market. Kern picks up Rockies production at Opal and has a delivery capacity of 1.74 Bcf/day after its expansion in 2003.

Gas Transmission Northwest (GTN) is an extension of TransCanada's British Columbia and Foothills pipeline systems and transports supply primarily from the WCSB to the Pacific Northwest and California with a delivery capacity of 2.1 Bcf/day into California.

Transportadora De Gas Natural De Baja California (TGN) and Tuscarora Pipeline (Tuscarora) are the two other interstates pipelines with interconnects into California. Tuscarora flows through the state of California and primarily serves demand in Nevada. The TGN pipeline extends from Mexico to an interconnection with San Diego Gas and Electric Company (SDG&E) pipeline facilities.



Pipeline	Location	Delivery Capacity
Gas Transmission Northwest	Malin	2.09 Bcfd
El Paso Natural Gas	Topock	2.00 Bcfd
El Paso Natural Gas	Blythe	1.77 Bcfd
Transwestern	N.Needles & Topock	1.185 Bcfd
Kern River Transmission	Goodsprings Compressor	1.735 Bcfd
TGN (LNG)	Mexico Border	174 MMcfd
Tuscarora*	Malin	185 MMcfd
Questar – Southern Trails	N. Needles	80 MMcfd

** Natural gas flows through the state of California on the Tuscarora pipeline*

Source: Energy Velocity; Final Reference Case in Support of the 2005 Natural Gas Assessment – CEC, Nov 2005

Figure 2-7: Interstate Pipeline Links to California

2.2.3. Intrastate Gas Pipelines/ Distribution System

The main utilities serving California are PG&E, SoCal, and SDG&E as shown in Figure 2-8. In addition, other large utilities and municipalities that also deliver gas in California are City of Long Beach Municipal Oil and Gas Department City of Los Angeles Department of Water and Power and Southwest Gas Corp.

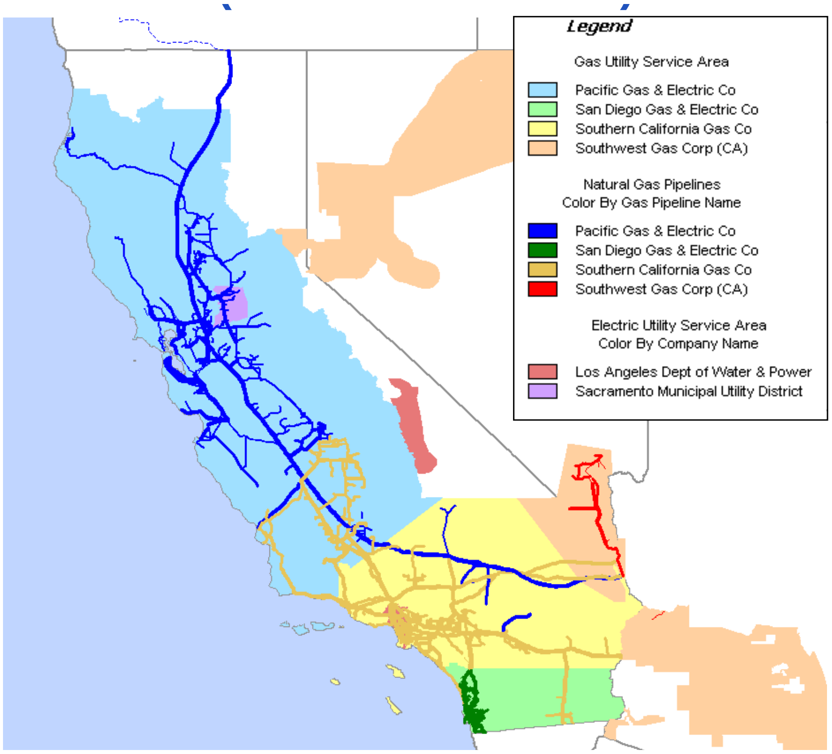
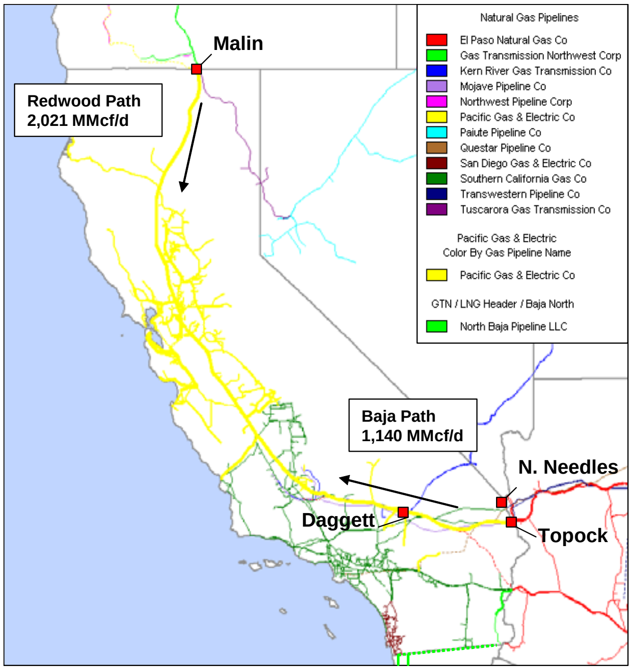


Figure 2-8: Utilities Serving California, Source: Energy Velocity

Pacific Gas & Electric

PG&E is the utility that serves the majority of northern California demand through supplies received from GTN on the Redwood path and from El Paso, Transwestern, Southern Trails and Kern on the Baja path in addition to California production as can be seen on Figure 2-9.

The total receipt capacity into the PG&E system is approximately 3.3 Bcf/day.



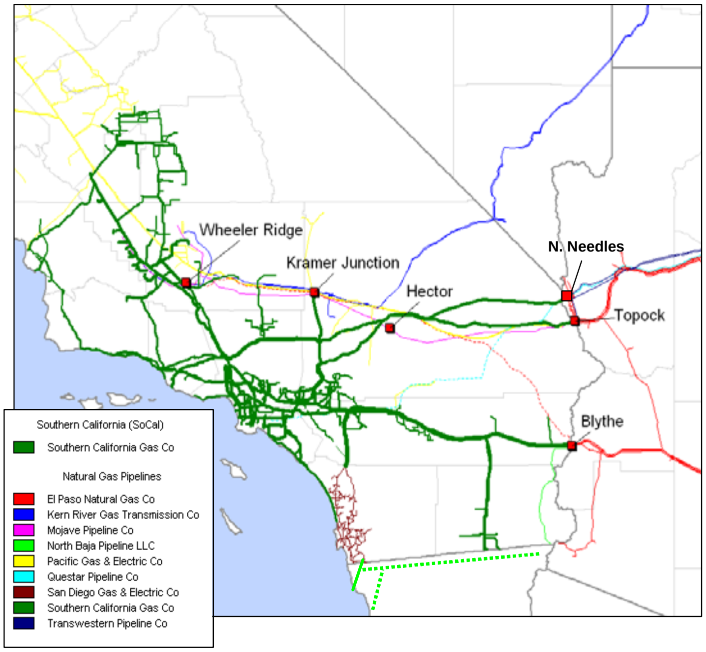
Receipt Capacity into PG&E

Interconnect	Capacity (MMcf/d)
Baja Path:	
Transwestern	400
El Paso	1,140
Kern	657
Southern Trails	120
Total Baja Path	**1,140**
Redwood Path:	
Gas Transmission Northwest	2,021
Total Redwood Path	**2,021**
CA Production	130
Total Firm Supply Access for PG&E	**3,291**

Figure 2-9: Receipt Capacity into PG&E, Source: Energy Velocity, Lippman Consulting, 2006 California Gas Report

Southern California Gas

SoCal, a subsidiary of Sempra Energy, is the nation's largest natural gas distribution utility and serves the southern California natural gas market. SoCal receives gas from El Paso, Transwestern, Southern Trails, and Kern in addition to California production with a total receipt capacity of about 3.9 Bcf/day as shown in Figure 2-10.



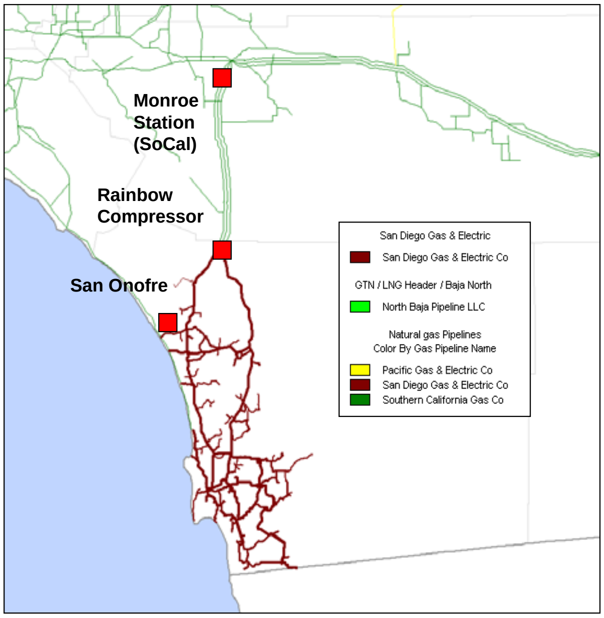
Receipt Capacity into SoCal

Interconnect	Capacity (MMcf/d)
El Paso at Blythe	1,210
El Paso at Topock	540
North Needles (Transwestern, Questar)	800
Hector Road (Mojave)	50
Wheeler Ridge (PG&E, Kern/Mojave, CA Prod)	765
Line 85 (CA Prod)	190
North Coastal (CA Prod)	120
Kramer Junction (Kern/Mojave)	200
Total Firm Supply Access for SoCal	**3,875**

Figure: 2-10: Receipt Capacity into SoCal, Source: Energy Velocity, Lippman Consulting, 2006 California Gas Report

San Diego Gas & Electric Co

SDG&E is the utility that provides natural gas to San Diego County and southern Orange County in southern California. It is owned by Sempra Energy. SDG&E is supplied as a wholesale customer of the SoCal system with deliveries at the Rainbow and San Onofre Metering Stations as shown in Figure 2-11. Maximum capacity at the Rainbow Station is 655 MMcf/day in the winter and 635 MMcf/day in the summer, excluding 45 MMcf/day of reserve margin.



Seasonal Capacity for SDG&E

Season	Capacity (MMcf/d)
WINTER	**655**
SUMMER	**635**
Total Capacity for SDG&E	**655**

Figure: 2-11: Seasonal Capacity for SDG&E, Source: Energy Velocity, 2006 California Gas Report, Prepared Direct Testimony of David M. Bisi, SDG&E and SoCal, A.06-10-XXX, filed October 27, 2006

2.2.4. Other Facilities

LNG above-ground storage tanks provide peak shaving services to the utilities serving California. These tanks have less storage capacity than underground storage but serve to "shave" the peak loads by supplying gas during days of highest demand. In addition, LNG supplies fuel to natural gas vehicles that are increasingly used in California. The main LNG storage facilities in California are:

1. SDG&E – Borrego Springs
- 7,750 gallon tank
2. PG&E – Sacramento
- 10,000 gallons per day
- Experimental technology demonstration plant
3. Quadren Cryogenics Processing - Robbins
- Liquefies high nitrogen gas from Robbins field and produces ultra-high purity methane for specialty gas market

The largest current source of LNG used to supply California, and other southwestern states, is a plant owned by an affiliate of El Paso Natural Gas Company located near Topock, Arizona that has approximately 29,000 gallons per day of LNG capacity.

2.3. Natural Gas Supply in California and Western North America

California's supply portfolio is comprised largely of pipeline imports from the WCSB, Southwest (San Juan basin, Permian basin, Anadarko basin) and Rockies production. Historically, the average supply of natural gas to meet California demand has been just over 6 Bcf/day, 85% which are pipeline imports. The remaining supply is met by a combination of California production and in-state underground natural gas storage with California production accounting for about 15% of total supplies. LNG imports are projected to be a new supply source enabling California to meet its increasing demand with the Energia Costa Azul project coming on-line as early as 2008.

2.3.1. California In-State Production

Natural gas reserves are primarily found in the southern and central areas of the state. B&V expects that no new reserve additions or growth in production will occur in California over the analysis period. Production within California has declined since 2000 and is shown in Figure 2-12 below. By 2020, California production is expected to be 10% of the state's supply portfolio.

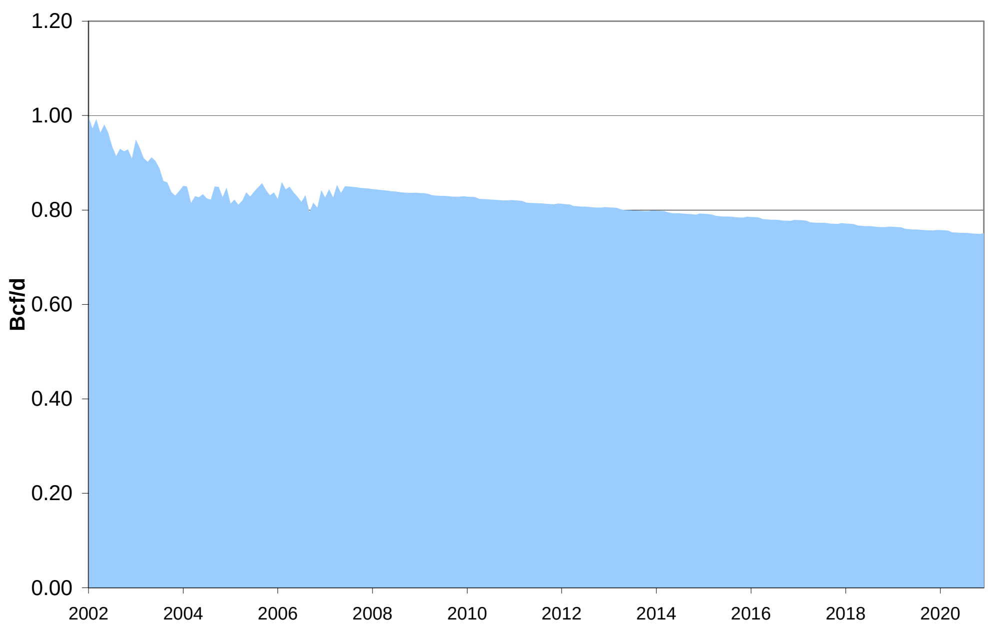


Figure 2-12: California Dry Production, Source: Lippman Consulting; EIA Annual Energy Outlook (AEO) 2007; B&V Analysis

2.3.2. Production Trends at Major Supply Basins

Western Canadian Sedimentary Basin

The WCSB is an important supply source for northern California. In 2007, the WCSB produced on average 16.2 Bcf/day, which is 0.4 Bcf/day off the peak in 2001. Over the next 20 years, sharp declines are expected in WCSB production due to rising production costs and the declines in productivity per new well delivered.

Overall Canadian production declines at a smaller rate, with WCSB declines partially offset by MacKenzie Delta volumes that are expected to come on line in 2014, as shown in Figure 2-13. However, the anticipated increase in demand in Canada especially driven by electric demand growth in Ontario and increased demand related to oils sands production is expected to cause a decline in the imports of natural gas from Canada.

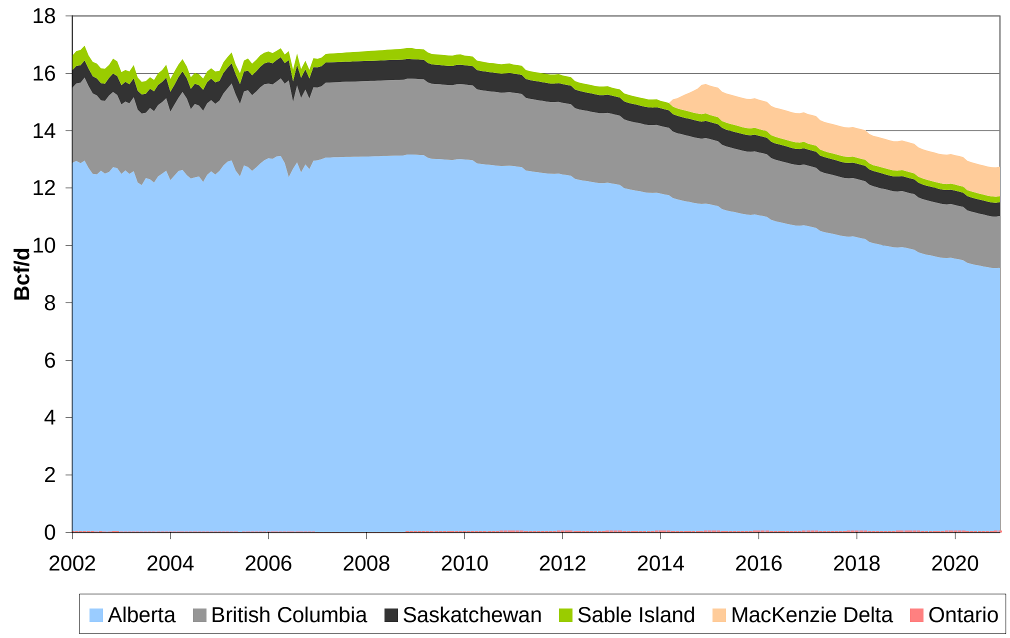


Figure 2-13: Canadian Production, Source: Lippman Consulting, B&V Analysis

Rockies Region

In 2007, the Rockies region averaged 8.3 Bcf/day of natural gas production. This reflects a 9.4% growth rate over the 4.3 Bcf/day produced in 1999. Expanded drilling and technology advancements to extract tight gas and coal bed methane gas reserves contributed to the dramatic growth in Rockies production. Despite the current constraints in take away capacity from the Rockies to market regions, drilling activities continue to be robust and the expectations are for these growth trends to continue in the near to mid term. Once the proposed Rockies Express Pipeline (REX) is placed in service, Rockies production is expected to grow and compete with Gulf of Mexico (GOM) production for a share of the Northeast market. Over the next 10 years, EIA expects Rockies production to grow from 8.92 Bcf/day in 2008 to 9.5 Bcf/day in 2020, an annual growth rate of 0.5%. B&V's analysis assumes a higher growth rate of 2.2% per year, as shown in Figure 2-14, based on proprietary field model estimates. Growth in the Rockies will occur predominately in the Jonah and Pinedale basins. Production growth is expected to start flattening out around 2015 without major expansions in take-away capacity.

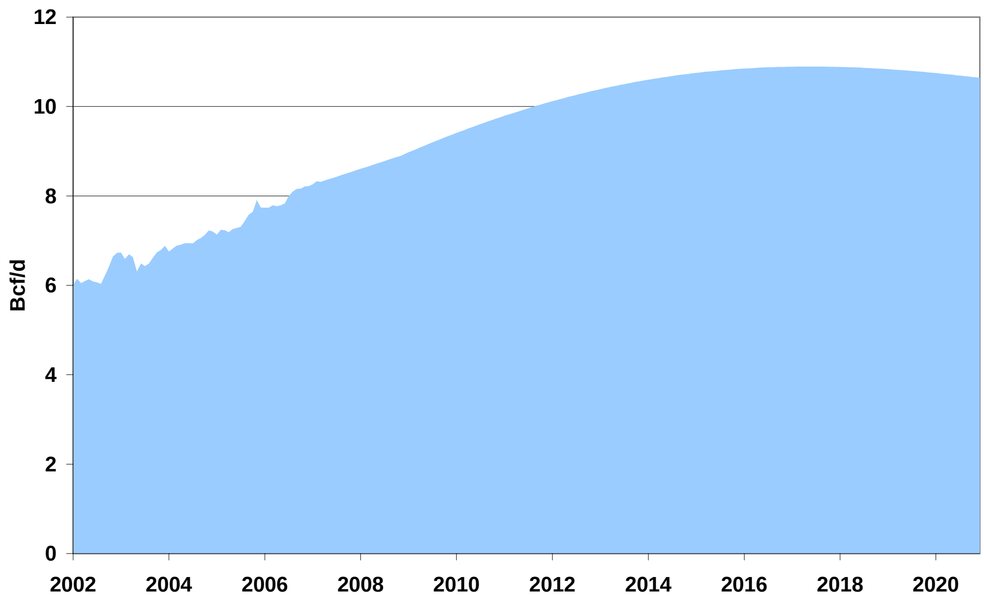


Figure 2-14: Rockies Production, Source: Lippman Consulting, B&V

Permian and San Juan Basins

From 1991 to 2006, Permian production declined from 4.9 Bcf/day to 4.1 Bcf/day, a 1.1% annual decline rate. The number of new gas wells delivered has increased steadily from 578 in 1991 to 1,592 in 2005. The production decline, coupled with the increase in wells first delivered, indicates that production per well is declining, as more wells are needed to replace production from declining wells. Figure 2-15 shows historical and forecasted production for the Permian Basin.

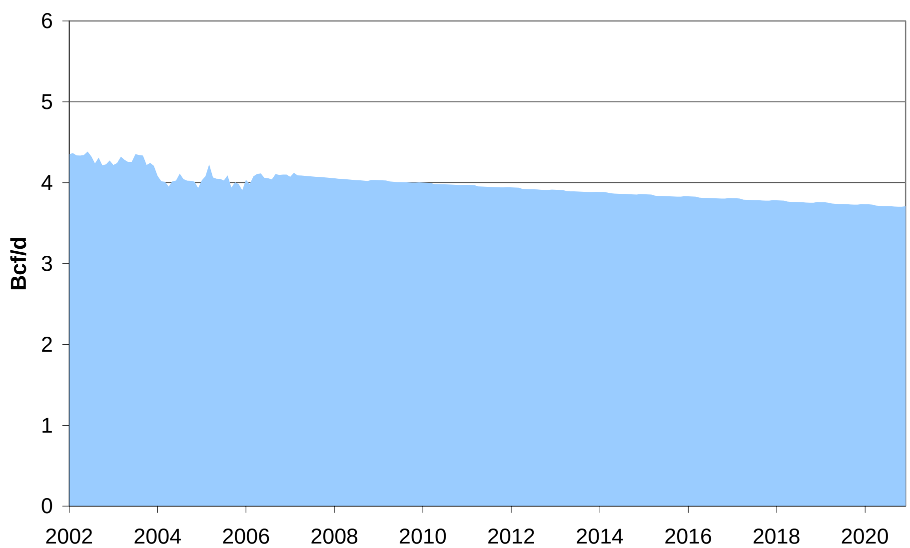


Figure 2-15: Permian Production, Source: Lippman Consulting, B&V

By 2020, production from the Permian basin is expected to drop to 3.7 Bcf/day. Historical utilization of the El Paso and Transwestern pipelines into California have declined over time in step with the production declines.

The San Juan basin produces natural gas from both coal bed methane and conventional resources. Production from coal bed methane increased from less than 0.5 Bcf/day in the early 1990s to peak at around 2.7 Bcf/day in 2000 and is currently 2.5 Bcf/day. Conventional production increased from 1 Bcf/day in 1990 to 1.5 Bcf/day in 2006. Drilling activities in the San Juan basin remain strong for the past several years. As shown in Figure 2-16, production from the San Juan basin is expected to remain relatively flat for the analysis period with coal bed methane growth offsetting potential declines from conventional resources.

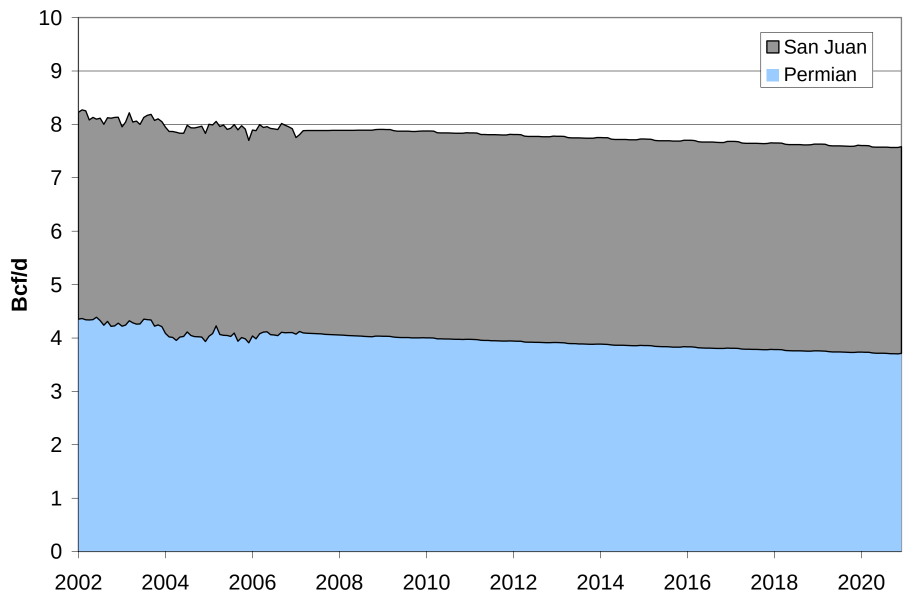


Figure 2-16: Permian and San Juan Production, Source: Lippman Consulting, B&V Analysis

2.3.3. *LNG Import Supply*

A large number of LNG regasification terminal projects have been proposed and are at various stages of approval and even construction in North America. Rising global demand for LNG and constraints on liquefaction capacity indicate that only a small number of the proposed LNG terminals will become operational and that these terminals will likely have utilization rates less than 100% of their design regasification capacity.

Figure 2-17 indicates the expectation for LNG import volumes entering the lower 48 market by 2020. The projections assume a seasonal pattern for the LNG imports to the US, with terminals experiencing higher load factors in the summer than in the winter. These projections reflect an expectation that non-dedicated LNG supplies will be delivered to higher value markets across the globe in winter. As the chart indicates, the maximum LNG imports will increase from 6 Bcf/day in 2008 to 10 Bcf/day by 2020.

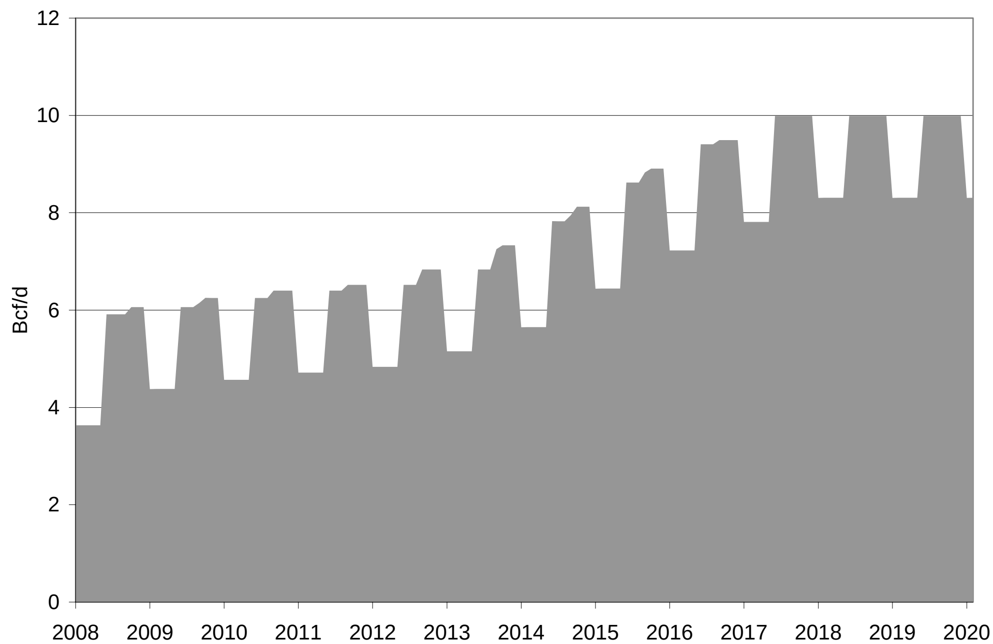


Figure 2-17: LNG Imports to Lower 48, Source: B&V Analysis

Several projects have been proposed within California as well as in Canada and Mexico to serve demand in California and the other western states. Figure 2-18 indicates the location of the proposed LNG terminals on the West Coast. Significant siting concerns and environmental factors influence the potential viability of these projects in addition to the availability of supply.

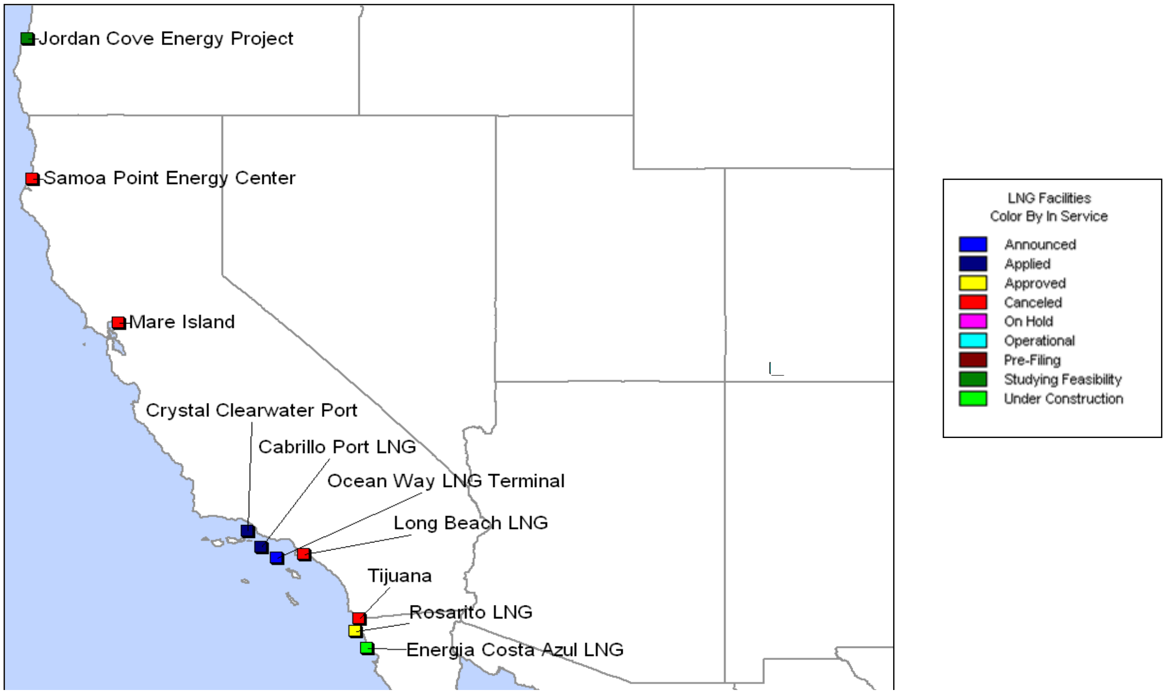


Figure 2-18: Proposed LNG Terminals, Source: Energy Velocity, B&V Research

Of these, the project that is expected to have near-term impact on the California market is the Energia Costa Azul Terminal being constructed in Baja, Mexico with Sempra Energy and Shell Oil as operators. The initial capacity of the project is 1.0 Bcf/day Capacity with expansion potential up to 2.5 Bcf/day. The Energia Costa Azul project is fully permitted and construction is anticipated to be completed in April 2008. The entire capacity of the terminal is contracted with half the capacity being contracted to BP and the other half to Shell. BP is expected to provide supplies from Indonesia (500 MMcf/day) while Shell is expected to provide supplies from Sakhalin II (500 MMcf/day).

The initial capacity will serve Mexico and California. A fifteen year supply agreement exists with the Comision Federal de Electricidad for 130 MMcf/day to serve in part the Juarez power plant in Rosarito.[7]

7. Energia Costa Azul

2.4. Natural Gas Demand for California and the Western United States

2.4.1. Elasticity

Price elasticity of demand is defined as the response of demand to price changes. It is generally negative, indicating that demand will decrease if price rises and increases if demand drops. Price elasticity is calculated as the percentage change of demand response to percentage change of price. Demand is considered "elastic" if elasticity is higher than one (i.e., a 1% price change will induce more than 1% of demand response) and is considered "inelastic" if elasticity is less than one.

There are economic estimates of price elasticity of natural gas, electricity or energy in North America from various sources. The general results tend to indicate that the energy product is not an elastic commodity and demand is not very sensitive to prices. The degree of inelasticity varies based on the data used and the analysis period.

B&V utilized two approaches to estimate the price elasticity for California demand by sector – the regression approach and the survey approach. Both show that the monthly California natural gas consumption is not very responsive to price signals.

Monthly residential, commercial and industrial consumption in California was utilized in the regression estimates of price elasticity. As shown in Figure 2-19, B&V regression estimates are slightly lower than estimates from EIA[8] and RSTEM[9] for the residential and commercial sectors and similar to EIA for the industrial sector. Estimates from the Baker Public Institute[10] are utilized in the Energy Commission long-term NARG modeling and seem to be significantly higher than other estimates.

	Residential	Commercial	Industrial	Power Generation	Total
Black & Veatch	-0.025	-0.025	-0.04	0	
EIA	-0.04	-0.04	-0.03	-0.045	
CEC/Baker Public Institute	-0.227	-0.214	-0.185	0	
Other Sources (RSTEM)	-0.042	-0.055	-0.269	-0.138	-0.137

Figure 2-19: California Consumption by Sector

B&V also surveyed major industrial consumers in the state of California to evaluate the industry's estimate of their elasticity to price in California. The survey was sent out to 40 firms and the survey responses received uniformly indicate that there is little demand flexibility in responding to natural gas prices in the short-run, either due to equipment or technology constraints.

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8. EIA Short-Term Energy Outlook

9. EIA Regional Short Term Energy Model

10. California Energy Commission Analysis

2.4.2. Regression Based Monthly Demand Analysis

Methodology Overview

Regression analysis is a statistical method to associate the variation of a variable (the dependent variable) with other variables (independent variables) hypothesized to have predictive power over the dependent variable. Regression analysis has been utilized in other studies to analyze and predict demand trend for natural gas, such as the National Petroleum Council study in 2003 and Baker Institute of Public Policy Study of natural gas demand in 2006. These analyses typically analyze annual national or state consumption while B&V's analysis focused on California demand by sector and utilized monthly data to understand seasonal pattern of demand.

B&V analyzed and forecast core (residential and commercial) demand and industrial demand in California using a regression based approach. The regression models were structured using historical monthly core and industrial consumption in California from EIA as dependent variables and regressing them against relevant variables obtained from government agencies, industries and other public sources, such as National Oceanic and Atmospheric Administration, Bureau of Economic Analysis, Bureau of Labor Statistics and US Census Bureau.

The models were structured and estimated using a step-wise approach. First, the list of relevant variables was identified based on economic reasoning for the specific consumption sector. The regression model was then estimated using one variable at a time, starting with the variable with the highest correlation with the dependent variable. Additional variables were added and the model re-estimated. The variable was retained in the model if it improved the overall R-square or dropped if it was not found to be significant. Data related model inefficiencies, such as co-linearity were eliminated using an appropriate statistical approach.

The forecast for future consumption using the regression approach was produced by making reasonable assumptions about the independent variables, such as weather and the economic growth rate.

Monthly Residential and Commercial Demand

Residential and commercial demand is responsible for two-thirds of natural gas demand in the US and about half of the demand in California. The demand comes from space heating at homes and commercial buildings. Therefore, it has a dramatic seasonal pattern that peaks in the coldest months in winter.

The independent variables that were chosen to analyze residential and commercial demand include:

1. Heating Degree Days (HDD), which is an indicator of winter weather. The analysis utilized average HDDs calculated from temperatures at the Los Angeles airport, Sacramento airport and San Francisco airport. The data was obtained from NOAA via the Energy Velocity database.

2. Lag of natural gas prices. B&V utilized the first of month (FOM) prices published by Platts Gas Daily at SoCal Topock and PG&E Citygate. These are wholesale natural gas prices at southern and northern California.
3. Lag of residential and commercial demand. As a time series analysis, possible serial correlation is incorporated by including the lag of the dependent variables in the regression equation.
4. Gross State Product, Per Capita Gross State Product, Real Income and Industrial Production Index. These economic indicators are tested for the income effect on gas consumption.

As expected, weather has the most significant impact on residential and commercial demand and can explain more than 90% of demand variations. The previous month's consumption and natural gas price were the other variables that were found to be significant. The variables representing macro-economic environment or personal income or California population were not significant in the regression.

The final regression model is summarized in Figure 2-20.

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.986
R Square	0.973
Adjusted R Square	0.972
Standard Error	0.060
Observations	90

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	4	11.158	2.789	769.253	0.000
Residual	85	0.308	0.004		
Total	89	11.466			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	6.957	0.446	15.587	0.000	6.070	7.845
Previous Month's Consumption	0.305	0.025	12.256	0.000	0.256	0.355
Average California FOM Natural Gas Price lagged one month ($/MMBtu)	-0.024	0.012	-1.957	0.054	-0.049	0.000
Derived California HDDs	0.002	0.000	30.245	0.000	0.002	0.002
IP Index - Lagged *	0.093	0.080	1.161	0.249	-0.066	0.253

Figure 2-20: Regression Model, Source: B&V Analysis

B&V utilized the final regression model shown in Figure 2-20 to forecast the residential and commercial demand in the future. The forecast was based on 30-year normal weather from 1975 to 2005. The industrial production index is assumed to start at a level to match the most recent historical consumption and grow at an annual rate of 4.5%. The natural gas price assumption was based on prices projected by NARG fundamental analysis. Figure 2-21 is the comparison of B&V forecast of residential and commercial demand along with forecasts from EIA AEO 2007 and Energy Commission Preliminary Report dated July 2007. B&V forecast is relatively similar to Energy Commission forecast in later years but starts at a higher level than the Energy Commission forecast, resulting in a smaller growth rate.

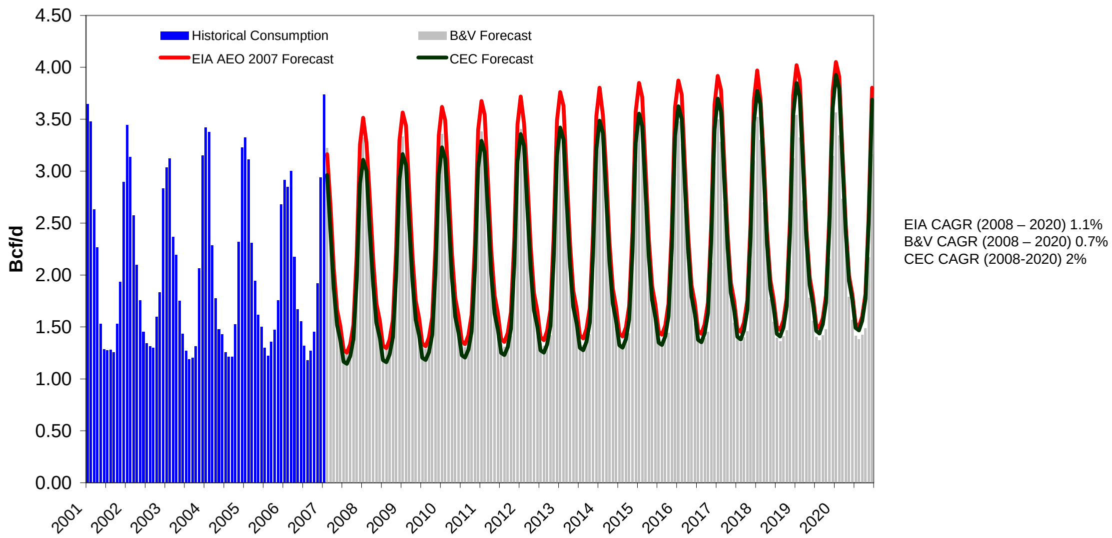


Figure 2-21: California Core Demand Forecast, Source: EIA, Energy Commission, B&V Analysis

Monthly Industrial Demand

Industrial demand is the natural gas consumed by the industrial sector for fuel, feed stock and other purposes. It has experienced a significant decline in the US market, from about 37% of total natural gas consumption in 1997 to 30% in 2006. The decline can be contributed to several factors, including relatively higher natural gas prices, the economic downturn and restructuring of the global industrial market with significant production moving overseas

The explanatory variables that were picked for the industrial demand model include:

- Seasonality. A dummy variable to indicate the summer season (April to October) or the winter season (November to March).
- Ratio of natural gas price to alternative fuel oil price (No 2. distillate). This is the measure of relative cost of natural gas vs. other fuels. The natural gas price is the average FOM price at SoCal Topock and PG&E city gate and the distillate price is the average monthly price from EIA.
- Lag of industrial demand. The previous month's consumption is incorporated in the model to eliminate serial correlation.
- Industrial Production Index, an indicator of production growth. The data is obtained from the Federal Reserve. An industrial production index for the natural gas intensive industry was constructed and compared to the total production as an indicator of the relative strength of the natural gas intensive industry.

The previous month's industrial demand is the most significant factor in the regression model, followed by industrial production index and the ratio of natural gas price to alternative fuel price. However, when both the latter variables are in the model, the price variable becomes statistically insignificant due to the high correlation between the industrial production index and the natural gas price.

An instrumental variable approach is applied to eliminate the co-linearity problem following a two-step process: First, a regression model of industrial production index is run on the relative fuel cost variable. The residual from the regression model is calculated. Second, the industrial demand model is run on the industrial production index residual and other variables.

The regression results from the instrumental variable regression model are shown in Figure 2-22. The model shows that the natural gas price influences total industrial gas consumption mainly through reducing production from natural gas intensive industries.

The forecast of industrial demand is based on the assumed average growth rate of 0.3% per year of natural gas intensive industrial production index to the total industrial production index – this assumption reflects the historical average growth rate for the past five years. B&V forecasts indicate that natural gas industrial demand is expected to grow minimally over time.

Figure 2-23 shows the B&V industrial demand forecast along with the EIA AEO 2007 forecast and Energy Commission preliminary forecast. The Energy Commission forecast indicates a weak decline, due partly from EOR decline. EIA is forecasting a weak growth. However, the difference between the forecasts is very small and industrial demand is essentially flat.

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.806
R Square	0.650
Adjusted R Square	0.634
Standard Error	0.060
Observations	71

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	0.455	0.152	41.506	0.000
Residual	67	0.245	0.004		
Total	70	0.700			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	5.022	1.209	4.152	0.000	2.608	7.436
Previous Month's Consumption	0.531	0.113	4.700	0.000	0.305	0.756
IP Residual	0.699	0.304	2.301	0.025	0.093	1.306
Natural Gas Price / No 2 Distillate	-0.011	0.022	-0.489	0.626	-0.054	0.033

Figure 2-22: Instrumental Variable Regression Model of Industrial Demand, Source: B&V Analysis

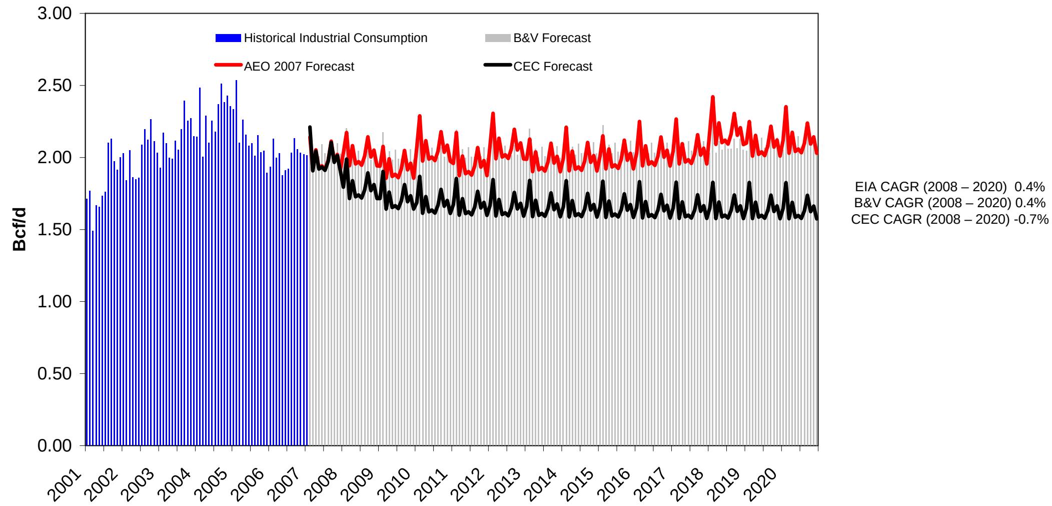


Figure 2-23: California Industrial Demand Forecast, Source: EIA, Energy Commission, B&V Analysis

2.4.3. Dispatch-based Electricity Demand Analysis

Natural gas is a very important fuel source for power generation plants in California. It accounts for almost half of California's total natural gas consumption. Natural gas is the source that fuels more than 40% of California's power generation and its demand is highly dependent on the overall demand for electricity and the availability of power generated from other sources.

B&V utilized a fundamental electricity dispatch model to forecast future natural gas demand in California from the electric sector. The power grid market simulation model incorporates a detailed database of generators and their operational parameters such as heat rate, O&M cost, and reliability for the entire Western Energy Coordinating Council (WECC) region. Aggregated transmission lines between major power consumption markets are incorporated to capture capacity exchange within the Western region.

Based on the inputs of annual and monthly electricity demand by market area, the model generates an hourly load profile. The model solves for a market driven supply stack and determines the market clearing price based on each unit's variable and fixed costs and the economic selection of additional generation resources to satisfy projections of load demand and reserve margin during the study time frame. Consumption of various fuels during the year is reported by state.

The model treats capacity additions as an investment decision and employs screening curves to determine the most economical generation unit type that must be added in order to satisfy additional load and reserve requirements in each year.

Power Generation Forecast

The major California power service territories are included in the B&V WECC model: Imperial Irrigation District (IID), Los Angeles Department of Water & Power (LADWP), Modesto Irrigation District, Northern California Power Agency, PacifiCorp, Pasadena WPD, PG&E North, PG&E South, Sacramento Municipal Utility District (SMUD), Southern California Edison (SCE), SDG&E, Silicon Valley Power and Turlock Irrigation District.

The analysis assumes that the electric load growth follows the assumptions in the "California Energy Demand 2008-2018 Staff Draft Forecast", released on July of 2007. Current regulation on the Renewable Portfolio Standard (RPS) is utilized to account for the renewables' share in the electricity mix (i.e., 20% of IOU sales are assumed to be from renewables by 2010 with a three-year grace period, under the 2003 Energy Action plan adapted by the Energy Commission and the California Public Utilities Commission (CPUC)). Although the latest Integrated Energy Policy Reports (IEPR) in 2005 and 2006 recommends expanding the targets to 33% by 2020, B&V's analysis assumes that the renewables share in the electricity mix stays flat at 20% as indicated by currently adopted policy initiatives The annual renewable generation amount was obtained from the following source: "Scenario Analysis of California's Electric System: Preliminary Results for the 2007 Integrated Energy Policy Report", Case 1B. The analysis assumes that there is no new coal in-state generation or new coal imports from out-of-state that do not meet California's emissions standards.

B&V utilized an integrated approach in the analysis where natural gas prices from the base NARG analysis are integrated as a key input into the fundamental power model.

Figure 2-24 shows B&V's estimate of gas consumption in California. The growth rate is consistent with Energy Commission's but starts from a slightly higher level, resulting in an overall higher consumption of 300 MMcf/day by 2020.

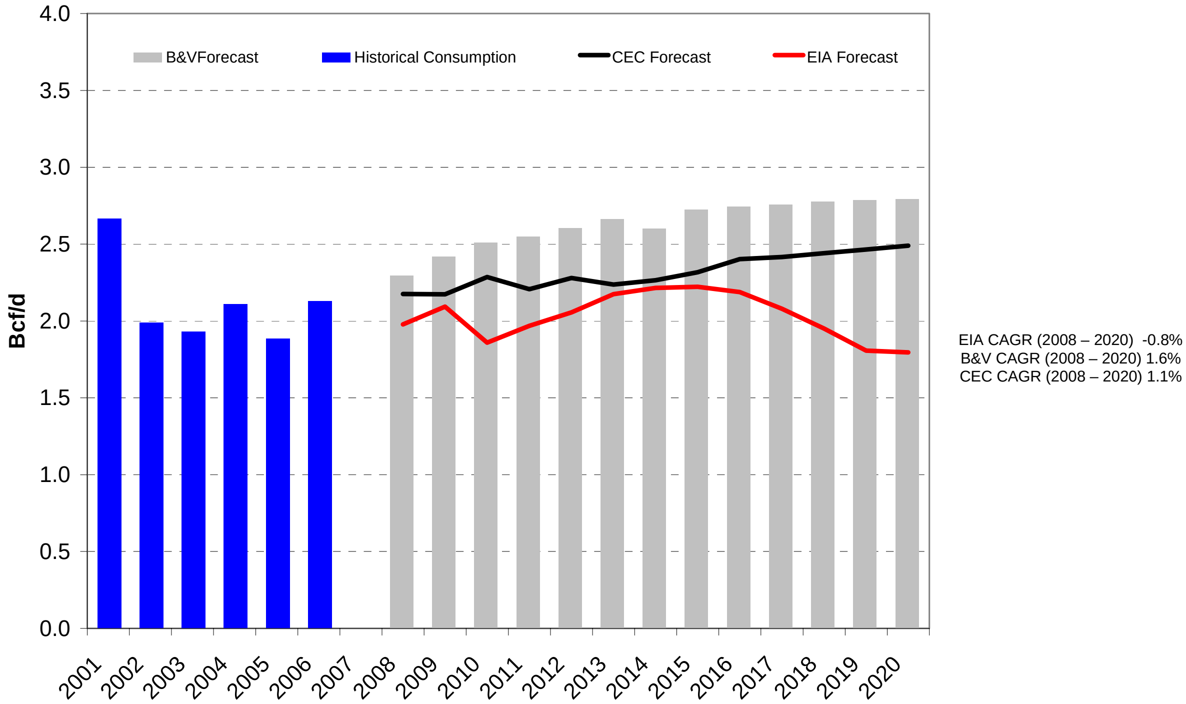
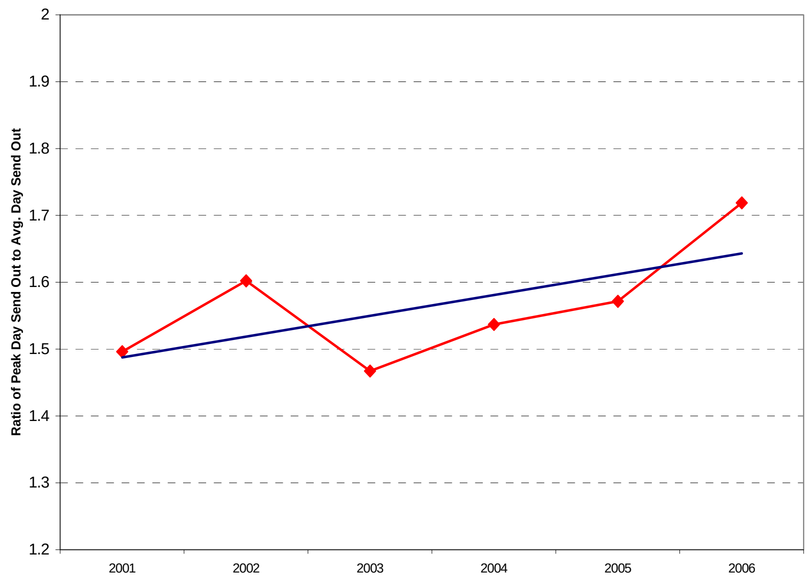


Figure 2-24: Estimated California Gas Consumption, Source: EIA, Energy Commission, B&V Analysis

2.4.4. Peak Day Demand Analysis

The forecasts generated from the fundamental market analysis using NARG and the electricity dispatch model provides projections of monthly average demand. Daily variations in demand drive higher supply requirements than reflected by monthly averages.

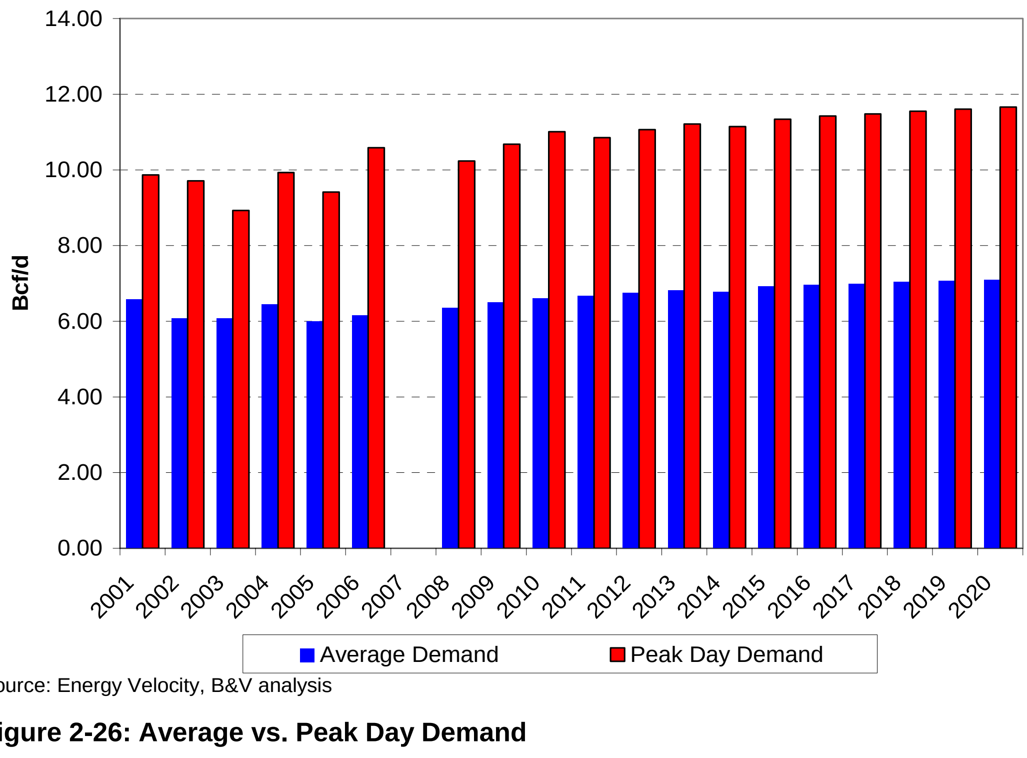
B&V utilized daily send-out data from SoCal, PG&E, Kern and Majove pipelines to approximate the peak day demand. The ratios of annual peak-day demand to average annual demand and summer peak day to summer average demand were calculated for the period of 2001 to 2006. Figure 2-25 shows the ratio of peak day demand to annual average demand.



Source: Energy Velocity, B&V analysis. The analysis is based on system send-out on PG&E, Socal and end-user send-out on Kern, the total accounts for 88% to 94% of CA consumption

Figure 2-25: Growth in Peak Day Demand to Annual Average Demand Ratio

Utilizing the average ratio of peak day to annual average demand, B&V estimated that California peak day demand, under normal operating conditions, will grow from current levels to almost 12 Bcf/day by 2020 as shown in Figure 2-26.



Source: Energy Velocity, B&V analysis

Figure 2-26: Average vs. Peak Day Demand

2.4.5. Aggregate Growth in Natural Gas Demand

Total demand for natural gas in California is expected to rise, led by the growth in demand from the power generation sector, from the current winter peak month demand of 8.5 Bcf/day to 10.5 Bcf/day in 2020, as shown in Figure 2-27. The CAGR for the period of 2008 to 2020 is expected to be 1.2% per annum.

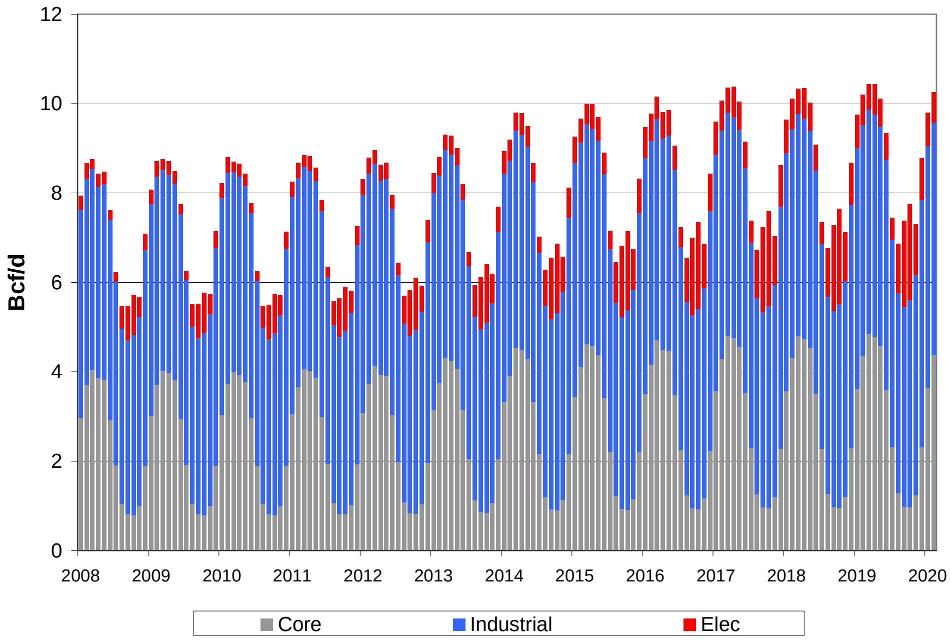


Figure 2-27: California Demand for Natural Gas, Source: B&V Analysis

B&V utilized the EIA AEO 2007 demand forecast for the remaining Lower 48 states. Total Lower 48 demand (including California) in the peak winter month is expected to grow from 80 Bcf/day in 2008 to reach 90 Bcf/day by 2020, with a CAGR of 1% per annum, as shown in Figure 2-28.

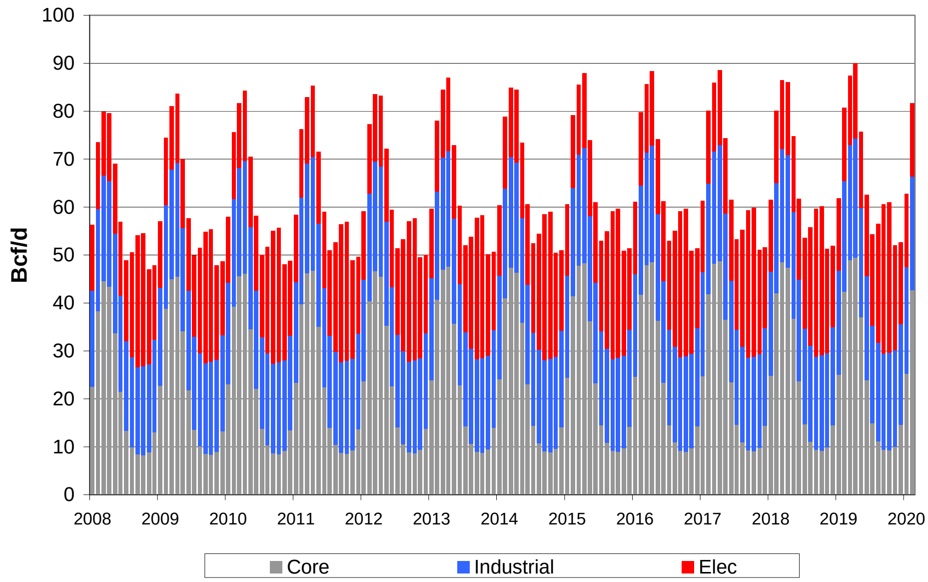


Figure 2-28: Lower 48 Demand, Source: B&V Analysis

2.5. Baseline Projections for Natural Gas Prices

B&V projections indicate that natural gas prices across North America average close to $7.00/MMBtu (million British thermal units) in 2008, declining to $6.40/MMBtu by 2013, before rising back close to $7.00/MMBtu by 2020 in the baseline analysis. Prices in both southern and northern California are expected to remain at relatively high levels over this time period. The commissioning of LNG regasification terminals on the West coast and the completion of the Alaska pipeline are expected to moderate prices.

2.5.1. Expectations for Natural Gas Prices at Henry Hub

Henry Hub prices are expected to average $7.14/MMBtu in 2008, falling to $6.94/MMBtu by 2020. A comparison with other forecasts as shown in Figure 2-29 indicates that B&V's forecast in the baseline analysis is lower than the current New York Mercantile Exchange (NYMEX) Futures curve, but higher on average than the EIA AEO 2007 and Energy Commission 2007 forecasts.

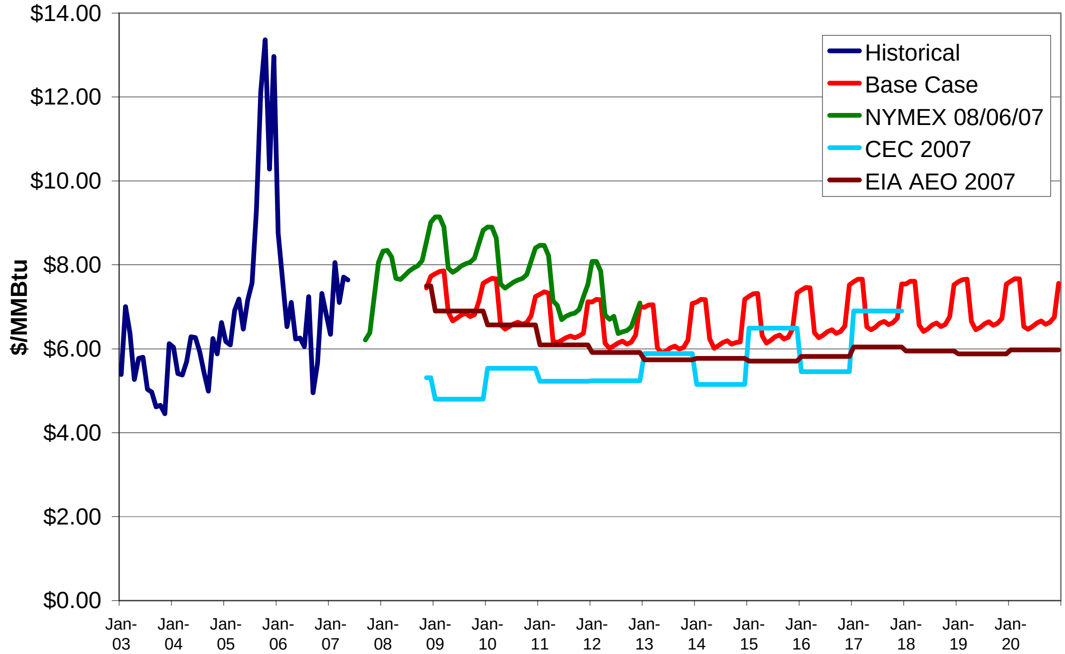


Figure 2-29: Henry Hub Price Forecast,[11] Source: Platts, Energy Commission, NYMEX, EIA and B&V Analysis

2.5.2. Expectations for Natural Gas Prices in Southern California

The SoCal price is expected to average $6.90/MMBtu in 2008, falling to $6.71/MMBtu by 2020. Compared to the Energy Commission 2007 forecast, the B&V forecast is higher in the 2008-2013 time frame, with both forecasts following an upward trend through 2018, as shown in Figure 2-30.

11. B&V, EIA, California Energy Commission and NYMEX forecasts are in 2008 dollars.

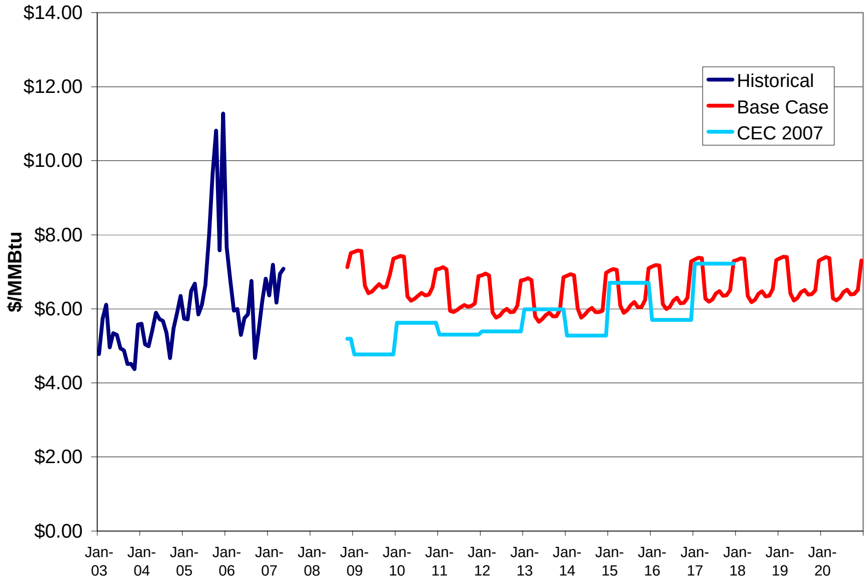


Figure 2-30: SoCal Price Forecast, Source: Platts, Energy Commission and B&V Analysis

The SoCal basis to Henry Hub, shown in Figure 2-31, is expected to tighten over the analysis period as new supplies reach the Gulf Coast, moderating the Henry Hub price. Demand growth in California and other western states will drive prices up, also tightening the basis to Henry Hub.

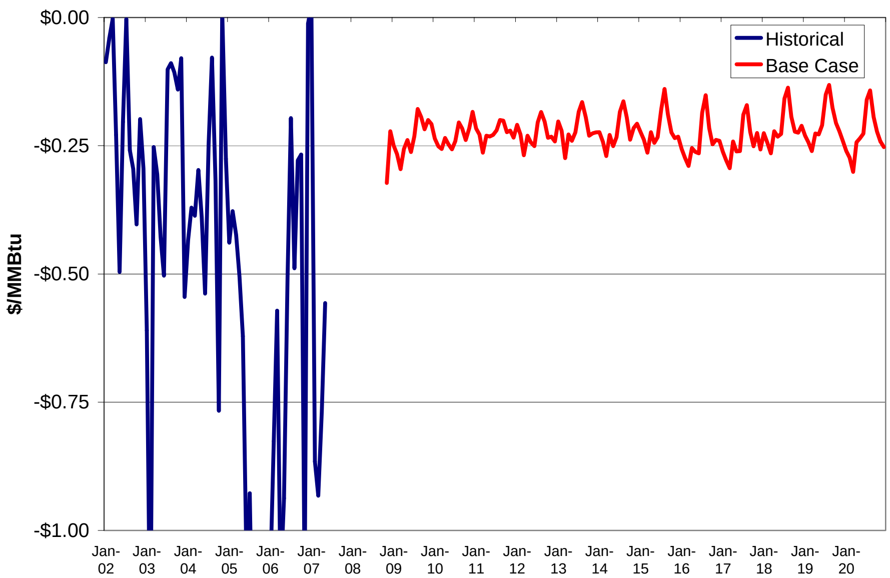


Figure 2-31: SoCal Basis Forecast, Source: Platts and B&V Analysis

2.5.3. Prices in Northern California

The PG&E Citygate price is expected to average $7.14/MMBtu in 2008, falling to $6.93/MMBtu by 2020, as shown in Figure 2-32. The PG&E price will be dependent on supplies from WCSB, or any additional LNG supplies into the Pacific Northwest. Canadian demand growth or the delay of LNG supplies into the West Coast may drive prices higher.

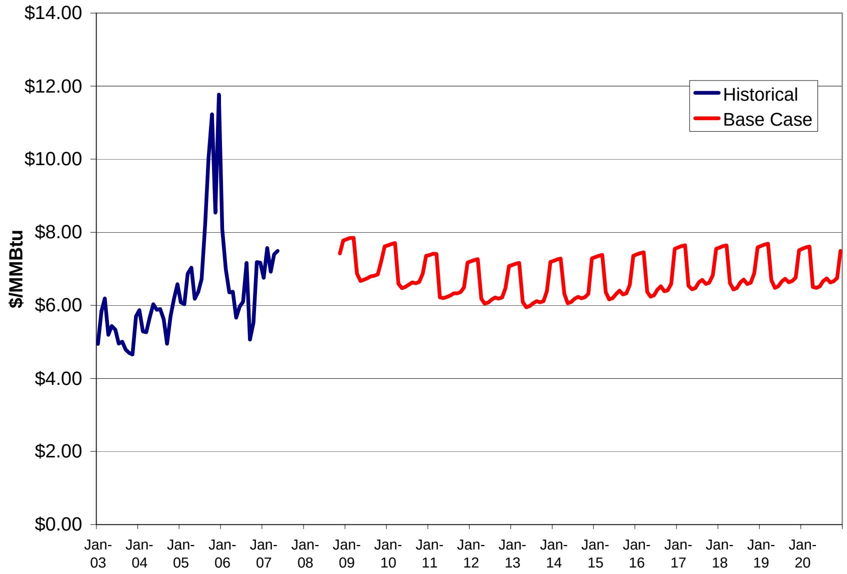


Figure 2-32: PG&E City Gate Price Forecast, Source: Platts and B&V Analysis

The PG&E Citygate basis to Henry Hub will continue to rise due to the growth in demand in California. Additional LNG supplies into the Gulf Coast will lower prices, causing the PG&E Citygate basis to rise, until additional LNG supplies reach the West Coast by 2015. The PG&E Citygate basis reaches $0.13/MMBtu before retreating to $0.01/MMBtu by 2020.

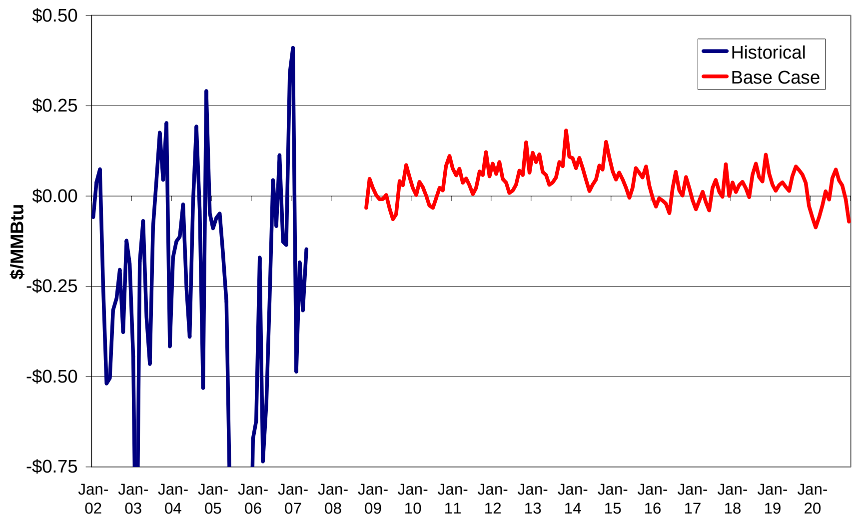


Figure 2-33: PG&E City Gate Basis Forecast, Source: Platts and B&V Analysis

2.6. Expectations for Pipeline and Storage Utilization

2.6.1. Gas Transmission Northwest

Pipeline flows on GTN into California, shown in Figure 2-34, are expected to continue to decline in the near term. Pipeline imports from Canada are expected to fall due to production declines in WCSB, coupled with demand growth in Eastern Canada. Pipeline flows on GTN are expected to decline until additional LNG supplies reach the Pacific Northwest in 2015. A Pacific Northwest LNG terminal could provide additional supplies to California and use underutilized pipeline capacity. Additional supplies from Alaska to Alberta could replace the declines in WCSB, and bring supply into California.

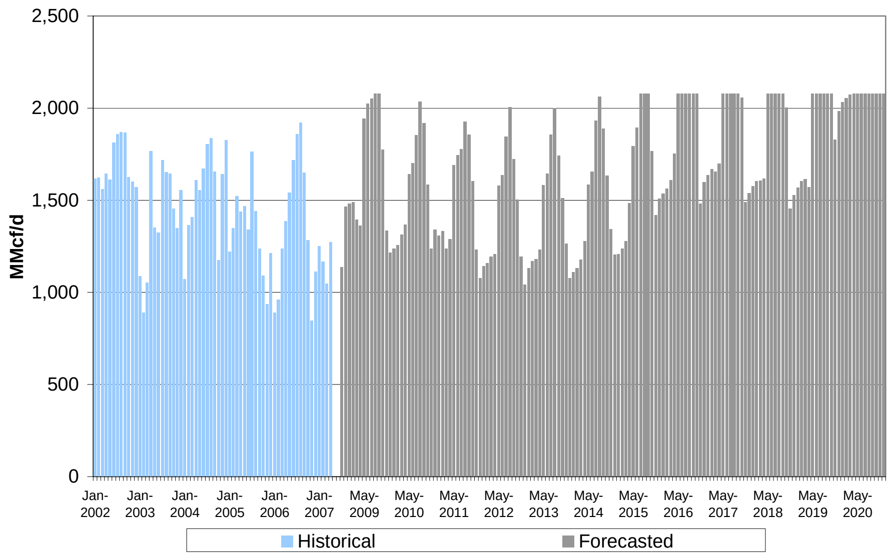
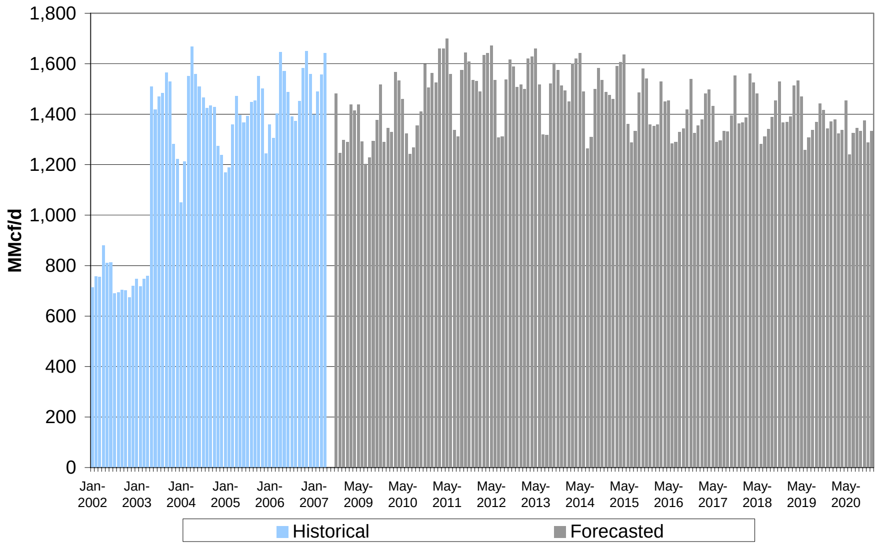


Figure 2-34: GTN Pipeline Flows, Source: Lippman Consulting and B&V Analysis

2.6.2. Kern River

Gas flows on Kern, shown in Figure 2-35, are dependent on the production growth and additional take away capacity expansions in the Rockies. Rockies production is expected to grow from 8 Bcf/day in 2008 to 11 Bcf/day by 2020. The REX pipeline will add 1.8 Bcf/day of additional take-away capacity, with the remaining additional production moving to other markets. Kern River pipeline is expected to deliver 1.4 Bcf/day on average to California, to serve both the summer power generation load, and the winter residential and commercial peak demand.

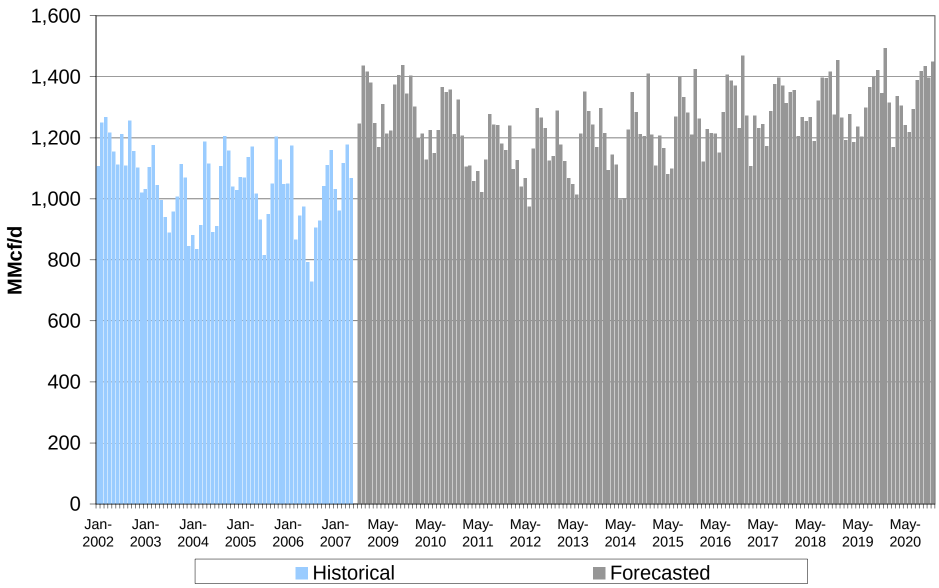


Source: Lippmann Consulting, LEG/B&V Analysis

Figure 2-35: Kern River Pipeline Flows

2.6.3. El Paso Pipeline

Gas flows on the northern El Paso pipeline into California at Topock, shown in Figure 2-36, are expected to range from 1.3 to 1.6 Bcf/day during the analysis period. Gas supplies from the San Juan basin, as well as flows from the Rockies into San Juan, use this pipeline to reach the California market.



Source: Lippmann Consulting, LEG/B&V Analysis

Figure 2-36: El Paso North Pipeline Flows

Gas flows into California from the El Paso pipeline at Ehrenburg, shown in Figure 2-37, are expected to remain low due to the decline in production in the Permian basin, and the demand growth in Texas, Arizona, and New Mexico. LNG flows into California on the Baja pipeline may displace pipeline flows on the El Paso system.

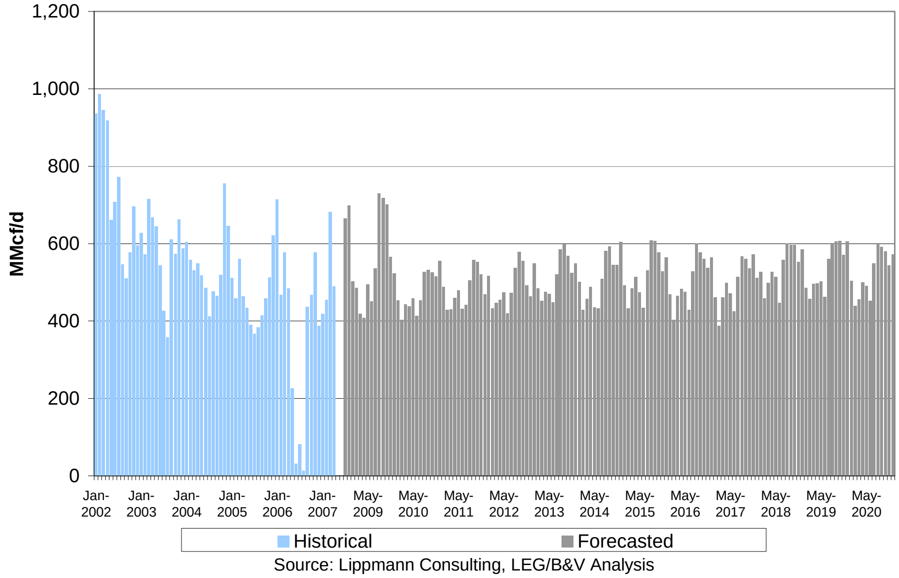


Figure 2-37: El Paso South Pipeline Flows

2.6.4. Transwestern Pipeline

Transwestern pipeline flows into California, shown in Figure 2-38, are expected to oscillate from 0.5 Bcf/day to 0.8 Bcf/day during the analysis period. The growth in flows is driven by the production growth in the Rockies as well as the growth in California demand. The firm transportation (FT) rate on Transwestern will make it the marginal supply into California, and allow new incremental supplies to displace pipeline flows on Transwestern to other markets.

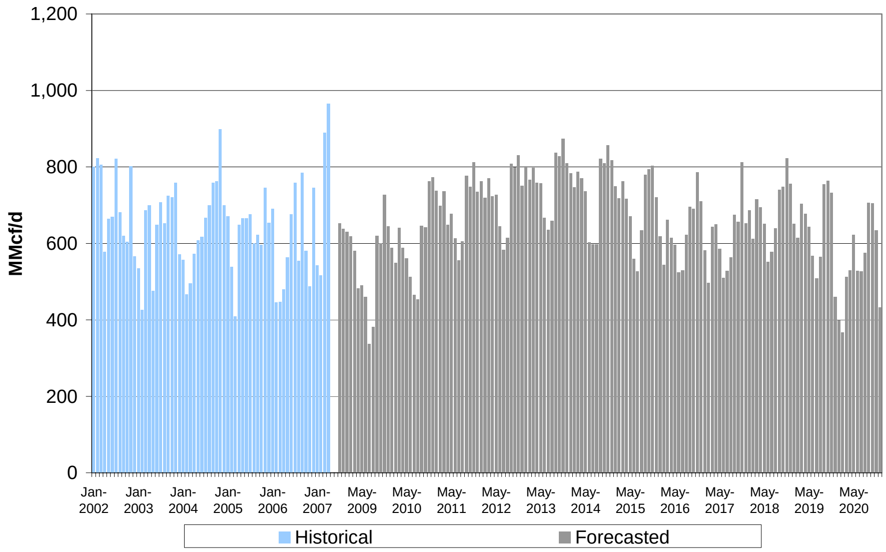


Figure 2-38: Transwestern Pipeline Flows, Source: Lippman Consulting and B&V Analysis

2.6.5. California Storage Utilization

In the NARG model, storage injections and withdrawals are dependent on the expected winter-summer spreads as well as the winter summer peak demand projections. Existing storage capacity and inventory in California is expected to be recycled up to 50%. This is due to the normal weather assumption, the average monthly demand profile, and excess capacity in the baseline analysis. This utilization pattern is consistent with historical observations of past three years.

Storage injections for the state are expected to primarily occur in the shoulder months, April-May and September-October. During peak summer months, gas is primarily supplied to gas fired power generators for the cooling load. During peak injection months, injections average almost 1.0 Bcf/day. Storage withdrawal in California is expected to primarily occur in December, January and February. Peak withdrawal is expected to be almost 1.2 Bcf/day.

In the baseline analysis, storage utilization in California is expected to slightly increase over the analysis period due to demand growth in the residential and commercial sector. The growing peak month demand in winter season will require more gas supplies from storage inventory.

3.0 Analysis of California Wholesale Market Responses to Changes In Natural Gas Supply and Demand

The baseline NARG analysis illustrates the natural gas demand and supply balance associated with the baseline assumption on demand growth and production expectation. There are several uncertainties associated with the assumptions in the baseline analysis. For example, population growth or economic growth could be higher or lower than assumed, weather could be different from normal, IOUs in California may be unable to achieve their renewable goals or production growth could be lower or higher depending on the rate of technology development or reserve discoveries.

Sensitivity analysis quantifies the range of uncertainties associated with major drivers and addresses their individual and/or combined impact to natural gas market prices. This analysis examines the impact of long-term variation in the fundamental factors that have the largest impact on the California natural gas market. Short-term changes in supply or demand such as those that may be caused by natural or man-made calamities are not modeled.

3.1. Analysis of Major Drivers that Impact Natural Gas Supply Demand in California

B&V's methodology to analyze the major drivers that impact the natural gas demand and supply in California involved a four step process.

1. Define the likely fundamental drivers and the distribution of their values using a P10, P50 and P90 range. Define a correlation structure between the fundamental factors in a correlation matrix.
2. Selected NARG scenarios are run to understand the relationship between California prices and the fundamental drivers.
3. Extract an analytical function from the NARG runs to approximate the relationship between California prices and fundamental driver.
4. Draw a large number of random realizations of fundamental drivers. Use the analytical functions to obtain a large number of simulated equilibrium prices.

3.1.1. Identification of the Fundamental Drivers for California

The main fundamental drivers that impact the California natural gas market are supply and demand driven and are summarized below. Major changes in these fundamental drivers will have a positive or negative impact on California's long term natural gas prices.

1. WCSB Production - WCSB production currently produces 16 Bcf/day, which serves Canadian gas demand and is imported via pipelines to the West Coast, Mid-West and East Coast. Due to growing production costs to replace reserves, production is expected to decline. The rate of decline will have a major impact on prices across North America and in California.

2. Residential and Commercial Demand - Demand in California and the other Western states can exceed 5 Bcf/day in the peak winter months. Population growth and changing weather patterns may impact the natural gas demand in the winter months, as well as the amount injected in the summer months for California and the Western states.
3. Natural Gas Demand from Power Generation - Demand in California and the other Western states can exceed 6 Bcf/day in the peak summer months. To meet renewable standards, new gas fired power plants may or may not be needed relative to the baseline assumptions. The uncertainty of the generation stack to meet the changing cooling loads will drive the demand for natural gas to serve the power plants.
4. Rockies Production – Production in the Rockies region is one of the fastest growing production regions in North America. Currently, the Rockies are producing over 8.5 Bcf/day, with expectations that production will continue to grow once additional take-away capacity is constructed. By 2010, the REX will bring an additional 1.8 Bcf/day of take-away capacity into the Midwestern U.S.. Expansions on both Kern and Northwest pipelines may also provide additional take-away to the West Coast market. Rockies production growth will depend on future market conditions and pipeline expansion plans for additional take-away capacity.
5. San Juan and Permian Basin Production – These production basins are two relatively stable and mature production regions. Together, they produce over 7.8 Bcf/day, serving California, Southwest and West Texas demand. Analysis of drilling and production activity indicates that more wells are being drilled to sustain the current production levels. Future production declines may be expected if producers in the basin slow down exploration and production activity or natural gas reserves continue to decline.
6. LNG imports will be the marginal natural gas supply into North America. The global LNG market will influence the level of imports into the United States. New regasification facilities are currently under-construction in the Gulf Coast, with many others proposed or in the process of seeking Federal Energy Regulatory Commission (FERC) approval.

3.1.2. Sensitivity of Fundamental Drivers

Range of Uncertainty for WCSB Production

The range for each fundamental driver is determined by a probability distribution where a P90, value would indicate a 10% chance that the fundamental driver could exceed the value for that particular year. A P10 value would indicate a 10% chance that the fundamental driver would fall below the value for that year. The baseline assumption will be considered the P50 likelihood of occurrence.

The WCSB fundamental driver range, as shown in Figure 3-1, is derived from two sources. The P10 values are based on a 2003 NEB forecast for the production basin. The P90 values are derived from the baseline analysis (P50 values) and the expected decline rate. Under a high price environment, the decline rate may not be a fast as expected in the base case. The P90 values are based upon a slower expected decline rate than the baseline assumption.

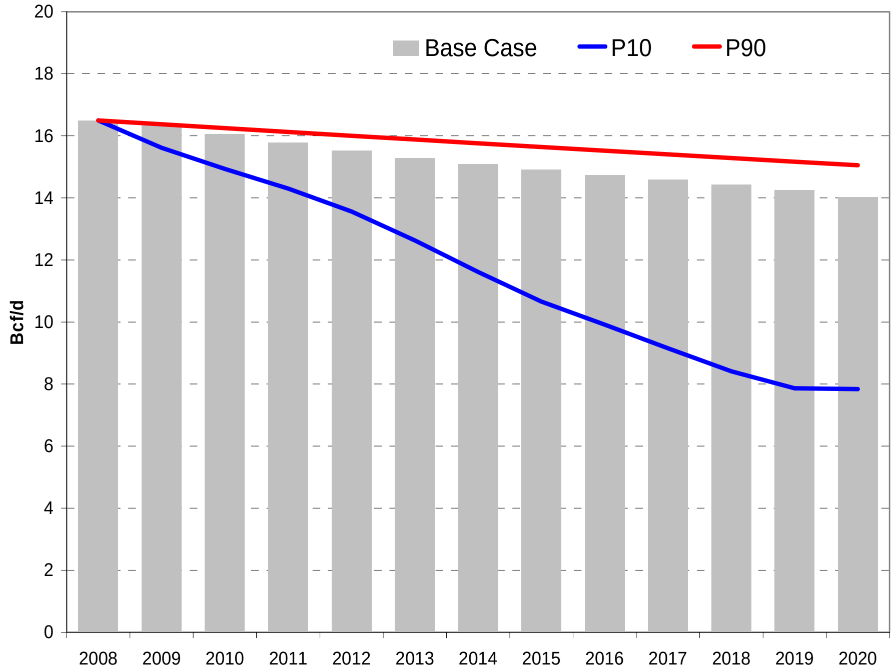


Figure 3-1: Assumptions for WCSB P90-P10 Range, Source: B&V Analysis

Range of Uncertainty for Residential and Commercial Demand

The fundamental driver range for residential and commercial demand for California and the Western states, as shown in Figures 3-2 and 3-3, are derived from weather analysis from the past thirty years. Using regression analysis, the P90 values are based on the coldest winter in the past 30 years. The P10 values are based on the warmest winter in the past 30 years. The baseline assumptions, P50 values, are based on normal weather.

Note that these assumptions, and the corresponding analysis competed by B&V, does not assume that California will experience consistent year after year hotter or colder than normal weather. The results from using these assumptions are utilized to understand the prices and infrastructure requirements within a year that experiences the conditions assumed.

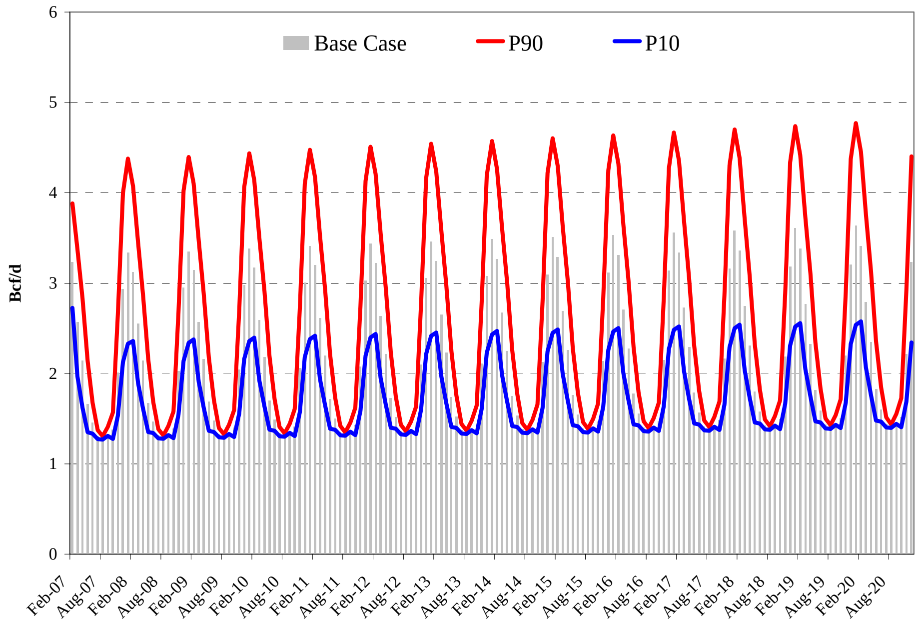


Figure 3-2: Assumptions for California Residential and Commercial Demand, Source: B&V Analysis

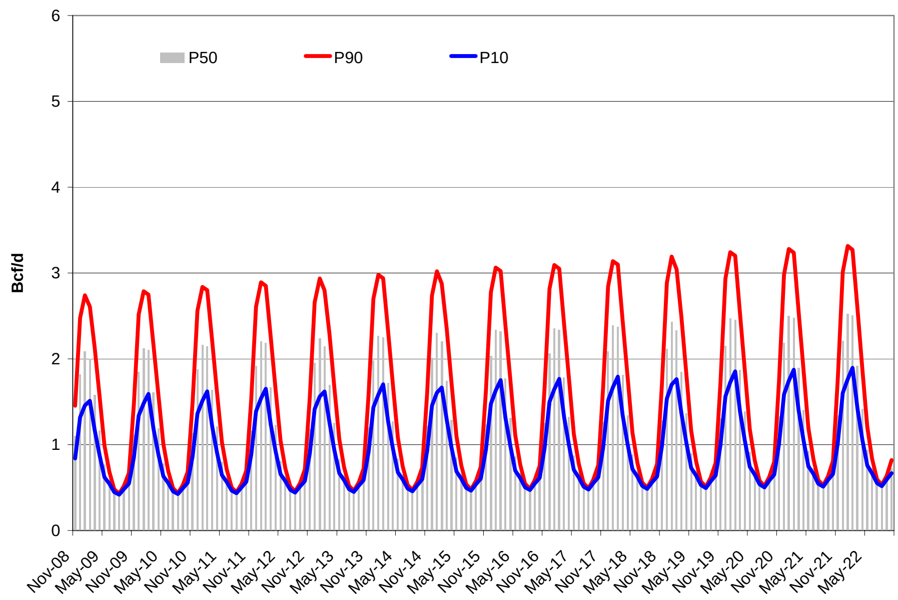


Figure 3-3: Western States Residential and Commercial Demand, Source: B&V Analysis

Range of Uncertainty for Natural Gas Demand from Power Generation

The fundamental driver range for California demand for gas fired generation, as shown in Figure 3-4, is derived from the state's renewable portfolio standards, weather, and efficiency gains. The baseline analysis value (P50) is based on B&V's analysis on the Energy Commission forecast of total load growth, the state's current RPS plan and normal weather. The P90 values are based on the expectation of higher load growth due to population, the state's failure to reach their current RPS goals, and warmer than normal summers. The P10 values are based on higher than expected efficiency gains, a more stringent RPS legislation, and a milder than normal summer. For the Western states, the ratio of the P90 and P10 value to the P50 values in the California market were applied to the P50 values for the Western states to reach the P90-P10 values, as shown in Figure 3-5.

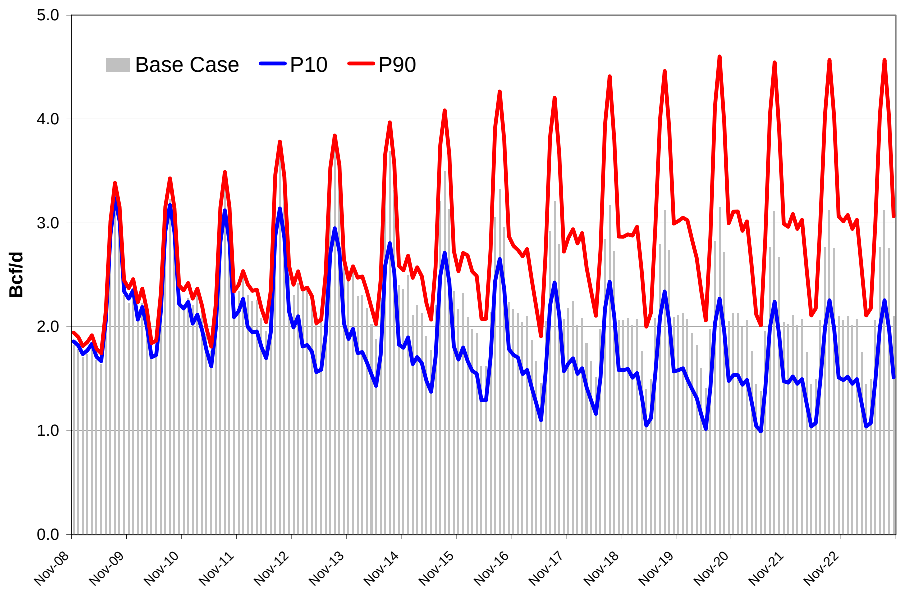


Figure 3-4: California Demand for Gas Fired Generation, Source: B&V Analysis

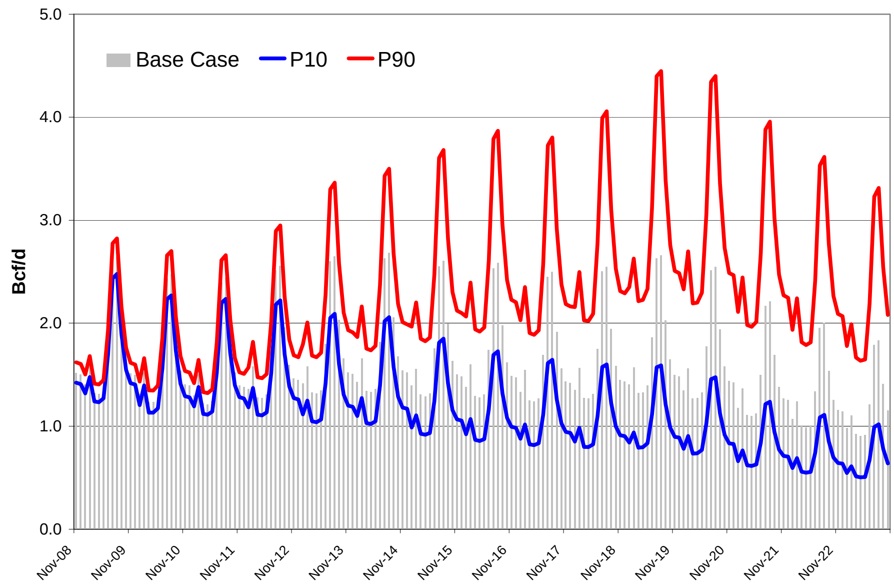


Figure 3-5: Western States Demand for Gas Fired Generation Source: B&V Analysis

Range of Uncertainty for Rockies Production

The fundamental driver range for Rockies production, as shown in Figure 3-6, is based on two sources. The P10 values are based upon the Energy Commission's forecast of Rockies production in their preliminary report[12]. The forecast is relatively flat with little or no growth from current production levels. The P90 values are based on historical production growth rates in the region from 2002-2006. With the increased growth in production, additional take-away capacity would be built to both the West Coast and the Mid-West.

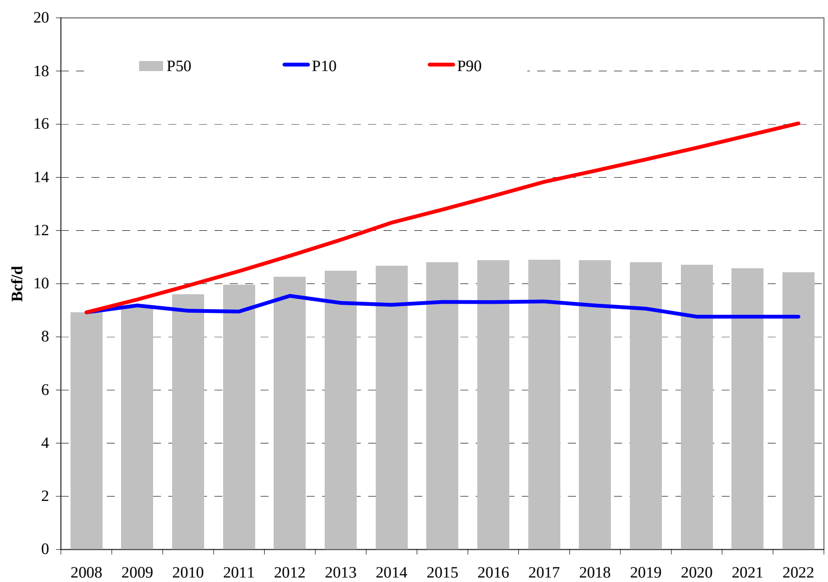


Figure 3-6: Rockies Production, Source: B&V Analysis

12. Natural Gas Market Assessment Preliminary Results May 2007

Range of Uncertainty for San Juan and Permian Basin Production

The fundamental driver range for the San Juan and Permian basins, as shown in Figure 3-7, is based on two sources - historical production rates and the preliminary Energy Commission report forecast[13]. The P10 values are based on the Energy Commission's forecast, which shows steep declines in production for the two production basins. The P90 values are based on historical growth rates for unconventional production from the Rockies. New technology may allow producers to develop shale production in San Juan or Permian basins.

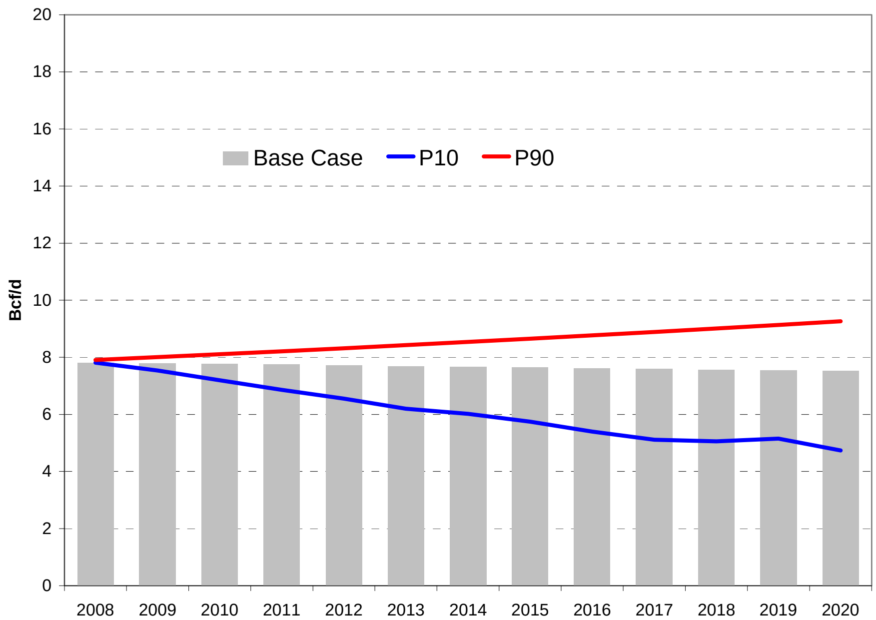


Figure 3-7: San Juan and Permian Basin Production, Source: B&V Analysis

Range of Uncertainty for North American LNG Imports

The fundamental driver range for LNG, as shown in Figure 3-8, is derived from the preliminary Energy Commission report[14] and recent historical LNG terminal utilization. The P90 values are from Energy Commission's forecast of LNG imports to Lower 48 states, with the majority of volumes reaching the Gulf and East Coasts. The P10 values are based on historical utilization of existing LNG terminals. Low utilization of LNG regasification capacity would occur if worldwide liquefaction was delayed or higher priced markets attract LNG cargoes. Due to the intense public scrutiny of LNG terminals, it is possible that no new LNG terminals will be sited on either the East or West coasts.

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13. California Energy Commission: Integrated Energy Policy Report 2007

14. California Energy Commission: Integrated Energy Policy Report 2007

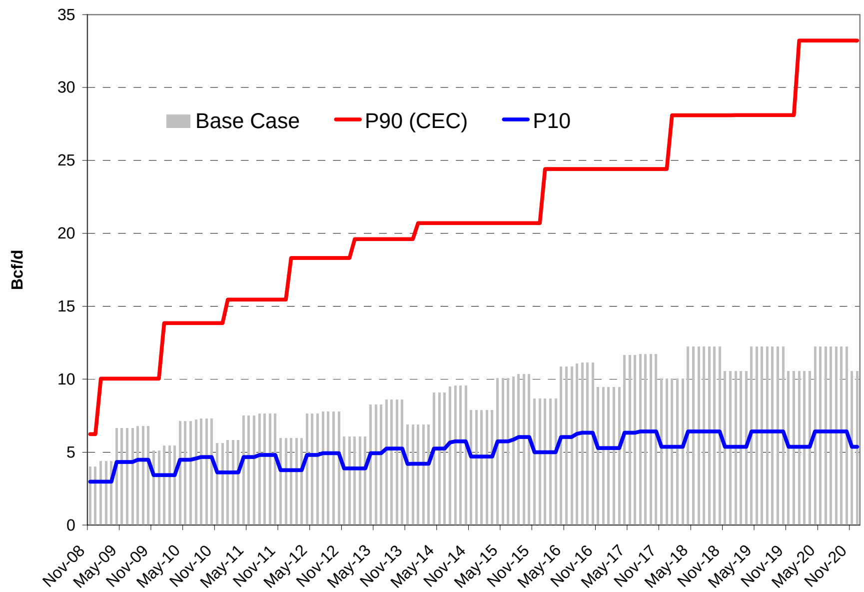


Figure 3-8: LNG Imports into the Lower 48 States, Source: Energy Commission and B&V Analysis

3.1.3. Developing Future Scenarios through Variations in Key Drivers

The analysis assumed a log normal distribution for all fundamental drivers. The P10, P50 and P90 range were revised slightly to maintain consistency with the distribution assumption. A correlation matrix of fundamental factors was constructed to develop the NARG sensitivity cases as shown in Figure 3-9.

	LNG	Core Demand	Power Gen Demand	Rockies	San Juan and Permian	WCSB
LNG	1.00	0.25	0.25	-0.50	-0.25	-0.25
Core Demand	0.25	1.00	0.25	0.00	0.00	0.00
Power Gen Demand	0.25	0.25	1.00	0.00	0.00	0.00
Rockies	-0.50	0.00	0.00	1.00	0.75	0.25
San Juan and Permian	-0.25	0.00	0.00	0.75	1.00	0.25
WCSB	-0.25	0.00	0.00	0.25	0.25	1

Figure 3-9: Correlation of Fundamental Factors, Source: B&V Analysis

The correlation assumptions are based on analysis of applicable historical data and expert opinions. While changes can occur over time to the correlations, B&V assumes that such changes would have minimal impact on the results. In Figure 3-9, the North American production is negatively correlated to LNG import volumes, but positively correlated to each production basin. Gas demand for power generation is weakly correlated to LNG because higher LNG imports will lead to lower prices and make gas fired generation a more cost efficient option.

Using the correlation matrix and the P10-P90 ranges from the fundamental factors, B&V developed random scenarios using statistical methods to cover the fundamental space. These scenarios were used to develop an analytical relationship between prices and each fundamental factor. Using the established relationship, B&V simulated the different fundamental factors, and obtained a large number of simulated equilibrium prices. A distribution of equilibrium prices summarized these random realizations.

3.1.4. Northern California Natural Gas Prices and Impact to Changes in Fundamental Drivers

As shown in Figure 3-10, the most significant factors that affect the PG&E Citygate price are LNG imports, power generation demand, and WCSB production. Significant volumes of LNG imports would impact price levels across all of North America. WCSB production has traditionally been the main source of supply to northern California. Fluctuations in power generation and core demand are significant drivers to prices in California. Power generation requirements in California and the western states will have a significant impact on the PG&E system.

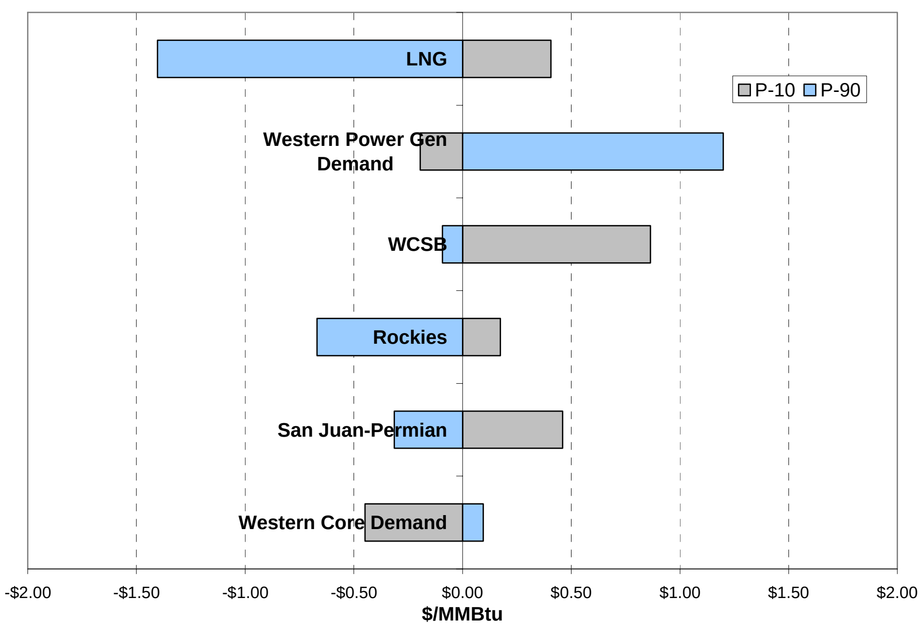


Figure 3-10: Impact of Fundamental Drivers on PG&E prices in 2020, Source: B&V Analysis

The PG&E Citygate prices exhibit increasing uncertainty over time due to variations in the fundamental drivers, as shown in Figure 3-11. The simulated PG&E Citygate prices also indicate a growth in the seasonal spread through time.

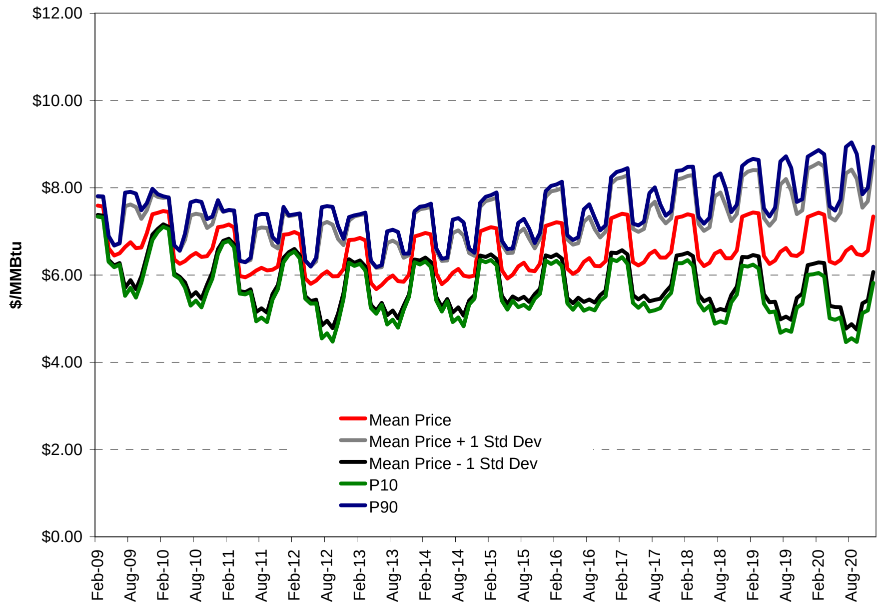


Figure 3-11: PG&E Price, Source: B&V Analysis

3.1.5. Southern California Natural Gas Prices and Impact to Changes in Fundamental Drivers

Besides LNG imports, the fundamental factors that have the most significant impact on SoCal prices are Rockies production and San Juan and Permian production, as shown in Figure 3-12. Due to its proximity to the Rockies and San Juan basins, the SoCal price is influenced more by production than demand factors. Supply variations in San Juan /Permian impact California due to the typical excess capacity available on the El Paso and Transwestern pipelines.

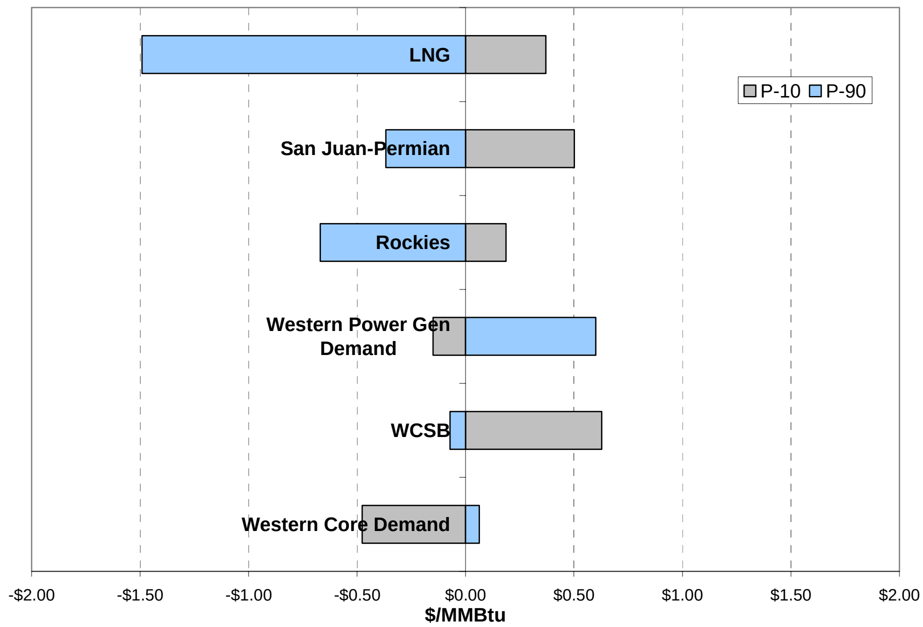


Figure 3-12: Fundamental Driver's impact on SoCal prices in 2020, Source: B&V Analysis

SoCal prices also show increasing uncertainty, but have a lower range of distribution than PG&E prices. The demand fundamental factors do not have as large an impact on SoCal prices as they have on PG&E prices.

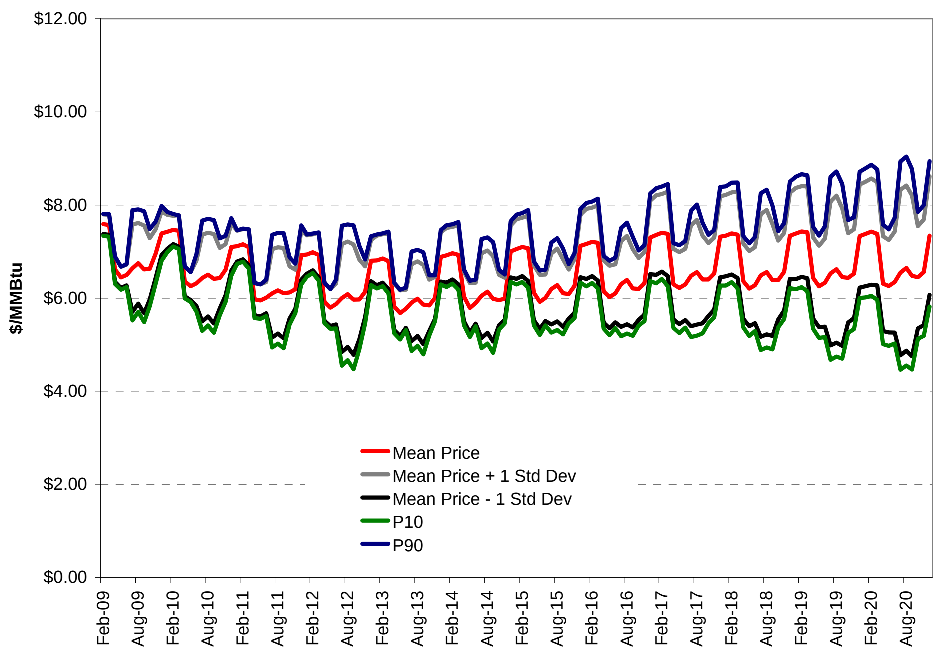


Figure 3-13: SoCal Prices, Source: B&V Analysis

4.0 Infrastructure Needs to Meet Growing California Natural Gas Demand

4.1. Analysis Methodology

The fundamental market analysis B&V conducted illustrates future supply and demand balance of the California market under the assumed average monthly demand profile. However, the underlying assumption that the daily load within a month is uniformly and evenly allocated underestimates California's true supply or infrastructure needs on a daily basis, given the range of fluctuations in real load dispatch. With low elasticity of demand, sufficient infrastructure and supply assets are needed to meet demand during peak days each year.

B&V evaluated the sufficiency of the existing and projected California supply portfolio using projections of future daily load requirements. The analysis focused on different demand scenarios to highlight the possible fundamental factors that could drive additional asset and infrastructure needs for the state. Separate daily load profiles were generated for the state, the PG&E service territory and the combined SoCal/SDG&E service territory to illustrate potential regional supply constraints.

The daily demand profiles generated by B&V are dependent on publicly available historical data and weather assumptions. The load profiles were developed as a means to illustrate the range of daily fluctuations, given monthly demand forecasts, in order to stress test California's natural gas infrastructure. They do not take into account daily operational issues or customer consumption pattern changes and are not intended to replace or contradict detailed peak load forecasts completed by the major LDCs operating in the state of California.

For the scenarios where B&V identified additional infrastructure and supply needs, B&V estimated the comparative range of costs for major supply assets to meet these needs and reviewed conditions that influence the relative economics of these assets.

4.2. Daily Load Fluctuations – Historical Review

B&V utilized historical daily send out data on the SoCal and PG&E wholesale pipeline systems as well as daily flows to end use customers on the Kern River pipeline for the period of 2001 to 2006 to construct daily load duration curves for the state and the major LDC service territories. Since SDG&E does not have direct interconnects with interstate pipelines, the analysis of SoCal load incorporates SDG&E load. Results are presented for the three most recent historical years of 2004 to 2006. Total California daily load is approximated as the adjusted total of the SoCal system demand, the PG&E system demand, and deliveries to end use consumers on Kern.

Historical data shows that California is a winter-peaking market with most storage withdrawals in the winter months. December, January and February typically have the highest demand. The storage injection season typically runs from April to June and September to October with occasional withdrawals in July and August to meet demand from natural gas fired power generation.

During the past three years, the pipeline and storage capacity available was sufficient to meet California's daily demand. Average pipeline utilization factors were less than the 70% and annual storage withdrawals were 50% - 60% of total working gas capacity, as shown in Figure 4-1. The table shows the total volumes of natural gas withdrawn from storage for the SoCal, PG&E and the independent storage facilities as a percentage of their respective working gas capacities. It also shows the combined withdrawal of SoCal, PG&E and the independent facilities as a percentage of the total working gas capacity in California. Note that the independent storage facilities indicate withdrawals of more than 100% of their working gas capacity reflecting that they are able to cycle the gas in their storage facilities more than once during the storage year.

Year	Total Withdrawal Bcf	Total Injection Bcf	Inventory Change Bcf	Average Pipeline Load Factor (%)	Withdrawal as % of CA Capacity (%)	Withdrawal as % of Socal Capacity (%)	Withdrawal as % of PG&E Capacity (%)	Withdrawal as % of Independent Capacity (%)
2004	154	183	28	67%	60%	73%	44%	122%
2005	136	154	18	63%	53%	63%	41%	130%
2006	148	143	-6	67%	57%	70%	41%	114%

Figure 4-1: Storage Utilization, Source: SoCal, PG&E and B&V Analysis

4.3. Daily Load Projections

Using a combination of statistical regressions based on historical data and fundamental analysis of future demand, B&V forecasted average monthly consumption for the period of 2008 to 2020 by sector. In order to examine whether the California supply portfolio is sufficient to meet peak day demands in the future, the analysis developed annual daily load curves under different demand scenarios.

4.3.1. Extrapolation of Historical Daily Load Profile

In order to examine whether existing and expected California supply infrastructure can meet the peak demand days in the forecasted future, B&V extrapolated the historical load profile to approximate the daily load distribution under different scenarios. The extrapolation of the historical load profile was completed using two approaches.

The first approach is to average the daily load profile for the past three years. From the historical daily send out data, ratios of daily send-out to annual average send-out are calculated for each calendar day for 2004 to 2006. The ratios are ordered from the highest to the lowest and averages of the three years are taken as an average daily load profile for a given calendar year.

The second approach considers the impact of weather on load fluctuations. B&V first normalized the historical daily send-out data using the 30-year normal HDDs and cooling degree days to extract the sensitivity of daily load fluctuations with weather. A future high demand load curve was then constructed using a 30-year extreme weather assumption. From a planning perspective, if the supply portfolio is sufficient to meet daily load requirement under extreme weather conditions, it is likely that there will be sufficient supply to meet other weather conditions.

The two alternative approaches produced very similar shapes of daily load expectations. Therefore, throughout this chapter, results and analyses based on the second approach are presented.

4.3.2. Discrete Scenarios Considered for Daily Load Projections

The sufficiency of California supply and infrastructure was tested under four discrete demand scenarios that are summarized below. These demand scenarios, theoretically, are incorporated in the random scenarios generated in the analysis summarized in Section 3 of this Report.

1. Base Case:The average monthly and annual demand is the baseline level under normal weather assumptions. The state of California is able to meet its RPS targets of 20% by 2010. Industrial demand remains essentially flat.
2. High Core Demand: The State experiences the coldest winter experienced in the 30-year period from 1976 to 2006 with baseline demand from power generation.
3. High Power Generation Demand: The State does not meet its RPS targets of 20% by 2010. The efficiency gains on electricity consumption are low and the demand for electricity grows at 2.9%. Winter weather is assumed to be similar to the 30 year average.
4. High Core and Power Generation Demand: The State does not meet RPS targets. Efficiency gains on electricity consumption is flat, demand for electricity grows at 2.9%. California experiences the coldest winter experienced in the 30-year period from 1976 to 2006.

4.3.3. Daily Load Expectations for California

By 2015, the peak daily load in California ranges from 11 Bcf/day for the base case to 14 Bcf/day for the high core and power generation demand case, as shown in Figure 4-2. By 2020, peak day load grows, as shown in Figure 4-3, from 11.5 Bcf/day in the base case to around 16 Bcf/day for the high core and power generation demand case. Despite growth in the power generation demand for natural gas, peak day demand occurs during winter in both 2015 and 2020.

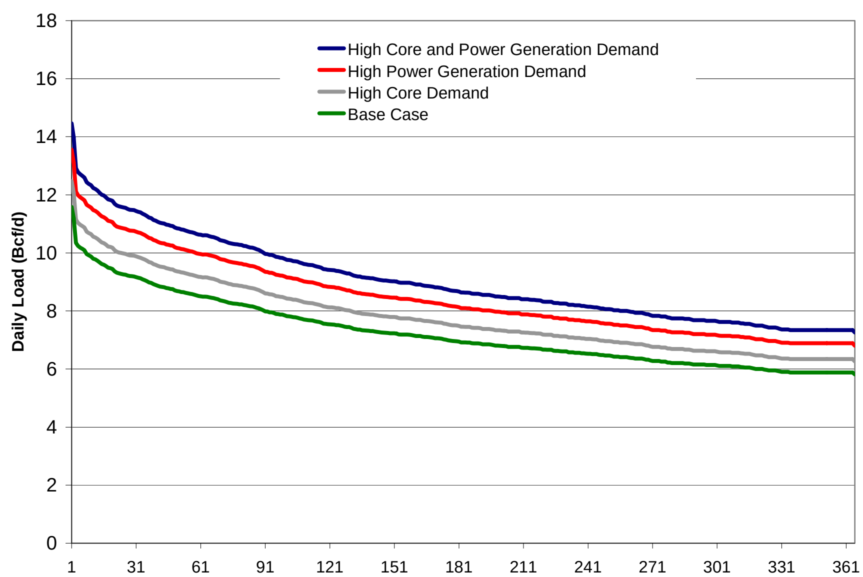


Figure 4-2: Total California Demand Load 2015, Source: B&V Analysis

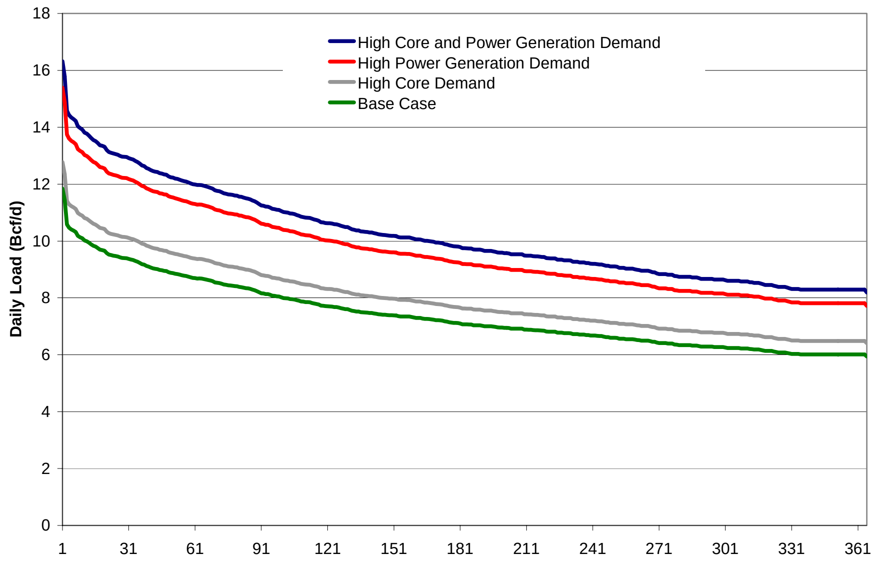


Figure 4-3: Total California Demand Load 2020, Source: B&V Analysis

4.3.4. Daily Load Expectations for PG&E Service Territory

As indicated by historical data, B&V assumed that the average PG&E and SoCal/SDG&E demand is about 35% and 49% of total California demand, respectively. The methodology used to derive a daily load curve for California was applied to estimate the daily load profiles for the service territories of PG&E and SoCal/SDG&E.

Figures 4-4 to 4-5 show the daily load forecast for PG&E under the four scenarios examined. PG&E's 2015 peak day demand ranges from 4 Bcf/day to 5.25 Bcf/day while its 2020 peak day demand increases from 4.25 Bcf/day to 6 Bcf/day.

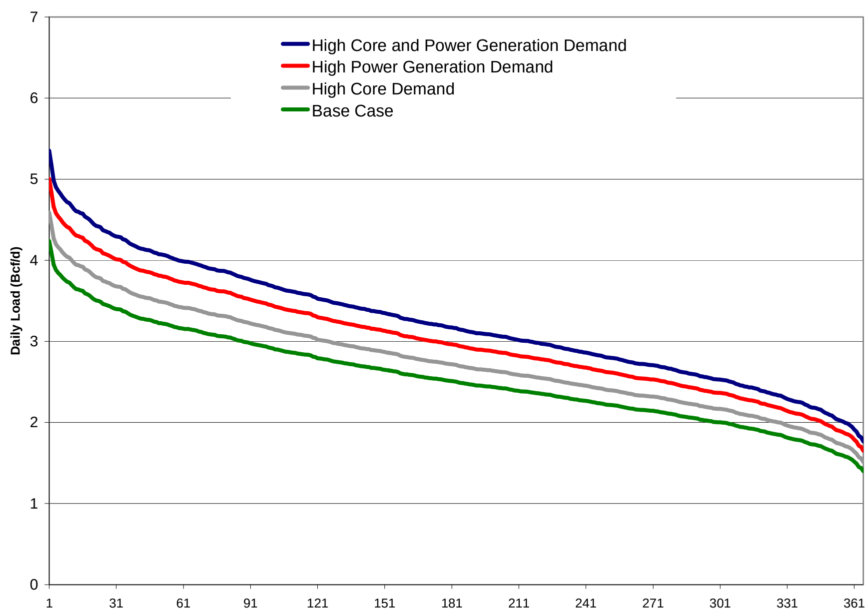


Figure 4-4: PG&E Daily Demand Load for 2015, Source: B&V Analysis

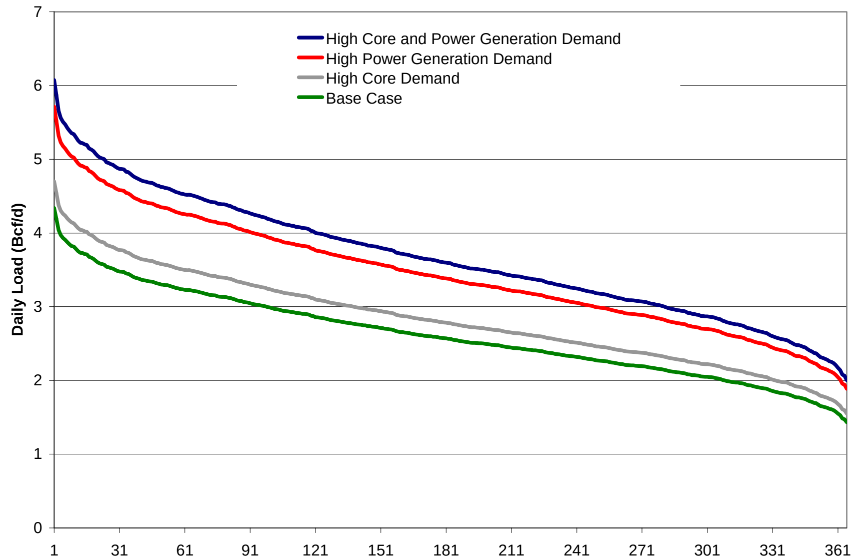


Figure 4-5: PG&E Daily Demand Load for 2020, Source: B&V Analysis

4.3.5. Daily Load Expectations for SoCal/SDG&E Service Territories

Figures 4-6 to 4-7 show the daily load forecast for SoCal/SDG&E under the four scenarios examined. For SoCal and SDG&E, the peak day demand in 2015 is expected to be between 5.8 Bcf/day and 7.2 Bcf/day and grow to 5.9 Bcf/day and 8 Bcf/day in 2020.

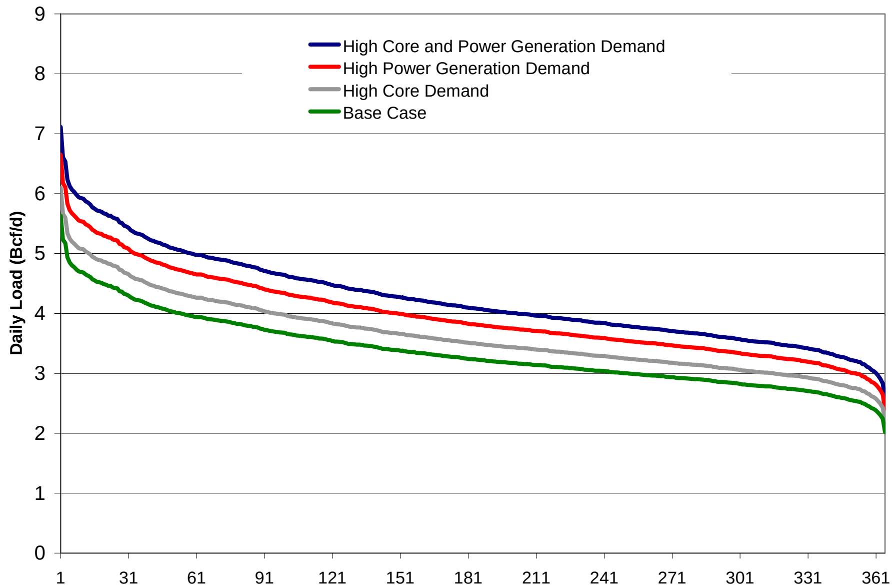


Figure 4-6: SoCal/SDG&E Daily Demand Load for 2015, Source: B&V Analysis

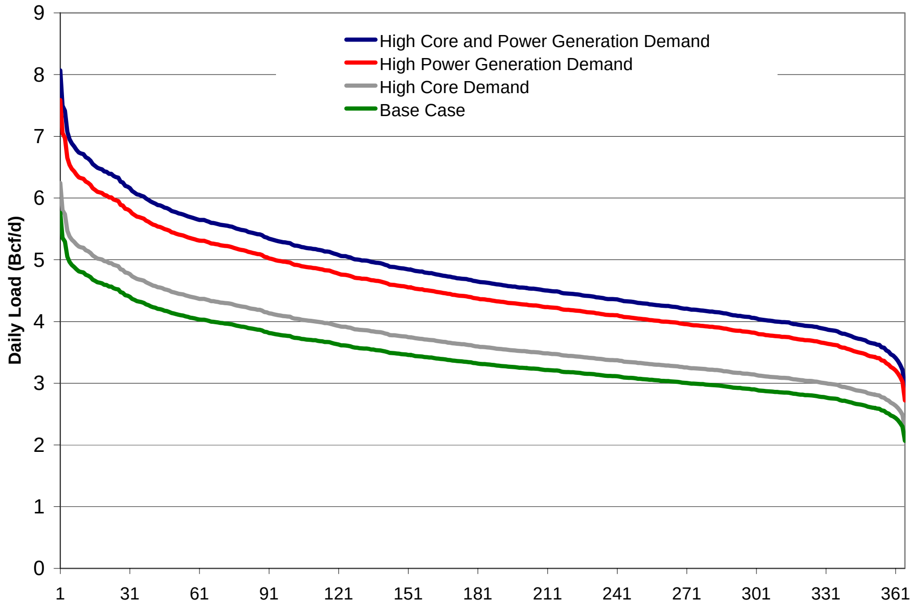


Figure 4-7: SoCal/SDG&E Daily Demand Load for 2020, Source: B&V Analysis

4.4. Supply and Infrastructure Needs to Meet Daily Load Expectations

Potential supply and infrastructure that could be used to meet daily load in the future in California include California in-state production, interstate pipeline deliveries from major production basins, deliveries from LNG terminals, seasonal storage inventories and/or other peaking facilities. B&V calculated the needs for additional infrastructure and supply assets using a bottom-up approach. Production and interstate pipeline and LNG deliveries are assumed as base load supply sources before any seasonal or peaking supplies are needed. For the four demand scenarios examined, B&V estimated the requirements for seasonal and peaking supplies beyond production and pipeline deliveries (including LNG) based on different load factor assumptions for interstate pipelines. Additional supply needs are assessed as the difference between existing storage capacity and the seasonal/peaking supply requirements.

Figure 4-8 indicates the expected supply sources for California, PG&E and SoCal/SDG&E service territories including proposed storage and LNG projects.

	CA	PG&E	Socal & SDG&E
Receipt Capacity (Bcf/d)	7.17	3.29	3.88
Direct Receipt from Mojave & Kern (Bcf/d)	0.83		
Direct Receipt from Tuscarora (Bcf/d)	0.10		
Production Access to Demand (Bcf/d)	0.40	0.15	0.25
Baja LNG (Bcf/d)	0.50		0.50
Subtotal	9.00	3.44	4.63
Storage (Bcf)	289	148	121

Figure 4-8: Expected Supply Sources for California, Source: B&V Analysis

4.5. Additional Natural Gas Supply or Infrastructure Needs for the State of California in 2015

Based on the availability of expected supply resources and the projected daily load for 2015, minimal additional supply sources are expected to be needed in the state under all demand scenarios if pipeline, production and LNG supply is 100% available on a daily basis. Figure 4-9 shows the supply and demand balance situation for 2015 under all scenarios. The estimated demand/supply is the total annual volume of gas required to meet California's demand during the year 2015 in the Base Case as well as the High Demand cases as estimated using the projected daily load profile. The available supply sources each day (excluding storage at this point) are interstate pipeline capacity, LNG and in-state production. The estimated demand/supply needs served by these three sources indicates the annual sum of the total volume of natural gas that is supplied each day by these three sources to meet the daily load profile. The estimated supply resource needs above pipeline capacity, LNG and in-state production represents the annual sum of any natural gas demand that is not met each day by the combination of these three sources. As seen in Figure 4-9, this supply gap ranges from 23 Bcf in the Base Case to 223 Bcf in the High Core and Power Generation Demand Case. Since the expected storage capacity is 289 Bcf, the 'supply gap' remaining after pipeline, LNG and in-state production are utilized is zero in 2015.

In order to determine whether the daily deliverability of the California natural gas infrastructure will be sufficient to meet the projected daily demand, the analysis examined the maximum deliverability needs on the peak day after deducting the interstate pipeline capacity, LNG and in-state production from the daily demand. As seen in Figure 4-9, the maximum deliverability needs on the peak day (before accounting for storage) ranges from 2.59 Bcf/day in the Base Case to 5.46 Bcf/day in the High Core and Power Generation Demand Case. The estimated storage deliverability of 7 Bcf/day is expected to be sufficient to meet California's deliverability needs on peak day in the demand scenarios considered.

There are two assumptions made in this analysis that are key to these conclusions. The first is that interstate pipeline, LNG and in-state production supply will be available each day at a 100% of its capacity. Due to various commercial and operational factors this theoretical assumption may not occur during normal operations. Section 4.5.2 examines the impact of the availability of these supply sources for less than 100% of their capacity during the year. The other assumption inherent in this analysis is that the pipeline and storage assets can be used concurrently when needed at their maximum capacity. In reality, when the pipeline system is fully utilized, the storage system is likely to be constrained as sufficient pipeline capacity will not be available to transport the gas from storage to end use customers. This analysis will be considered a conservative, or low, estimate of the needs for additional supply infrastructure in California. Any potential constraints in the intrastate pipeline system or within the LDC distribution system are also not considered within the scope of this study.

	Base Case	High Core Demand	High Power Generation Demand	High Core and Power Generation Demand
Estimated Demand/Supply Needs (Bcf)	2,641	2,847	3,093	3,298
Interstate Pipeline Capacity (Bcf/d) (100% Peak Util)	8.1	8.1	8.1	8.1
LNG (Bcf/d)	0.5	0.5	0.5	0.5
Estimated in-state Production Access to Demand (Bcf/d)	0.4	0.4	0.4	0.4
Estimated Demand/Supply Needs Served by Pipeline, LNG and In-state Production (Bcf)	2,618	2,786	2,956	3,075
Estimated Supply Resource Needs Above Pipeline Capacity, LNG and In-state Production (Bcf)	23	61	137	223
Storage Capacity (Bcf)	289	289	289	289
Additional Supply Resources Beyond Expected Storage Capacity	0	0	0	0
Est.Storage Deliverability (Bcf/d)	7.0	7.0	7.0	7.0
Max. Deliverability Needs above Pipeline Capacity, LNG and In-state Production (Bcf/d)	2.59	3.49	4.56	5.46
Average Deliverability Needs above Pipeline Capacity, LNG and In-state Production (Bcf/d)	0.64	0.87	1.24	1.46

Figure 4-9: Estimated California Daily Demand Load Requirement for 2015, Source: B&V Analysis

4.5.1. Additional Natural Gas Supply or Infrastructure Needs for the State of California in 2020

Figure 4-10 shows similar information for 2020. Due to demand growth over time, the supply needs in 2020 are significantly higher for the high power generation demand and high core and power generation demand cases. B&V estimates that 51 Bcf of additional supplies are needed in the High Power Generation Demand Case by 2020 after taking in to account the available supply from interstate pipelines, LNG and in-state production as well as the expected storage capacity. Similarly, 199 Bcf additional supplies are needed for the High Core and Power Generation Demand Case. As before, analysis shown in Figure 4-10 assumes that these supply sources will be available each day at a 100% of their capacity. The impact of their availability less than 100% of the time is examined in Section 4.5.2.

	Base Case	High Core Demand	High Power Generation Demand	High Core and Power Generation Demand
Estimated Demand/Supply Needs (Bcf)	2,701	2,913	3,510	3,723
Interstate Pipeline Capacity (Bcf/d) (100% Peak Util)	8.1	8.1	8.1	8.1
LNG (Bcf/d)	0.5	0.5	0.5	0.5
Estimated in-state Production Access to Demand (Bcf/d)	0.4	0.4	0.4	0.4
Estimated Demand/Supply Needs Served by Pipeline, LNG and In-state Production (Bcf)	2,669	2,835	3,171	3,236
Estimated Supply Resource Needs Above Pipeline Capacity, LNG and In-state Production (Bcf)	31	79	339	487
Storage Capacity (Bcf)	289	289	289	289
Additional Supply Resources Beyond Expected Storage Capacity	0	0	51	199
Est.Storage Deliverability (Bcf/d)	7.0	7.0	7.0	7.0
Max. Deliverability Needs above Pipeline Capacity, LNG and In-state Production (Bcf/d)	2.84	3.78	6.39	7.33
Average Deliverability Needs above Pipeline Capacity, LNG and In-state Production (Bcf/d)	0.72	0.94	1.67	1.87

Figure 4-10: Estimated California Daily Demand Load Requirement for 2020, Source: B&V Analysis

4.5.2. Reliance on Uninterrupted Natural Gas Supply or Infrastructure

As discussed in Section 4.5.1, 100% availability of interstate pipeline capacity may not be a sustainable assumption for each day of the year. The analysis presented in this section recreates the analysis in Section 4.5.1 but with assumptions of lower availability of interstate pipeline, LNG and in-state production assets. The total estimated supply/demand needs were assumed to be met by less than 100% utilization of the interstate pipelines, LNG and in-state production assets each day and the additional supply requirements was calculated before incorporating the estimated storage capacity. Figure 4-11 shows the additional supply requirements (or 'supply gap') for the four demand scenarios given different pipeline, LNG and in-state production utilization assumptions. Also shown on the chart is the estimated storage capacity of 289 Bcf. As shown in the chart, the supply gap increases as the availability of the interstate pipelines, LNG and in-state production decreases. When the supply gap lines are lower than the estimated storage capacity line, there is sufficient storage capacity to meet the supply gap. When the supply gap lines are above the estimated storage capacity line, the supply gap cannot be fully met by the estimated storage capacity. In the High Power Generation and High Core and Power Generation Cases, the supply gap exceeds the estimated storage capacity indicating that the available supply sources including storage will not be sufficient to meet daily demand requirements in these scenarios when the assumed sustainable pipeline, LNG and in-state production utilization rate decreases. As shown in Figure 4-12, the shortage in supply sources becomes significant by 2020 if less than 100% resource availability is assumed.

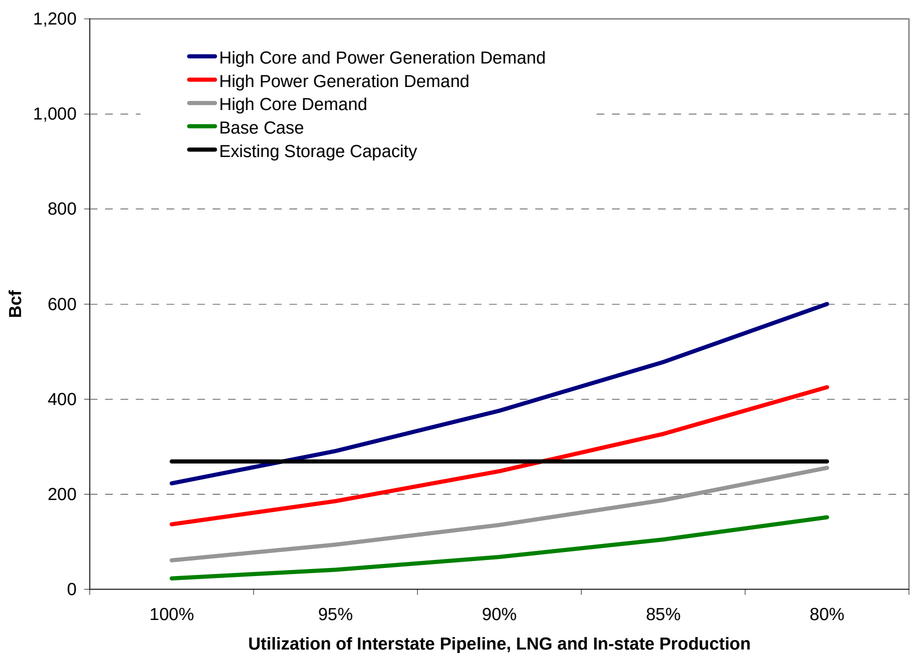


Figure 4-11: Additional Supply Requirements for California in 2015, Source: B&V Analysis

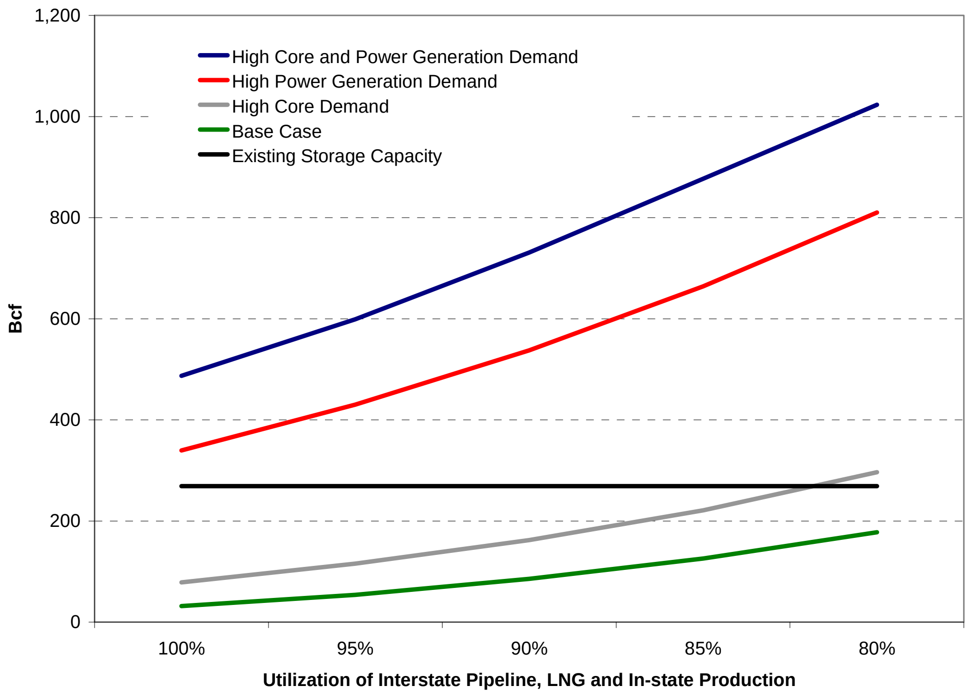


Figure 4-12: Additional Supply Requirements for California in 2020, Source: B&V Analysis

4.5.3. Additional Supply Needs for the PG&E and SoCal/SDG&E Service Territories

Figures 4-13 through 4-16 indicate the additional supply requirements for the SoCal/SDG&E and PG&E service territories under different demand scenarios. With the assumption of 100% pipeline, LNG and in-state production utilization factors, neither PG&E nor SoCal/SDG&E are expected to have substantial needs for additional supplies in 2015. When utilization can only be sustained at a lower rate, SoCal/SDG&E is expected to need additional supply if either core or power generation demand becomes higher than the base case.

By 2020, both PG&E and SoCal/SDG&E are expected to need substantial additional supply under the high power generation scenario. Moreover, the SoCal/SDG&E service territory is also vulnerable to higher than expected core demand. PG&E seems to have a slightly higher supply margin due to access to independent storage capacity.

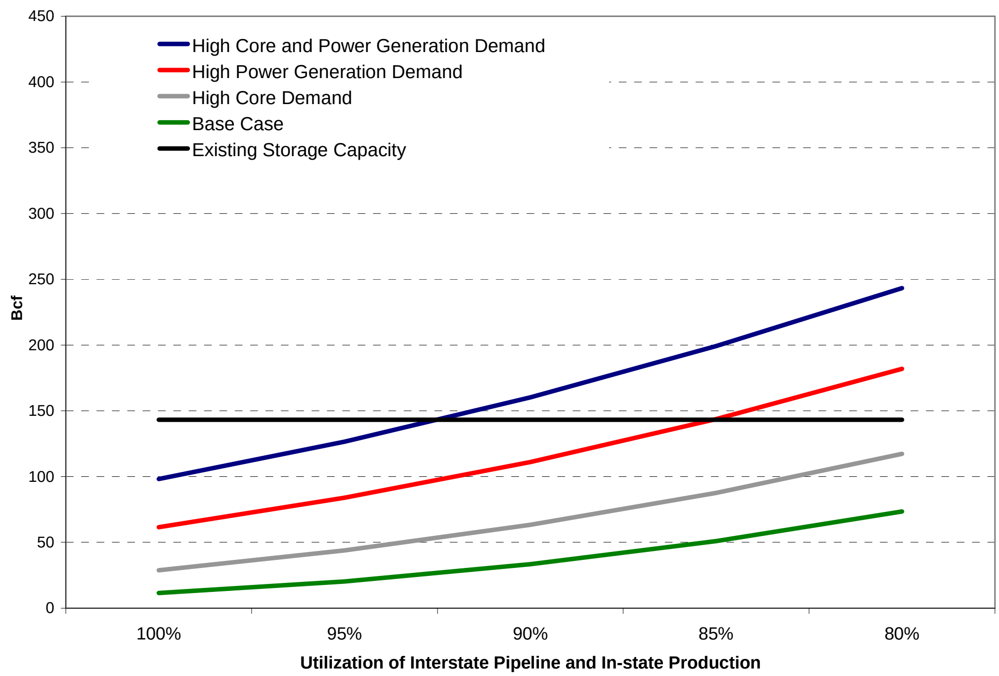


Figure 4-13: Additional Supply Requirements for PG&E for 2015, Source: B&V Analysis

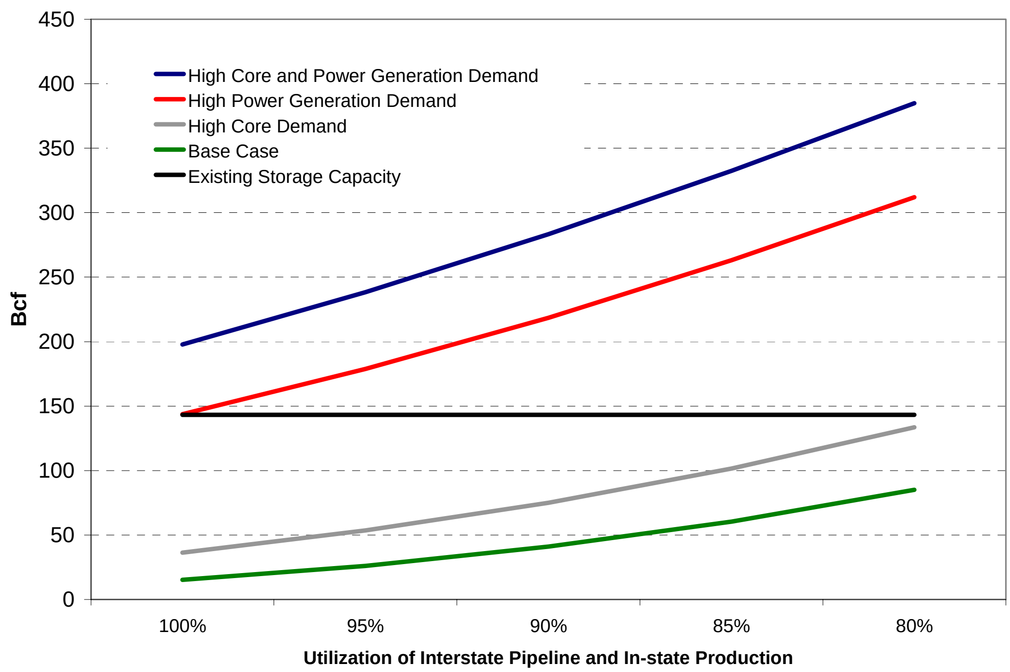


Figure 4-14: Additional Supply Requirements for PG&E for 2020, Source: B&V Analysis

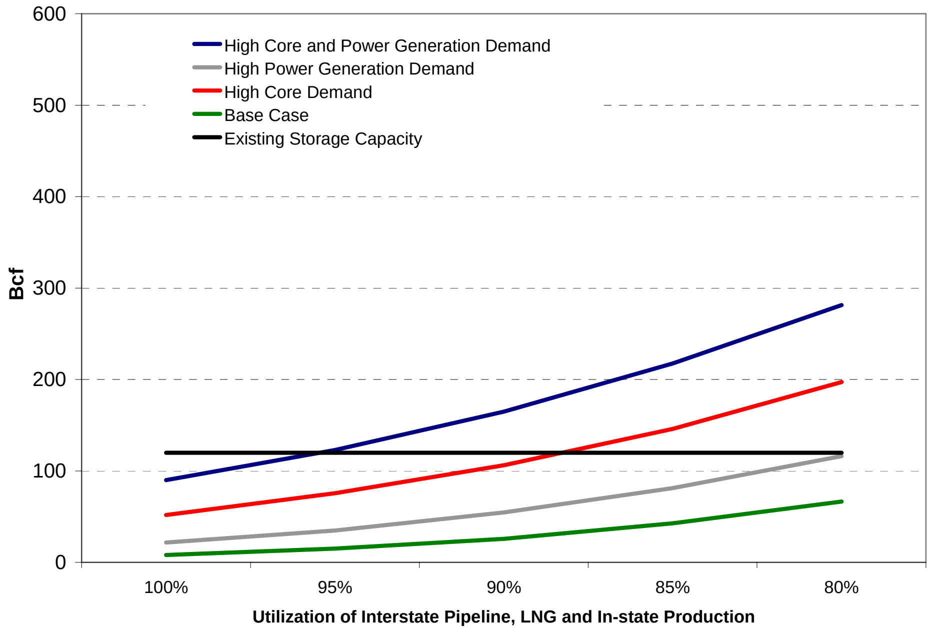


Figure 4-15: Additional Supply Requirements for SoCal/SDG&E for 2015, Source: B&V Analysis

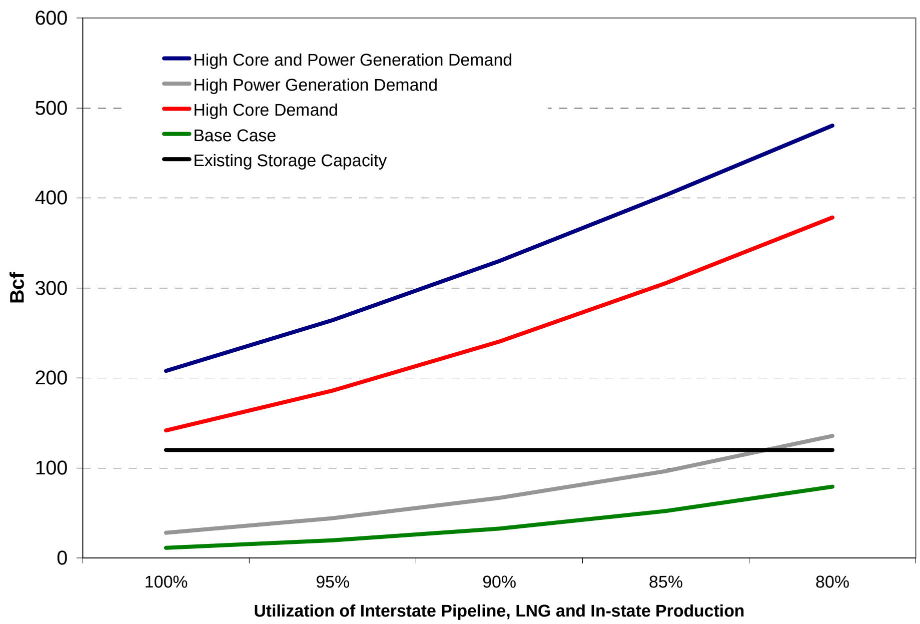


Figure 4-16: Additional Supply Requirements for SoCal/SDG&E for 2020, Source: B&V Analysis

4.5.4. *Summary of California Supply and Infrastructure Needs*

The report conclusions concerning the need for additional natural gas supply and infrastructure hinges on important assumptions that drive the demand forecast for different sectors.

As key drivers change due to weather or changing trends for the fundamental factors identified in this study, California will need additional supplies to meet its growing demand, especially during the later part of the study period from 2015 to 2020. The impact of the changes in the demand assumptions have been illustrated with the three demand scenarios analyzed.

High residential and commercial demand has a smaller impact on total supply needs compared with power generation demand. B&V has assumed uncertainty in residential and commercial demand driven by weather. If, in addition, the economic growth rate is significantly higher than assumed in the base case forecast, the need for additional supplies could be higher than indicated in the analysis.

The uncertainty in power generation demand forecast is higher than in other sectors. The ability of the state electric utilities to meet the RPS is a very important factor influencing power generation demand. If the electric utilities are unable to make progress towards meeting the RPS goals, and high power generation demand materializes by 2020, the state could need substantial additional supply. Additionally, if interstate pipeline, supply and LNG utilization rates can only be sustained at 90% or less, the state may need to find additional supply sources as early as 2015 to meet the higher power generation demand.

The PG&E service territory is geographically closer to newly developed independent storage fields, reducing their immediate need for additional storage capacity. However, substantial new supplies are still needed when the power generation demand is higher than in the base case or the pipeline utilization factor can not be maintained. The PG&E service territory's limited access to new and growing supply sources and the expected decline in WCSB production decline in the next decade could cause constraints in identifying additional supply sources. With limited available capacity on the Kern River pipeline, in the absence of capacity expansion, growing Rockies production does not immediately benefit California.

The SoCal service territory is vulnerable to demand swings in both the power generation sector and the core sector.

4.6. Analysis of Natural Gas Supply Assets to Meet California Demand Requirements

Potential assets to meet the additional California supply needs include long-haul pipeline transportation capacity from production basins, additional in-state and out-of-state storage capacity, LNG terminals and LNG peak shaving facilities.

Based on the pattern of the additional supply needs and the economic cost and feasibility of bringing in additional supplies, different combination of assets would be economical in serving California demand.

4.6.1. Overview of the Costs for Additional Pipeline Capacity

Additional pipeline capacity is most cost effective when used to meet constant, base load demand throughout the year that allows for high pipeline utilization. The majority component of FT costs is a fixed demand charge. Everything else being equal, the higher the utilization factor for the firm capacity throughout the year, the cheaper the cost of the capacity on a per unit basis.

Pipeline capacity is not an appropriate asset type for a demand pattern that only peaks in a short-period of time and drops significantly on most other days. This demand pattern implies that, even though the capacity will only be needed for a short time, the demand charges would need to be paid throughout the year.

The cost of supply from additional pipeline capacity is also dependent on the existing operating status of the pipeline i.e., whether the pipeline can be easily expanded to accommodate the needs for additional capacity, and the cost of gas at the supply region. For example, Kern River pipeline into California is fully contracted and is currently being utilized at a high rate. Additional capacity is likely to come from expansions of the pipeline. Kern is expected to hold an open season to explore expansion opportunities to California ranging from 250 MMcf/day to 750 MMcf/day. Combined with the production growth in the Rockies, the Kern expansion route may be an economic path to bring additional supply, if the incremental pipeline cost on Kern is competitive with other transportation and storage alternatives.

Currently, there is underutilized capacity on El Paso and Transwestern. However, as demand in California and other western states grows and the expected production in the Permian basin flattens or declines over time, the cost of gas along the Southwest pipelines is expected to rise. Bringing in additional supply from south could be a more expensive alternative in the future.

WCSB is currently a major source of supply for northern California with pipeline capacity running at a relatively high utilization rate. Expansion of the pipelines that bring WCSB production to California involves two segments – Nova and GTN – and the expansion cost is expected to be significantly higher than current FT rate. On the supply side for this pipeline route, even though production from the WCSB is expected to decline, gas from the Alaska North Slope could replace most of the lost volumes if a pipeline from Alaska is constructed into the Alberta market.

The assumptions made for the pipeline costs in this analysis of the natural gas supply assets needed to meet California's demand requirements incorporates an FT charge for capacity as well as a total gas cost that includes the commodity rate on the pipeline, the fuel losses and the projected price of gas in the supply basin. For Kern and GTN, the B&V analysis assumed that the FT cost for expansion would be 60% to 80% more expensive than the existing capacity. For El Paso and Transwestern, the B&V analysis assumed that the FT cost for expansion would be the same as for the existing capacity. The price of gas at the supply basin was obtained from the fundamental analysis of the natural gas market. Figure 4-17 shows the costs assumed in the analysis for additional pipeline capacity.

Pipeline	Basin	Demand Charge ($/Mcf/d)	Commodity ($/Mcf)	Fuel (%)	Gas Price ($/Mcf)		Total Cost $/Mcf	
					2015	2020	2015	2020
El Paso	San Juan	$0.40	$0.02	2.9%	$6.22	$6.45	$6.82	$7.06
El Paso	Waha	$0.40	$0.02	2.9%	$6.25	$6.73	$6.85	$7.33
Transwestern	San Juan	$0.36	$0.01	2.5%	$6.22	$6.45	$6.75	$6.98
Transwestern	Waha	$0.38	$0.02	2.6%	$6.25	$6.73	$6.82	$7.30
GTN	WCSB	$1.33	$0.03	1.3%	$5.49	$5.84	$6.92	$7.27
Kern	Rockies	$0.76	$0.06	5.5%	$5.55	$5.88	$6.68	$7.02

Figure 4-17: Additional Pipeline Capacity Costs

4.6.2. Overview of the Costs for Additional Storage Capacity

Additional storage capacity is an appropriate asset to meet seasonal demand or short term demand peaks. It is best suited for disproportionate demand growth during peak season. The major cost factors associated with additional storage are the cost of the storage capacity, the price of gas during the injection season and the variable costs involved in storage withdrawal and injections.

From our real option based valuation of storage to serve the California market (discussed in detail in Section 6), in-state storage offers a more economic alternative than out-of-state storage due to the costs of interstate transportation that are required for using out of state storage capacity to serve California demand.

High turn storage capacity allows the users to sign up for less storage space than their actual needs, potentially offering significant cost savings. However, an offsetting factor will be the availability of pipeline capacity to inject gas into storage during the multiple cycles.

The assumption made in this analysis is that additional storage capacity will be able to provide two turns of service[15]. The assumption of two turns of service is a conservative assumption reflecting that any future reservoirs available for storage development are likely to have lower capabilities than the currently proposed storage expansions and facilities that are expected to provide three turns of service. The total cost of storage includes the capacity cost of the storage facility, the injection and withdrawal fuel losses and the price of gas. The cost of storage capacity is the average cost of proposed storage facilities in California as estimated using a real options based approach (discussed in detail in Section 5). No interstate FT capacity is assumed to be required for storage injections as gas is purchased at the SoCal border or at the PG&E Citygate pooling point. As estimated in the fundamental analysis, the projected price at these points incorporates transportation costs from the production basins providing the supply. Figure 4-18 shows the storage costs assumed in the analysis.

15. Turns of service represents the number of times a year that natural gas can be injected into storage and withdrawn from storage for one complete cycle.

Storage Facility	Capacity Cost ($/Mcf/Year)	Injection Fuel (%)	Withdrawal Fuel (%)	Gas Price ($/Mcf)
Sacramento Storage	$1.59	1.0%	1.0%	$6.26
Kirby Hills Area Expansion	$1.23	1.0%	1.0%	$6.26
Wild Goose Expansion	$2.08	1.0%	1.0%	$6.26
Average	$1.63	1.0%	1.0%	$6.26

Figure 4-18: Assumed Storage Costs

4.6.3. Overview of the Costs for Additional LNG Supply

LNG supply is similar to a pipeline with supplies coming from LNG cargos instead of North American production regions. The major domestic cost components for importing LNG supplies to California include the terminal cost, cost on transportation pipelines from the terminal to the citygate and the ex-terminal[16] gas cost.

The terminal construction cost has been on the rise in recent years due to material and labor cost increases. Potential LNG terminal costs could also be substantially higher on the west coast than along the GOM due to land access and permitting. Expansion on the Baja LNG facilities could offer a more economical alternative than a new facility to acquire additional LNG receiving capabilities. However, additional pipeline infrastructure needs to be in place for the Baja LNG gas to reach northern California.

There is a high level of uncertainty around the ex-terminal gas cost that the LNG importers or LNG suppliers could charge. Currently, cargoes to most terminals along the US coast are either indexed to the local market price or a Henry Hub price. This could evolve over time depending on the supply and demand balance in the global LNG market.

This analysis of the natural gas supply assets needed to meet California's demand requirements incorporates a demand charge for the LNG terminal, pipeline cost to bring the LNG to California, fuel losses and the ex-terminal price of the LNG supply in order to estimate the total cost of LNG supply for California. Figure 4-19 summarizes the assumption on LNG costs utilized in the analysis.

16. Ex-terminal gas cost refers to the cost of natural gas sold by the supplier to the LNG regasification capacity holder.

LNG terminal construction cost is assumed to be $900 million dollars for a 2 Bcf/day facility. Recent transaction information indicates that existing LNG supplies into California are contracted at a discount to Henry Hub, reflecting the surplus capacity in the California market. [17] California is projected to experience increased tightness of supply as well as an increase in demand. At the same time, various proposed LNG terminals in the Gulf Coast are expected to lower the Henry Hub price. With the combination of these factors, there is a potential for the LNG supply index for California to trend higher than Henry Hub. Ex-terminal price is assumed to be 5% higher than Henry Hub prices in this analysis to reflect this projected premium.

Estimated Terminal Capital C	$900,000,000
Capital Structure	
Long-Term Debt	50%
Common Equity	50%
Billing Determinants (Mcf/d)	
Daily MDQ	2,000,000
Annual MDQ	730,000,000
Demand Charge ($/Mcf/d)	$0.27
Pipeline Cost ($/Mcf/d)	$0.25
Fuel Retention Rate	1.00%
Henry Hub Price ($/Mcf)	
2015	$6.67
2020	$7.23
Ex-terminal Gas Price (105% HH) ($/Mcf)	
2015	$7.00
2020	$7.59

Figure 4-19: LNG Costs Assumptions

4.6.4. Overview of the Costs for Additional LNG Peak Shaving Facilities

As discussed in Section 2.2.4, LNG peak shaving facilities are above ground storage assets that deal with peak demand lasting 10 days or less. They can be used as a supplemental asset to meet localized distribution or transmission constraints or peak day needs on a gas distribution level. The costs of these facilities can range from $4/Mcf for a facility offering four turns of service a year to $7/Mcf for a facility offering two turns of service a year.

17. Based on the reported price in Mexico's CFE Federal Electricity Commission contract with Spain's Repsol YPF to supply LNG to the Manzanillo terminal on the Pacific Coast.

LNG peak shaving facilities should be considered as a suitable supply asset to deal with localized constraints to serve peak day needs. B&V's analysis scope was focused on wholesale market requirements and did not include analysis of the intrastate constraints where LNG peakshaving facilities may be required within California.

4.6.5. Relative Competitiveness of Wholesale Supply Assets – Assessment of Economically Optimal Portfolio

B&V examined high demand scenarios to illustrate the relative economics of the different wholesale supply sources that can serve California's incremental supply needs.

Given the projections for additional supply needs and the assumptions for the costs of the different supply assets considered – pipeline capacity, storage capacity and LNG supply – this analysis assesses the relative competitiveness of the supply assets to meet California's additional supply needs. The cost comparisons are intended to offer insight on the relative competitiveness of the supply alternatives and are not intended to represent an in-depth assessment of the costs of these assets. The relative attractiveness of the assets depends on the load profile anticipated. A flatter demand profile generally supports addition of pipeline assets while a peakier load profile supports the addition of storage assets.

This analysis considers two scenarios of high demand where additional supply would be needed – i) High Power Generation Demand and ii) High Core and High Power Generation Demand

High Power Generation Demand Scenario

For the High Power Generation Demand scenario, the cost of gas supply per Mcf (1000 cubic feet of natural gas) as California's additional supply needs increase is shown in Figure 4-20. The additional supply needs shown on the x-axis are driven by varying the assumptions of the availability of interstate pipeline, LNG and in-state production capacity from 100% down to 80% as elaborated in Section 4.5.1 and 4.5.2. These supply needs are estimated after taking the estimated storage capacity into account. As shown in Figure 4-20, transportation offers the most economic alternative to meet the additional supply needs in this demand scenario driven by the following factors:

1. The additional demand for power generation peaks in summer and makes the daily load flatter over time. A flatter demand profile provides higher utilization of pipeline capacity year round.
2. Since storage capacity is better suited for load profiles that peak during a certain period during the year, per unit storage cost is relatively high compared to the cost of pipeline capacity for the relatively flat load profile in this demand scenario.
3. The difference between Henry Hub and California prices is not sufficient to make LNG supply more attractive.

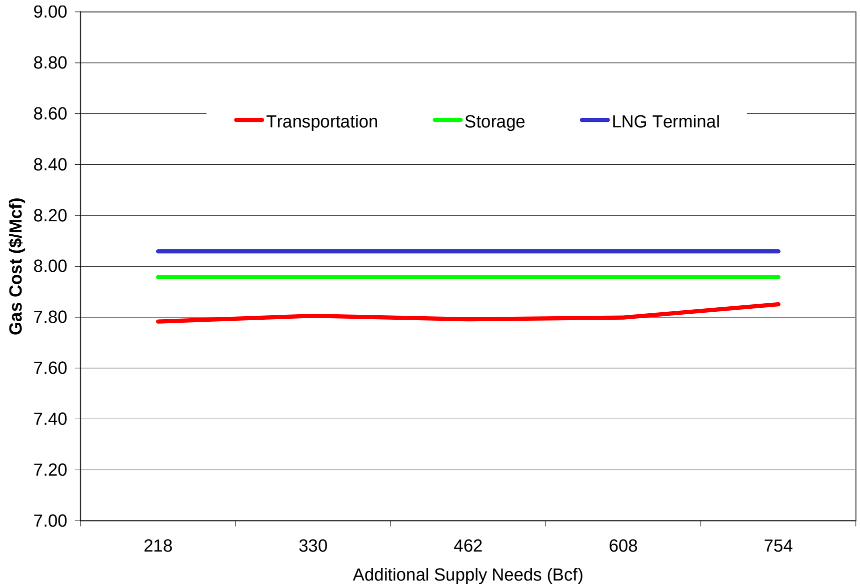


Figure 4-20: Additional Supply Needs vs. Per Unit Gas Cost 2020, Source: B&V Analysis

High Power Generation Demand and High Core Demand Scenario

For the High Core and High Power Generation Demand scenario, the cost of gas supply per Mcf as California's additional supply needs increase is shown in Figure 4-21. The additional supply needs shown on the x-axis are driven by varying the assumptions of the availability of interstate pipeline, LNG and in-state production capacity from 100% down to 80% as elaborated in Section 4.5.1 and 4.5.2. These supply needs are estimated after taking the estimated storage capacity into account. As shown in Figure 4-21, a combination of storage and transportation offers the most economic alternative to meet the additional supply needs in this demand scenario driven by the following factors:

1. Storage is more competitive than the transportation alternative when additional supply needs from high core demand increases during peak demand in winter and the incremental pipeline capacity is less than 100% utilized in summer. Transportation becomes more competitive when the additional supply needs are consistently greater since the utilization of the pipeline capacity increases making the per Mcf cost lower.
2. The cost of LNG supply is highly dependent on the ex-terminal price that the LNG importers are willing to offer to purchasers. If the ex-terminal price is at a premium to Henry Hub to reflect a future premium in the California market, LNG supply is a more expensive option than transportation and storage capacity.

Although storage capacity is more economically competitive than other supply alternatives, the magnitude of the additional supply needs makes it highly unlikely that the storage alone could fulfill the supply gap. A combination of storage, pipeline transportation and/or LNG terminal would be needed to meet California's supply needs in this scenario.

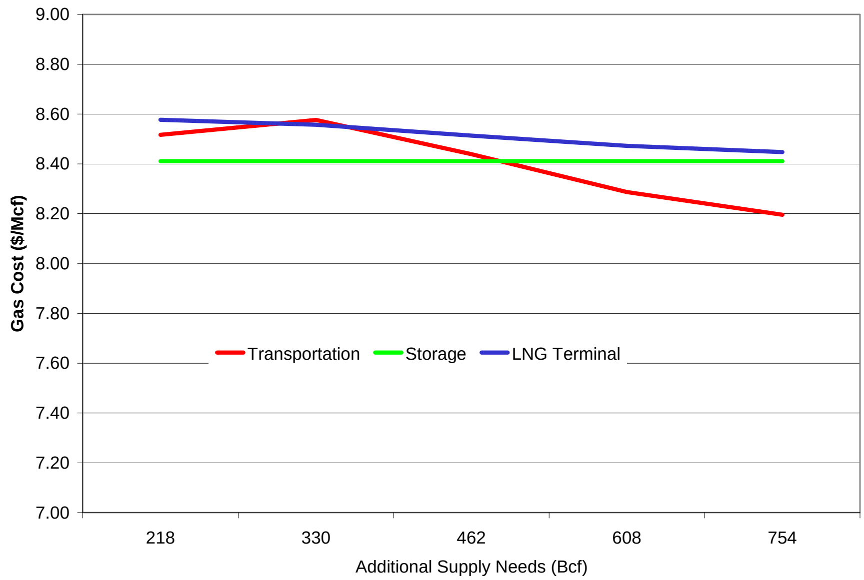


Figure 4-21: Additional Supply Needs vs. Per Unit Gas Cost, Source: B&V Analysis

5.0 Overview of Storage Valuation and Analysis of Trends in the Drivers that Determine Storage Value

5.1. Storage Valuation

Storage valuation is typically based on the cost of service or market value. To determine storage value for facilities with cost of service based rates, B&V utilized the maximum firm storage tariff as published by the entity that operates the storage facility. Storage facilities considered include interstate pipeline storage service and storage offered by the two main gas utilities in California – SoCal and PG&E.

The current approach favored in the natural gas industry to value independent storage facilities that have market based rates is based on an estimate of the value that can be generated by the storage facility by arbitraging price differentials. The analysis methodology utilized by B&V to measure the value, or cost, of storage relies upon this approach. A description of the valuation methodology is described in detail in the following Sections.

5.1.1. Storage can be Viewed and Valued as an Option

A financial call option gives the owner the right to purchase a specific asset at a pre-determined strike price; and a financial put option gives the owner the right to sell a specific asset at a pre-determined strike price. Option owners have the right but not the obligation to arbitrage or make decisions through time up until the point where the option expires.

Similar to financial options, many assets or contracts have some element of flexibility such as:

1. ability to use / not use,
2. ability to expand / contract,
3. ability to modify price structure,
4. ability to accelerate / defer.

Ownership of storage capacity is equivalent to owning both a call option and a put option on future spreads on natural gas prices – it represents a right, but not an obligation to purchase gas at low prices for injection and to sell gas at high prices from storage withdrawals. The flexibilities offered by storage have value to the owner of the storage and can be valued using an option analysis framework.

The option imbedded in a storage asset or contract for storage capacity is a complex combination of spread options on natural gas prices. The underlying asset of the storage option is natural gas spot and futures prices. The volatility of gas prices as well as the correlation between prices has a significant impact on the value of the storage option. The strike price of the storage option is the total variable cost of the storage injection and withdrawal, which is to say, as long as the price spread is higher than the storage injection and withdrawal cost, the storage option is in the money.

The intrinsic value of an option is the difference between the underlying asset price and the strike price when the option contract is first consummated. In the money options have positive intrinsic value while out of the money options have zero intrinsic value. The extrinsic value of an option is the value beyond the intrinsic value that is determined by the future price movement of the underlying asset. An option premium is the sum of intrinsic and extrinsic value with the positive option premium committed by out-of-money options coming exclusively from extrinsic value.

Like a financial option, storage has an intrinsic value component and an extrinsic value component. The price differential the storage asset owner can realize given the current spot price and forward curve is the intrinsic value. The extrinsic value is the potential value the capacity owner is expected to realize due to future movement of these prices. In reality, the extrinsic value that a storage holder can realize may depend on the exercise strategy of the capacity owner. The option value of storage is the sum of intrinsic value and any extrinsic value.

Description of Storage Valuation Methodology for Independent Storage Facilities

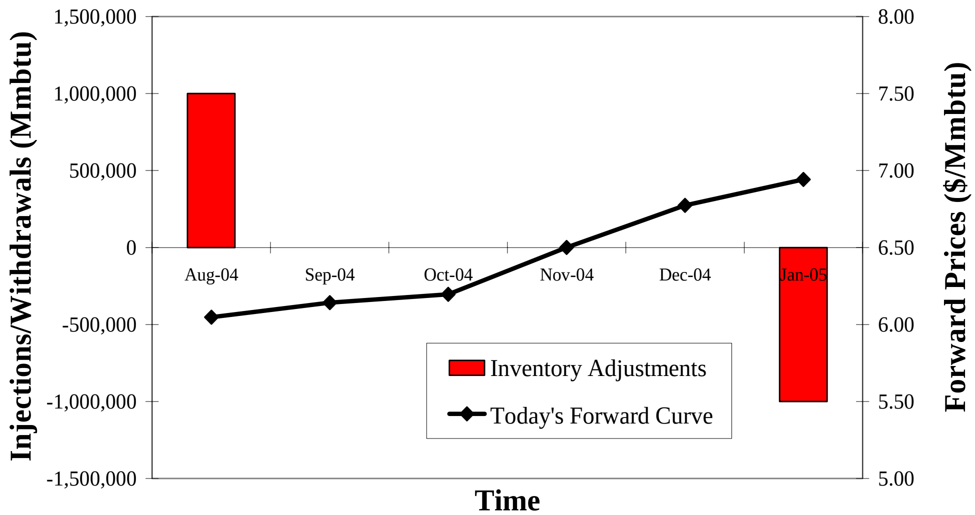
Storage can be utilized to profit from differences in future natural gas prices and the volatility of price movement as opposed to utilization for purely operational considerations. Therefore, storage provides capacity holders the ability to arbitrage natural gas prices across time and markets. Storage capacity owners can benefit from price movements by injecting and withdrawing from storage in response to periodic movements in natural gas prices.

For independent storage facilities with market based rates, B&B utilized a market based arbitrage value approach. Specifically B&V's proprietary software valuation model, Storage Valuation Advisor™, was utilized. The valuation methodology imbedded in this tool relies on arbitraging natural gas price spreads utilizing a storage facility through the hedging of all injection and withdrawal decisions. The valuation approach assumes that the storage capacity owner always locks in any positive price spreads from observed gas prices to extract the intrinsic value and wait for the opportunity to realize the extrinsic value when prices change. To lock in spreads, storage capacity owners can purchase futures contracts for their injection needs and sell corresponding futures contracts for gas withdrawal to lock in the intrinsic value of storage. In this way, they have guaranteed a minimum profit on the stored gas and are protected if gas prices subsequently move against their positions.

As mentioned in the previous section, the value of a storage asset is the sum of intrinsic value and extrinsic value of the asset. Value in excess of the intrinsic value is the extrinsic value and represents the "real option" value associated with the storage facility. As mentioned above, gas prices can move against the position after gas is injected into storage. If the transaction was hedged, this movement does not impact profit. But gas prices can also move in your favor. When gas prices do move in the favor of the purchaser, the hedge can be "unwound" and additional profits captured. This additional profit is the extrinsic or real option value. Estimates of future extrinsic value are divided into two components:

Example of Market-Based Storage Valuation

Consider the example of a storage field with 1,000,000 Dth (dekatherms) of capacity, 50,000 Dth/d injection capability and 100,000 Dth/d in withdrawal capability operating over a six month period from August 2004 to January 2005 comprising of three summer months and three winter months. The intrinsic value profile based on the initial forward curve is shown in Figure 5-1. Based on this methodology, injection is done in the summer month with the lowest gas price i.e., August and withdrawal takes place in the winter month with the highest price, i.e. January.

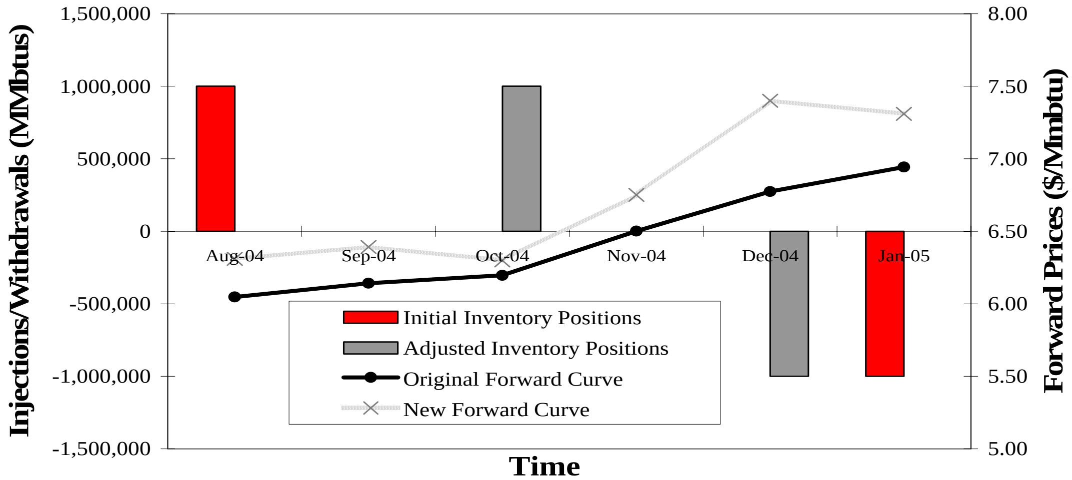


Intrinsic Calculation (initial forward curve)

	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04	Jan-05
Forward Curve	$6.048	$6.142	$6.197	$6.501	$6.774	$6.943
Inventory Changes	1,000,000	0	0	0	0	(1,000,000)
	$6,048,000	$0	$0	$0	$0	($6,943,000)
Intrinsic Value	$895,000					

Figure 5-1: Intrinsic Value Profile, Source: B&V Analysis

As prices change over time, the forward curve moves such that the lowest priced summer month is now October and the highest priced winter month is December as shown in Figure 5-2. The new injection/withdrawal profile is also indicated in Figure 5-2 with injection in October and withdrawal in December.



Reoptimized Value Calculation (new forward curve)

	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04	Jan-05
Forward Curve	$6.310	$6.392	$6.300	$6.751	$7.400	$7.310
Inventory Changes	0	0	1,000,000	0	(1,000,000)	0
	$0	$0	$6,300,000	$0	($7,400,000)	$0
Re-optimized Value	$1,100,000					

Figure 5-2: New Forward Curves and Adjusted Inventory Levels, Source: B&V Analysis

The cost of unwinding the initial positions and the estimation of extrinsic value is now $995,000 including $895,000 of intrinsic value and $100,000 of extrinsic value after unwinding costs. Repeating this process as prices change in the forward and spot markets during the contract period accrues extrinsic value. Since changes in future prices cannot be estimated with certainty, a simulation based approach is used to create a range of possible future price scenarios based on assumptions about the mean price level, volatilities and correlations.

5.2. Main Drivers of Storage Value for Independent Storage Facilities

There are several drivers that influence the value of a storage facility or storage services contract. These drivers can be grouped into two broad categories – operational characteristics and market characteristics. Operational characteristics include the injection and withdrawal capacity of the field in relation to its storage capacity and the variable costs associated with injection and withdrawal. The location of the storage facility within the natural gas infrastructure and access to multiple pipelines can also be considered as characteristics representative of a storage facility that drive its value. Market characteristics include the price level, seasonal spread, prices volatilities, correlation between prices and the interest rate. These characteristics represent the market condition and also play a key role in determining the value of the storage facility.

5.2.1. Inventory Levels vs. Injection / Withdrawal Capability

The greater the operational flexibility of the storage field, the greater the value of the storage service. Higher cycling ability of the storage facility allows the contract holder to respond more rapidly to short-term price movements in the market. This enables the contract holder to take advantage of short-term price arbitrage opportunities and creates incremental value. Both the intrinsic and extrinsic values are impacted by the injection/withdrawal capability relative to storage inventory. An increase in operational flexibility however is usually obtained through higher capital investments. In general, as the cycling ability of the storage field increases, the storage value increases.

5.2.2. Variable Costs

Variable costs associated with storage injection and withdrawal is designed to cover the operations and maintenance costs and the fuel consumption. These costs reduce the price arbitrage opportunity available to storage capacity holders. Storage facilities with lower variable costs offer higher value since they allow a higher margin from price arbitrage.

5.2.3. Seasonal Spread

The regional price differential between shoulder months and winter is a fundamental driver of storage value. The main use of storage as discussed earlier is to mitigate the imbalance between a relatively stable annual production rate and highly seasonal demand patterns. Large price spreads between shoulder month and winter prices provide greater value for storage services since injection is done in the lowest priced months-typically during the spring and fall -- and withdrawal in the higher priced winter months. Seasonal spreads predominantly impact the intrinsic value of storage.

The greater the disconnect or distance between a storage location from the benchmark Henry Hub market, the greater the likelihood of increased price volatility for the storage asset due to basis volatility that is an additive to Henry Hub and NYMEX volatility.

5.2.4. Price Volatility

Movements in the futures and spot prices during the period of the storage contract offer opportunities to re-optimize the storage portfolio and extract greater value from storage. Volatility is a measure of price movements – the greater the price movements, the greater the volatility. High volatilities increase the extrinsic value of storage assets. In addition, how closely correlated the price movements are to each other also impacts the extrinsic value. The less correlated the price movements, the greater the opportunity for large variances to develop in the forward market.

The greater the disconnect or distance between a storage location from the benchmark Henry Hub market, the greater the likelihood of increased price volatility for the storage asset due to basis volatility that is an additive to Henry Hub and NYMEX volatility.

5.2.5. Location and Surrounding Pipeline Infrastructure

The competitive position of a storage facility relative to comparable storage facilities can be a significant driver of storage value. A storage facility can contribute value due to its location within the natural gas infrastructure. This is especially true for market area storage facilities that offer tremendous value in managing peak winter demand at costs that are usually much lower than those associated with long-haul transportation from production areas. Another factor is the presence of multiple pipeline interconnects. In addition to allowing arbitrage opportunities, access to multiple pipelines increases the likelihood of having sufficient pipeline capacity to move gas out of storage during high price environments when withdrawal is most valuable.

5.3. Expected Trends in Regional Volatility

5.3.1. Definition and Sources of Volatility

Generally defined as the dispersion of the returns on a security or commodity, volatility measures the uncertainty of price movement over time. Wider range of price movement signals a more volatile market and higher risks associated.

Volatility results from unpredictability of market events in the future that could cause price responses. In the natural gas market, it is intuitive to classify future influential market events into two categories: long-term fundamental events and short-term market shocks.

Long-term events include general demand/supply balance, infrastructure developments, such as pipeline expansions or LNG terminals. The B&V analysis addressed their impact through a combination of NARG fundamental analysis on selected statistical scenarios using the principal component analysis. A common characteristic of the long-term events is that once they occur, they will become stable factors in the market demand or supply balance and somewhat predictable in nature. Therefore, uncertainty in equilibrium price is a less significant component of the price volatility as observed in the market.

A significant component of volatility reflects short-term market disturbances, such as weather changes, sudden supply or demand disruptions, geopolitical events or trading momentum in the market. These events are constantly unpredictable in nature and become the major sources of price movements. B&V analysis utilized known statistical financial models – generally referred as short-term volatility models - to understand trends in natural gas price volatility.

5.3.2. Models of Volatility

Several statistical and financial models are candidates for natural gas price movements. They differ in the underlying price distribution assumptions and implied volatility characteristics. B&V compared the following models: Geometric Brownian Motion, Mean-reversion model, Two-factor mean-reversion and ARCH/GARCH type models. These are well established financial models and some have been widely utilized in the commodity and energy context.

In order to find an appropriate model to characterize the volatility trend in California prices, B&V analyzed the historical FOM prices at SoCal, Topock, and the PG&E Citygate. The period of May 1998 to July 2007 was reviewed. A parallel analysis is also conducted excluding the California Energy Crisis period that occurred from December 2000 to June 2001 to take into account the unusual market circumstance. Figure 5-3 shows these two price series.

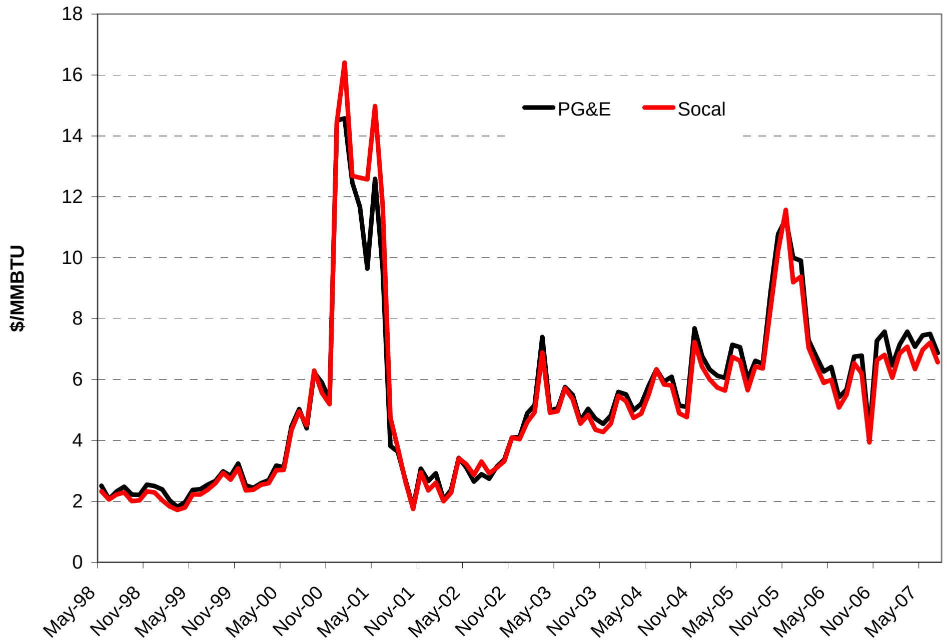


Figure 5-3: FOM Price for SoCal and PG&E, Source: Platts FOM Prices

B&V first tested the price series for normality to examine if the normal return assumption based model is a good fit. Even though historical prices do not perfectly fit a normal distribution, the price distribution is relatively symmetric with a bell-shaped density.

The ARCH model was first proposed by Robert Engle in 1980 to account for a special case of heteroskedasticity – the volatility clustering often observed in the stock market. Engle developed simple statistics to identify the time series with ARCH effect. B&V applied the test to both PG&E and SoCal FOM prices and concluded that the test rejected the hypothesis that there is ARCH effect in both price series.

The most striking statistical property of an ARCH model is the series correlation in the residual terms. One corroborative statistic to test the ARCH effect in a time series is to examine if there are significant correlations. The first order and second order correlations resulting from the B&V analysis are below 0.1, and not significant. The lack of correlation in squared residuals corroborates the observation that there are limited ARCH effects in the two price series.

Geometric Brownian motion and Mean-reversion models have different implications for the volatility in the futures market. B&V estimated the volatilities in the PG&E and SoCal futures market using historical NYMEX plus forward basis data from 2005 to 2007 available from NYMEX Clearport™.

The pronounced declining term structure, as shown in Figure 5-4, indicates inconsistency with Geometric Brownian motion. A mean-reversion spot price model is expected to be more theoretically consistent.

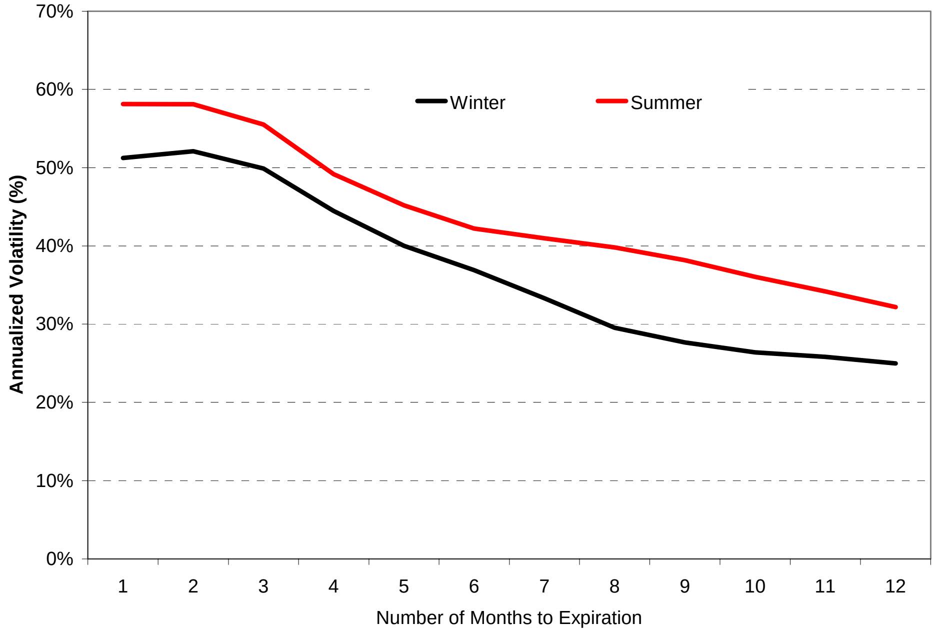


Figure 5-4: Volatility Term Structure by Season, Source: B&V Analysis

5.3.3. Estimating Mean-Reversion Parameters

Based on the statistical tests, the mean-reversion model as the choice of short-term model B&V estimated model parameters from historical data under two mean-reversion model setup – mean-reversion with a constant mean and mean-reversion with a time-varying mean. Two sets of parameters are estimated with and without the California Energy Crisis period. They were not found to be significantly different from each other. The analysis indicates that mean reversion with time-varying mean is an appropriate model for the PG&E and SoCal price series.

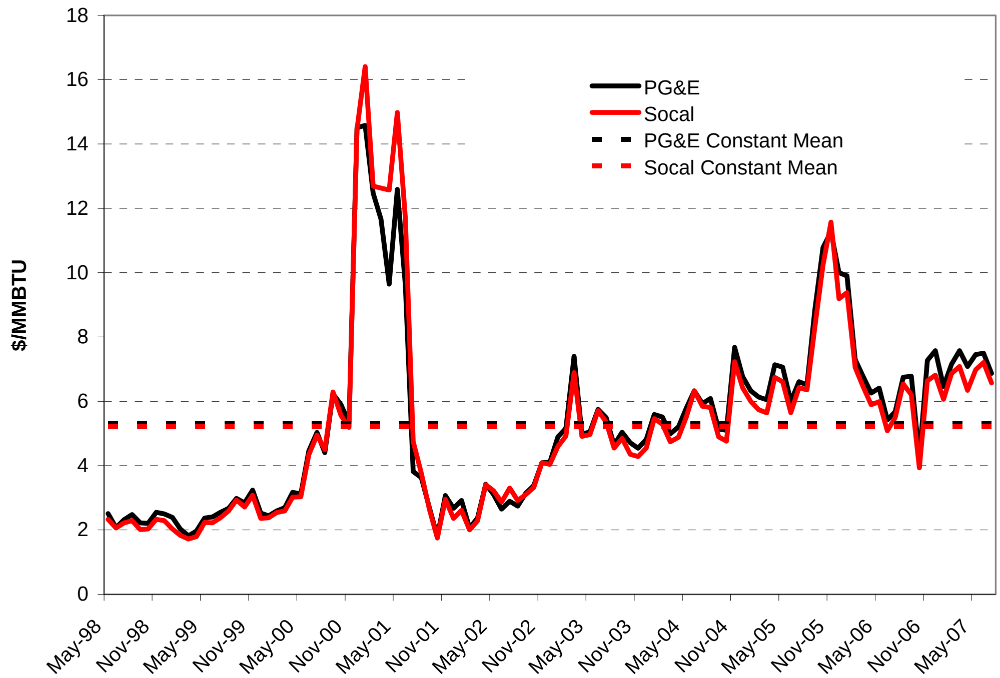


Figure 5-5: FOM Prices at PG&E and SoCal with Mean Reversion with Variable Mean, Source: Platts FOM Prices and B&V Analysis

5.3.4. Simulating Range of Future PG&E and SoCal Prices

The long-term equilibrium price uncertainty was combined with the short-term price uncertainty to create the range of future price movements. For each simulated price path, B&V estimated a volatility level under the mean-reversion framework and calculated the average of these estimated volatilities

Historically, the estimated FOM price volatility, using a mean-reversion process at PG&E and SoCal, is 88%, which is used in the short-term volatility simulation. The average of the estimated volatilities from simulation ranges from 92% to 93%, which indicates that uncertainty in fundamental price drivers is estimated to increase the volatility by 4-5%. Increase in FOM (spot price) volatility will also lead to increase volatility in the futures market under the Mean-Reversion price assumptions.

Given that price volatility is a key factor in influencing arbitrage storage value (primary valuation methodology utilized for independent storage facilities), increases in volatility support storage valuation that encourages storage development. Increased storage infrastructure not only provides arbitrage opportunity but also provides short term deliverability to mitigate supply disruptions or demand spikes.

6.0 Evaluation of In-State and Out-of-State Storage Alternatives to Serve the California Market

As discussed in Section 4.6.5, storage could be one of the alternatives to serve California demand under conditions of high core and power generation demand. This section considers a comparative analysis of the storage assets that can serve California demand that were identified in Section 2.2.1. The economic merits of the in-state and out-of-state storage facilities are analyzed in this section. The comparative analysis utilizes expectations for market behavior in 2020.

For each storage asset considered, the total costs of reaching the California wholesale market, including transportation costs and storage costs have been included in the analysis.

6.1. Analysis Assumptions

6.1.1. Cost Components for In-State Storage

Both utility owned and independent storage facilities exist within the state of California. The cost of storage services within California may hence be either market driven or defined in the utility tariff. The two independent storage facilities, Wild Goose and Lodi Storage (including Kirby Hills), offer market based rates. PG&E system storage may be accessed at costs defined in the utility tariff while SoCal system storage may be accessed either at costs defined in the tariff or via an auction mechanism that may be expected to result in a market based rate.

In-state storage reaches its market in California through utility pipeline systems. The total cost of accessing in-state storage services is therefore calculated as the cost of storage service and the cost of intrastate transportation on PG&E, SoCal, SDG&E as shown in Figure 6-1.

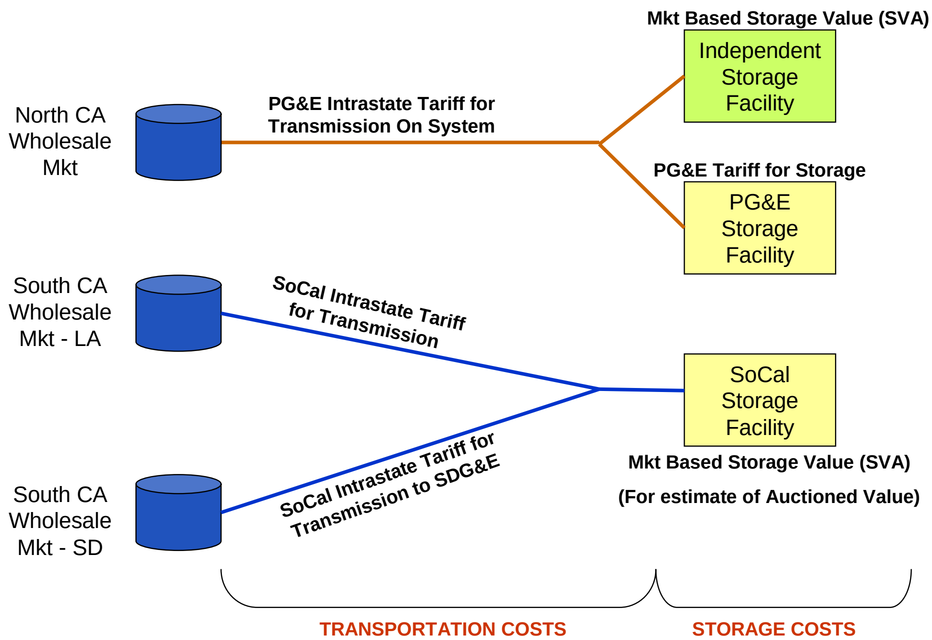


Figure 6-1: Cost Calculation for In-State Storage, Source: B&V Analysis

6.1.2. Cost Components for Out-of-State Storage

Both utility owned and independent storage facilities that exist outside California can serve demand within the state. The cost of storage services for California from these out-of-state storage facilities may hence be either market driven or defined in the utility tariff. Independent storage facilities offer market based rates to access their storage services while pipeline system storage may be accessed at costs defined in the tariff.

Out-of-state storage reaches its market in California through interstate pipelines and California utility pipeline systems. The total cost of accessing out-of-state storage services is therefore the sum of the cost of storage service, the cost of interstate transportation, and the cost of intrastate transportation on PG&E, SoCal and SDG&E as illustrated in Figure 6-2.

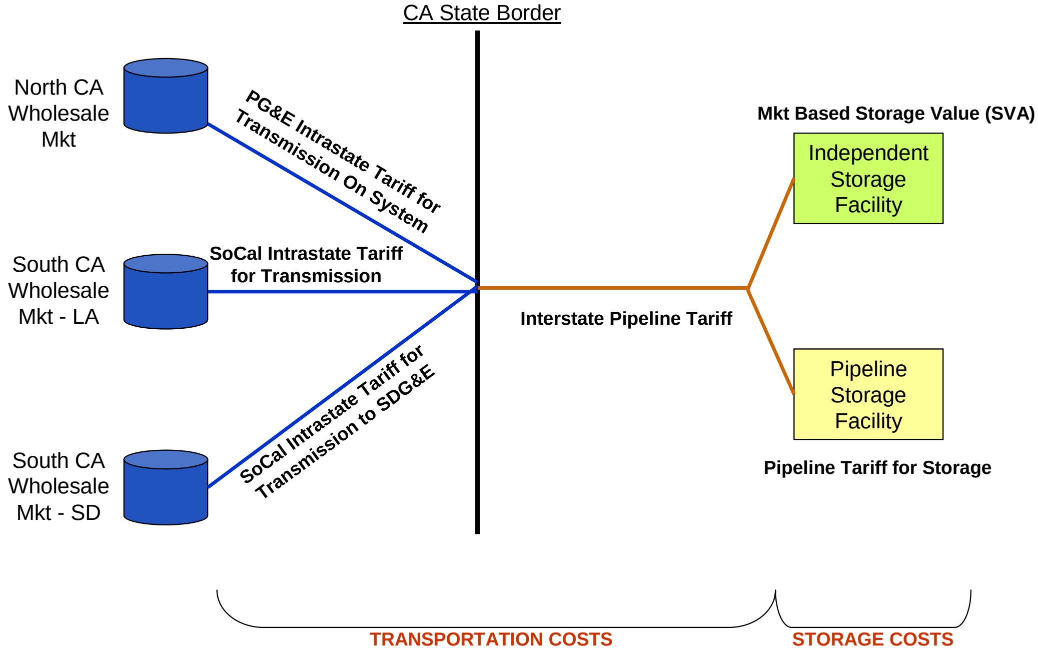


Figure 6-2: Cost Calculation for Out-of-State Storage, Source: B&V Analysis

6.1.3. Assumptions for Transportation Cost Component – Intrastate Transportation

The analysis assumes that annual FT service is contracted for on PG&E and / or SoCal systems. FT service corresponding to the maximum withdrawal quantity is assumed to be contracted for annually. Storage inventory is assumed to be turned over as many times as is operationally possible. The transportation is assumed to take storage gas into the PG&E and SoCal pools for sale in the wholesale market. Since various tariffs are available for customers on the PG&E and SoCal systems, the assumption made in this analysis represents one estimate of cost. The actual costs will likely vary depending on the tariff choices of the end-users and wholesale marketers. Since uniform assumptions on intrastate transportation costs have been utilized in this analysis for the in-state as well as the out-of-state storage alternatives serving each market in California, the intrastate transportation costs are unlikely to impact the relative economics of the different alternatives.

6.1.4. Assumptions for Transportation Cost Component – Interstate Transportation

The transportation costs associated with bringing natural gas from out-of-state storage into California have been incorporated in making a comparative assessment of storage alternatives. FT rates have been utilized to assess transportation costs to bring gas from storage into California since it is assumed that FT would be required to serve California demand during periods of peak demand. The analysis assumes that FT service corresponding to the maximum withdrawal quantity is contracted for annually and that the storage inventory is turned over as many times as is operationally possible.

Pipeline tariffs for the interstate pipelines have been obtained from the currently effective tariffs for the pipelines serving California. For El Paso and Transwestern, the assumed transportation rate is the currently effective FT rate since these two pipelines are not fully utilized and may have additional capacity available at the current FT rates. For the Kern River and GTN pipelines that currently have high utilization rates and bring supply from the Rockies and the WCSB, pipeline tariffs are assumed to be 50% higher than current tariffs as discussed in Section 4.6.1. The higher tariff reflects an expansion of the pipeline at an incremental rather than a rolled-in rate for the expansion capacity in order to provide additional capacity to bring the storage gas to the California market.

6.1.5. Assumptions for Storage Cost Component – Pipeline and Utility Storage

Pipeline and utility operated storage services have been evaluated using the pipeline and utility tariffs for firm storage service. The exception is SoCal's storage service that can be sold using an auction mechanism. In this case, the analysis assumes that the auction mechanism would lead to a market based rate for SoCal's storage services. Reservation and capacity charges as well as variable costs for injection, withdrawal and fuel have been incorporated in the analysis. The storage facility's total working gas capacity and maximum injection and withdrawal capacities have been taken into account while estimating the value and cost of storage services

6.1.6. Assumptions for Storage Cost Component – Independent Storage Facilities

Independent storage facilities with market based negotiated rates and SoCal's storage service that is available through an auction mechanism have been valued using B&V's proprietary real-options based valuation model, Storage Valuation Advisor (SVA™). The storage facility's total working gas capacity and maximum injection and withdrawal capacities have been taken into account while estimating the value and cost of storage services. The valuation estimates the value of the storage service net of variables costs for injection and withdrawal and represents the value/cost a third party buyer would theoretically pay for storage access.

6.1.7. Assumptions for Market Prices and Volatilities Used to Value Storage

The analysis utilizes long term trends in seasonal basis and volatilities based on the fundamental NARG analysis of North American natural gas market that is discussed in Section 2.

Regional prices were obtained from the following pricing points:

1. North California – PG&E Citygate
2. South California – SoCal
3. Southwest – El Paso Permian Basin, Waha
4. Rockies – Kern - Wyoming
5. Northwest – Malin - Oregon
6. Canada – Alberta, AECO Hub

Figures 6-3, 6-4 and 6-5 show the forward curves and volatility assumptions utilized in the analysis.

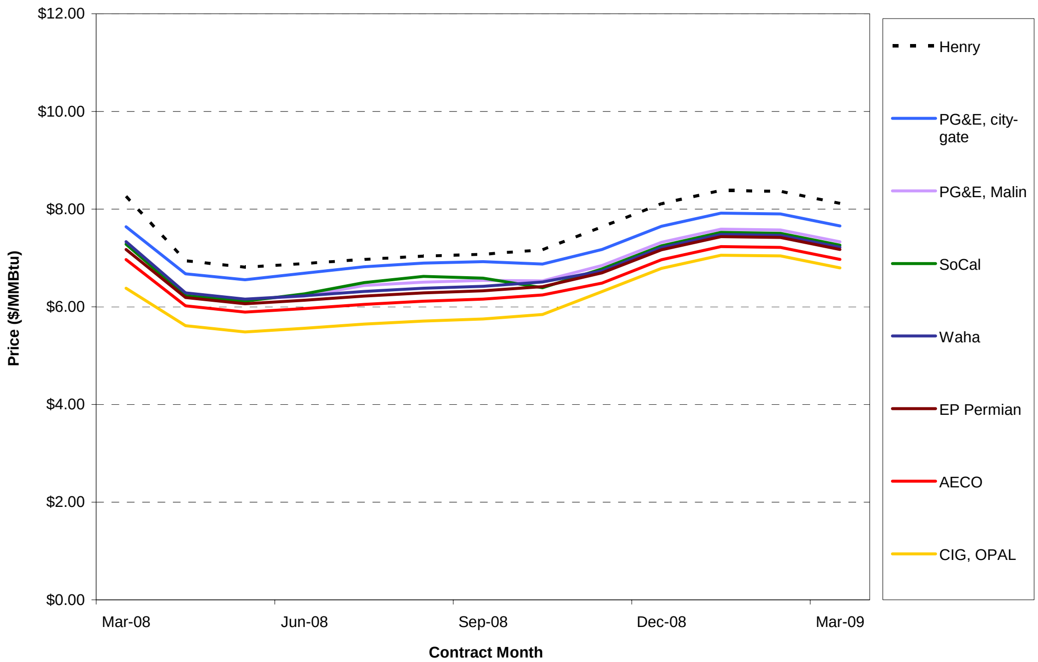


Figure 6-3: Adjusted Futures Strip from NYMEX / Clearport, Source: NYMEX

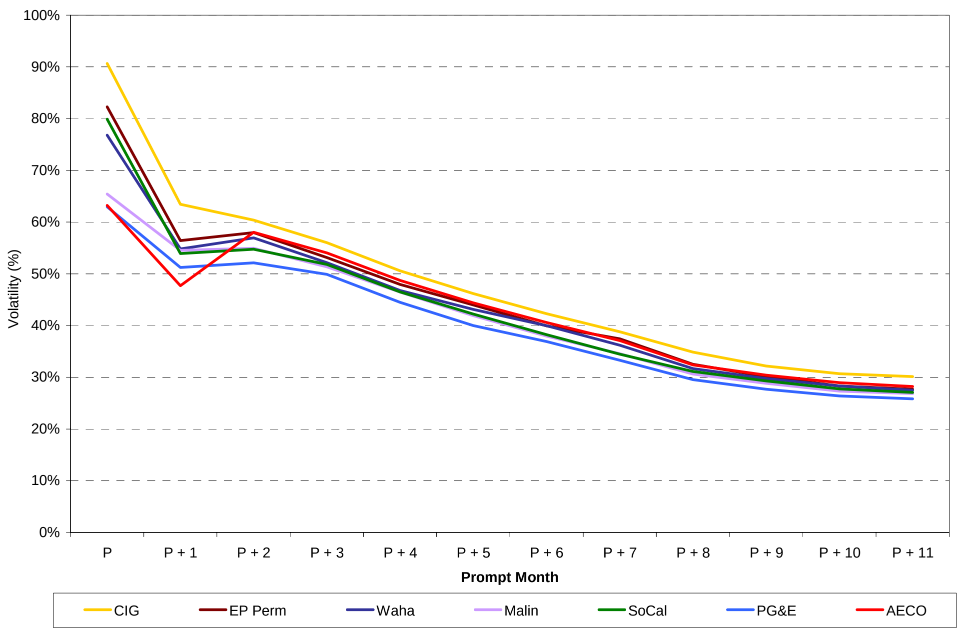


Figure 6-4: Annualized Average Volatility – Summer, Source: NYMEX and B&V Analysis

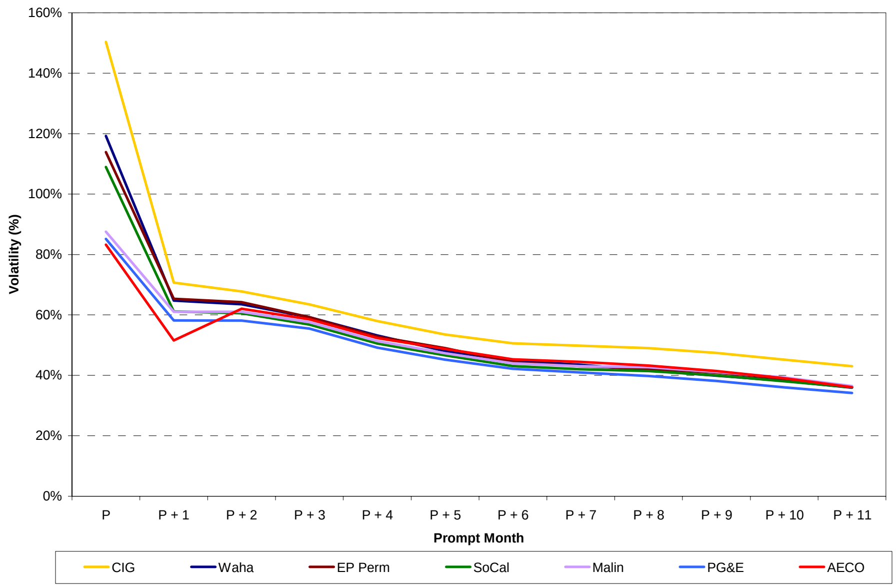


Figure 6-5: Annualized Average Volatility – Winter, Source: NYMEX and B&V Analysis

Other cost assumptions utilized in the storage valuation are indicated in Figure 6-6.

Other Cost Assumptions	
Injection cost	$0.01/Mcf
Withdrawal cost	$0.01/Mcf
Injection fuel cost	1%
Transaction cost	$0.005/Mcf
Interest Rate (annual)	5%

Figure 6-6: Storage Valuation Cost Assumptions

6.2. Economic Comparison of In-State and Out-of-State Storage Alternatives

The economic comparisons of in-state and out-of-state storage alternatives were assessed for the PG&E, SoCal and SDG&E markets. Storage facilities directly linked to the PG&E and SoCal systems were considered as in-state alternatives for these two markets. Storage facilities directly linked to the SoCal system were considered as in-state alternatives for the SDG&E market. Out of state storage facilities that were connected to the Northwest Pipeline, and the Rockies and Southwest pipelines interconnecting to the PG&E system were considered as out of state alternatives for the PG&E market. Out of state storage facilities that were connected to the Rockies and Southwest pipelines interconnecting to the SoCal system were considered as out of state alternatives for the PG&E and SDG&E markets.

6.2.1. *Alternatives for the PG&E Market*

The economic comparison of the costs of existing and proposed storage facilities with service to the PG&E market are shown in Figures 6-7 and 6-8. The total cost of storage and transportation to serve the California market are considered in the analysis as discussed in Section 6.1. In-state storage is estimated to offer the most cost effective alternative to serve this market since the cost of interstate transportation is significant and adds significant expense to out of state storage facilities. Assuming that interstate transportation capacity is available at current FT rates, the Southwest storage facilities offer the least expensive out of state alternatives to serve the PG&E market.

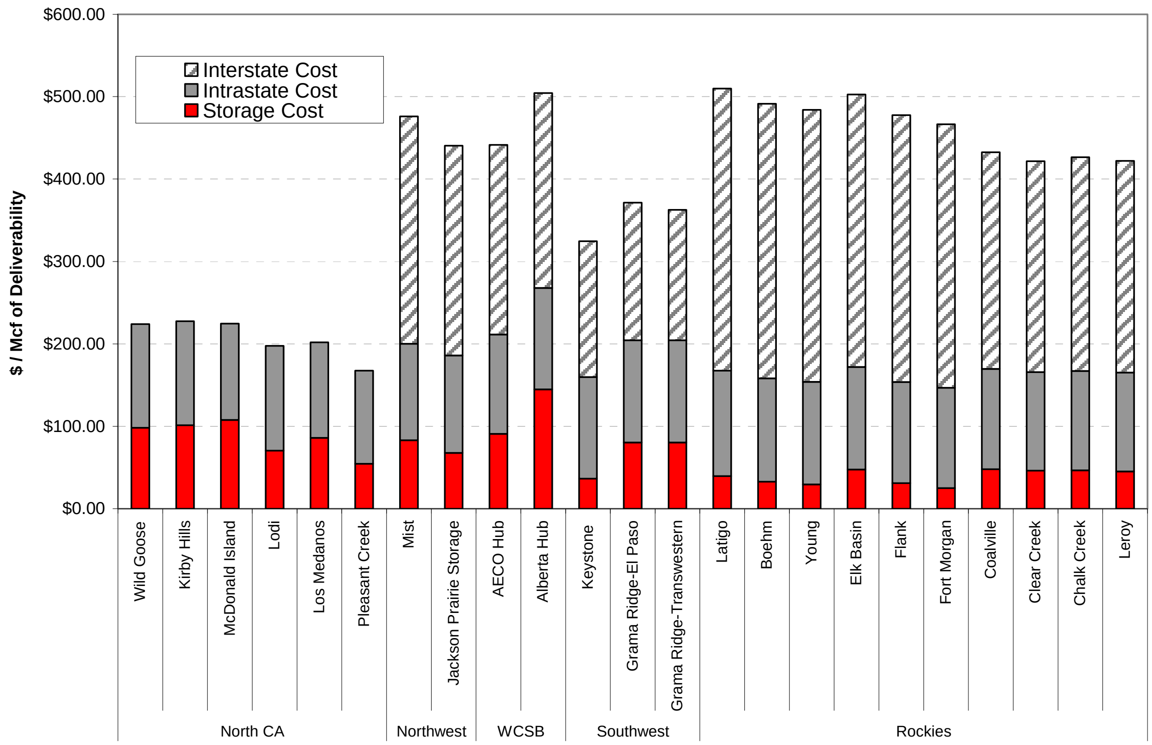


Figure 6-7: Existing Facilities with Service to PG&E, Source: B&V Analysis

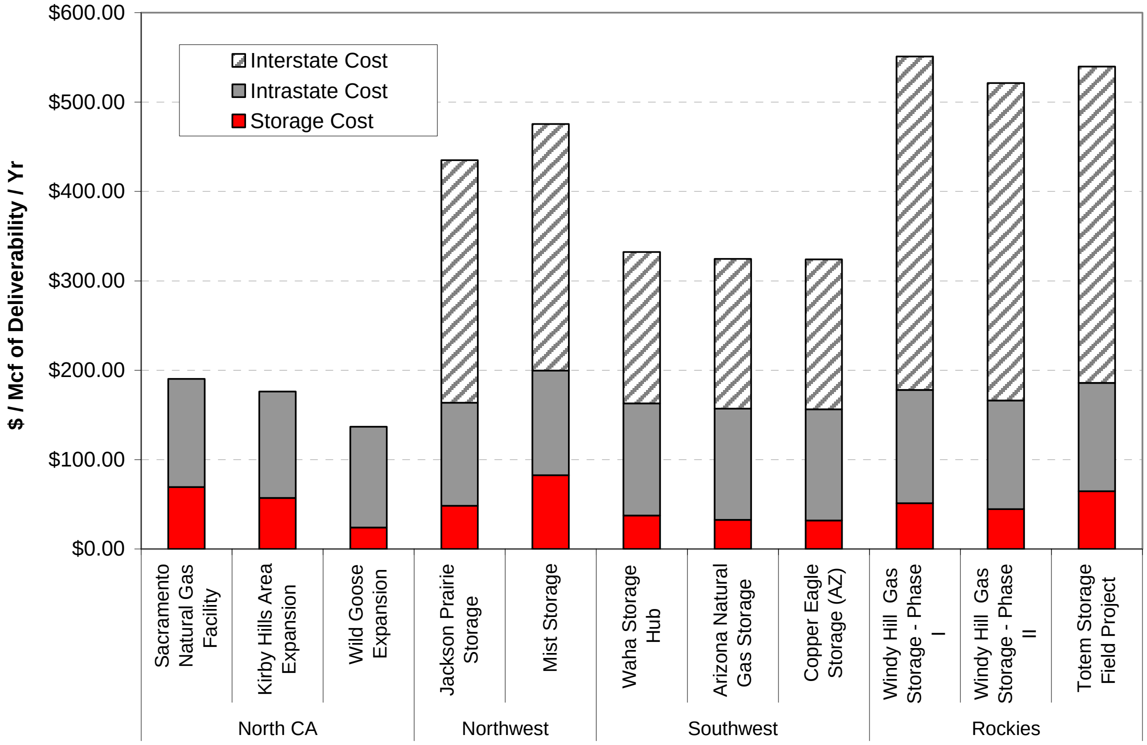


Figure 6-8: Proposed Facilities with Service to PG&E, Source: B&V Analysis

6.2.2. Alternatives for the SoCal Market

The economic comparison of the costs of existing and proposed storage facilities with service to the SoCal market are shown in Figures 6-9 and 6-10. The in-state storage fields within the SoCal territory are owned by SoCal and are operated as combined system storage. This combined in-state storage offers the most economic storage alternative for the SoCal market since the cost of interstate transportation makes out of state storage a relatively expensive alternative. The availability of in-state storage may act as a constraint that determines how much demand can be met by in-state storage. Assuming that interstate transportation capacity is available at current FT rates, the Southwest storage facilities offer the least expensive out of state alternatives for the SoCal market.

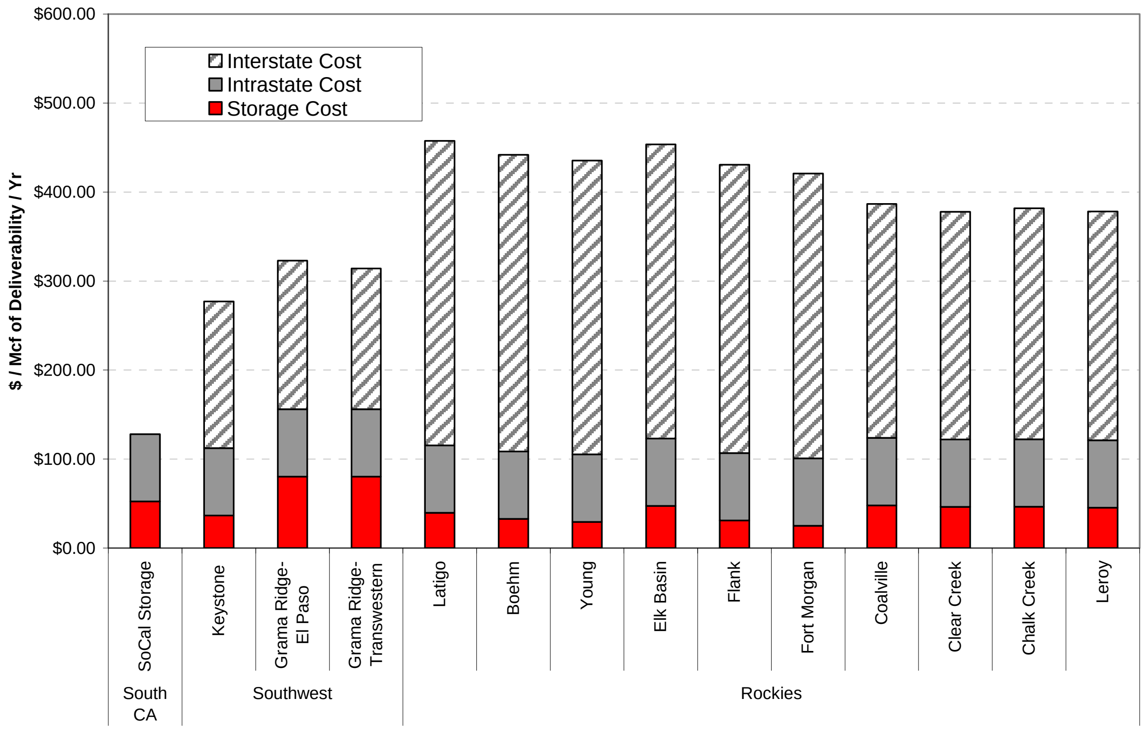


Figure 6-9: Existing Facilities with Service to SoCal, Source: B&V Analysis

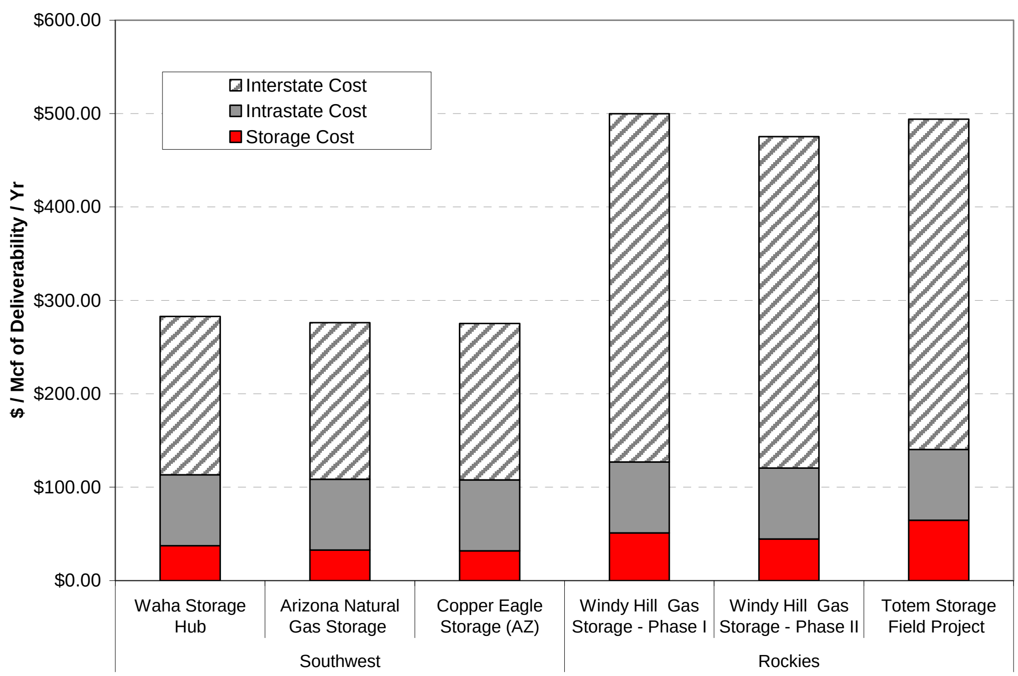


Figure 6-10: Proposed Facilities with Service to SoCal, Source: B&V Analysis

6.2.3. Alternatives for the SDG&E Market

The economic comparison of the costs of existing and proposed storage facilities with service to the SDG&E market are shown in Figures 6-11 and 6-12. The dynamics of the storage market for SDG&E are similar to those for the SoCal market with additional transportation costs on the SoCal and SDG&E systems to access the SDG&E market. In-state SoCal system storage offers the least expensive alternative to serve this market since the cost of interstate transportation makes out of state storage facilities a relatively expensive alternative. As with the PG&E and SoCal markets, assuming that interstate transportation capacity is available at current FT rates, the Southwest storage facilities offer the least expensive out of state alternatives for the SDG&E market.

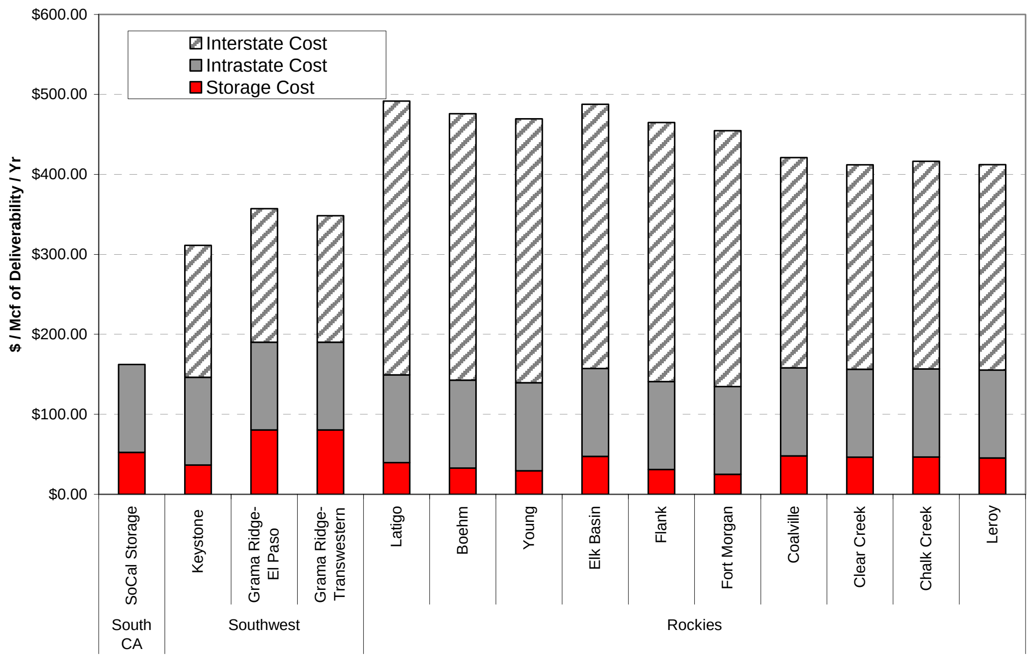


Figure 6-11: Existing Facilities with Service to SDG&E, Source: B&V Analysis

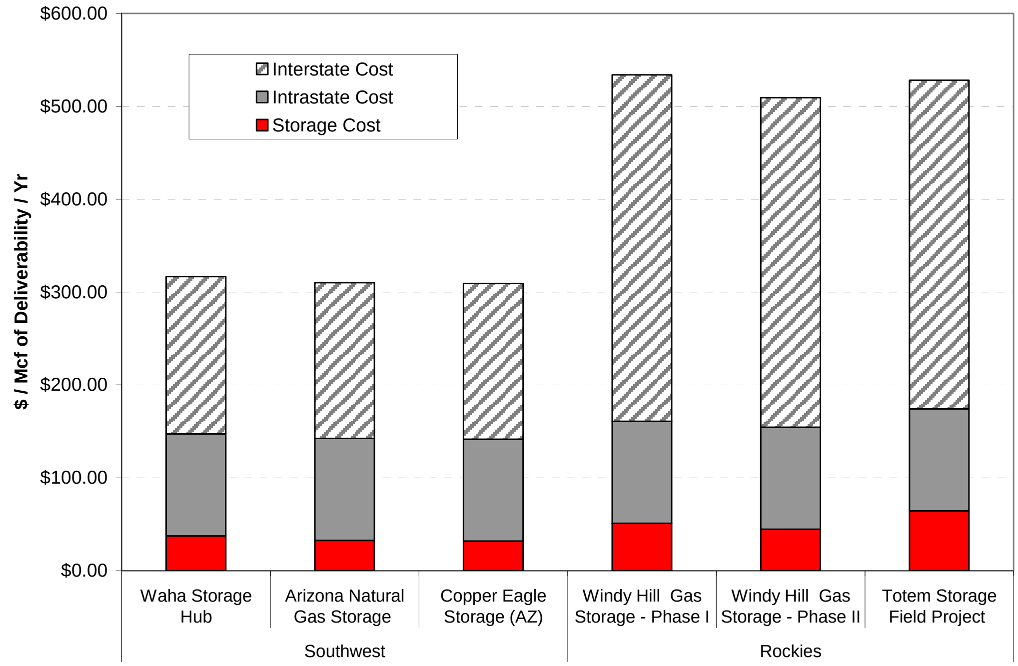


Figure 6-12: Proposed Facilities with Service to SDG&E, Source: B&V Analysis

6.3. Economic Valuation of Potential New Storage in California

This section examines the economics of new storage development in California. For the purpose of this analysis, a notional storage facility with 8 Bcf working gas capacity that represents a mid-sized storage project has been considered. The storage facility was assumed to be able to provide three turns of service consistent with the average deliverability of the existing and proposed independent storage facilities in California.

6.3.1. Capital Cost Estimates for New Storage in California

In order to estimate capital cost requirements for a new storage facility in California, B&V reviewed capital costs associated with relatively recent storage developments in California. Specifically, capital costs associated with the Wild Goose, Lodi and Kirby Hills (including expansion) storage facilities and the proposed Sacramento Storage project were utilized in the analysis. A cost escalation rate based on the Producer Price Index (PPI) was utilized to adjust the capital costs of the different projects to 2007 dollars.

The average capital cost of the storage facilities was assessed based on four different capabilities of the storage facilities:

1. Mcf of working gas capacity
2. Turn of service
3. Mcf of withdrawal capacity/day
4. Mcf of injection capacity/day

Based on this assessment, the capital cost estimate for a new storage facility in California with 8 Bcf of working gas capacity and offering 3 turns of service ranges from $37 to $49 million[18] as shown in Figure 6-13.

Estimated Capital Cost for an 8 Bcf Storage Facility		
Based on Bcf of working gas capacity	$	49,081,608
Based on Turn of service	$	49,224,636
Based on Mcf of Withdrawal/day	$	37,444,180
Based on Mcf of Injection/day	$	36,438,680

Figure 6-13: Estimated Capital Cost

6.3.2. Estimation of Return on Investment for Developing New Storage in California

The return on a new storage project in California was estimated by averaging the capital cost estimate based on the Mcf of injection and withdrawal capacity in a day to obtain a capital cost of $37 million for an 8 Bcf working gas capacity, three turn facility. In addition, a cost of $54 million was included for 8 Bcf of pad or base gas valued at an average PG&E price over the analysis period of $6.75/MMBtu. Standard assumptions were made on the debt/equity structure and its associated costs as well as other financial inputs required to estimate the return on investment as indicated in Figure 6-14.

The revenue attributable to the storage facility was based on the valuation of the storage facility using B&V's proprietary storage valuation software, SVA™, using the methodology described in Section 6.1.6. The valuation incorporates the projections for seasonal spread and price volatility that were discussed in Section 5. The total storage lease rate per Mcf was assumed to comprise of 100% of the intrinsic value and 50% of the theoretical extrinsic value to account for risk adjustment to the contracting party associated with monetizing the extrinsic value.

In addition to the lease rate, hub services revenues were attributed to the storage facility. Hub service revenues arise from additional services generally provided by the storage facility such as wheeling service and park and loan (PAL) services. Wheeling service involves moving gas between different pipeline interconnects on a storage header or hub. PAL service generally involves short-term storage where the storage receives and parks gas for customer until it is returned at an agreed time or the storage lends gas to the customer to be received back at an agreed time. A 10% uplift in value arising from hub services has been assumed in this analysis to reflect B&V's assessment of hub services value generally achieved by comparable independent storage facilities. Revenue streams are also assumed from a 1% fuel retention rate and a variable fee of $0.02/Mcf.

18. Does not include the cost of base gas.

The analysis indicates a Net Present Value (NPV) of $17.6 million using a discount rate corresponding to a 10.8% weighted average cost of capital (WACC). The Internal Rate of Return (IRR) of the project is 16.3%. These returns represent a fair return on investment and indicate that new storage development in California could be economically feasible given sustained high volatility and seasonal spreads in the natural gas market. The two proposed storage facilities in California, Sacramento Storage and Gil Ranch Storage seem to bear out the attractiveness of underground natural gas storage under the current natural gas market conditions.

Operation Assumptions		Revenue Components	
Working Gas Capacity (Bcf)	8.0	Rate ($/Mcf/month)	0.13
Turns of Service (Turns / Yr.)	3.0	Hub-Service Revenue (as % of Storage Rev)	10%
In-Service Date	2010	Fuel Retention %	1.00%
Cost Escalation Factor Per Year	6.2%	Variable Fee ($/Mcf)	0.02
Financial Assumptions		**Capital Assumptions**	
Debt Weight	60.0%	Gas Price ($/Mcf)	6.75
Equity Weight	40.0%	Pad Gas (Mcf)	8,000,000
Debt Cost	8.0%	Pad-Gas Capital Costs ($)	$ 54,000,000
Pre-tax Equity Cost	15.0%	Facilities Capital Costs	$ 36,941,430
Loan Term (Yrs)	15	Total Development Costs	$ 90,941,430
Tax Rate	38.3%		
Escalation Rate (Revenue)	1.50%		
Escalation Rate (Opex)	1.50%		
EBITDA Multiple for Terminal Value	12		

Figure 6-14: Cost of Service for New Storage, Source: B&V Analysis

7.0 Regulatory Impediments to the Development of Underground Storage in California

7.1. Review of California Regulatory Requirements

On June 19, 2006, the FERC issued Order No. 678 in Docket Nos. RM05-23-000 and AD04-11-000. The order permits the consideration of close substitutes to storage in defining the relevant product market, including transportation and local peak shaving capabilities. The order further establishes a uniform set of regulations for the materials and showings that must be provided with each application for new or expanded storage at market-based rates.

Further, the FERC adopted regulations to implement Section 312 of the Energy Policy Act of 2005, which permits the Commission, in appropriate circumstances, to authorize storage providers to charge market-based rates for service utilizing new capacity even when the storage cannot (or does not) demonstrate that it lacks market power. Facilities put into service after August 8, 2005 may apply for market-based rates if it can be demonstrated that the rates are in the public interest and necessary to encourage the construction of the storage capacity in the area needing storage services. The storage provider must also provide a means of protecting customers from the potential exercise of market power. Northern Natural Gas Company was one of the first companies to apply for market-based rates under this provision, for the expansion capacity at its Redfield, Iowa facility. The Commission issued a Declaratory Order authorizing market-based rates for Northern's expansion capacity at Redfield.[19]

Together, or separately, the FERC's new regulations provide a clearer path for applicants to follow and generally serve to encourage the development of new FERC-regulated storage, and expansions, at Market-based rates.

7.2. National Environmental Policy Act Provisions

The FERC's regulations contain provisions to implement the Commission's procedures under the National Environmental Policy Act (NEPA). Under NEPA, natural gas storage projects and expansions may require the preparation of an Environmental Assessment or an Environmental Impact Statement. FERC's extensive NEPA regulations are set forth in the Code of Federal Regulations at 18CFR§380.

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19. 117 F.E.R.C. P61,191; 2006 FERC LEXIS 2654, Northern Natural Gas Company, Docket No. RP06-437-000, November 16, 2006.

7.3. California Rate and Environmental Policies

7.3.1. *California's Market-Based Rates Policy*

With respect to California intrastate storage facilities, the CPUC in 1993 adopted a "let the market decide" policy for gas storage, implementing market-based rates for non-core storage from new or expanded facilities. The California Public Utility Commission's decisions set the stage for allowing non-utility companies to develop storage facilities in competition with the regulated intrastate storage services in the state.[20]

7.3.2. *California Environmental Quality Act*

California's Environmental Quality Act (CEQA) provides that applicants for California projects shall submit Environmental Impact Reports that include: a summary, a project description, an environmental setting description, a consideration and discussion of environmental impacts section, a consideration and discussion of major environmental impacts section, a consideration and discussion of mitigation measures proposed to minimize significant effects, a consideration and discussion of alternatives to the proposed project, a statement of effects not found to be significant, a listing of organizations and persons consulted, a discussion of cumulative impacts, and economic and social effects of the proposed project. The CEQA includes provisions for joint activities with federal agencies and coordination and cooperation for those projects that may be subject to both the provisions of NEPA (such as with FERC-regulated storage projects) and with the provisions of CEQA.

7.4. Survey of Storage Developers

In order to determine if there are impediments to the development of new storage and/or storage expansions in the state, B&V developed a survey questionnaire for distribution to existing and potential gas storage providers in the state. In general the survey was focused on understanding, from the storage operator's perspective, the regulatory issues that they face to develop new storage facilities in California. The survey was sent to all western US operators of natural gas storage. Since the response to the survey was limited, the survey and its results are not presented in this study.

The responses received were limited. Due to the low response rate, the general conclusions developed from the survey results are limited and may not reflect the majority opinion concerning storage regulation issues.

7.5. Summary

Based on B&V's review of California regulations, there appears to be no major impediments to the development of new and/or expanded natural gas storage projects in the state. Obviously, it is incumbent upon the developer to work closely with the CPUC and other state agencies, and to comply with all applicable regulations.

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20. 2000 Cal. PUC LEXIS 394, Decision No. 00-05-048, Application No. 98-11-012, Lodi Gas Storage Application for Certificate of Public Convenience and Necessity, page 75.

8.0 Conclusions and Recommendations

The conclusions of the B&V analysis are a logical compilation of the observations and study results across the different scope elements that incorporate the commonalities between them and are not mapped one-to-one with the scope elements discussed in the Executive Summary. The conclusions are grouped into the following areas for discussion: natural gas supply/demand outlook for California, market responses to natural gas supply/demand sensitivity scenarios, infrastructure needs to meet growing California demand, and the future role of storage in California. The conclusions are listed as a logical progression from supply/demand based conclusions to asset infrastructure based conclusions.

8.1. Conclusions

8.1.1. Natural Gas Supply/Demand Outlook for California

Expectations for Future Demand for Natural Gas in California

The average annual demand for natural gas in the State of California is projected to grow from 6.2 Bcf/day in 2008 to 7.1 Bcf/day by 2020 under baseline projections. The growth in natural gas demand for the residential and commercial sectors is expected to be 0.7% CAGR or 55 Bcf over the study period. This growth projection is lower than recent estimates by the EIA of 1.1% CAGR[21], and the Energy Commission of 2% CAGR[22] By 2020, B&V's forecast is 0.6 Bcf/day and 0.4 Bcf/day lower, during peak months, than the EIA and Energy Commission forecasts respectively.

The residential/commercial sector consumption pattern is expected to change over the analysis period. Growth in peak day demand versus average demand is expected to occur in both northern and southern California. Implications for this change include the growing requirements for peak day deliverability. The analysis of infrastructure requirements to meet California peak day demand is summarized in Executive Summary.

Industrial demand is expected to grow at 0.4% CAGR or by 30 Bcf over the study period. This growth projection is similar to recent estimates in the EIA AEO 2007 but higher than the Energy Commission estimate of -0.7% CAGR[23]. Annual industrial demand within California has dropped from a peak in 2004 – 2005 to the current levels of 732 Bcf for 2006. B&V believes that this trend will reverse due to overall expectation for economic growth in California and the fact that much of the price sensitive industrial demand has already either shut-down or switched to alternate fuels.

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21. EIA AEO 2007

22. California Energy Commission: Integrated Energy Policy Report 2007

23. California Energy Commission: Integrated Energy Policy Report DRAFT October 2007

The growth in demand for natural gas from power generation in California is expected to be substantial and increase at a rate of 1.6% CAGR or by 235 Bcf from 2008 to 2020. This growth projection is higher than recent estimates by the EIA of -0.8% CAGR[24], and the Energy Commission of 1.1% CAGR[25]. As a comparison, the B&V analysis results in a projection for natural gas demand from power generation that is 1 Bcf/day higher by 2020 than the Energy Commission analysis in peak months. The main driver of the forecast for natural gas demand from power generation is the assumption that gas-fired generation located in California will be required to meet a substantial portion of increased demand for electricity in California.

Short-term price elasticity of demand in California for the residential, commercial and industrial sectors is estimated by B&V to be slightly lower than previously published analysis by the Energy Commission[26] and EIA[27]. Our expectation is that residential, commercial and industrial consumption sectors will show some conservation as natural gas prices rise. The resulting reduction in demand with a 1% increase in burner tip prices is small with an expectation of annual reduction in total California natural gas demand of 10 Bcf.

Expectations for Future Natural Gas Supply into California

The main natural gas supply basins serving California include the Rockies production region, San Juan basin in northern New Mexico, Permian Basin in western Texas, WCSB, and in-state California production. The average historical natural gas supply to the state is projected to grow from approximately 5.7 Bcf/day to 6.4 Bcf/day by 2020. This results in a 0.7% CAGR increase over the study period.

Gas supply imports from the Rockies into California remain flat even though Rockies production is expected to increase significantly, growing from approximately 8 Bcf/day to over 10 Bcf/day by 2020. In the absence of pipeline expansion capacity into California, increases in Rockies production are expected to flow into eastern U.S. markets. Imports into California from the Rockies through the Kern River pipeline, which has a current capacity of 1.98 Bcf/day, are expected to remain at or near pipeline capacity throughout the study period.

Canadian Gas remains an important supply source for Northern California. Production from the WCSB is expected to decline from approximately 16 Bcf/day to 15 Bcf/day by 2020. These estimates incorporate the start-up of the Mackenzie Valley Pipeline in 2014. The expected growth in Canadian demand and declining WCSB production limit exports to California. Gas supply from Canada is transported into California via the GTN. B&V projects that the availability of Canadian supply and the utilization of the GTN pipeline will decline over the analysis period, until additional LNG supplies reach the Pacific Northwest, or the construction of a pipeline from Alaska into Alberta, Canada.

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24. EIA AEO 2007

25. California Energy Commission: Integrated Energy Policy Report DRAFT October 2007

26. California Energy Commission: Western Natural Gas Assessment 2005

27. EIA AEO 2007

Natural gas production in the San Juan and Permian basins is projected to be relatively stable with a slight decline from 7.9 Bcf/day to 7.6 Bcf/day from 2008 to 2020. Gas supply from these two basins flows into California on the El Paso and Transwestern Pipeline systems. These systems are expected to have sufficient capacity to meet base load projections over the analysis period.

LNG imports into California are assumed to come from the Energia Costa Azul LNG facility that is currently under construction in northern Mexico near Baja California. The projected LNG imports from the Costa Azul facility of 0.5 Bcf/day are critical in meeting the expected demand growth in California.

Finally, in-state California production remains a key source of gas supply to the state and is expected to remain relatively flat from 2008 to 2020 at a rate of 0.8 Bcf/day.

Baseline Forecast for California Natural Gas Prices

Based on the B&V baseline assumptions for natural gas supply and demand in North America, natural gas prices in both southern and northern California will remain at relatively high levels over the analysis time period. The SoCal price is expected to increase from $5.50/MMBtu in 2008 to $7.50/MMBtu by 2020. The PG&E Citygate price is also expected to increase from $5.80/MMBtu in 2008 to $7.80/MMBtu in 2020. Compared to the Energy Commission 2007 forecast[28], the B&V forecast is higher in the 2008-2013 time frame, with both forecasts following an upward trend through 2018.

Relationship of California Prices to Henry Hub

Our findings indicate that the baseline expected prices at the Henry Hub in Louisiana, the main pricing point for the North American gas market, will range from $6.50/MMBtu to $8.00/MMBtu during the study period of 2008 through 2020. The price basis differential expected between northern California at the PG&E Citygate and Henry Hub is $-0.01/MMBtu in 2008 growing to $0.13/MMBtu by 2013, before declining to $0.01/MMbtu by 2020. Similarly B&V expect prices in southern California, delivered into the SoCal system, relative to the Henry Hub to be relatively flat at $-0.24/MMBtu in 2008 and $-0.23/MMBtu in 2020.

8.1.2. Sensitivity of California Prices to Changes in Supply/Demand

Market Responses to Natural Gas Supply/Demand Sensitivity Scenarios

B&V's baseline forecast relies upon an assumption for demand growth and production expectations. However, it is expected that actual supply and demand will vary from the baseline assumptions. Therefore the impacts of variations in supply and demand assumptions were analyzed to understand the main drivers to natural gas prices in California.

28. California Energy Commission: Integrated Energy Policy Report DRAFT October 2007

The main supply and demand drivers identified as having a key impact on market prices in California and the associated utilization of assets were WCSB production, Rockies production, San Juan/Permian basin production, LNG imports into North America, residential/commercial gas demand in California and the western U.S., and the gas demand from power generation in California and the western U.S. gas.

The amount and timing of North American LNG imports has the greatest impact on northern and southern California prices. For southern California, San Juan/Permian Basin and Rockies production had the second largest influence on prices. The price in southern California, into the SoCal pipeline at the border, has a significant probability of ranging between $6.20/MMBtu and $7.07/MMBtu in 2020 due to the uncertainty in actual supply/demand factors. For northern California, natural gas demand from power generation had the second largest impact on prices. Prices in northern California at the PG&E citygate showed an equal range of expected uncertainty. Northern California prices have a significant probability of varying between $6.80/MMBtu and $8.20/MMBtu in 2020.

Demand from Gas-Fired Generation and Implications of Meeting the California Renewables Targets for Natural Gas Prices

Natural gas demand from power generation will vary based on load growth and conservation, weather and the generation fleet required to meet electricity demand. B&V developed scenarios around these uncertainties and found that natural gas demand from power generation and the ability to meet the California's renewable target of 20% by 2010 had a significant impact on the demand for natural gas and natural gas prices in California. If the RPS requirement is met, natural gas demand from the power generation sector grows at 1.6% from 2008 to 2020 under baseline assumptions.

The increase in natural gas demand for power generation when additional gas-fired generation is required, due to the non-compliance with the renewables targets and when California power demand peaks due to weather, is 13% greater in 2015 and 32% greater in 2020 than the baseline demand forecast. This higher demand, when all other variables are constant, results in an increase in natural gas prices in southern California of $0.60/MMBtu by 2020. Similar increases were seen in northern California where prices could be $1.20/MMBtu greater by 2020.

Implications to California Prices from Growing LNG Imports

As stated in the Executive Summary, variance in the amount of North American LNG imports will have a substantial impact on prices throughout North America. B&V varied the amount of LNG imports to understand the price sensitivity in North America, and specifically, California. A B&V based estimate was utilized for reduced imports that resulted in LNG imports of approximately 6 Bcf/day by 2020. For a high import scenario, B&V utilized the baseline LNG import assumptions made by the Energy Commission in its preliminary report[29] where LNG imports grow to approximately 33.2 Bcf/day by 2020.

29. California Energy Commission: Integrated Energy Policy Report DRAFT October 2007

California natural gas prices in 2020 are expected to range from $7.15/MMBtu if LNG imports fall to the lower range of the expectations to approximately $5.34/MMBtu should the flood of LNG into North America occur as projected by the Energy Commission.

8.1.3. California Natural Gas Infrastructure

Infrastructure Needs to Meet California Baseline Natural Gas Demand Projections

Based on the fundamental analysis completed by B&V, the existing pipeline, storage, LNG and production infrastructure serving the western United States is expected to be sufficient to meet growing baseline natural gas demand projections. Pipeline utilization into California, and the corresponding availability of natural gas supply, will either grow or remain at high utilization levels for the GTN and Kern River pipeline systems. The El Paso and Transwestern pipeline systems currently have surplus capacity into California and this underutilization is expected at levels observed today, on average, throughout the planning period. Storage utilization is projected to reach 70% of capacity for the currently operating and planned storage facilities.

California Peak Day Natural Gas Demand is Expected to Grow

Using the fundamental demand projections completed by B&V coupled with an analysis of daily natural gas consumption, B&V developed projections for peak day demand in 2015 and 2020. These projections were the basis for reviewing the capabilities of the current natural gas infrastructure in meeting future California natural gas demand requirements.

Peak day demand in California is projected to grow from 10.1 Bcf/day in 2008 to 11.8 Bcf/day in 2020 under normal operating conditions. With higher demand, peak day needs can reach 16 Bcf/day by 2020 within California. The growth in peak day demand is projected to be slightly different in northern California where peak day needs, in high demand periods, could reach 6.1 Bcf/day by 2020 with a 4% CAGR from the 2006 peak-day send-out of 3.5 Bcf/day. In southern California, peak day needs could grow at 4.2% CAGR to 9.7 Bcf/day by 2020.

With High Demand, Additional Natural Gas Infrastructure Serving California is Required

The sensitivity of the California natural gas market to variations in supply/demand assumptions, coupled with the peak day analysis completed by B&V, leads to the conclusion that additional natural gas assets are required to serve the State during peak periods, from a planning perspective. The type of asset required varies depending on the peak load profile expected.

If increases in peak load are driven by increases in natural gas demand for power generation, a combination of new interstate transportation or LNG supply coupled with additional intrastate storage is expected to be the optimal asset infrastructure combination. B&V projects that 70 Bcf of additional supplies are needed annually to meet daily demand requirements under a high power generation demand scenario. Depending on the feasibility of acquiring additional interstate transportation capacity or LNG supply, storage development can be used as a supplementary supply source.

Meeting expected weather sensitive natural gas demand predominantly requires the addition of storage assets in the State or increased availability of base load LNG. However, additional interstate transportation capacity, or LNG imports into California, is also likely to be needed to ensure the availability of sufficient capacity to fill the increased storage working gas capacity. B&V projects that 218 Bcf of additional natural gas supply is needed on an annual basis to meet daily demand requirements with the combination of high core and power generation demand.

Future Natural Gas Infrastructure Needs could be Higher Depending on the Availability of Assets during Peak Periods

A key element behind these projections for new infrastructure to serve California during extreme demand events, is the 100% availability of interstate pipeline capacity, intrastate production and base load imports of natural gas into California from the Costa Azul LNG terminal. If peak day planning incorporates some level of unavailability of these supply infrastructure assets, greater levels of supply assets are required to ensure that sufficient infrastructure is in place to meet demand in California. The same mix of supply assets that are summarized in the Executive Summary is expected to be required in this case. As an example if in-state production, LNG imports and interstate pipeline capacity are available only 90% of the time during peak demand periods, 248 Bcf and 376 Bcf of additional pipeline capacity and storage capacity are needed to meet daily requirements from a high power generation demand scenario and a high core and high power generation demand scenario, respectively.

8.1.4. Future Role of Storage in California

Intrastate Storage is more Cost Effective than Storage Located Outside California

In-state storage offers the most economical source of storage service for California. Existing storage in both northern and southern California are less expensive than new build alternatives in the state or the import of storage services, from facilities located east or north of California. The current market value of in-state storage ranges from $150 to $280 per Mcf of deliverability. Of the potential and proposed storage services that could become available to serve California demand, expansions of in-state facilities proposed at Kirby Hills and Wild Goose, as well as the development of new in-state storage such as the facility proposed by Sacramento Storage, offer the most economic alternatives for California with an estimated storage cost range of $150 to $220 per Mcf of deliverability.

Out-of-state storage offers a relatively expensive alternative for California but could present an option if development of storage within California becomes unviable. The least expensive alternative for out-of-state storage to serve California is storage from the southwest basins, connected to the El Paso or Transwestern pipeline systems, with a storage cost range of $291 to $351 per Mcf of deliverability. These facilities could be economically viable if discounted firm interstate transportation is available on the El Paso and Transwestern pipelines.

Future Expectations for Natural Gas Price and Volatility in California Supports the Market Value of Intrastate Storage

Utilizing statistical methods to analyze historical behaviors of natural gas prices in California allowed B&V to understand the best method to simulate short term price volatility and understand implications on a forward looking basis. B&V then coupled the short term analysis with the long term analysis of California prices and the sensitivity to fundamental factors to understand the expect trends in natural gas price volatility.

Based on this analysis approach, B&V projects that natural gas volatility in California will increase by 5% over the analysis period. This will lead to slight increases in the value of market based storage services. The importance of this projection is that the market conditions will remain supportive for future development of independent storage facilities with market based rates.

Market Based Returns for New Independent Storage Development Appear Favorable for New Development Projects

B&V estimated capital costs for new independent storage development based on information filed by existing independent storage facilities in California adjusted for inflation. The analysis results indicate that with the projected prices, seasonal spreads and volatility, market based valuation of independent storage facilities provides adequate returns. The analysis indicates that the IRR for new project development exceeds 15%, a rate of return that can attract investment capital. Although typical independent storage projects target higher returns, the assumptions used by B&V to estimate the economics for new storage development in California were conservative.

Minimal Regulatory Impediments Exist that Limit Development of Market Based Storage Facilities in California

B&V reviewed existing federal and state regulations to understand the requirements for new storage development and did not find any unreasonable regulatory requirements, relative to other locations in the United States, which would prevent additional storage development in California. In addition, B&V completed a survey of independent storage operators and developers to better understand their individual concerns. Again, our findings from the survey indicated that while there are unique requirements to develop storage in California, they are not insurmountable for a developer that has a strong knowledge of the California market and regulatory process.

8.2. Recommendations

B&V recommendations for future research relating to the California natural gas market and supporting supply, pipeline and storage infrastructure are summarized below. The B&V developed recommendations are based on the conclusions developed by B&V and summarized in this report. The recommendations are not listed in order or priority. They are listed in the same general order as the conclusions.

Update Estimates of Future Supply Infrastructure Needs on a Regular Basis to Reflect Changes in Supply/Demand and Infrastructure Serving California

Section 4 of this report developed peak day demand estimates to understand whether additional natural gas supply infrastructure is required within the State. Supply, demand and infrastructure serving the State are constantly changing. As an example during the course of completing the analysis for this report, there have been announcements to develop an additional gas storage facility in California, Gill Ranch, and to construct a new pipeline into California from the Rockies supply region, Bronco Pipeline. These announcements occurred well into the B&V analysis and were not incorporated into the results. In addition, demand scenarios associated with changes to renewable targets or expected carbon emission costs in the western United States would provide additional, valuable insights.

Given the fluidity of the market, it is appropriate to routinely re-evaluate the balance of needs for the State. B&V recommends a regular update to the infrastructure needs analysis to incorporate changes that occur on a year to year basis.

With a base analysis completed, an update will require substantially less man hours and costs to complete than the original B&V study. The time required to complete the additional scope is estimated to be two to three months.

Expanded Review of Market Uncertainties that Cause Natural Gas Price Volatility

Section 3 of this report explored the sensitivity of natural gas prices to key drivers. The report analysis was focused on B&V's designated main drivers to California prices. Additional secondary California market drivers merit consideration include, as examples, varying load factors for Costa Azul LNG imports, alternative scenarios of natural gas demand from power generation, and energy conservation. The outcome would be a more robust understanding of the key drivers to natural gas prices in California, the expected range of prices that the State may experience, and insights into future market volatility.

The determination of the range of these drivers can be completed independently by B&V or in collaboration with the Energy Commission and/or natural gas utilities and pipelines serving California. The time required to complete the additional scope is estimated to be 3 to 4 months.

Revise Peak Day Planning Analysis and Infrastructure Assessment to Incorporate Utility Peak Day Expectations

The B&V analysis developed alternative peak demand scenarios which are different or subsets of those developed and utilized by California utilities. The findings outlined in this report concerning the need for additional wholesale gas supply infrastructure can be expanded to include these utility defined scenarios. B&V, coupled with CIEE and/or the Energy Commission, would jointly developed alternative peak day demand scenarios in conjunction with selected California utilities. Once the updated scenarios are complete, the conclusions to Section 4 of this report would be expanded.

The estimated time required to complete this expanded analysis would be two to three months.

Understand the Implications of Supply Asset Reliability to Peak Day Needs and Supply Asset Redundancy

The B&V analysis conclusions in Section 4 highlighted the sensitivity of future supply needs to the availability of the natural gas supply assets during peak periods. B&V recommends expanding this analysis to understand the availability of the different supply assets and trends in utilization. The findings from this analysis would indicate the amount of supply redundancy, if any, required to ensure the natural gas supply infrastructure is sufficient to meet peak day requirements with California.

The estimated time required to complete this expanded analysis would be three to four months.

8.3. Benefits to California

The benefits to California associated with the analysis and findings of this report are multi faceted. The report conclusions and findings should not be viewed necessarily as a replacement to other analysis completed by the Energy Commission or stakeholders in California. Rather, it should be viewed as an independent assessment that either challenges current thoughts concerning the natural gas infrastructure in California or confirms findings published by other stakeholders in California.

Specific benefits noted by B&V are as follows:

- Improve understanding of expected natural gas prices in California under base conditions.
- Increase awareness of the impact of power generation demand for natural gas and the implications to California in meeting the RPS.
- Understand the sensitivity of natural gas prices in California to changes in market conditions.
- Highlight issues concerning the availability of natural gas supply infrastructure to California and potential requirements for supply asset redundancy to meet peak day conditions.
- Recognize that a combination of new supply (production or LNG), pipeline capacity and storage are required in the future to meet California supply requirements.
- Highlight that storage is an important asset in meeting California natural gas demand and is projected to have a growing role into the future.
- Recognition that it is more cost effective and reliable to facilitate and allow increased storage development within California.

9.0 Glossary

AEO	Annual Energy Outlook
B&V	Black & Veatch Corporation – Enterprise Management Solutions
Bcf	Billion Cubic Feet
Bcf/day	Billion Cubic Feet per Day
CAGR	Compound Annual Growth Rate
CEQA	California Environmental Quality Act
CIEE	California Institute for Energy and Environment
CPUC	California Public Utilities Commission
Dth	Dekatherms
EIA	Energy Information Administration
El Paso	El Paso Natural Gas
FERC	Federal Energy Regulatory Commission
FOM	First of Month
FT	Firm Transportation
GOM	Gulf of Mexico
GTN	Gas Transmission Northwest
HDD	Heating Degree Days
IID	Imperial Irrigation District
IRR	Internal Rate of Return
Kern or Kern River pipeline	Kern River Gas Transmission
LADWP	Los Angeles Department of Water & Power
LDC	Local Distribution Company
LNG	Liquefied Natural Gas
Mcf	Thousand Cubic Feet
MMBtu	Million British Thermal Units

MMcf/day	Million Cubic Feet per Day
NARG	North America Regional Gas
NEB	National Energy Board
NEPA	National Environmental Policy Act
NGI	Natural Gas Intelligence
NPV	Net Present Value
NYMEX	New York Mercantile Exchange
PAL	Park and Loan
PG&E	Pacific Gas and Electric Company
PIER	Public Interest Energy Research Program
PPI	Producer Price Index
RD&D	Research, Development, and Demonstration
REX	Rockies Express Pipeline
RPS	Renewables Portfolio Standard
RSTEM	Regional Short Term Energy Model
SCE	Southern California Edison
SDG&E	San Diego Gas and Electric Company
SMUD	Sacramento Municipal Utility District
SoCal	Southern California Gas Company
TGN	Transportadora De Gas Natural De Baja California
Tuscarora	Tuscarora Pipeline
WACC	Weighted Average Cost of Capital
WCSB	Western Canadian Sedimentary Basin
WECC	Western Energy Coordinating Council