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THE VALUE OF NATURAL GAS STORAGE AND THE IMPACT OF RENEWABLE GENERATION ON CALIFORNIA'S NATURAL GAS INFRASTRUCTURE

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PREFACE

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The Value of Natural Gas Storage and the Impact of Renewable Generation on California's Natural Gas Infrastructure is the final report for the Developing a Multi-State Natural Gas Infrastructure Simulation Model to Analyze the Value of Natural Gas Storage in California project (Contract Number 500-02-004, Work Authorization number MR-056) conducted by ICF International. The information from this project contributes to Energy Research and Development Division's Energy Systems Integration Program.

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ABSTRACT

The California energy crisis of 2001 showed the past inadequacy of the natural gas infrastructure in California to cope with significant weather-related increases in gas demand. California has invested since then in significantly expanding this infrastructure, both by increasing capacity along current pipelines and adding new natural gas pipelines into and within the state, as well as adding additional natural gas storage capacity within the state.

The first two phases of this project attempted to better understand the nature of natural gas storage infrastructure within California. The first section in this report was a conceptual analysis of natural gas storage within the state, with the goal of understanding fully the value of storage to both the private and public sectors. The second section detailed the modeling done to simulate California's natural gas infrastructure for better understanding the capability of the current infrastructure to withstand adverse weather conditions and to quantify the resulting impacts on storage within the state.

The third section of this report examined the future adequacy of California's natural gas infrastructure as renewable energy becomes an increasingly larger portion of the State's generating mix. On September 15, 2009 Governor Arnold Schwarzenegger signed Executive Order S-21-09, directing the California Air Resources Board to adopt regulations increasing California's Renewables Portfolio Standard to 33 percent by 2020. Such an increase in renewable generation could potentially stress California's natural gas infrastructure due to the inherent variability of some types of renewable generation, which could be an issue since this infrastructure provides fuel to the majority of the state's power plants. The reliability of California's gas infrastructure under a 33 percent Renewables Portfolio Standard scenario was also examined in this section of the report using the same modeling framework as in the storage analysis.

Keywords: Natural gas, infrastructure, weather, pipeline, storage, value, modeling, renewables portfolio standard, RPS, Executive Order S-21-09, renewable generation.

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EXECUTIVE SUMMARY

Introduction

The 2001 California energy crisis proved the inadequacy of the state's natural gas infrastructure at the time to deal with extreme weather conditions. Since 2001 the natural gas infrastructure within the state has expanded significantly, multiple pipelines into the state have increased in capacity, interconnects between pipelines in the state have expanded, and additional natural gas storage infrastructure has been developed. An analysis of the natural gas system in California with an emphasis on storage would provide valuable information given the changes that have occurred since 2001.

Project Purpose

The first objective of this work was to define and describe the value derived from natural gas storage on a conceptual level by identifying the various sources of value for the public and private participants in the storage market. The second objective was to develop a detailed model that could be used to evaluate California's natural gas system's response to various future scenarios including a variety of weather scenarios, and to draw conclusions about the system's adequacy. The third objective was to specifically understand the capability of California's natural gas infrastructure to respond to variations in renewable generation in the future under a Renewable Portfolio Standard (RPS) that requires 33 percent of electricity to come from renewable energy.

The project objectives relating strictly to natural gas storage were to:

- Identify private and public sector sources of value for natural gas storage.
- Understand the potential public policy and regulatory issues facing natural gas storage.
- Develop a model of California's natural gas infrastructure that was integrated with a national model.
- Quantify the seasonal impact of variations in weather on the natural gas in storage in California based upon storage utilization and natural gas prices using ten different weather scenarios.
- Quantify the peak-day impact of variations in weather on natural gas demand levels and prices in California using the same weather scenarios.

The project objectives regarding the impact of variations in renewable generation in California in 2019-2020 were to:

- Identify the average natural gas demand levels, storage working gas levels, and natural gas pipeline flows into and within California on a monthly basis.
- Identify the demand for natural gas within the three main demand sectors (power generation, industrial, and residential/commercial) for the peak demand day.
- Identify the sources of supply for natural gas in California and quantify the level of supply provided by these sources on an average and peak-day basis.

- Quantify the natural gas demand impact of variations in weather and renewable generation on the Base Case scenario using separate sensitivity analyses.
- Quantify the impact of differing renewable generation mixes such as higher solar photovoltaic capacity or higher wind capacity on natural gas demand compared to the Base Case scenario.

Project Results

In the first phase of this project the author identified four primary sources of value for private sector natural gas storage players: security and reliability; the ability to balance supply and demand; the ability to economically substitute for the next best alternative such as pipeline capacity; and the ability to manage price volatility and variability. The author also analyzed whether or not appropriate public policy rules and regulations were in place to generate incentives for the proper level of gas storage assets needed to maintain a prudent level of reliability.

The volume of contracted natural gas storage services should be able to achieve the socially desirable improvement in reliability if:

- The reliability of storage was contractible through the use of specified performance clauses and damages.
- The reliability was observable by customers.
- There were storage alternatives and switching costs among the alternatives were sufficiently low.
- Consumers of storage services were able to adjust the level of services or change service providers if an alternative provider could better meet requirements with acceptable termination costs.
- Access and entry into the market for new providers of storage was not restrictive.
- Growth in demand continued for new storage services.
- Natural gas consumers without storage appropriately paid for reliability.

The second phase of this project focused on modeling California's natural gas storage. The author modeled ten cases focused on the effects of differing weather patterns on the natural gas system within California, with an additional emphasis on how gas storage infrastructure within the state responded to the changes in demand. The worst case scenario analysis reflected a replication of the 2000-2001 energy crisis in California, depleting the amount of natural gas in storage at the end of the withdrawal season to levels similar to those in 2000-2001. The California gas market was still able to function even under these extreme conditions due to the infrastructure expansions that have occurred since 2001.

The author concluded that changes in California's natural gas infrastructure since 2001 have reduced vulnerability to adverse weather. California's gas infrastructure and gas supply situation have changed substantially since 2001. Pipeline capacity into the state has increased, pipeline interconnects within the state have been improved, and storage holders have changed operational behavior, with storage injection patterns less sensitive to short-term price trends.

The analysis indicated that the California gas market is better prepared to adjust to extreme weather and hydro conditions than it was during 2000-2001, and the price impacts of an extreme weather/hydro scenario were expected to be much lower than observed during this historical period.

Another conclusion from the storage modeling effort was that weather and storage activity outside of California and the Western Region had an impact on California's storage activity. The North American natural gas market was highly integrated, and conditions outside of California could have a significant impact on storage activity within the state. For example, cold weather in the Eastern United States could reduce pipeline flows into California and thereby increase withdrawals at California's storage fields even if gas demand within the state was not at above average levels.

The third phase of this project was the 33 percent RPS modeling effort. The author modeled five cases representing mixtures of differing inputs by varying weather patterns, renewable generation, and mixtures of renewable technologies. The conclusions from this phase of the analysis were:

- A 33 percent RPS would result in an incremental reduction in California's gas demand. Achieving a 33 percent RPS by 2020 would result in greater incremental growth in renewable generation than growth in electric load based on the California Energy Commission's 2007 electric load projection. Gas-fired generation would be displaced as a result and California's total gas consumption would decrease below current levels.
- California's natural gas infrastructure was adequate to handle increases in peak day gas demand caused by reduced renewable generation. All of the cases with reduced renewable generation caused an incremental increase in January 2020 peak day gas demand of about 0.5 billion cubic feet per day (Bcfd) relative to the Base Case, but these increases were not enough to cause wide-spread problems for California's gas pipeline or gas storage infrastructure given the lower level of gas demand projected in the Base Case.
- California's natural gas supply options and infrastructure would improve over time. Increases in the United States' natural gas production, additions of new pipeline capacity, and additions of new storage capacity would increase both the availability and reliability of California's gas supplies.
- Technology mix and geographic diversity in renewables would minimize the potential impact of reduced renewable generation. Using a mix of different renewable technologies and spreading renewable generators over a wide geographic area reduced the chances for a large reduction in renewable generation and thereby reduced the chances of a large surge in gas demand for power generation.

The author concluded there were many considerations that the California government should take into account as it considers regulatory propositions in the future in order to support a well-functioning natural gas storage industry. Some of these considerations included:

- Transparency in transaction reporting.
- Limiting of potential barriers to entry in the industry.
- Supporting and incentivizing innovation and research and development within the industry.

The author concluded that the California natural gas market can continue to function even under some of the most severe weather conditions based on the results of the California natural gas storage modeling effort. The infrastructure changes since the 2000-2001 energy crisis such as pipeline expansions into the state and the addition of new natural gas storage fields in the state have greatly enhanced the resilience of the system to withstand these situations.

The results of the renewable generation analysis indicated that with the expected levels of renewable generation the California Energy Commission's electric load forecast combined with the 33 percent RPS yielded a net decrease in California gas demand through 2020. California's natural gas infrastructure should be generally adequate to meet the potential swings in demand cause by intermittent reductions in wind and solar renewable generation given the reduction in the base level of gas demand.

Some potential localized constraints were discovered in both of the modeling efforts. Gas supply to the Los Angeles area appeared to be constrained on peak demand days in some of the more extreme weather scenarios based on the gas storage modeling effort, which could become a potential issue in the future. Additionally, the results of the 33 percent RPS modeling effort showed that pipelines into the San Diego market area could become constrained on peak demand days in some of the cases.

Project Benefits

This study provided a number of benefits to California, including:

- A greater understanding of the factors in play regarding natural gas storage with regards to both the public and private sector.
- An understanding of the resiliency of California's current natural gas storage and pipeline infrastructure to handle extreme weather situations.
- An understanding of California's natural gas infrastructure to reliably serve demand in the future (2020) and to serve as a backup source of supply to the power generation sector under a 33 percent RPS scenario.

CHAPTER 1:
Conceptual Analysis of the Valuation of Storage from the Public and Private Perspective

1.1 Introduction

This section provides a conceptual analysis of the valuation for gas storage services in California and the surrounding states, and discusses the public benefits of gas storage. Gas storage plays an extremely important role in the natural gas market. Storage can serve as a short-term or interim economic substitute for gas production or as a short-term or interim substitute for long-term natural gas pipeline capacity. It also serves a critical role in the natural gas market in terms of its influence on natural gas prices and providing supply security and system reliability. As a result, storage services influence the availability of gas and the price of gas to California consumers and power generators that produce electricity.

Storage is only an intermediate product. Storage capacity, like pipeline capacity, provides value only to the extent that it increases the value of the natural gas injected into storage, or increases the reliability of natural gas flowing through natural gas pipelines connected to the storage.

In competitive markets, buyers and sellers will determine an optimal level of production and consumption of a product from the perspective of each individual *economic actor* or firm. If, in an economic transaction, all of the costs and/or benefits of the transaction are borne by the parties that enter into the transaction, the competitive market will produce an optimal level of investment from both the perspective of the firms and from a societal perspective. If, however, there are market imperfections or there are benefits or costs borne by parties other than the participants in the transaction, the *market result* may well produce suboptimal results from a societal perspective.

1.1.1 Section Scope and Objectives

In this section, we examine how storage is valued by individual market participants versus how it might be valued from the perspective of societal benefits. This section also examines how public policies could be used to encourage optimal storage investment and utilization from the perspective of society. Specifically, we consider the hypothesis that market imperfections and externalities produce a market result that produces under-investment in storage and suboptimal utilization of existing storage from a societal perspective.

1.1.2 Overview of Valuation of Storage Section

Section 1.1 above provides a summary and brief overview of findings presented in this section. Section 1.1.2 lists the key issues addressed the Valuation of Storage Section. Section 1.2 provides a broad background on the uses and trends of natural gas storage throughout the United States. Section 1.3 provides a more detailed review of natural gas storage in the Western United States that has an impact on the California market. The value of natural gas storage from the perspective of market participants is reviewed in detail in Section 1.4, while the externalities and public benefits of natural gas storage are discussed in Section 1.5. Section 1.6 reviews a

variety of additional issues likely to impact the value of storage in California, both from the perspective of the private market participant as well as from the public policy perspective. Finally, Section 1.7 provides a review of the key implications for public policy in California.

1.1.3 Key Valuation of Storage Issues Addressed

This section provides a cross cutting look at key issues associated with the use and development of natural gas storage in California. The following discussion provides a brief introduction to some of the key issues that are examined in this section.

The Impacts of Storage in the Natural Gas Market

In addition to the direct impacts of storage within areas, the study considers the impacts of storage on broader gas markets. These impacts are analyzed and categorized in terms of the impacts on parties entering directly into the transactions as well market participants that are not parties to the transactions.[1]

When additional storage capacity is added, there are a number of effects on the natural gas market. These effects can increase or reduce the economic value of other assets. For example, the construction of new storage capacity can increase the value of gas production that is in close proximity to, or upstream of the storage facility. The new storage capacity allows a gas producer to bring production to market on the days when its value is highest. The new storage also provides producers an alternative to *shutting in* gas production in the event of a pipeline outage or constraint. These impacts are felt by producers in the region whether or not they are direct participants in the storage transaction that created the new storage.

Conversely, the construction of new storage can reduce the value of pipeline capacity upstream of the storage facility during peak demand periods. The storage capacity provides shippers on the pipeline with the ability to move gas to the storage facility during *off-peak* periods, thereby reducing their demand—and the shippers' willingness to pay—for peak-day pipeline capacity.

The Value of Storage to Participants in the Storage Transactions

The study discusses the differing types of storage transactions and the impact of differences on how participants may value storage. In economic literature, the construction of storage is termed a *relationship specific investment*. Once installed, the asset is "so specialized to a particular use that if the price paid to the owner were somehow reduced, the asset's services to that user would not be reduced."[2] In other words, the ability of the investor to recover the original investment and a reasonable return may be at risk after the investment is made because there is no alternative use and the costs are sunk.

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[1] Market participants that are not parties to a transaction, yet still receive benefits, are generally referred to as "free riders" in economic literature.

[2] Klein, B.J., Crawford, R. and Alchian, A., *Vertical Integration, Appropriable Rents, and the Competitive Contracting Process*, The Journal of Law and Economics, Vol. XXI, No. 2. October 1978, p. 299.

At the same time, storage transactions such as injections and withdrawals are very much short-term transactions that respond to short-term market conditions. In these transactions, the storage capacity is fixed and once the "space" in the facility is filled—or emptied—the supply of storage becomes totally price inelastic.

Finally, storage provides value to the firms that contract for and utilize storage facilities by providing reliable gas supplies. In a sense, storage can substitute as an "insurance policy", allowing market participants to warrant other gas market commodity transactions against market disruptions.

Each of these elements is discussed in this section, along with a discussion of the implications for storage investment, contracting, and utilization. In addition, the report discusses how recent regulatory and market events, such as adoption of Standards of Conduct, have impacted participants' ability to manage risks inherent in investment in long-lived facilities such as storage.

Cost-Based Ratemaking versus Market-Based Ratemaking

The role of storage and the analysis of storage economics and social benefits have been changed by commodity deregulation and the tremendous growth in the use of natural gas for power generation in California and throughout North America. In recent years, there has been a trend towards allowing storage owners to operate using market-based rates rather than traditional cost-of-service rates in certain situations. Specifically, market-based rates have been granted for facilities that are able to show through traditional market concentration analysis that they lack market power.

In June 2007, however, the Federal Energy Regulatory Commission (FERC) in Order 678 expanded the conditions under which market-based-rates could be applied by issuing regulations to implement Section 312 of the *Energy Policy Act of 2005*. FERC expanded the definition of the relevant product market to be used in market concentration analysis. This action will likely increase the number of instances in which market-based rates are found to be appropriate for new storage capacity.

The application of market-based rates has an impact on the allocation of risks between the buyer and seller of storage services. The buyer must rely on contracts exclusively to address price risk because there is no "backstop" price determined by regulation. Conversely, the seller has no regulated recourse assuring the "opportunity to recover prudently incurred costs" granted by regulation. The analysis conducted herein evaluates the implications of this reallocation of risk in the context of the value of storage transactions to the participants and the impediments to new construction.

Storage Services to Power Generation

The interface between the market for storage and electric power present some specific issues regarding optimization of value for an individual firm versus optimizing storage to provide public benefits. In general, power generators have been hesitant to enter into storage capacity contracts. While there has been some increase in the amount of storage held by generators, the amount remains small by comparison to the amount held by local distribution companies

(LDCs) despite the rapid growth in gas consumption for generation. The structure of the electricity market places payments for storage capacity at risk for recovery. By contrast, payments for natural gas at prevailing *spot market* prices are generally recovered in the price of electricity. These dynamics essentially reduce or remove power generators from the pool of potential parties contracting to support new storage construction.

Public Benefits of Storage

There are clear examples where the amount of working gas in storage and storage deliverability could have had a direct impact on consumers and the broader public. During the California energy crisis of 2000-2001, additional working gas and/or deliverability would have mitigated some of the disruptions in the electricity market and could have had significant positive impacts for the broader economy in California. More broadly, even a cursory examination of gas industry trade publications indicates the importance of storage inventories on natural gas price levels.

Decisions on future investments in, and utilization of, storage capacity will continue to have significant impacts on the broader natural gas and electricity markets. Increasing the total amount of storage capacity and deliverability can dilute some of the effects of fluctuations in gas demand and thereby mute the severity of gas price volatility compared to the volatility that would exist in the absence of additional storage.

Beyond that, there are locational differences in storage that can affect public benefits. As mentioned above, storage provides important operational and reliability benefits. Importantly, these benefits are greatest in the immediate proximity of the storage facility and decline as the distance from the storage facility increases. While market participants may view storage in surrounding regions as an economic substitute for California storage, that storage may not provide the same reliability benefits to the State as those that would result from storage within the State.

This study provides a systematic framework for examining public interest and societal costs and benefits of gas storage. Specifically, the study identifies the conditions and circumstances where public interest in funding for storage technologies and projects might be appropriate and could produce significant and tangible public benefits.

1.2 Background on Natural Gas Storage

In this section, we provide an overview of natural gas storage in the United States, where it is, how it works, and its economic rational. Section 1.3 focuses on storage specifically in and near California.

1.2.1 Basic Gas Storage Concepts

Gas storage operates in much the same way as any other commodity storage service such as oil storage and the storage of agricultural commodities. Storage is a way to reserve gas produced in one time period for use in a later time period. Gas wells operate optimally when they produce at steady rates. Gas demand, on the other hand, is seasonal, with higher demand in the winter and lower demand in the summer. On top of the seasonal cycle, there are weekly and daily use

patterns that do not match well with production and pipeline deliveries. Thus, early in the development of the gas pipeline system, gas storage was designed to manage swings in demand.

Aboveground gas storage typically was located in or near major cities, where large floating top storage tanks were used. Some of these are still found in or near older cities in the East. Underground gas storage allowed for far larger volumes of gas to be stored, and serve as major assets in the national pipeline system. Underground storage also allows for a more economical design of the pipeline system when it is located close to markets. In this way, pipeline capacity downstream of storage (which is generally closer to the market) is greater than the long-haul pipeline capacity upstream of storage. The latter can be used at a steady rate, dumping gas into storage in the summer. Conversely, pipelines downstream of storage facilities flow at or near capacity only in the winter when most storage withdrawals occur. Since underground storage is the dominant storage technology, this chapter focuses on it.

Gas in storage that cycles (or may be injected and withdrawn) is referred to as working gas. A large percentage of the gas in underground storage fields is base gas[3]—it essentially provides pressure necessary to permit the working gas to cycle. The ratio of working gas to base gas varies with the type of underground storage and the characteristics of the storage reservoir. When referring to gas in storage, working gas is the relevant concept. Base gas is an element of the original development cost of a storage project and is not generally available to the market. The deliverability of working gas is the rate on a per day basis that the gas can be withdrawn from storage. It is usually much higher than the injection rate as it takes a storage field longer to fill than to be withdrawn.

There are three main types of underground storage: depleted reservoir, aquifer, and salt cavern storage. About 84 percent of the working gas storage capacity and 71 percent of the deliverability in the United States are in depleted natural gas or oil fields (Table 1). Depleted reservoirs are the most commonly used underground storage sites because of their widespread availability (Figure 1). Conversion of a field from production to storage takes advantage of existing wells, gathering systems, and pipeline connections. All of the existing natural gas storage facilities in California have been developed in depleted reservoirs.

[3] Base gas is often referred to as cushion gas.

Table 1: Summary of Underground Storage by Region, 2007

	Depleted Gas/Oil Fields			Aquifer Storage			Salt Cavern Storage			Total		
Region	Sites	Working Gas Capacity Bcf	Daily Deliver-ability (MMcfd)	Sites	Working Gas Capacity Bcf	Daily Deliver-ability (MMcfd)	Sites	Working Gas Capacity Bcf	Daily Deliver-ability (MMcfd)	Sites	Working Gas Capacity Bcf	Daily Deliver-ability (MMcfd)
East	**219**	**1,683**	**34,269**	**41**	**360**	**8,023**	**5**	**8**	**590**	**265**	**2,052**	**42,882**
Producing	**64**	**989**	**17,339**	**4**	**22**	**495**	**26**	**175**	**13,945**	**94**	**1,187**	**31,779**
West	**29**	**463**	**8,698**	**5**	**28**	**1,075**	**0**	**0**	**0**	**34**	**491**	**9,773**
- California	4	273	5,865	0	0	0	0	0	0	4	273	5,865
- Rest of West	25	190	2,833	5	28	1,075	0	0	0	30	218	3,908
Total	**312**	**3,136**	**60,306**	**50**	**410**	**9,593**	**31**	**183**	**14,535**	**393**	**3,730**	**84,434**
	79%	84%	71%	13%	11%	11%	8%	5%	17%	100%	100%	100%

Sources: American Gas Association, Natural Gas Intelligence, and Energy and Environmental Analysis

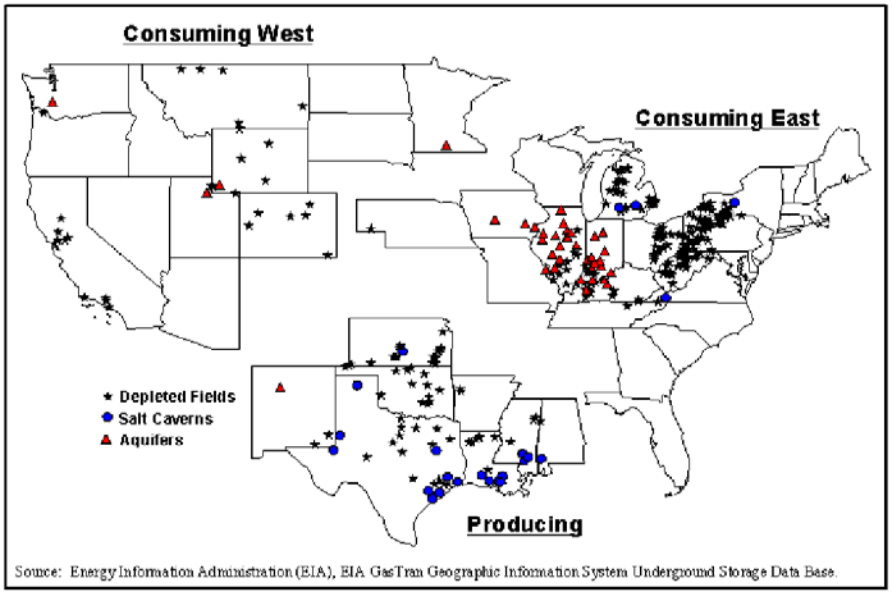

Figure 1: Underground Natural Gas Storage Locations in the United States

Source: United States Energy Information Administration (EIA)

In some areas, most notably in Illinois and Indiana, natural aquifers have been converted to gas storage reservoirs. In total, aquifer storage accounts for 11 percent of the working gas capacity and 11 percent of the deliverability in the United States An aquifer is suitable for gas storage if the water-bearing sedimentary rock formation is overlaid with an impermeable cap rock. While similar to depleted production fields, aquifer use in gas storage usually requires more base gas and greater monitoring of withdrawal and injection performance. Operational flexibility is less than it is in other types of storage. There are no aquifer storage facilities in California; however, major aquifer storage facilities in Washington (Jackson Prairie) and several smaller facilities in

the Rocky Mountains are closely tied into major pipelines serving the California gas market, and play an important role in California natural gas prices and gas availability into the State.

Salt caverns provide very high withdrawal and injection rates for their working gas capacity. Whereas other underground storage typically is cycled seasonally (injected into during the summer and withdrawn from during the winter—although there are exceptions), salt cavern storage can be cycled more frequently. In the United States, salt cavern storage typically averages more than 2 cycles per year.[4] In contrast, other types of storage typically average less than 1 cycle per year. Also, base gas requirements are relatively low for salt caverns. In the United States at present, salt cavern storage accounts for only 5 percent of the working gas capacity but 17 percent of the deliverability. The large majority of salt cavern storage facilities are along the Gulf Coast, where there are large bedded salt deposits.

Before the gas price run-up that has occurred during the past decade, salt cavern storage was more costly to develop than depleted field or aquifer-type storage, when measured on the basis of dollars per thousand cubic feet of working gas capacity. However, with the increased gas prices during the past decade, the cost of depleted reservoir and aquifer-type storage has risen significantly due to the rising cost of base gas. Therefore, it is no longer true that salt cavern storage is more costly than its other counterparts. Further, the ability to perform several withdrawal and injection cycles each year reduces the per-unit cost of each cubic foot of gas injected and withdrawn in salt cavern storage. That is why most recent construction of new storage has been in salt caverns as opposed to depleted fields or aquifers. At present, there are no salt cavern storage facilities that directly serve the California gas market.

Reported working gas capacity for all underground storage in the United States ranges from 3.8 to 4.0 trillion cubic feet (Tcf).[5] However, as shown in Figure 2, the record maximum United States storage fill achieved was a little over 3.5 Tcf in 2006. This is also the level of fill going into the recent 2007–08 winter. The reason that the observed fill is less than reported capacity is probably due to various operational constraints, and/or constraints on accessing pipelines, markets, or supplies. Therefore, maximum fill for the last two years may reflect a practical limit for working gas fill.

The lowest observed level for North American working gas occurred in March 2001 at just over 0.7 Tcf. It is unlikely that United States working gas storage could fall to much lower levels because of constraints that become evident when storage levels and reservoir pressures fall below certain limits.

Considering both the observed minimum and maximum levels over the past few years, the practical United States working gas capacity is probably about 3.5 Tcf less 0.7 Tcf, or only about 2.8 Tcf. This equates to an average 7-month injection season rate of 13.5 billion cubic feet per

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[4] However, there is no reason why salt cavern storage can't be turned over even more frequently in the future.

[5] Some storage fields listed by the EIA database have shown no activity in recent years and may have been abandoned. This is the source of some of the uncertainty in this value.

day (Bcfd) and a 5-month withdrawal season rate of 19.2 Bcfd. However, withdrawals are typically concentrated in December through February, and daily withdrawals in January and February have averaged as high as 27.0 Bcfd, well above the practical 5-month limit.

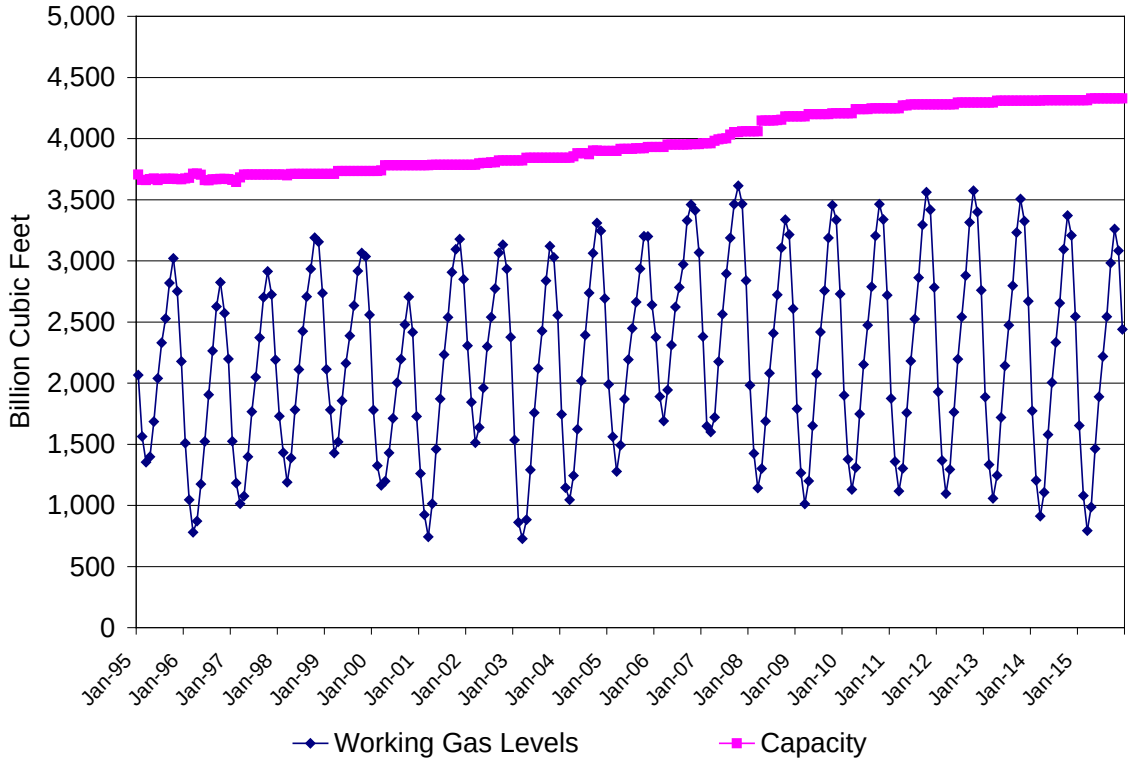

Figure 2: United States and Canada Working Gas and Capacity from January 1995 to December 2015

Sources: United States EIA and Canadian Enerdata Ltd. for Historical data. Energy and Environmental Analysis

1.2.2 Economics of Storage

Historically, storage has served two relatively simple functions. Pipelines and local distribution companies (LDCs) have used storage to fulfill their obligation to provide a reliable supply of gas. Storage has also provided consumers and suppliers the operational flexibility to balance supply and demand on a seasonal, weekly, and daily basis. Thus, the value of gas storage lies in its ability to match production and consumption and in realizing the value spread between the two. Storage capacity provides value only to the extent that it increases the value of natural gas injected into storage, or increases the reliability of natural gas flowing through natural gas pipelines connected to the storage.

The classic way to think about the role of storage is with the load-duration curve shown in Figure 3, which presents daily gas consumption, from the point of view of an LDC arranged in descending order for the year. Thus, for a very few days in this year in which the weather is about normal, California's daily gas consumption peaks between 9.0 and 9.5 Bcf, then declines

to levels that are considered to represent a base-load level of consumption. An LDC would not contract for pipeline capacity to meet peak consumption since the pipe would be underutilized during the rest of the year. Nor would the LDC simply contract to meet the base-load level, since demand would be not be served throughout much of the year. In this example, the optimal mix involves peaking services (for example, liquefied natural gas [LNG] peak shaving), local production, and pipeline gas. The pipeline is sized to provide enough gas to store during the off peak period and to be withdrawn in the peak period. It should be noted that the load data provided in this chart is from a near-normal weather year, and that a year with colder temperatures in the winter would potentially show many greater peak loads.

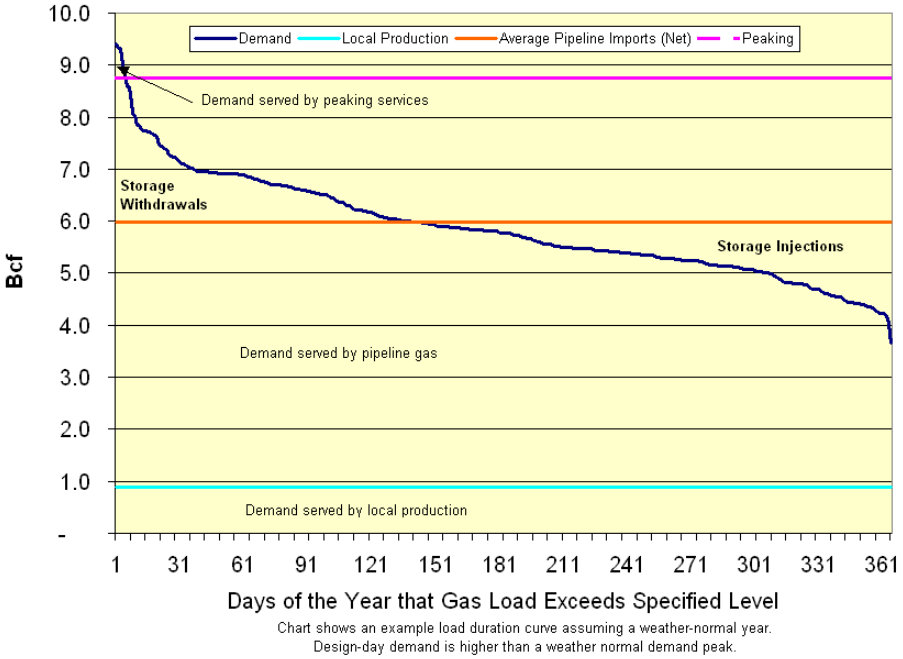

Figure 3: Stylized Load Duration Curve for California

Source: Energy and Environmental Analysis

The market reforms of the 1980s and 1990s have had a major impact on the economics and value of storage. First, the shift to straight-fixed-variable rate design for pipelines, which was part of the transition from merchant services to transportation services in FERC Order 636, helped to signal the true price of pipeline capacity to meet peak winter demand. It is cheaper in many cases to add storage deliverability than to add pipeline deliverability. A thousand miles of pipeline to meet a peak week of demand makes little economic sense. At the same time, FERC provided open access to storage services in a way that LDCs and other customers could manage their own storage usage, subject to pipeline operating rules. Most storage is owned and operated by pipelines and LDCs; albeit an increasing amount of third party, independent storage has been developed. Storage services could be purchased by LDCs, large end users, and natural gas marketers (the new merchant middlemen in the industry).

The second major impact on storage economics was the deregulation of natural gas prices which has resulted in considerable price variations. Under this new regime, gas prices have generally peaked in the winter and are lower in the summer. Just as important, volatility of gas prices has increased. This has created important price signals that reflect the value of storage. Commodity price deregulation has introduced variability and, therefore, uncertainty into gas commodity pricing. While storage maintains an important role in providing reliability of gas supply, storage also has come to play an increasingly important role for producers, customers and intermediaries in arbitrage and hedging.

Third, storage also provides a balancing function in the short-term (for example, daily and even hourly balancing). In the deregulated environment and with the increase in reliance on natural gas for power generation, pipelines have had to implement policies to manage imbalances on the system (what is injected into the pipe must equal what is withdrawn from the pipe) when hundreds of shippers on any one pipeline are making independent decisions about gas purchases and deliveries. Pipelines have instituted a system of fees and penalties[6] to incentivize shippers to balance their injections and withdrawals. Thus, because of the natural fluctuation in demand, flows, and supply, economic value has been created in the ability to manage short-term imbalances. Enter again storage, which provides the flexibility to meet short-term demand shifts through short-term gas loans, and balancing and peaking services.

In sum, the reforms have created value for storage that could be realized by a number of parties for a variety of different reasons. Below, we address some uses of storage and the value associated with those uses.

Marketable Storage Services

While the uses of natural gas storage are straightforward, at least conceptually, the actual application and use of natural gas storage is not straightforward. Storage capacity is repackaged into different storage services that are provided to the market in a variety of different ways. Operational control of physical storage capacity allows a storage provider to offer a number of different services, based on the bundling of different storage characteristics for different customers. Potential marketable storage services include:

- **Long-term Storage**: Multi-year contract for firm storage service with injections during the summer and fall, and withdrawals during the winter and spring to take advantage of seasonal price differences and to increase utilization of upstream pipeline capacity.
- **Short-term Storage**: Storage service with injections during the summer and fall, and withdrawals during the winter and spring to take advantage of seasonal price differences and to increase utilization of upstream pipeline capacity.
- **Off-peak storage services**: Storage service with injections and withdrawals that are primarily within the same season and do not utilize space required during the peak time

[6] The fees and penalties charged to meet hourly fluctuations has become a central issue on the El Paso Pipeline, which serves Southern California and the rapidly growing requirements of Phoenix and Southwest.

frame to take advantage of short-term price differences and to increase utilization of upstream pipeline capacity.

- **Hub Parking**: Short-term storage that allows the holder to park gas in storage for short periods (typically up to 60 days) to provide market and transportation flexibility.
- **Hub Loans**: Short-term loans of natural gas to meet balancing and supply shortfall requirements.

Economic Substitutes for Storage

Security and Reliability

Storage can mitigate supply interruptions due to production outages or pipeline deliverability problems (disruptions upstream of the storage). There are a number of potential substitutes that can serve the security role of gas storage. First, there are alternatives to underground natural gas storage that can provide gas to be transported through the LDCs distribution system. These would include LNG and propane-air facilities. LNG facilities are an expensive storage method both to construct and to operate. The gas is liquefied by cooling and then is stored in insulated, aboveground tanks. Due to its cost, LNG storage is generally used to meet peak day demands. Stored propane can also be distributed through the local gas system in the event of a disruption in the producing area or in the long-distance transportation pipeline system. Because propane has a significantly higher heat content than natural gas, it must be mixed with air before moving through the distribution system, hence the term *propane-air*.

A shipper can also achieve security through pipeline access to alternative sources of supply. This option depends, of course, upon the availability of gas and the availability of pipeline capacity when the alternative source of supply is required. Sources of supply that are connected to a market by a relatively short pipeline route offer more security of supply than sources connected by longer pipeline routes. Sources of supply that are connected to a market by a pipeline with significant excess capacity offer more security of supply than sources connected by pipelines that are already highly utilized.

Finally, natural gas users, primarily industrial users and power providers, can insure against supply disruption by investing in dual-fuel capabilities. A number of dual-fuel facilities, most notably units with gas-to-oil switching capability, exist throughout the United States; however, relatively high prices of alternate fuels (for example, high oil prices) could discourage the addition of such capability.

Balancing Supply with Demand

In North America, the supply (production) of natural gas is relatively stable throughout the year while demand is not. The initial investment in production facilities is typically very high relative to the marginal lifting costs (for example, the cost of producing an additional unit of gas from the well). As a result, producers cannot quickly increase production and are likely to reduce production substantially (for example, *shut in* a well) only when gas prices are very low. Therefore, within a wide price band, production tends to be relatively constant over the year.

Demand, on the other hand, fluctuates with exogenous factors such as weather and economic activity. In general terms, production exceeds consumption in the summer, and consumption exceeds production in the winter.

There are several ways that peak winter demand can be met. Underground market area storage is one of them. Gas can be injected into storage facilities in the summer and can be withdrawn to meet winter demand. An obvious alternative is investment in production and pipeline capacity to meet winter requirements. However, this strategy carried to the extreme would result in substantial, costly excess capacity in the summer. As another alternative, customers might diversify their sources of supply, drawing from production areas in the winter that are less subject to winter peak demands.

Each of the means of balancing supply with demand, as discussed above, is relatively costly when compared with gas storage. This is why the United States market has become reliant on gas storage for balancing purposes. Further, operationally, and as mentioned above, storage satisfies daily imbalances that occur on pipelines. The operation of gas transmission is extremely complicated and storage provides the flexibility and reliability that is needed as daily and hourly loads change on the transportation systems. As mentioned earlier, storage can provide the flexibility to meet short-term demand shifts through short-term gas loans, and balancing and peaking services.

Management of Price Volatility and Variability

Before deregulation, the price of natural gas was set by contracts, and as a result, price volatility was low or non-existent. However, price stability came at a cost. Markets were denied the rationing function of price and the result was shortages and surpluses. Indeed, the shortages of the mid-1970s were instrumental in the initiation of the deregulation process that later came to pass in the late 1970s.

In the regulated environment before the late 1970s, domestic petroleum, natural gas, and electricity prices were set by regulators and infrequently changed. Unfortunately, stable prices resulted in shortages in some areas and surpluses elsewhere, and supported by complex cross-subsidies from areas where prices would have been lower to areas where prices would have been higher, with accompanying efficiency costs. The free and competitive markets that have been implemented since have revealed that energy prices are among the most volatile of all commodity prices.[7]

In the unregulated environment that has evolved, natural gas market prices are extremely volatile due to the underlying supply and demand conditions. Supply has become relatively *fixed* (inelastic) in the short to medium term as the basic supply infrastructure (wells and pipelines) cannot rapidly increase output in the face of increasing prices. Demand is also relatively price-insensitive in the short to medium term. With the exception of dual-fuel users,

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[7] United States Department of Energy, Energy Information Administration. *Derivatives and Risk Management in the Petroleum, Natural Gas, and Electricity Industries*. October 2002, pg. ix (available at: http://eia.doe.gov).

most customers, particularly residential and commercial consumers, cannot substitute other products or do without gas in response to price increases. In addition, natural gas prices are still generally regulated at the retail level for most residential and commercial customers. Prices to these customers are adjusted over the longer term to reflect average commodity prices but there is not an immediate price signal reflecting changes in market prices to these customers. Importantly, demand fluctuates substantially seasonally, and even daily, with changes in the weather. Inelastic supply and demand, coupled with significant shifts in demand generate price volatility.

Deregulation of gas prices has introduced uncertainty in future gas prices. Both sellers and buyers contend with that uncertainty. Some have wished to avoid this uncertainty by *locking in* prices, while others see price volatility as an opportunity to profit by arbitraging between low and high price periods. Physical storage could assist with both of these activities. For example, buyers could purchase gas at a specific price, store it, and then withdraw it as needed. To them, the cost of gas has been locked-in at the purchase price plus the storage cost. Those interested in arbitraging can buy when they believe gas prices are low, store the gas, and, if successful, sell when prices are high. However, physical storage is not required to avoid, or, symmetrically, to profit from price volatility. Financial instruments, common for over a century in agricultural commodity markets, can serve the same purpose.

There are a large and increasing number of financial instruments that can be used to manage risk associated with future price changes. General types of financial instruments that accomplish this include forward contracts, futures, options, hedges and swaps. Every one of these instruments can be customized to the buyer's and seller's requirements or combined with other products to meet the needs of a specific customer, so the set of possibilities is nearly endless. Examples include *exchange traded* products such as the New York Mercantile Exchange (NYMEX) gas futures contract and options contracts, as well as *over-the-counter* products such as commodity swaps, collars, and basis swaps.

Financial derivatives can compete with storage in managing seasonal price risk. Consider an end-use industrial transportation customer that will need gas during the winter months. The customer, either directly or (more likely) through a third party marketer, has an option of buying gas in the summer and contracting for storage capacity to use the gas during the winter months. Alternatively, the customer could plan on buying gas at the prevailing market price for the winter months and purchase a futures contract that gives the customer the right to buy gas at a specific price in a specific future month, such as January. If the price for January gas in the futures market is less than the current price of gas plus the cost of storage, the customer is better off with the futures contract. If, however, the futures price is above the current cost of gas plus the cost of storage, the customer is better off storing the gas.

From the perspective of a seller of storage service, the nature of this competition is important. If the storage provider attempts to raise prices for storage, the seller risks driving customers to the futures market.

Alternatives to Natural Gas Storage in California

Natural gas storage is used by customers to serve all of the storage end-uses described above. Competitive options to natural gas storage include:

- **Physical Storage Outside California**: The North American natural gas market is generally considered to be an integrated market, and for certain end-uses, including price arbitrage and supply balancing, storage capacity throughout the North American market can serve the same role as storage services provided by natural gas storage located within California. However, physical storage outside of California cannot replace market area storage for markets predicated on security of supply or load balancing requirements.
- **LNG and Propane-Air Peaking Facilities**: LNG and propane-air peaking facilities owned by LDCs provide a direct substitute to underground storage for meeting low load factor peak day natural gas requirements. The availability of these facilities limits the rates that underground storage providers can charge for the same services.
- **Pipeline Capacity into California**: Additional pipeline capacity into California would serve as a direct alternative to storage capacity. Traditionally, reliability of service requires purchase of firm transport capacity. Utilities and customers with winter reliability requirements meet those requirements with a combination of pipeline capacity and storage capacity where the amount of pipeline and storage capacity has been determined by the costs of the available alternatives. Pipeline capacity costs increase as load factor declines. As a result, it is typically economic to use pipeline capacity to meet a certain amount of firm service, with storage used to meet remaining requirements. As storage prices increase, or pipeline costs decline, pipeline capacity becomes more competitive and can be economically substituted for storage capacity.
- **Open Market Natural Gas Purchases in the Competitive Market Region**: One of the fundamental changes in natural gas markets resulting from deregulation has been the development of regional natural gas market centers where customers can purchase natural gas, rather than purchasing it from production regions. If customers are willing to accept the vagaries of natural gas market pricing, they can purchase gas at a variety of market centers. As a result, customers with access to a liquid market for natural gas, where gas supplies can be reliably purchased at market prices, no longer are required to hold long term pipeline capacity and storage capacity in order ensure reliable natural gas delivery. Instead, these customers can purchase daily or monthly supplies at the local market center, and allow natural gas marketers and other entities to manage the natural gas purchasing, transportation, and storage requirements needed to reliably deliver the natural gas to the market center. These customers pay a premium to encourage other companies to take the risk of managing natural gas supplies from the wellhead. Hence, open market purchases can substitute for holding storage and pipeline capacity upstream of a liquid market center.

1.3 Western United States Natural Gas Storage

This section focuses on current natural gas storage infrastructure within California and in the surrounding states. Recent historical activity including working gas capacity additions, injections, and withdrawals are examined. Regional pipeline infrastructure is discussed and some of the recently announced storage projects for California and the surrounding states are briefly discussed.

1.3.1 Storage Serving California and the Western United States

Natural gas storage fields have been built throughout the Western United States where the geography is most favorable (Figure 1). Storage fields are used to satisfy market area demand during peak periods (both monthly and daily) and for production area balancing. The Western United States currently has an underground storage capacity of approximately 490 billion cubic feet (Bcf) with a peak deliverability of 9.8 Bcfd. This accounts for about 13 percent of the country's working gas capacity and about 12 percent of its peak deliverability. The majority of the storage fields—29 of 37—are depleted reservoirs, along with six aquifers and three LNG peak shaving facilities.

Several different types of entities own and operate storage in the Western United States. Approximately 170 Bcf of the storage working gas capacity, or 34 percent of total Western United States storage, is part of regulated pipeline networks such as interstate pipelines. Total deliverability for these regulated storage assets is about 3.5 Bcfd.

Other storage assets in the west are owned by intrastate pipelines, LDCs, or their affiliates. Most of these assets have only single pipeline connections to their parent company. Although these assets are sometimes separate legal entities, they are mostly used to manage operations of only the associated pipeline or LDC, and are often used to manage the LDC and pipeline resale gas as well as third-party customer gas. Approximately 279 Bcf, or 56 percent, of the Western United States working gas capacity is LDC or pipeline affiliate owned. Peak deliverability of associated operators accounts for 56 percent of the total Western United States deliverability, at 5.6 Bcfd.

In the Western United States, there are three fields owned by two operators that can be viewed as independent storage operations. The Wild Goose project located in Northern California was one of the first independent storage projects in the country. The Lodi field and newly developed Kirby Hills project are both operated by Lodi Gas Storage. All three of these fields are connected to the Pacific Gas and Electric (PG&E) pipeline system. Total working gas capacity of the three fields is about 47 Bcf, or 9 percent of total working gas capacity in the Western United States; peak deliverability accounts for 10 percent of the Western United States total, at 1.0 Bcfd.

The largest storage operator in the area, based on working gas capacity, is The Southern California Gas Company (SoCal Gas), with about 129 Bcf of capacity in four fields located in Southern California. The giant Aliso Canyon field has 1.4 Bcfd of deliverability and 82 Bcf of working gas capacity. The four SoCal Gas fields combined can deliver a peak of 3.2 Bcfd, or approximately 32 percent of the Western United States deliverability. The Northern California utility, PG&E is second in terms of working gas capacity with about 98 Bcf of capacity and 1.6

Bcfd of deliverability in three different fields. As mentioned above, PG&E's storage in Northern California is augmented by two independent storage operators—Wild Goose and Lodi—which together add another 47 Bcf of capacity and 1.0 Bcfd of deliverability. Total Northern California storage capacity is approximately 144 Bcf with 2.7 Bcfd of deliverability.

In summary, storage ownership in the Western United States is dominated by the gas distribution companies. There are 18 identified storage operators in the Western United States, of which 8 companies are LDCs, and several others, like Questar Pipeline, are interstate pipelines that are affiliated with LDCs. The top four companies (SoCal Gas, PG&E, Questar, and Williston Basin) own and operate 67 percent of the total Western United States working gas capacity.

As shown in Figure 5, Western United States end-of-injection-season working gas levels rose to almost 470 Bcf in October 2006, or to about 96 percent of capacity. The capacity series in the figure was determined from a historical back-cast based on the timing of new fields and storage field expansions, and it includes the most recent storage development in the Western United States, most notably the new Kirby Hills field. The Kirby Hills 5.0 Bcf storage facility went into service in early 2007.

Other recent storage expansions in the west include the Jackson Prairie field in Washington. This field, which is owned jointly by Puget Sound Energy, Northwest Pipeline, and Avista Corp., has been routinely expanded five times over the last ten years. Each expansion to this aquifer field has added 2 to 3 Bcf of new storage capacity, and has increased deliverability as well.

As shown in Figure 6, California's end-of-injection-season working gas levels approached 260 Bcf in October 2006, rising to over 95 percent of total capacity. Capacity and deliverability have increased since 2001 as SoCal Gas and PG&E have enhanced their existing fields.

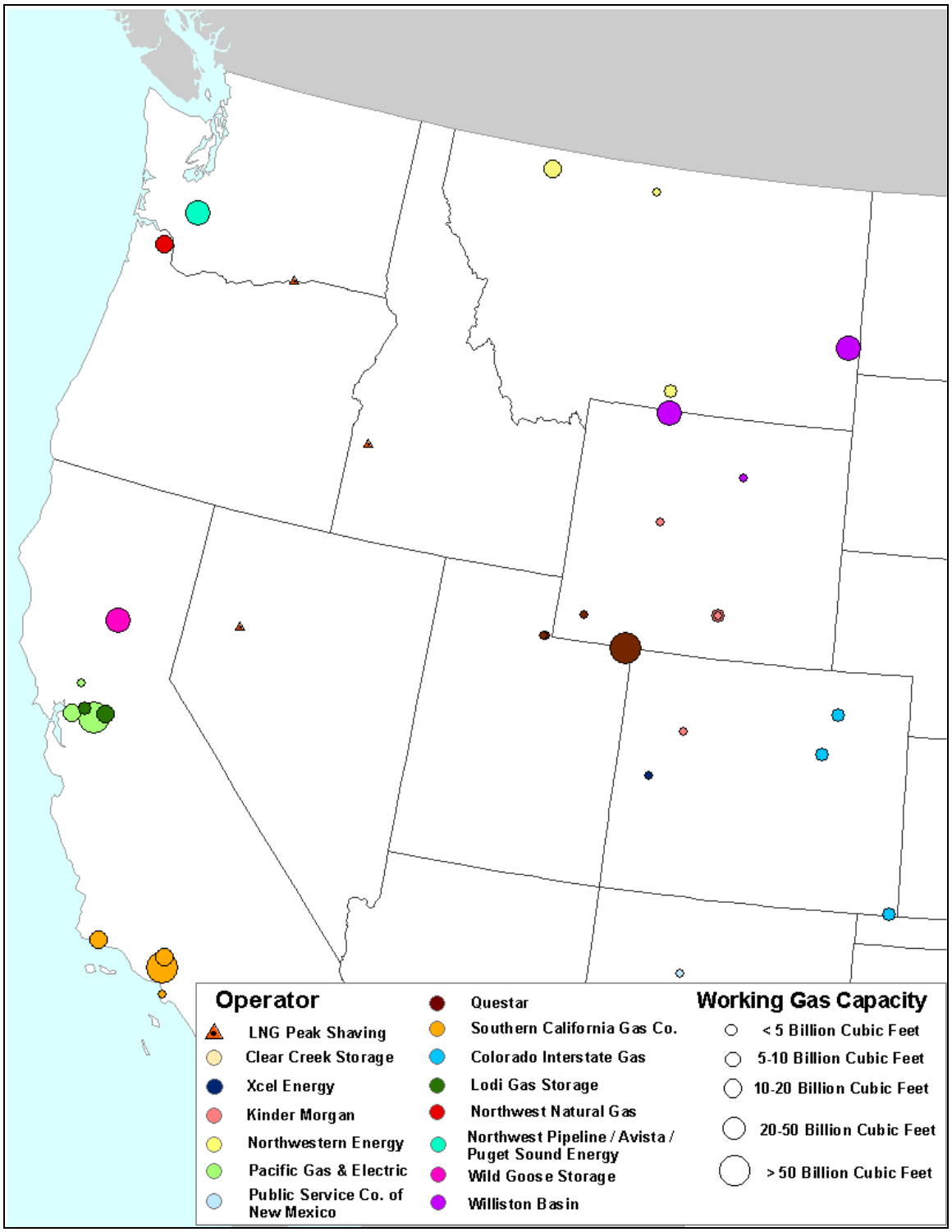

Figure 4: Natural Gas Storage Locations in the Western United States

Source: ICF Representation of American Gas Association and Natural Gas Intelligence Data as of December 2007

Table 2: Summary of Western United States Working Gas Storage Capacity and Deliverability

Operator State	Field Name	Field Type	Working Gas Capacity (MMcf)	Maximum Deliverability (MMcf)	Working Capacity Deliverability Ratio (Days)	Pipeline Connections	Operator Type
Interstate Pipeline and LDC Regulated Assets							
Questar Pipeline			**53,034**	**940**	**56**		
Utah	*Chalk Creek*	Aquifer	256	35	7	Questar	
	Clay Basin	Depleted Reservoir	51,250	765	67	Questar & Northwest	Interstate
	Coalville	Aquifer	692	65	11	Questar	Pipeline
Wyoming	*Leroy*	Aquifer	836	75	11	Questar	
Colorado Interstate Gas			**30,519**	**984**	**31**		
Colorado	*Flank*	Depleted Reservoir	7,183	171	42	All	Interstate
	Fort Morgan	Depleted Reservoir	8,496	468	18	Colorado Interstate Gas	Pipeline
	Latigo	Depleted Reservoir	9,050	145	62		
	Young	Depleted Reservoir	5,790	200	29		
Williston Basin			**51,902**	**330**	**157**		
Montana	*Baker*[1]	Depleted Reservoir	35,000	135	259	All	Interstate
Wyoming	*Billly Creek*	Depleted Reservoir	542	5	108	Williston Basin	Pipeline
	Elk Basin	Depleted Reservoir	16,360	190	86		
Kinder Morgan Inc.			**4,564**	**18**	**254**		
Colorado	*Wolf Creek*	Depleted Reservoir	4,564	18	254	Rocky Mountain Natural Gas	
Puget Sound Energy-Avista-Northwest Pipeline			**22,000**	**850**	**26**		LDC
Washington	*Jackson Prairie 2, 9*	Aquifer	22,000	850	26	Northwest Pipeline	Affiliate
Clear Creek Storage			**4,000**	**50**	**80**	Questar, Northwest Pipeline,	Interstate
Wyoming	*Clear Creek Storage*	Aquifer	4,000	50	80	Overthrust, & Kern River	Pipeline Affiliate
Northwest Pipeline			**2,545**	**257**	**10**		Interstate
Washington	*Plymoth LNG*	LNG Peak Shaving	2,545	257	10	Northwest Pipeline	Pipeline
Paiute Pipeline Co.			**950**	**51**	**19**		Interstate
Nevada	*H.G. Laub LNG - Lovelock*	LNG Peak Shaving	950	51	19	Paiute Pipeline	Pipeline
Total Regulated Assets			**169,514**	**3,480**	**49**		
Percent of Total			**34%**	**34%**			
Assets Associated with Intrastate Pipelines or Gas Distribution Opperations							
Southern California Gas Co.			**129,100**	**3,205**	**40**		
California	*Aliso Canyon*	Depleted Reservoir	82,000	1,405	58	All	
	Honor Rancho	Depleted Reservoir	23,000	1,000	23	Southern California Gas	LDC
	La Goleta	Depleted Reservoir	21,500	350	61		
	Playa del Ray	Depleted Reservoir	2,600	450	6		
Pacific Gas and Electric Co.			**97,850**	**1,630**	**60**		
California	*Los Medanos*	Depleted Reservoir	15,600	360	43	All	LDC
	McDonald Island	Depleted Reservoir	80,000	1,200	67	PG&E	
	Pleasant Creek	Depleted Reservoir	2,250	70	32		
Kinder Morgan Inc. (Casper Division)			**11,730**	**33**	**355**		
Wyoming	*Bunker Hill*	Depleted Reservoir	1,450	5	290	All	Intrastate
	Kirk Field	Depleted Reservoir	580	3	193	KMI Casper	Pipeline
	Oil Springs	Depleted Reservoir	9,700	25	388		
Northwest Natural Gas			**15,450**	**430**	**36**		
Oregon	*Mist - (Als, Bruer, Flora, Reichold)*	Depleted Reservoir	15,450	430	36	Northwest Natural Gas	LDC
NorthWestern Energy			**16,250**	**205**	**79**		
Montana	*Box Elder*	Depleted Reservoir	500	10	50	All	
	Cobb	Depleted Reservoir	10,250	150	68	NorthWestern Energy	LDC
	Dry Creek	Depleted Reservoir	5,500	45	122		
Xcel Energy			**8,197**	**68**	**121**		
Colorado	*Asbury*	Depleted Reservoir	2,797	16	175	All	
	Fruita	Depleted Reservoir	226	2	113	Xcel Energy	LDC
	Roundup	Depleted Reservoir	5,174	50	103		
Intermountain Gas Co.			**639**	**60**	**11**		
Idaho	*Nampa LNG*	LNG Peak Shaving	639	60	11	Intermountain Gas	LDC
Total Associated Operators			**279,216**	**5,631**	**50**		
Percent of Total			**56%**	**56%**			
Independent Operators							
Lodi Gas Storage - ArcLight Energy Partners			**22,500**	**550**	**41**		
California	*Kirby Hills*	Depleted Reservoir	5,500	50	110	All	Storage
	Lodi	Depleted Reservoir	17,000	500	34	PG&E	Company
Wild Goose Storage Inc.			**24,000**	**480**	**50**		Storage
California	*Wild Goose*	Depleted Reservoir	24,000	480	50	PG&E	Company
Total Independent Operators			**46,500**	**1,030**	**45**		
Percent of Total			**9%**	**10%**			
Total of Western US Storage			**495,230**	**10,141**	**143**		

[1] Baker storage reservoir has working capacity of over 160 Bcf but this capacity has been unused do to low deliverablity. Effective capacity for Baker field estimated at 35 Bcf.

Source: United States EIA and Energy and Environmental Analysis Inc.

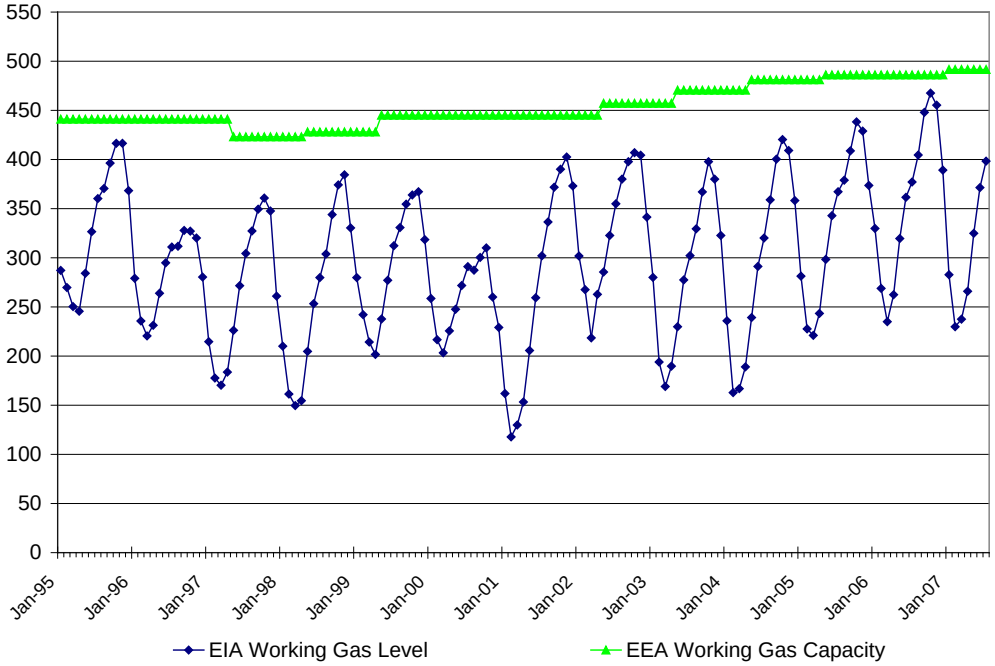

Figure 5: Western United States Working Gas Storage Levels with Capacity

Sources: United States EIA, with Energy and Environmental Analysis representation of working gas capacity

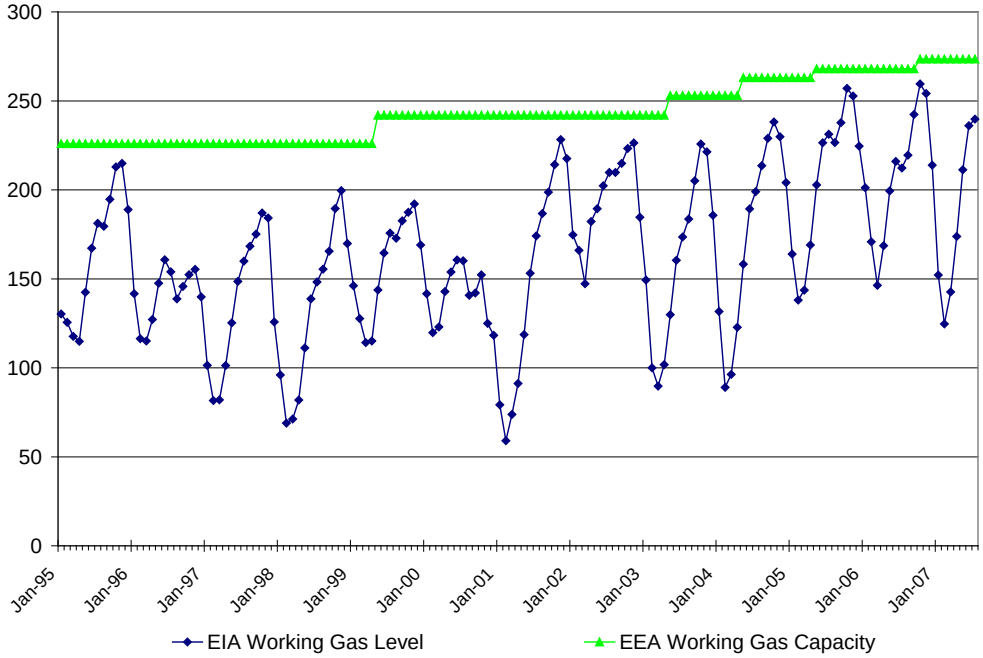

Figure 6: California Working Gas Storage Levels with Capacity

Sources: United States EIA, with Energy and Environmental Analysis representation of working gas capacity

1.3.2 Pipelines Serving California and the Western United States

There are over 20 major interstate and intrastate pipelines within the Western United States (Figure 7). A number of interstate pipelines, such as Northwest Pipeline, Questar Pipeline, Colorado Interstate, Kinder Morgan, and Williston Basin have been designed to serve specific regional markets. Intrastate pipelines, such as SoCal Gas, PG&E, and Northwest Energy are the backbone of distribution operations.

Other interstate pipelines constructed in the past ten years, like Cheyenne Plains, Trailblazer, Trans-Colorado, and Rockies Express (currently under construction), have been built to transport increasing Rocky Mountain production to markets east of the Rocky Mountains. With the completion of Rockies Express, export capacity going eastward out of the Rocky Mountains will be about 4.5 Bcfd.

The North Baja pipeline was built to deliver gas to power plants south of San Diego along the Pacific coast of Mexico. With the completion of the Energia Costa Azul LNG import terminal in 2008, North Baja will begin transporting gas back to California and Arizona.

Total import pipeline capacity into California is just under 10 Bcfd. Just over 2 Bcfd enters California in the north at the Oregon border via Gas Transmission Northwest (GTN) and Tuscarora. The capacity of Kern River Gas Transmission entering the center of the state is also just over 2 Bcfd. The remaining import capacity of about 5.8 Bcfd enters California along the Arizona border and includes El Paso Natural Gas, Transwestern Pipeline, North Baha, and Southern Trails. In the future, there is a potential for gas imports along the Mexico border near San Diego from the Costa Azul facility mentioned above.

1.3.3 Recently Proposed Storage for California and the Western United States

An expansion is planned for the recently completed Kirby Hills storage facility in Solano County, California. Project planners say the project will bring the facilities working gas capacity up to around 12 Bcf and the expansion could be in service by the end of 2008. The entire Lodi Gas Storage operation, which includes Lodi field, Kirby Hills, and the Kirby Hills II expansion, is currently being sold for $440 million.

A new storage company called Sacramento Natural Gas Storage (SNGS) plans to build and operate a 7 Bcf storage field in Sacramento County, California. The project would cost approximately $30 million to convert the depleted Florin Gas Field reservoir to gas storage, and connect it to PG&E and the Sacramento Municipal Utility District (the project's co-sponsor and first customer). The original target in-service date for SNGS was early 2009, but the project has been delayed and will not be in-service until at least 2010.

Oregon utility Northwest Natural Gas (NWN) is teaming up with PG&E to develop a new gas storage field at the Gill Ranch site west of Fresno, California. The Gill Ranch field, a depleted gas field owned by PG&E, is attractive due to its proximity to existing pipelines. Gill Ranch Storage would have an initial capacity of about 20 Bcf with plans to expand to 40 Bcf. NWN would develop the project and hold 75 percent of the capacity with PG&E holding the remaining 25 percent.

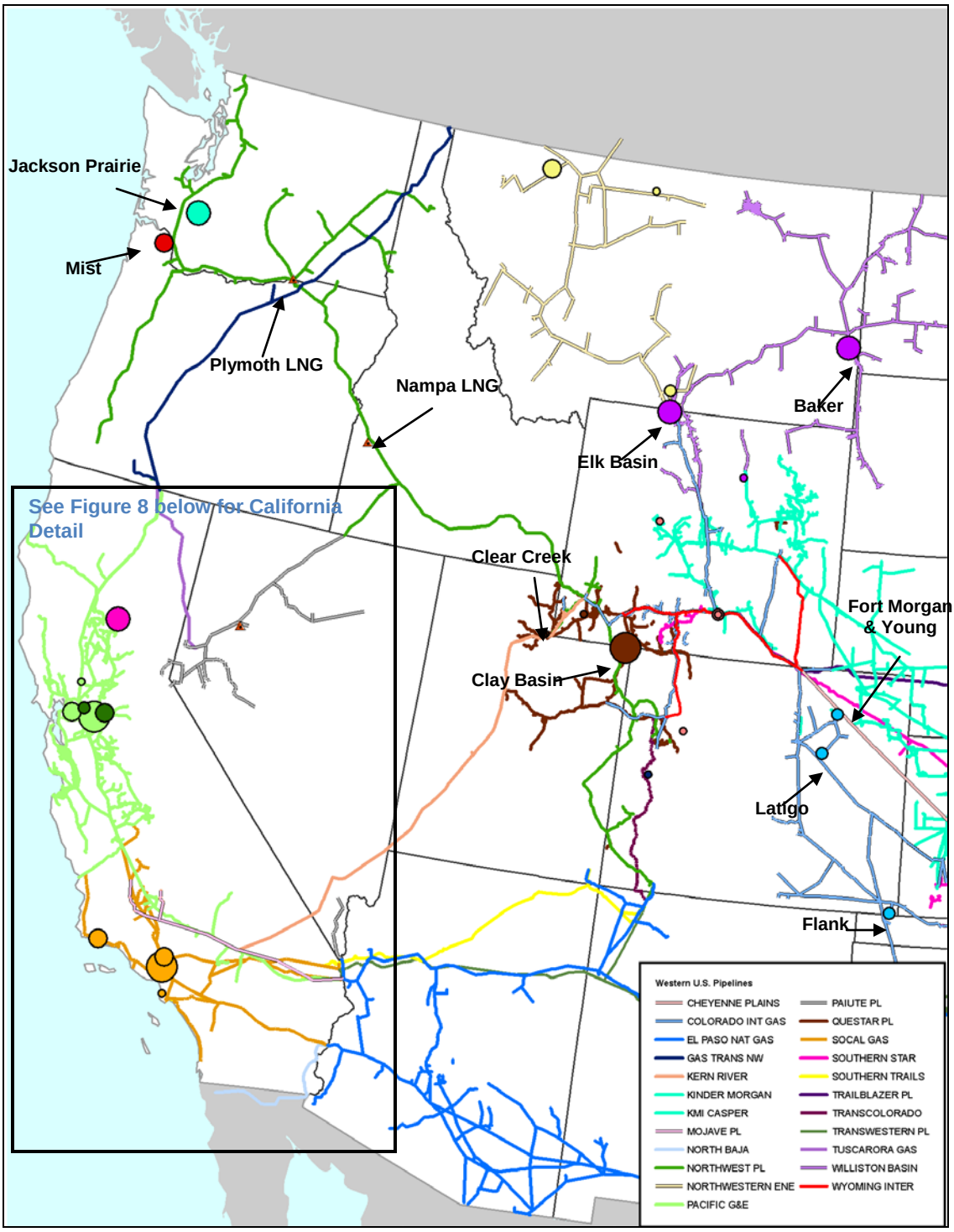

Figure 7: Natural Gas Pipelines along with Storage in the Western United States

Source: ICF Representation of American Gas Association and IHS Energy Group Data

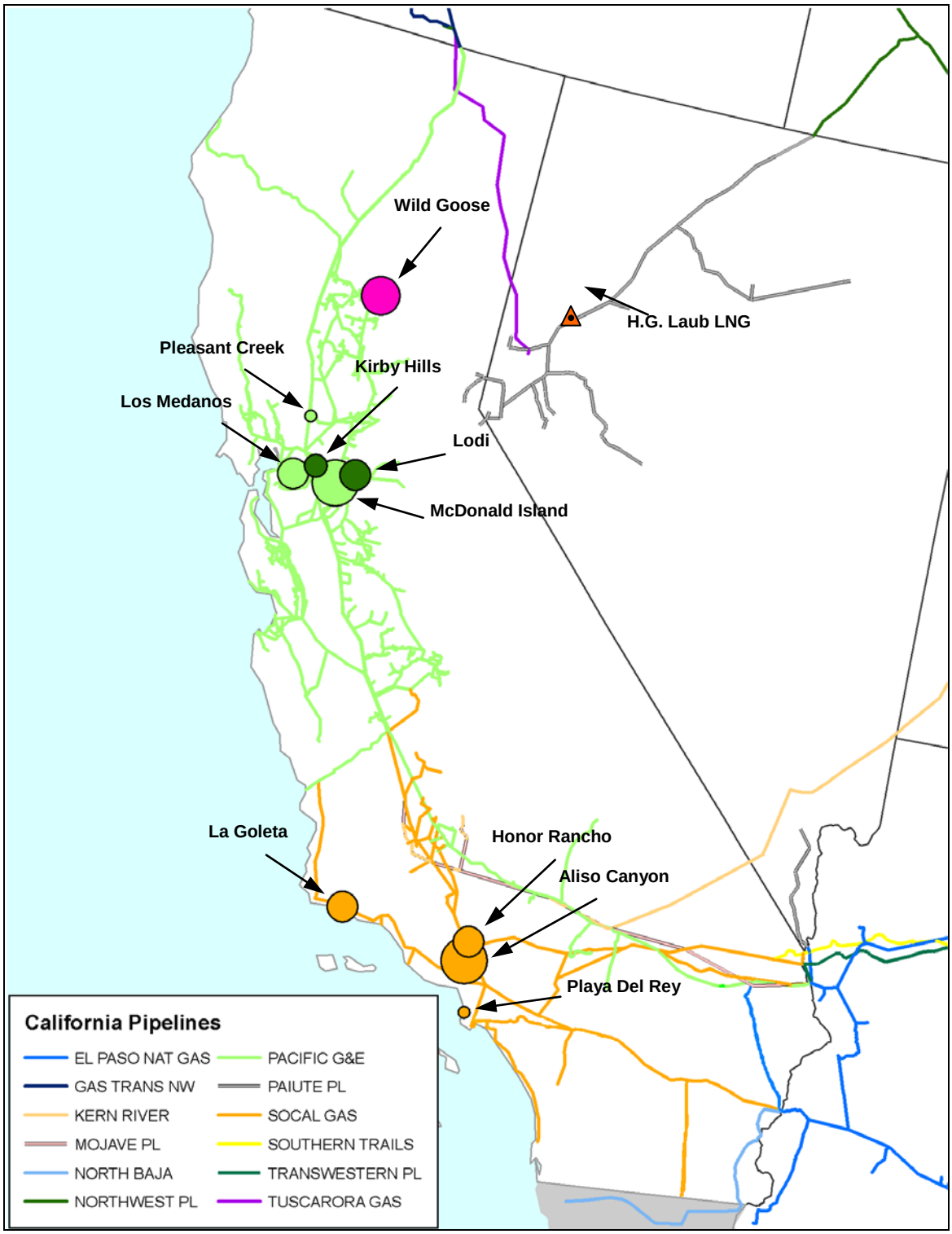

Figure 8: Natural Gas Pipelines along with Storage Fields in California

Source: ICF Representation of American Gas Association and IHS Energy Group Data

1.4 Factors Determining Value of Storage for Market Participants

In this section we address the specific factors that drive storage value and the factors that determine the willingness of gas market participants to pay for storage services. Storage capacity provides value only to the extent that it increases the value of the natural gas injected into storage, or increases the reliability of natural gas flowing through natural gas pipelines connected to the storage.

At the same time, storage transactions such as injections and withdrawals are very much short-term transactions that respond to short-term market conditions. In these transactions, the storage capacity is fixed and once the "space" in the facility is filled—or emptied, the supply of storage becomes totally price inelastic.

As a result, the value of storage, or the price that a customer is willing to pay for the use of storage capacity, can vary widely with market conditions. At the low end, in a region with excess storage capacity,[8] storage providers will compete for a limited pool of storage customers, and storage prices will be bid down well below the price needed to ensure recovery of the initial investment. The floor will be determined by the storage operating costs of the other fields in the region with un-contracted capacity, which typically would be quite low. At the upper end, the value of a storage field with permission to charge market-based rates is capped only by the availability of storage services, and the value placed on the available storage services by the incremental storage customer. The price received by the storage operator will fall between these two extremes, based on the overall tightness of the storage market. Today, in most regions of the country, storage markets are very tight, and storage customers are typically willing to pay well above the cost of service rates for most existing storage capacity.

1.4.1 Measuring The Value of Natural Gas Storage to Market Participants

The amount that different customers are willing to pay varies widely by customer. Different storage customers place different values on storage capacity based on the specific characteristics of, and opportunities available to, them.

At the most basic level, the elements of storage that create value to a storage customer can be categorized as either intrinsic or extrinsic, where the intrinsic value of the natural gas storage measures the expected difference between the cost of the natural gas when it is placed into storage during the injection season, and the value of the natural gas when it is removed from storage in the withdrawal season. The extrinsic value of storage measures all of the other benefits and costs associated with storing natural gas, including security of supply, amelioration of risk, opportunities for short-term arbitrage and other factors. These two storage valuation concepts are discussed in detail below.

Intrinsic Value of Storage

[8] Excess storage capacity can exist in a regional market when either upstream or downstream pipeline capacity is constrained.

Intrinsic value is a relatively simple concept. It is a measure of expected difference in the seasonal value of the gas commodity (volume weighted withdrawal price minus the volume weighed injection price) minus the variable costs of storage (injection and withdrawal charges and fuel charges) adjusted for the time value of money. However, in considering how the concept is evaluated by market participants, there is a significant complexity that results from price uncertainty.

The simplest calculation of the intrinsic value of storage is an ex-post valuation, which is a *backward looking* calculation, based upon the actual gas prices in the regional markets in proximity to the storage facility. However, an ex-post valuation of storage for any storage cycle is affected by all of the factors that are affecting the underlying gas commodity market, including weather patterns, changes in oil prices, supply disruptions (for example, hurricanes, etc.), economic activity, etc. Given the significant volatility in gas commodity prices in recent years, this effect can be quite significant and has resulted in a negative intrinsic value of storage in several years. As a result, an ex-post measure of the intrinsic value of storage must be averaged over a significant number of years, which risks obscuring any changes in the underlying intrinsic value that may occur as gas market fundamentals may change.

An ex-ante, or *forward looking*, valuation of storage is a more relevant measure of the current value of storage of natural gas storage in the marketplace. The ex-ante value of storage represents the expected seasonal value of future storage by the market participants making decisions. However, a forward looking estimation of storage value is necessarily a projection that will differ significantly among market participants.

Our discussions with storage market participants indicate that the ex-ante estimate of storage value is heavily influenced by the current NYMEX forward curves,[9] modified by an ex-post evaluation of the value of storage from previous years. Hence, the price that market participants are willing to pay for storage in the future is heavily influenced by the actual value of storage in the previous two to three years.

Seasonal Natural Gas Price Differential

Seasonal price spreads, which represent the intrinsic value of holding capacity for a storage customer, are primarily driven by national price trends. To add clarity, except when natural gas pipeline capacity into a specific region is constrained, seasonal price trends tend to be determined primarily by national patterns. Hence, seasonal price trends in California tend to be similar to seasonal price trends in Texas and Louisiana, and historical and projected seasonal price differences are similar (Figure 9 and Figure 10). [10,11]

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[9] The NYMEX forward curves are also heavily influenced by recent market behavior, and also include market perceptions of risk and uncertainty.

[10] The three-month seasonal price spread is the average natural gas price of the 3 peak withdrawal months of December, January, and February less the average price of the 7 injection months from April to October. The year on the x-axis refers to the injection year.

Actual price spreads depend greatly on weather. In general, a colder winter increases realized price spreads. In addition, market perturbations resulting from weather can have significant short-term impacts on prices and on seasonal price spreads. When natural gas prices are increasing rapidly, seasonal price spreads tend to expand as the difference between the winter and summer gas price expands due to the underlying market trend. Similarly, if the overall price trend is downward, seasonal natural gas price spreads tend to decline.

Natural gas prices in the California market are projected to remain in the $6 to $8 per million British thermal units (MMBtu) range for the next several years. As a result, storage asset costs, which are significantly related to base gas costs, could remain at roughly current levels.

Assuming normal weather, we would expect that the seasonal price patterns are likely to remain relatively stable for the next few years (Figure 10). However, *normal weather* is typically an exception, and actual weather and market conditions are likely to generate price volatility that is consistent with recent historical volatility. Thus, seasonal price spreads are likely to be more volatile than those shown in the figure.

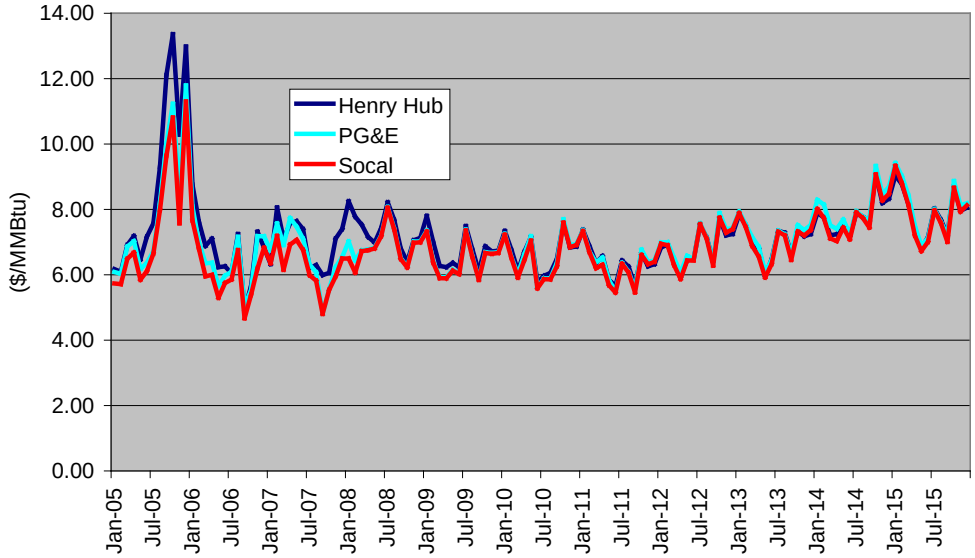

Figure 9: Recent Historical and Projected Gas Prices for California and Henry Hub

Source: Energy and Environmental Analysis October 2007 Base Case Provided as Part of ICF's Compass Service

[11] The California energy crisis resulted in much higher than typical seasonal price spreads in 2000/2001 as gas prices peaked during the winter and then much lower than typical seasonal price spreads in 2001/2002 as gas prices declined after the following storage injection season.

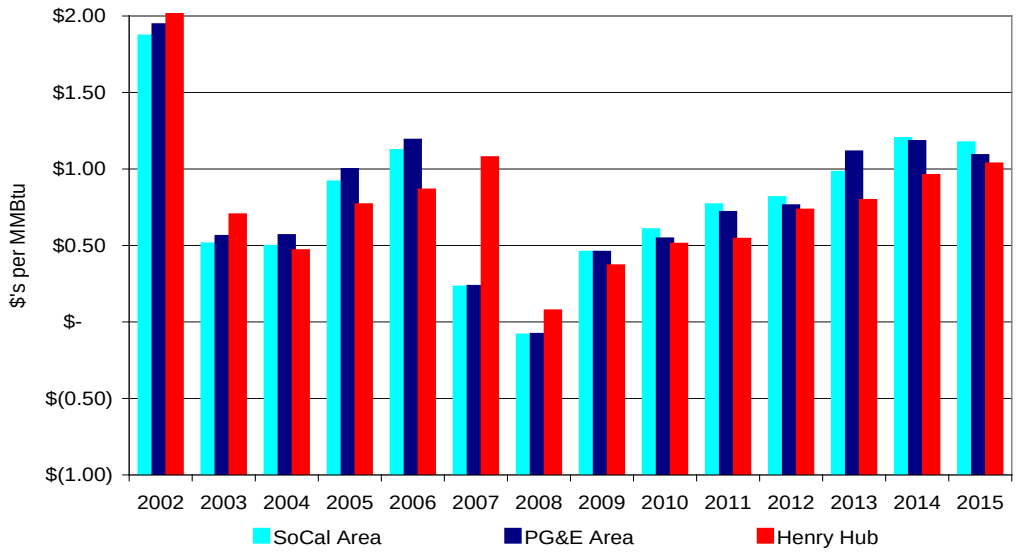

Figure 10: Three Month Seasonal Price Spread at Henry Hub and in California

Source: Energy and Environmental Analysis October 2007 Base Case Provided as Part of ICF's Compass Service

From 1995 through 2006, the winter versus summer seasonal price differences averaged approximately 75 cents per MMBtu. However, the seasonal price differences changed dramatically from year to year, depending on market conditions. Over this period, the seasonal price differences ranged from a high of over $14 per MMbtu in 2000-2001 to a low of almost negative $4 per MMBtu in 2001-2002.

Looking forward from 2008 to 2015, we project that the average seasonal price difference will be similar to the recent historical average at about 75 cents per MMBtu. However, this value is expected to change from year-to-year. The trend is for lower seasonal differences in the near-term with increasing seasonal price spreads in the longer term. For the next few years, seasonal price differences should be closer to 50 cents per MMBtu as a continued tight supply and demand balance tends to keep summer prices relatively high throughout North America. Power generation load is anticipated to compete with storage injections for relatively scarce gas supplies. As incremental LNG enters the North American market and as production continues to grow in the Rocky Mountains and in the Midcontinent shales, summer prices will trend toward a relatively lower level when compared with winter prices. Therefore, we project that storage values are likely to trend higher in the future. Conversely, the relatively tight supply and demand balance creates the potential for increased volatility of gas prices and the seasonal price spread, which increases the option value of holding storage.

Extrinsic Value of Storage

Most storage participants find value in natural gas storage above and beyond the intrinsic value of storage (or the value reflected by price movements). Termed *extrinsic value*, it is a measure of the additional value that a market participant who is purchasing storage is willing to pay for the

service above and beyond the seasonal price differential. Analysis of most markets throughout North America indicates that storage transactions are priced at levels in excess of the projected seasonal price spread. This is certainly true in California and the West.

Because extrinsic value is reflected directly in the purchase price of storage, it is not an *externality*. (See Section 1.5 for a discussion of Externalities.) Rather, extrinsic value reflects additional value associated with the operation of the storage facility and specific attributes related to the location and physical relationship to the storage facility in the broader gas transmission and distribution network.

Sources of Extrinsic Value

Extrinsic value can be derived by market participants from a number of attributes. Importantly, not all attributes are valued by all market participants. Rather, differences in the objectives of individual market participants result in different sources of extrinsic value being important to different classes of market participant. For example, many, if not most, natural gas utilities—local distribution companies (LDCs)—have limited ability or incentive to actively trade gas in the daily market with the objective of generating trading profits. By contrast, that can be a principle objective of a mid-stream gas marketer.

With the exception of some aquifer reservoirs, storage facilities are physically capable of injecting and withdrawing gas more quickly than is required to complete one seasonal cycle. This capability can be employed in a number of different manners including price arbitrage, operational flexibility, reliability, and redundancy that can be employed in case of an equipment failure or outage.

As discussed earlier, storage service is defined in terms of space and injection and withdrawal capability. The withdrawal capability can be described as a percentage (for example, 1.1 percent deliverability) or in terms of the number of days of withdrawal needed to cycle the storage (for example, 90 day service). These two examples provide roughly the same withdrawal capability.

The same concept of deliverability capacity can be described in terms of the number of possible *cycles* that can be used. For example, 90 day storage with equivalent injection and withdrawal right could theoretically be cycled twice each year if that is how the shipper chooses to utilize the service. For some, such as high deliverability salt cavern storage, the facility is capable of eight or more cycles each year. While the seasonal differential can only be captured once, the ability to cycle gas more than once per year creates opportunity for a market participant. In the following sections, discuss how the flexibility to use storage service for more than a single seasonal cycle of gas can create different sources of extrinsic value.

Arbitrage Value of Storage

So far, we have mostly focused on the value of natural gas storage based on expected seasonal differences in natural gas prices. However, the natural gas market is extremely volatile, and prices move substantially on a daily basis, for example, due to changes in weather, changes in oil prices, news about potential hurricanes, etc.

Figure 11 illustrates the volatility in natural gas prices at the SoCal Gas Citygate. Over the period of time the data in the figure represents, the daily change in gas prices has ranged from a high of 33 percent to a low of 26 percent of the previous day's price. The standard deviation in price movements (excluding weekends and holidays) is nearly 6 percent of the previous day's gas price. Thus, with gas prices averaging about $7 per MMBtu, the standard deviation for price volatility is a little over 40 cents per MMBtu. That is to say that gas prices will typically swing by up to 40 cents per MMBtu from one day to the next day.

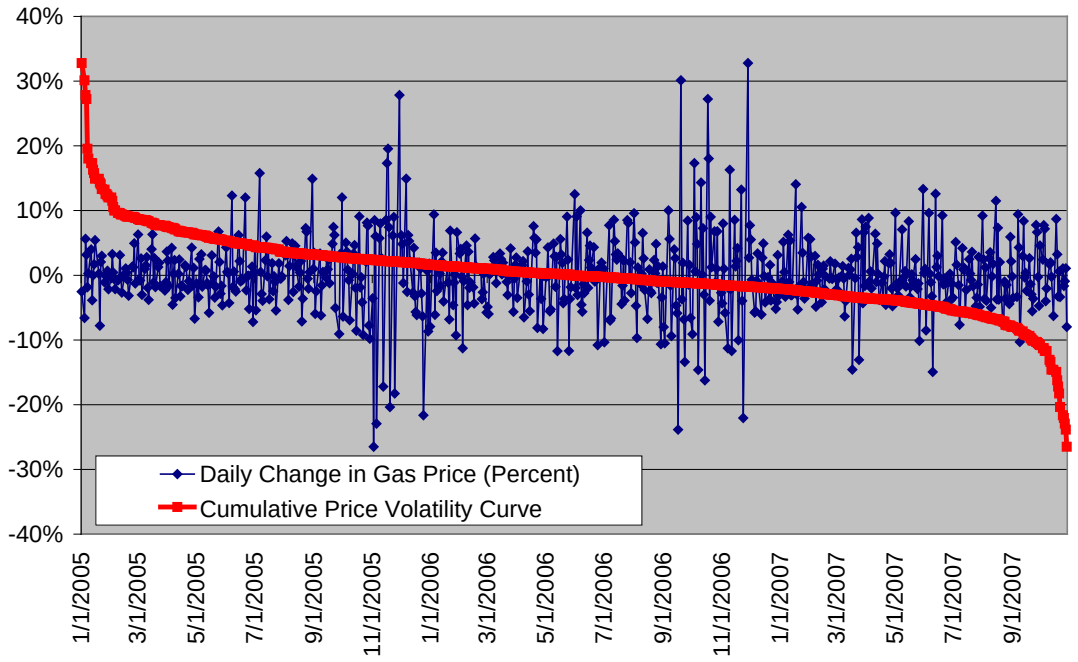

Figure 11: Natural Gas Price Volatility in California

Source: Energy and Environmental Analysis representation of Platts Gas Daily price information

These daily changes in natural gas prices provide an opportunity to holders of storage capacity to arbitrage daily natural gas prices. That is typically done by purchasing and injecting into natural gas storage during periods when prices are perceived to be below the expected price, and selling natural gas into the market (based on storage withdrawals or reductions in planned injections) during periods when prices are perceived to be higher than the expected price. For example, if a marketer has a view as to what the average price of gas will be within the month, the marketer may be willing speculate on the price movements by selling more gas on the days when prices are below the expected price and less on days when the price exceeds the expected price.

The structure of the gas market provides additional opportunities. For example, the marketer may have sold or bought gas during *bid week* with uniform volumes each day within the month

at a predetermined fixed price. Storage can allow the marketer to seek to capture the value from selling more gas on the high priced days.

The ability to arbitrage short-term gas prices provides value both for natural gas market participants that are seeking to profit from the price volatility, and for natural gas market participants that are seeking to minimize risks associated with volatile natural gas prices. Storage provides a ready method to manage risk with physical gas as a speculator or as a hedging strategy.

Physical storage capacity can also be used for price arbitrage in combination with financial derivative and forward products such as a *futures market* price. If the NYMEX (or other futures markets) prices for future delivery are higher than the current cost of purchased gas plus the cost of natural gas storage, traders can profit by simultaneously purchasing gas in the physical market and by selling gas on the futures market.

As discussed earlier, the ability to arbitrage daily price volatility is dependent on the amount of storage deliverability relative to the space in storage. For low deliverability storage, such as aquifer based storage in the Midwest United States, all of the deliverability is used to cycle the gas once, withdrawing the gas in the peak winter months. Using storage injections and withdrawals to arbitrage daily price volatility would reduce the amount of seasonal gas that could be placed into storage, hence, reduce the seasonal value of storage. Moreover, there is little ability to vary the daily patterns to take advantage of daily price movements and doing so, can risk damaging the reservoir.

However, arbitrage activity using high deliverability storage from salt caverns or high deliverability depleted fields can significantly increase the value of the storage capacity. Figure 12 below shows the potential increase in arbitrage value of storage with an increase in storage deliverability relative to capacity. The results indicate that very high deliverability storage can be expected to achieve over $6.00 per MMcf of capacity in incremental value from storage arbitrage, while a standard 90-day storage contract would limit the potential arbitrage value to about 25 cents per MMcf of capacity.[12]

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[12] The arbitrage value shown in this figure assumes that sophisticated market participant with perfect foresight for gas prices will be able to capture up to 50% of the total potential arbitrage value that is available. The example does not include the intrinsic value of storage as a seasonal price hedge. The total value of storage would include the implicit value of storage, the arbitrage value of storage and the other elements discussed in this report.

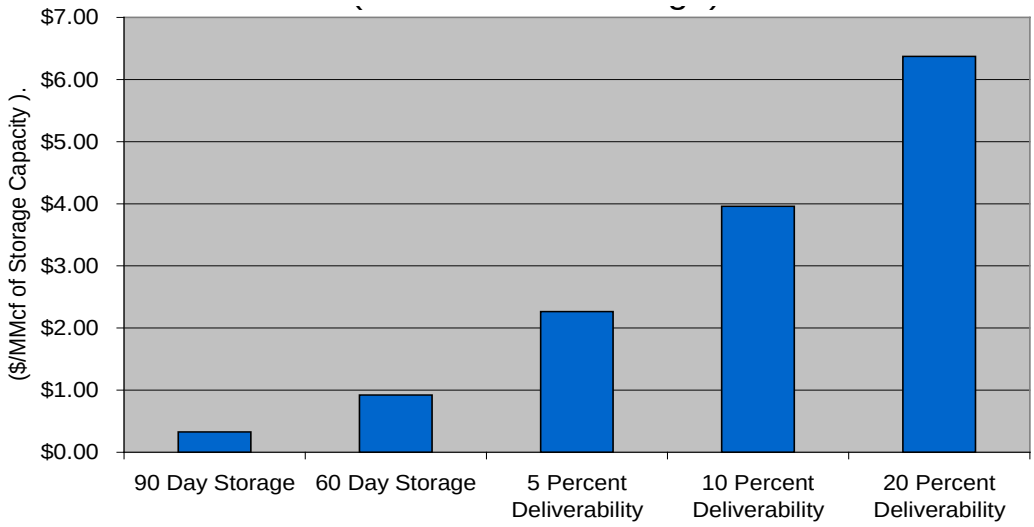

Figure 12: Impact of Deliverability on Potential Arbitrage Value, 2007 to 2013 Average

Source: Energy and Environmental Analysis

For risk-averse users of storage, such as most LDCs, there is little or no value created from speculation on daily price movements and arbitrage. Many are prohibited by the state regulators from engaging in such activity. Even if the LDC is not prohibited from the activity, there is often asymmetric risk involved in the activity. If the LDC makes profitable decisions, the gain is generally flowed through completely, or in large part, to the rate payers, while positions that lose money, may be found imprudent. Even if the regulation is designed to provide some symmetry through a performance based rate design (PBR) for gas cost recovery, the complex activity involved in such activity creates regulatory risk by making the exposition of purchases and sales much more intricate in the "cost of gas" review proceeding.

Nevertheless, storage can provide extrinsic value to LDCs and other risk-averse customers. For example, storage provides a hedge against weather and price risk, as well as a hedge against disruptions in the physical availability of natural gas. The extrinsic value in these categories is discussed below.

Physical Storage Capacity Risk Premium

Physical gas in storage, particularly in the market area, has value above and beyond the value represented by the seasonal price differential to both risk-averse (for example, an LDC) and risk-tolerant (for example, a mid-stream marketer) customers. This value is based on the increase in gas supply reliability provided by gas in the market area that can be accessed in the event of natural gas pipeline constraints or supply disruptions.

For any market participant, there is value in an asset that increases the probability that gas will be delivered without disruption. For an end-user, deliveries can ensure that a facility that uses gas can operate. At a minimum, there can be lost opportunity associated with a disruption. For

applications such as electric generation, there can be more severe consequences, including regional blackouts.

The direst of consequences would be a loss of supply to a portion, or an entire, gas distribution system. These occurrences are extremely rare due to all of the planning and redundancy that goes into avoiding such events. Natural gas for space heating is an essential human service. A loss of gas service during cold weather can threaten the lives and health of customers.

Moreover, when a portion of a gas distribution system loses gas supply, the entire area must be isolated. When gas supplies become available, the system cannot be simply "turned on." To do so would create a severe risk of fire. Every individual meter must be *valved*, or closed. Before the gas service can be restored, every line must be purged to ensure that air is not in the line. Once purged, each individual meter must be turned on one at a time and every individual pilot light re-lit and appliance checked for correct operation. Beyond the clear safety risk, the process is incredibly expensive.

As noted above, re-light events are very rare because of the steps taken to avoid them. Access to gas in storage is an important tool that can be utilized to ensure that gas is available to maintain the system.

Weather Risk Premium

Physical gas in storage provides a hedge against price volatility resulting from weather uncertainty. In market areas, particularly those that are down-stream of pipeline constraints, there is an asymmetry in the impact of weather-related changes in demand on natural gas prices. In areas with large heating load, all other things equal, weather that is colder than normal (for example, 5 percent higher than normal Heating Degree Days) raises natural gas prices by a greater amount than warmer than normal weather (for example, 5 percent lower than normal Heating Degree Days) moderates prices (Figure 13). The impact of this asymmetry is that the expected value of prices in a probabilistic sense is higher than the level that is expected under normal weather conditions.

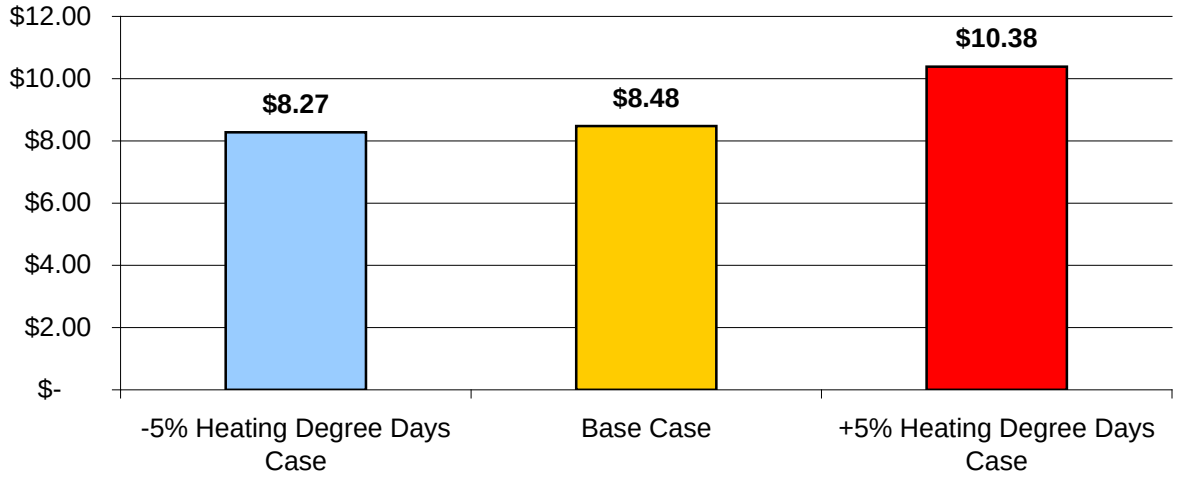

Figure 13: Average Winter Prices for the United States East Coast in a Representative Year

Source: Energy and Environmental Analysis

In markets with large amounts of gas-fired electricity that is used for space cooling, deviations in the number of Cooling Degree Days can have a similar effect. In today's market, the magnitude of the effect of hotter than normal summer weather is smaller than the impact of colder than normal winters. Even with increasing demand for gas from power generation, the relative impact is likely to be principally driven by winter weather in North America.

Gas in storage also provides a hedge against weather-related supply disruptions, such as hurricanes in the Gulf of Mexico. When a hurricane occurs in the Gulf, natural gas production platforms are often evacuated and production is suspended. If no damage occurs, the production can be brought back "online" in a matter of hours or days. Nevertheless, some production is lost for that season or year and there can be a related tightening of gas supply and an increase in prices. It is rare that a hurricane season will pass without the loss of at least 10 Bcf of gas.

If, however, there is substantial damage to infrastructure, as was the case after Hurricanes Ivan, Katrina, and Rita, and the loss of production can be much more significant and recovery can take months or even years. In the 2005 season when Katrina and Rita hit back to back, approximately 1 Tcf of production was lost over the next year.

The loss of production has an asymmetric impact on prices in the same manner that colder or warmer than normal weather will have. In a probabilistic sense, a market participant that is exposed to weather risk can attach some additional value to gas in storage that can limit the exposure to these unanticipated price movements.

Storage Services to Power Generation

As mentioned above, the interface between the market for storage and electric power presents some specific issues regarding optimization that may provide extrinsic value for an individual

firm. In addition, there may be public benefits beyond the extrinsic value that could be considered as externalities. As discussed in Section 1.5, the difference depends on whether the costs and benefits are reflected in the private transactions.

In general, power generators have been reluctant to enter into storage capacity contracts as well as firm pipeline transportation service. The reluctance arises, at least in part, because the structure of the electricity market does not match well with the fixed monthly charges for holding storage or pipeline capacity whether or not withdrawals are being made. The mismatch of payments for storage capacity and the payments for electricity create a risk for recovery for the generator.

By contrast, payments for natural gas at prevailing *spot market* prices are generally recovered in the price of electricity. The marginal cost of electricity when gas-fired electricity is required is highly correlated with the spot market gas price. For the generator, it can make more sense to bid for gas no matter what it costs when the gas-fired generation is being dispatched rather than pay monthly charges when the units are idle.

These dynamics can reduce or remove power generators from the pool of potential parties contracting to support new storage construction unless there are requirements for generators to demonstrate fuel adequacy to bid into a market. Capacity payments that are contingent upon supporting infrastructure such as pipeline, storage capacity and/or alternative fuel capability can provide a mechanism to internalize the costs and benefits.

While there has been some increase in the amount of storage that is held by power generators, the amount remains small compared to the amount of storage contracted for by LDCs, despite the increase in the volume of gas consumed in electricity generation. Unlike LDCs, where regulatory proceedings provide a direct impetus to contract for storage, generators have shown a willingness to purchase gas from the spot market even when prices are extremely high and hope to recover the high fuel cost from concurrently high electricity prices. However, in New England, where pipeline capacity constraints have limited the availability of gas on the spot market, generators have begun to contract for more storage as well as firm pipeline capacity. This process has been accelerated by regulatory proceedings that highlight the need for firm service as well as an electricity capacity market structured in a manner that provides a revenue stream that aligns better with storage and pipeline demand charge obligations.

Other Factors Influencing Storage Value

As discussed earlier, market area natural gas storage serves multiple purposes. For some uses, such as seasonal supply management and short-term natural gas price arbitrage and price hedging, there are many very good substitutes including pipeline capacity and financial derivatives. For others such as supply security, in particular insurance against disruptions of major pipeline flows, there are fewer non-storage substitutes.

Aside from location, gas storage operations are relatively homogeneous from the perspective of a buyer.[13] The core issue for the customer is the proximity and accessibility of the storage field. Put differently, the geographical market boundaries are critical in defining the relevant market from a competition policy perspective.

1.4.2 Market Valuation of Natural Gas Storage

So far, we have introduced several theoretical concepts explaining how and why storage customers value gas storage. As we have discussed, the marginal value of natural gas storage to the market typically is greater than the amount that is actually paid for the use of storage capacity.[14] There are several items that could be considered to assess the actual value of storage capacity, including:

- Market expectations on seasonal natural gas prices.
- Storage tariff rates.
- Prices that companies have been willing to pay to purchase existing storage.
- Costs that storage providers have been willing to pay to develop new storage or expand existing capacity.

Each of these items is discussed below.

Market Expectations

Market expectations—future expectations—for the value of storage are indicated by the seasonal price differentials exhibited in the NYMEX futures strip. The NYMEX futures strip reflects market expectations concerning the intrinsic value of storage, plus elements of the extrinsic value of storage that influence longer term storage values, such as weather premiums related to perceived hurricane risks. However, as a financial instrument based on monthly average prices, the NYMEX contract reflects little or no daily *optionality*.

Figure 14 illustrates the volatility of these expectations at Henry Hub.[15] Along with the volatility, this figure indicates a steady increase in market expectations for the seasonal value of natural gas over the past several years. The data show that the NYMEX futures market has exhibited an expected value for natural gas in storage that has averaged between $1.00 and

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[13] This is not to say that storage facilities themselves are homogenous. For example, the industry differentiates facilities on the basis of "deliverability" which is commonly expressed as the amount of gas that can be withdrawn daily from a storage facility. High deliverability is a positive attribute and depends on the amount of gas in the reservoir, the pressure within the pool, compression capability available to the reservoir, the surface infrastructure (for example, pipelines), and other factors. In general, deliverability is highest when the pool is full (see U.S. Energy Information Administration, *The Basics of Underground Storage*, available at: http://www.eia.doe.gov).

[14] By definition, the price that storage customers are willing to pay for natural gas storage should never exceed the marginal value of storage to those customers.

[15] Note the sharp decline in seasonal price spreads in the second half of 2006 corresponding with the collapse of the Amaranth Advisors Hedge fund.

$2.00 per MMBtu. The value has been as high as $3.50 per MMBtu. These values are, of course, indicative of storage values at Henry Hub, and not California. However, as mentioned earlier, regional seasonal price spreads generally follow national trends unless a market becomes significantly constrained by pipeline capacity, which does not currently appear to be the case in California.

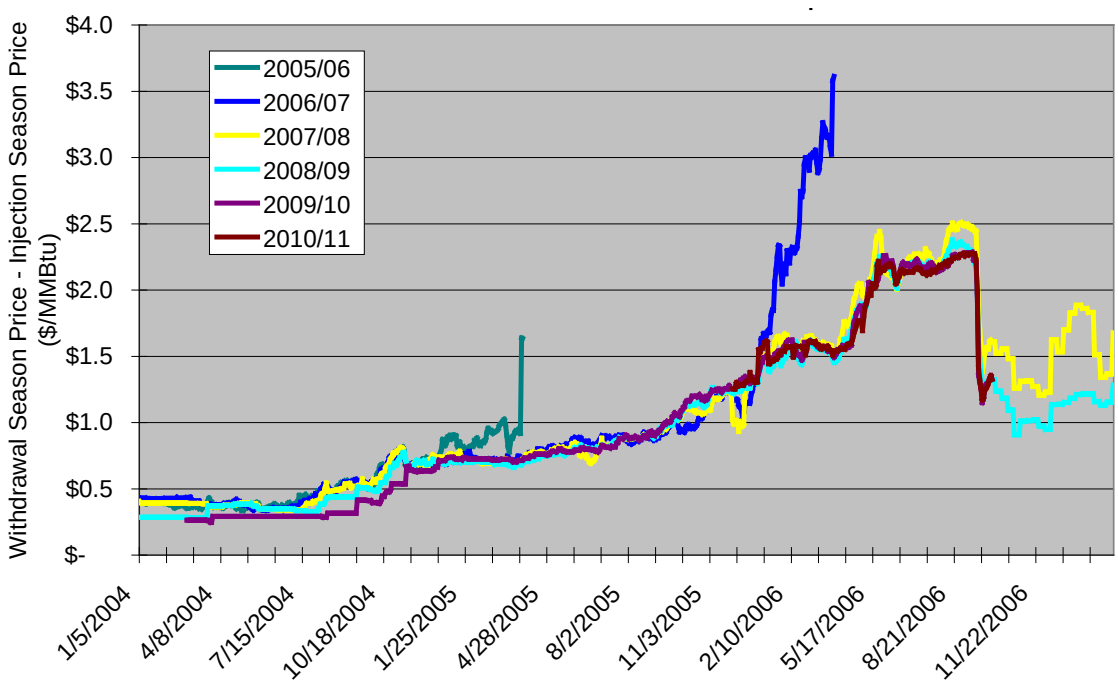

Figure 14: Seasonal Value of Storage at Henry Hub Based on NYMEX Futures Strip

Sources: NYMEX and Platts Gas Daily

Storage Tariff Rates

Table 3 shows natural gas storage rates for firm service in the Western United States.[16] Generally, the rates average between 70 and 80 cents per MMBtu for the single-cycle service that is reflected in the table. The one outlier is the Northwest Natural Gas rate at $2.00 per MMBtu. The table also shows an average fuel cost of between 1 and 2 percent.

The rates for storage within California range between 73 and 81 cents per MMBtu. SoCal Gas' rates are slightly less than PG&E's rates, but the two rates are very close to each other. These

[16] Depending on the specific storage field tariffs, there can be a variety of fixed and variable rate components to a storage service. Storage charges often include fees for maximum delivery rights, maximum gas in place, average gas in place, amount of gas injected, and the amount of gas withdrawn. Fuel paid with gas in kind may apply to injections, withdrawals, or to both. To compare various storage providers on an equal basis, the provided rates are for firm storage with the assumption for one full cycle within the year with an average 50% of maximum allowable gas in place. Multiple cycles will lower the per unit rate cost. A lower than average 50% gas in place level will also lower the per unit storage rates.

rates are well below some of the values shown in Figure 14, so the market is clearly valuing storage at levels that exceed the cost-based rates for firm service.

Table 3: Current Rates for Natural Gas Storage in California and Nearby Markets

Storage Operators	Rate Schedule	Maximum [1] 1-Cycle Rate	Total Inj & Wth Fuel	Type	Field Type
Southern California Gas	G-LTS	$0.73	2.44%	45 Day	Depleted Reservoir
Pacific Gas & Electric	G-SFS	$0.81	1.10%	30 Day	Depleted Reservoir
Lodi Gas Storage	FSS			45 Day	Depleted Reservoir
Wild Goose Storage	BLS	$0.74	1.00%	50 Day	Depleted Reservoir
Northwest Natural Gas	FSS	$2.00	2.00%	40 Day	Depleted Reservoir
Northwest Pipeline	SGS-2F	$0.74	0.45%	30 Day	Aquifer
Questar Pipeline	FSS	$0.80	2.00%	70 Day	Depleted Reservoir
Clear Creek Storage	FS	$1.02	NA[2]	80 Day	Aquifer
Colorado Interstate Gas	FS-1	$0.62	0.86%	35 Day	Depleted Reservoir

[1] The 1-Cycle Rate is the per unit cost to inject and withdraw 100% of contracted storage capacity during. a 1-year period. Cycling more than once will reduce the per unit rate.

[2] Fuel use billed monthly based on actual rates.

Source: Individual Company Electronic Bulletin Boards

Storage Acquisition Costs

The price that companies are willing to pay to own additional storage capacity provides another useful measure of the value of natural gas storage. Companies can increase the amount of storage capacity owned by either purchasing existing storage assets, or building new storage capacity either via expansion or new construction. There is limited public information regarding costs of storage purchases or new construction. Much of the information regarding purchase price is not reported. Often, storage deals are part of larger acquisitions and the separate costs of the storage field assets are not known. However, a review of the available information provides some rough estimates of current capital costs.

Table 4 summarizes information for the purchase prices for a few storage assets that have changed hands since 2005. The deals represent a sale of nearly 250 Bcf of working gas capacity and 6.3 Bcfd of deliverability. The most significant portion of capacity that traded hands is reflected in the Riverstone Holdings purchase of Encana properties. This deal included two undeveloped salt caverns in Louisiana. Most of the assets listed are depleted reservoirs.

Purchase prices per Bcf of working gas capacity range from just over $9 million to $19 million. Regional differences can influence storage values. For example, the sale of the Encana properties, which included assets in both the Mid-Continent and in Louisiana, sold for an average of about $9 million. Storage asset sales in California have been completed at much greater cost to the acquirer. The Lodi Gas storage field sold for an average of almost $15 million per Bcf in 2005. Two years later, the asset packaged with another storage field sold for $19 million per Bcf. Thus, there is some indication that the cost, and underlying value, of the asset has been increasing.

The value of storage assets tends to increase with growing market demand and/or increasing gas prices. Working gas is owned by the storage field's customers and is cycled (used and replaced) by them on a regular basis. However, base gas is owned by the owner of the storage field, and is required for storage field operation. As a result, base gas represents a long term storage asset that appreciates and depreciates with the price of natural gas. As a result, current and expected future gas prices are the main determinant of the value of base gas. A $1 per MMBtu change in the price of natural gas will change the value of 1 Bcf of base gas by $1 million dollars, and thus the purchase price by a similar amount, *ceteris paribus*.

The volume of base gas needed for depleted reservoirs varies widely from field to field, and can be reduced via additional investment in compression capacity or additional injection/withdrawal wells into the field. However, the amount of base gas required is typically equal to, or slightly greater than, the working gas capacity. The base gas needed per volume of working gas capacity is less for a salt cavern field. Approximately 1 Bcf of base gas is needed for every 2 Bcf of salt cavern working gas capacity. Thus, the *base gas premium* paid for working gas capacity in a salt cavern field is typically only half that of the premium paid working gas capacity in a depleted reservoir type storage field. Base gas influences not only the cost of purchased fields, but also the cost of newly developed fields. Base gas is always an asset that can be sold if the field is abandoned.

Table 5 summarizes the projected costs of two salt cavern projects in Louisiana scheduled to be in-service in 2008, Pine Prairie and Port Barre. Costs are approximately $10.5 million per Bcf of working gas capacity. This is similar or slightly higher than the average prices for recent purchases of storage assets reflected in Table 4. Salt cavern fields have a premium in value due to their increased flexibility in injection and withdrawal capabilities. However, this premium is offset by the reduced cost associated with base gas, because, as discussed above, salt caverns require less base gas for the same amount of working gas capacity when compared with depleted reservoirs or aquifers.

Expansion of existing fields is often a lower cost alternative to new field development. Much of the necessary infrastructure is likely to already be available, reducing the capital investment required to ready the field for operation. New wells or additional compression capacity can often create incremental storage deliverability at a lower cost than would be required for development of new storage capacity.

Table 6 summarizes information on recent storage field expansions. Examples include expansions of both salt cavern and depleted reservoir fields. On average, the cost of the depleted reservoir expansions ranges from about $4 to over $5 million per Bcf of additional working gas capacity. The Petal Gas Storage expansion, which is a salt cavern expansion, is slightly higher at just over $6 million. The cost for all of the listed expansions is significantly lower, at about half the cost of storage purchases, as reflected in Table 5 and Table 6.

Table 4: Summary of Recent Purchases of Underground Gas Storage

Field_Name(s)	Operator_Name	Transaction Date	State/ Province	County	Purchaser/ Operator	Seller/ New/ Expansion	Field_Type
Blue Water	Blue Water Gas Storage LLC	Aug-2005	Michigan	St. Clair	Plains All American/Vulcan Gas Storage	Energy Center Investments (Sempra)	Depleted Reservoir
Lodi (50% Interest)	Lodi Gas Storage	Dec-2005	California	San Joaquin	Arclight Energy Partners Fund II	Western Hub Properties	Depleted Reservoir
Suffield, and Countess	AECO Hub	Mar-2006	Alberta	Suffield, Countess	Riverstone Holdings and the Carlyle Group	EnCanna Corp.	Depleted Reservoir
Wild Goose	Wild Goose Storage	Mar-2006	California	Butte	"	"	Depleted Reservoir
Salt Plains (Manchester)	Niska Gas Storage	Mar-2006	Oklahoma	Grant	"	"	Depleted Reservoir
Starks Gas Storage No. 1 (Under development April 2008)	Niska Gas Storage	Mar-2006	Louisiana	Calcasieu	"	"	Salt Dome
Starks Gas Storage No.2 (Under development Starks April 2009)	Niska Gas Storage	Mar-2006	Louisiana	Calcasieu	"	"	Salt Dome
Lodi and Kirby Hills Phase 1	Lodi Gas Storage - ArcLight Energy Partners	Jul-2007	California	San Joaquin, Solano	Buckeye Partners	Arclight Capital Partners	Depleted Reservoir

Field_Name(s)	Operator_Name	WorkGasCap (MMcf)	Max Deliverability (MMcf per day)	Dollars per MMcf of WG Cap	Dollars per MMcfd of Deliv	Sale Price/ Cost Mil Dollars	Note
Blue Water	Blue Water Gas Storage LLC	24,500	700	$10,204	$357,143	$250	Include rights to Pine Praire Energy Center
Lodi (50% Interest)	Lodi Gas Storage	17,000	500	$14,706	$500,000	$125	
Suffield, and Countess	AECO Hub	125,000	3,050	$9,146	$402,145	$1,500	Total Purchase Price for all Encana Properties
Wild Goose	Wild Goose Storage	24,000	480	$9,146	$402,145		
Salt Plains (Manchester)	Niska Gas Storage	15,000	200	$9,146	$402,145		Purchase included 164 Bcf of operational storage and the Starks facility under development
Starks Gas Storage No. 1 (Under development April 2008)	Niska Gas Storage	8,800	400	n.a.	n.a.		
Starks Gas Storage No.2 (Under development Starks April 2009)	Niska Gas Storage	10,400	400	n.a.	n.a.		
Lodi and Kirby Hills Phase 1	Lodi Gas Storage - ArcLight Energy Partners	22,000	550	$19,455	$713,333	$428	
Total Purchase		246,700	6,280	$9,335	$366,720	$2,303	

Sources: Various Press Releases and Other Public Sources

Table 5: Summary of Estimated Costs for New Underground Gas Storage

Field_Name(s)	Operator_Name	Transaction Date	State/ Province	County	Purchaser/ Operator	Seller/ New/ Expansion	Field_Type
Pine Praire Energy Center	SG Resources Louisiana LLC	Apr-2008	Louisiana	Evangeline	Plains All American/Vulcan Gas Storage	New	Salt Dome
Port Barre	Bobcat Gas Storage	Apr-2008	Louisiana	St. Landry	Porte Barre Investments	New	Salt Dome

Field_Name(s)	Operator_Name	WorkGasCap (MMcf)	Max Deliverability (MMcf per day)	Dollars per MMcf of WG Cap	Dollars per MMcfd of Deliv	Sale Price/ Cost Mil Dollars	Note
Pine Praire Energy Center	SG Resources Louisiana LLC	24,000	2,400	$10,833	$108,333	$260	Estimated cost to complete the project
Port Barre	Bobcat Gas Storage	12,000	1,200	$10,417	$104,167	$125	Dollar estimate adjusted to increase size form 10.5 Bcf to 12 Bcf.
Total Purchases		36,000	3,600	$10,694	$106,944	$385	

Sources: Various Press Releases and Other Public Sources

Table 6: Summary of Recent Expansions of Underground Storage

Field_Name(s)	Operator_Name	In-Service Date	State/ Province	County	Purchaser/ Operator	Seller/ New/ Expansion	Field_Type
Petal Salt Dome	Petal Gas Storage (Enterprize PP)	Nov-2005	Mississippi	Forrest	Petal Gas Storage	Expansion	Salt Dome
Midland - Expansion	Texas Gas Transmission	Nov-2007	Kentucky	Muhlenberg	Texas Gas Transmission	Expansion	Depleted Reservoir
Cold Springs 1	ANR Pipeline	Apr-2008	Michigan	Kalkaska	ANR Pipeline	Expansion	Depleted Reservoir
Kirby Hills Phase 2	Lodi Gas Storage - ArcLight Energy Partners	Nov-2008	California	Solano	Buckeye Partners	Expansion	Depleted Reservoir

Field_Name(s)	Operator_Name	WorkGasCap (MMcf)	Max Deliverability (MMcf per day)	Dollars per MMcf of WG Cap	Dollars per MMcfd of Deliv	Cost Mil Dollars	Note
Petal Salt Dome	Petal Gas Storage (Enterprize PP)	2,400	950	$6,250	$15,789	$15	
Midland - Expansion	Texas Gas Transmission	6,750	90	$5,333	$400,000	$36	
Cold Springs 1	ANR Pipeline	14,000	200	$5,500	$385,000	$77	
Kirby Hills Phase 2	Lodi Gas Storage - ArcLight Energy Partners	12,000	250	$4,333	$208,000	$52	$12 Million for expanion rights after CPU approval and $40 Million for expansion cost
Total Expansions		35,150	1,490	$5,121	$120,805	$180	

Sources: Various Press Releases and Other Public Sources

1.5 The Value of Storage from the Perspective of Public Sector Costs and Benefits

The value of natural gas storage as defined in the previous section was based on the costs and benefits to the market participants that either provide or utilize natural gas storage. As such, the description provides concepts that are used to assess the market value of natural gas storage to entities directly involved in transactions. As with any economic good, robust trade in natural gas storage services increases net social welfare by transferring the goods or services to those who value them most. Trade will play a pivotal role in minimizing the economic and social costs of obtaining needed additional natural gas storage assets provided that the trade allows for the unhindered re-allocation of storage service to those parties.

However, from a societal perspective, the market value of gas storage may not fully reflect the overall value of storage. Third parties not involved in the transaction may incur direct benefits or costs, which are externalities. If the full costs and benefits are not reflected in natural gas storage service prices, the socially optimal quantity of gas provided to the market may not be achieved.

Natural gas storage transactions may impact third parties' negotiating position and/or prices resulting in a third party effect. From a political and public policy perspective, third party effects are important even if they do not increase or decrease net social welfare. This section examines potential externalities and third-party effects for natural gas storage.

1.5.1 Defining Externalities and Third Party Effects

According to the classic definition by A.C. Pigou[17], an externality is a cost or benefit that is experienced by someone who is not a party to the transaction that produced it and is not reflected in the price. A negative externality is a cost experienced by someone who is not a party to the transaction that produced it. A positive externality is a benefit experienced by someone who is not a party to the transaction that produced it.

Externalities are important from an efficiency perspective because they can create incentives to engage in too much or too little economic activity. In the absence of significant externalities, both parties to an economic transaction are assumed to benefit, improving the overall welfare of society; the benefits outweigh the costs. In the presence of externalities, others who are directly affected do not have a choice concerning whether or not the transaction takes place, and thus, do not influence the amount of the good or service provided.

The classic example of a negative externality is pollution. Manufacturers that pollute may create uncompensated costs for nearby residents. An example of a positive externality would be bees raised to make honey that pollinate nearby fields. Both the residents near the manufacturer and the farmer near the beekeeper are impacted directly, but may not influence the price or the amount of goods produced.

There are potential public and private solutions to account for or to reduce potential externalities. The market-driven approach to correcting externalities is to *internalize* third-party costs and benefits, for example, by requiring a polluter to repair any damage caused. The public policy choice to internalize any external costs or benefits depends on whether it is feasible or whether a close approximation of the true value can be determined. If costs and benefits can be internalized by market participants, private costs and benefits will equal social costs and benefits.

With third-party effects, non-participants in a transaction do not incur direct costs or benefits. However, a transaction may impact a third party's potential options and choices and can be crucially important to others and may have public and/or political ramifications. An example would be a third party transaction that significantly lowers the prevailing market price. Two third parties in the same market may still go through with a planned transaction, but the customer will benefit from the lower market prices, while for the seller, it would be a detriment. The third party effect in this case would not impact total net social welfare, although the welfare of the consumer would be higher, and, conversely, the welfare of the seller would be lower.

1.5.2 Potential External Benefits

This section looks at the potential external and third-party effects that are generally considered benefits of natural gas storage development.

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[17] Pigou, Arthur C. *The Economics of Welfare*. 1920.

Natural Gas Commodity Price Level and Volatility

In general, lower natural gas commodity prices and lower price volatility are often considered desirable from a public policy perspective. The amount of natural gas storage assets in California and elsewhere will impact both natural gas price levels and price volatility. However, the desirability is a matter of perspective. It is also unclear that lower natural gas prices and volatility increase net social benefit.

Lower prices are beneficial to consumers of natural gas but not necessarily to sellers of natural gas. Lower prices may increase total natural gas and energy consumption. This may not be a desired outcome for certain groups for environmental reasons. Finally, some key participants in the California's natural gas market may be neutral in regard to commodity price. The commodity price level may not have significant impact on the profits of natural gas pipelines delivering to the state who do not take title and distribution companies who pass through the commodity costs to consumers. However, these entities may desire lower commodity prices due to the adverse impacts that prices have consumers and for other political or public relations reasons. A public policy of lower natural gas prices is generally a desired goal.

Natural gas price volatility is also undesirable to most natural gas consumers. It makes planning more difficult for businesses to the extent that natural gas costs account for total costs. It also creates uncertainty in personal budgets of residential consumers. However, some entities may desire increased price volatility. Volatility increases arbitrage and trading opportunities. Sellers of natural gas storage services will see an increase in demand for their services. Therefore, groups that trade in natural gas or provide gas storage may desire increased price volatility. However, if the majority of market participants are risk-averse, the net effect of lower price volatility should be an increase of net social benefit.

Storage gas influences seasonal gas supply and demand, and therefore the price of gas to all participants and not just the parties involved in the storage transactions. Storage injections increase demand during off-peak requirement periods from April to October. The amount of total annual storage injections is a function of total working gas capacity. Incremental California storage assets will tend to increase the volume of storage injections in non-winter months.

Gas purchases for storage injections will compete for consumption of natural gas, most notably gas used for power generation in the summer. As discussed earlier, storage refill in the summer will tend to increase gas prices during the summer and shoulder months. In fact, as the market has become more volatile during this past decade and the importance of storage has grown, there have been price peaks in both the summer and the winter. It is likely that incremental natural gas storage could reduce the highest price peaks in the winter by providing available supply during that peak demand period. However, incremental storage injection may continue to increase summer prices, offsetting some of the winter price reduction.

Net costs associated with building and running incremental storage fields would increase total costs for the California natural gas market. These costs are borne only by the customers who have contracted for storage services. Price savings during high demand periods may or may not completely offset incremental storage costs. If average annual gas prices are lower because the

highest prices in the highest demand periods are reduced to a greater extent, then most gas consumers that do not contract for storage services will benefit from the lower average annual market price. Gas consumers who contract for gas storage services may still be better off even if any potential annual gas savings do not offset gas storage costs. Those entities may value gas storage for other reasons, such as the ability to consistently buy base-load gas supplies and serve a varying gas load by relying on storage for market swings.

Natural gas storage reduces natural gas price volatility. As gas prices increase, there is a tendency to increase storage withdrawals or reduce storage injections to capture some of the value through incremental natural gas sales. Conversely, relatively lower gas prices tend to do the opposite, which is to encourage a moderate reduction of gas withdrawals or increase in gas injections, as some holders of storage capacity delay sales hoping for better future prices. Natural gas storage reduces price volatility to all participants in the gas market, while storage costs are only borne by those who contract for storage. Both daily and seasonal volatility will generally be inversely proportional to the amount of gas storage.

Holders of storage will be able to enter into a higher degree of base-load gas supply and transportation contracts by using storage for consumption load following. The storage holders may be able to hedge or enter into more stable gas price purchase contracts. If storage services are not restricted in the market, entities that value price stability most and are most able to cover the cost will enter into storage contracts. For those entities, the benefits of storage exceed its costs and the net benefits are internalized. Those that do not contract for storage might still benefit from lower price volatility, but they do not value direct use of storage enough to commit to prevailing storage market rates. Incremental storage capacity without active voluntary purchases of storage capacity could reduce net societal benefits.

Natural Gas Network Reliability

Network reliability and system integrity is arguably one of the most important public interests for California's natural gas market. The impact of a gas network failure on social welfare could be significant. Individual failures may affect the entire network system and other industries in the economy; notably the electric generation market where a loss of service can create a threat to human health and safety. Natural gas storage is a crucial asset that helps maintain gas delivery and transport system integrity.

As a matter of public policy, the question is whether or not appropriate rules and regulations are in place to generate incentive for the proper level of gas storage assets in order to maintain a prudent level of reliability. Does competition among storage providers alone create the proper incentive or does market power provide suboptimal levels of reliability? Are private interests in line with public interests such that if market participants pursue their own desired level of network reliability, the socially optimal level is achieved?

It is impractical and essentially impossible to create a gas network that is 100 percent reliable. No amount of redundant infrastructure and costs could cover every conceivable contingency. The correct level of natural gas storage capacity to maintain the appropriate level of reliability occurs when costs of incremental storage equal the value of incremental reliability. If most

participants in the market are risk-averse, then the appropriate incremental reliability will be greater than the simple estimated economic cost times the probability of an outage occurring. In other words, people generally value some extra level of safety and reliability. It is important to note that improvement in reliability does not always reduce social welfare, but it may improve welfare in the case where initial reliability is well above an acceptable level.

Achieving the desired reliability in the natural gas market is complicated by the fact that, in a network system, it is difficult to separate those who pay for system reliability from those who do not. A major disruption in the natural gas transmission network would be detrimental to all users, not just for those who caused it. Even after a problem occurs, it may be difficult to determine causes and consequences for all participants to a significant degree of accuracy.

In addition, there is often difficulty in setting an appropriate reliability standard. Customers are not homogenous. Customers who desire or demand higher levels of reliability may end up subsidizing those who desire lower levels of reliability if they pay for most of the gas storage themselves. Increased reliability may lead to higher natural gas consumption for those consumers who receive benefits from the increased reliability and do not adequately pay for it.

The volume of contracted natural gas storage services should achieve the socially desirable improvement in reliability if:

- The reliability of storage is contractible,
- The reliability is observable by customers,
- There are storage alternatives and switching costs among the alternatives are sufficiently low,
- Consumers of storage services are not locked in,
- Access and entry into the market for new providers of storage is not restrictive,
- Growth in demand continues for new storage services, and
- Natural gas consumers without storage appropriately pay for reliability.

Contracting for Storage

Natural gas storage services are clearly contractible. It is possible to specify the relevant services and the degree to which the storage operator can be held accountable for them under different contingencies. Customers are able to contract for varying levels of service based on volume and the quality of the service to satisfy their needs. The amount of working gas in place and storage injection and withdrawal volumes can be customized for each customer. The quality of the service (for example, firm service of some type of interruptible service) can also be specified. Legal and financial consequences for the storage operator for not delivering the contracted service are usually included in storage contracts.

Current regulations at the Federal and state levels can inhibit innovation and customization of the service. Because of concerns regarding undue discrimination, FERC and other regulators

place restrictions on the negotiated terms and conditions of service. Rather, the regulated service provider is required to offer a new tariff service to respond to a service request.

Recognition of Reliability by Customers

Whether a storage operator achieves an agreed upon level of reliability is readily observable by individual storage customers. If the proper volume of natural gas is allocated by the transmission and distribution companies to their accounts and terms of the contracted service have been met, the customer can clearly determine that an appropriate service has been provided and the contracted reliability has been achieved. This will remain the case even if the physical gas does not enter the system and the storage operator has contract terms governing imbalances employed to cover resulting changes in volume. In this instance, the customers should observe reliability, at least ex-post.

To assist customers in understanding the reliability that they are contracting ex-ante, historical reliability can and should be provided. By doing so, the contracting parties will have the appropriate information upon which to make decisions regarding the amount of reliability that should be contracted. Moreover, providing reliability information to the buyer of the service addresses potential problems created by asymmetry of information given that the service provider will necessarily have such information.

Reasonable Alternatives to Storage Service

Reasonable alternatives for storage customers are necessary to provide individual customers an ability to switch to an operator that offers the best price-to-quality ratio. If all customers have reasonable choices and the storage services are priced appropriately based on their level of reliability, then the marginal consumer of storage services will contract for some quantity of storage capacity. The market would value additional storage, but it would be valued by an amount that is less than the cost of providing it, thus reducing social welfare.

Natural gas storage is likely to be priced appropriately if there are sufficient competitive pressures among alternatives. Competing private firms typically consider the adverse effects of pricing storage too high or of offering a storage service that is below the standards of other storage services that are being provided in the market. If they don't, they are likely to lose their customers to competitors. Alternatives not only include storage from other providers, but other feasible options, such as additional pipeline transportation capacity. Natural gas storage reduces requirements for incremental pipeline capacity upstream of the storage fields, and can reduce costs to serve total gas demand in the network.

Ability to "Switch" to an Alternative Service

Costs for gas shippers should not so be high as to prevent shippers from switching to a better, or perhaps best, cost alternative. Switching costs to alternative storage suppliers or pipeline transportation cannot be unreasonably prohibitive; otherwise it may give existing storage operators market power. In this case, the storage providers may be able to price storage at very high prices and significantly reduce reliability to the detriment of the market.

If customers are locked into their natural gas storage choices for terms longer than they can freely negotiate, this may produce results similar to high switching costs. Regulatory

requirements for minimum contract length could give market power to storage operators. As was the case above, storage providers may be able to price storage at very high prices or offer a suboptimal service in this case.

Entry into the Market by New Service Providers

Access to the market for new natural gas storage providers is important in maintaining competitive pressure on existing storage providers. Existing storage providers will have to continuously provide service that maintains the market price, given its value. Their customers may switch or threaten to switch to new storage providers only if new fields are not unduly restricted from entering the market.

Ease of siting storage and access to gas pipeline transmission and distribution systems are vitally important to allow access for new entrants. If access to the pipeline network by third-party storage fields is at a financial disadvantage relative to storage fields owned by the pipeline network operator, marginal storage demanded in the market will be lower. This may reduce the amount of storage contracted in the market to a level that would be optimal if the access was priced at its actual cost.

Demand Growth and Maturity of the Market

Natural gas demand growth aids competition among storage providers. If the market demand for new storage fields is increasing, it may offer existing customers more options in regards to switching or threatening to switch to new providers. New fields may use new technologies that increase efficiency in providing storage services. If the gas market is stagnant or has very slow growth, this may increase potential market power to existing gas storage providers as existing customers may have fewer alternatives. In this case, storage providers may be able to price storage at very high prices or offer a suboptimal service.

Cost Responsibility and Free Riders

Policies must be in place to reduce or eliminate free riding of the reliability that gas storage creates in the transmission system by those that do not directly contract for storage services. Consumers of natural gas on the network that do not contract for natural gas storage should be exposed to the full consequences of the reduced network reliability. This could be in the form of both fees and penalties. Fees may be appropriate to account for load variances in excess of what reasonable levels of linepack may accommodate. Fees need not be separate surcharges, but could be priced into transport fees.

Imbalance penalties must be priced appropriately to network users without storage. If existing gas storage is used to cover a gas shortfall, the actual cost may not be appropriate. The incremental cost to cover a gas shortfall on a non-peak day may be relatively small. As a minimum, full incremental per-unit costs for additional storage capacity would be appropriate. Higher costs may be appropriate, particularly during peak periods. For example, costs that reflect the increased risk (probability of network failure) per unit of overrun times the cost of a failure may be justified during such periods. Both the increased risk and the potential cost of failure may be difficult to determine. However, the principle should be considered when pricing imbalances. If the cost of reliability is appropriately priced to all participants in the gas

network, users of the gas network will internalize the cost and total storage contracted for in the market will be socially optimal.

1.5.3 Potential External Costs

This subsection looks at the potential external and third-party effects that are generally considered costs of natural gas storage development.

Land Use Impacts on Contiguous Property

New and existing natural gas storage fields may impact the value and sometimes the allowable use of land around the fields. A storage company must follow the proper regulatory procedures (Federal and/or state, depending upon the circumstances) and obtain the proper permits. Regulators, interveners, and/or commenters may suggest alternatives and modifications to reduce effects on nearby landowner interests. Alternatives are taken into account in the site approval process. However, storage fields are usually located in depleted oil or natural gas production fields or salt caverns. Therefore, potential locations are most dependent on geologic conditions. Facilities needed to develop and use a storage field can be moved only to a limited extent.

Storage operators typically negotiate a right-of-way easement and financial compensation with each landowner directly impacted by a storage field. Landowners may be paid for loss of certain uses of land during and after construction, loss of any other resources, and any property damage. Eminent domain (a right given to a pipeline company by statute to take private land for Commission-authorized use) with a court determining compensation under state law may be necessary if an agreement between the two parties cannot be reached.

However, any loss of land value to nearby residents not directly impacted by easements and right-of-ways may not be compensated. This is a direct negative externality. This could include property in which the storage field is physically underneath but without any above ground facilities. The concerns of such residents or businesses that are impacted may be heard during regulatory proceedings when weighing alternatives, including not building the storage field under consideration. If the costs associated with nearby landowners are not taken into account, potentially more storage will be built in the market than is optimal. Standard regulatory proceedings should determine that externalities to nearby landowners do not outweigh the net benefits of the gas storage field.

Security Costs and First Responder Contingency Costs

Protection of critical gas network infrastructure such as natural gas storage fields requires both heightened security awareness and investment in protective equipment and systems. Costs associated with direct security of the facility are borne by the storage operator, and are included in the price that is charged to storage customers. Public policy should require the level of security that is desired not only by the storage provider, but also by nearby residents and users of the gas network.

First responders to a security incident or accident at a natural gas facility will most likely include local police and fire departments. A new natural gas storage field may increase the need for greater capabilities and preparedness of the local departments to mitigate and/or respond to

potential incidents. This would be supplemental to the contingency procedures put in place by a storage operator. Additional revenue (for example, tax revenue) should cover the increased expenditures of the first responders to provide an appropriate level of security and safety for the new facilities. If additional revenue (for example, tax revenue) is not planned for and achieved, then a negative externality reflecting an inadequate level of security and safety will occur.

1.5.4 Internalizing Externalities: Equating Social and Private Costs

There are a number of potential means of improving total social welfare when externalities are involved. A market driven approach can be most efficient if the costs can be internalized by market participants and property rights can be defined. Following the *Coase Theorem*[18], the market will produce a socially optimal level of a good or service if trade is available and there are not significant transaction costs. For the California gas market, near-optimal levels of gas storage may be achieved if market participants are able to enter into agreements for incremental storage capacity, and the costs of that capacity can be internalized across all market participants, even those not entering into specific storage agreements.

There are a number of factors that could limit the *market solution* to equating social and private costs suggested by Coase's theorem. The assumption of zero—or minimal—transaction costs, may be far from valid in energy markets. Moreover, the property rights may be defined in such a way so as to limit transferability. For example, mineral rights related to capacity rights needed to create storage may be severed and held by parties that are only interested in surface uses of the property, notwithstanding the fact that surface development can often preclude development of a gas storage facility.

In addition, a number of economists have studied other limitations on Coase's theorem. George Stigler offered that "The Coase theorem ... asserts that under perfect competition private and social costs will be equal".[19] In this assertion, Stigler places a restriction that perfect competition must exist, a limitation that is hard to find in Coase's own discussion. Natural gas markets and gas storage have not been found to operate in a *perfectly competitive* market throughout California and the Western states. Even though some storage has been found to operate in a *workably competitive* market and therefore receive market-based rates, utility storage remains subject to traditional utility regulation.

Certainly in energy markets, there are situations in which imperfect or asymmetric information can inhibit price behavior that is consistent with a perfectly competitive market. In addition, regulatory intervention and an "obligation to serve" can interfere with an unfettered market.

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[18] The Coase theorem, attributed to Ronald Coase, describes the economic efficiency of an economic allocation or outcome in the presence of externalities. The theorem states that when trade in an externality is possible and there are no transaction costs, bargaining will lead to an efficient outcome regardless of the initial allocation of property rights.

[19] Stigler, George J. *The Theory of Price* (3rd edition). New York, Macmillan. 1966, p.113.

Other, but perhaps less important, limitations to Coase's theorem has been suggested, including separable versus non-separable cost functions; negotiation starting point; and income, taste and preference effects. Taken collectively, these limitations suggest a possibility that there may be some limitations that will make it difficult for the market solution to equate social and private costs.

At the same time, these limitations also create complexities in any proposed solution that attempts to take action to better equate social and private costs. Any attempt to more fully internalize external costs and benefits requires a complete understanding the nature of the interaction between market decisions and the dynamics of external costs and benefits. The ability to selectively capture additional efficiency may be difficult, if not impossible.

1.6 Other Issues Regarding Gas Storage

In this section, we consider some of the other issues relevant to gas storage.

1.6.1 Storage Interaction with LNG Imports

There is a strong nexus between storage and LNG imports. Most natural gas industry analysts expect that LNG imports in North America will increase substantially, rising from about 1.6 Bcfd in 2006 to over 10 Bcfd by the middle of the next decade.[20] To support this expected increase, there is a significant amount of new LNG import capacity currently under construction throughout North America, particularly along the United States Gulf Coast. However, there are some new facilities under construction in other locations as well, for example, in eastern Canada and in Mexico. In addition, existing LNG import facilities have been recently expanded or are undergoing expansions. Finally, there are numerous proposals for many projects in other locations.

Several characteristics of LNG imports argue for the pairing of storage and LNG import terminals. LNG imports will tend to be seasonal. The expectation is that many of the cargos will be delivered in the summer rather than in the winter. This is because the United States has a fairly abundant supply of storage, while Europe and Asia do not. The result is that LNG will go to Europe and Asia primarily in the peak winter months and to the United States mainly in the lower demand summer months. North American gas storage may very well provide a "parking space" for LNG until it is needed and thus become a critical link in the global LNG supply chain.

When LNG is delivered, the liquefied gas is piped into large, above ground insulated storage tanks. From there, the gas is sent through regasifiers, where it is heated and, after returning to the gaseous state, injected into the pipelines—this process is typically referred to as *gas send out*. LNG storage tanks located at terminals can hold on average about 10 days of gas send out capability; and the tanks have to be emptied before they are able to receive the next LNG shipment. This means that buyers of the regasified LNG must either sell it into the market

[20] This is a common trend in many projections that are available, including EIA's *Annual Energy Outlook*. Our own projection for the North American natural gas market projects 11 Bcf per day of LNG imports to North America by 2015.

within 10 days or send it to storage. In the latter case, storage provides a place to put the gas to prepare for the next cargo.

At the same time, storage allows LNG importers to avoid situations where they are selling directly into a market during a period when demand is relatively low and prices are also low. It can be expected that a ship delivering LNG can depress nearby gas prices as the gas is being regasified and sold into the market. This is more likely to occur in markets that are not very deep or broad and rather illiquid. As an option, the LNG providers could store the regasified LNG in underground facilities to be released in a more regular pattern to reduce the impact of a sudden large amount of gas on the market. Thus, gas storage is a mechanism by which LNG providers can better manage their sale of gas into the market, selling to the market when gas is most needed. Salt cavern storage is especially suited to storing regasified LNG to manage price exposure and modulate deliveries because of the large injection and withdrawal capability relative to the maximum volume of gas that can be stored.[21] In fact, many analysts believe that the surging interest in high deliverability storage in salt caverns along the Gulf Coast is linked to supplier concerns about market liquidity and depth for large incremental deliveries of LNG.

1.6.2 Role of Gas Storage in Markets

For gas merchants, gas storage can be a valuable asset to hold either as a managed facility where gas is stored for others, or through storage contracts with storage providers. In these instances, the value created by storage is more than simple sum of storage and the other assets (for example, pipeline capacity). Some examples of services where these synergies can be created include the following:

- **Parking and lending services**: Pipelines usually provide this for shippers but it also can be provided by independent storage operators. It involves short-term storage or short-term loans of gas from storage. A merchant may have excess gas in a pipeline, and to avoid imbalance charges that merchant may store gas for a day or some other brief period before withdrawing it. Similarly, a merchant may be short by a certain amount of gas. In that case, a storage provider can loan the merchant gas, again to avoid imbalance penalties. The merchant pays a fee for these types of services and is required to replace the borrowed gas.
- **Hub balancing services**: Hub operators must manage receipts and deliveries through the hub from multiple parties. At any given point in time, hub accounts may be long or short. That is to say that there may be a mismatch of receipts and deliveries at the hub. As a consequence, hub operators will have storage accounts to manage these imbalances. Indeed, many hubs are located at interconnections of pipelines and storage fields for this reason. In this way, hub operators keep the hub exchanges moving, much in the same way that stock market specialists on the New York Stock Exchange use their own stock inventories to maintain an orderly market.

[21] To date, no salt cavern storage has been developed in California.

- **Market reliability**: The presence of storage inventory provides a cushion against unforeseen developments, such as pipeline outages or supply disruptions. In the 1970s and early 1980s, producing area storage was developed by many pipelines to help manage what was then perceived as a gas shortage. Storage was viewed as a means of managing curtailments of services, which were a staple of the early 1970s. Even though gas curtailments have not been commonplace for many years, storage remains a means of providing reliability of deliveries to retail gas markets.
    - Related to reliability is the value of storage as a way of firming gas supplies. Marketers purchase gas from a variety of sources, under firm and interruptible contracts. Storage allows them to bundle firm with non-firm contracts to provide firm gas service to customers. The storage allows them to have back-up to their non-firm tranches of supply.
- **Risk Management**: A characteristic of the current gas market is price volatility. Storage provides a way of managing price risk. Gas can be purchased when prices are perceived to be relatively low, stored, and used when prices are perceived to be relatively high. Storage is a critical component of this process. It can act as a hedge for risk-averse parties and provide an asset for parties engaged in more risky market timing activities. The net effect of these hedging and price arbitrage activities is that risk is mitigated across the market.
- **Load Shaping**: A key role of storage for gas merchants and for LDCs is the use of storage to meet swings in demand. We have discussed this in the context of LDCs who store in the summer months to satisfy higher winter demands. In load shaping, marketers may have a variety of customers, each with a consumption, or load, profile. When combined together, the profiles may offset each other and provide a more stable load pattern that better matches the rate of deliveries to the marketer. Gas storage helps to fill in the gaps and shape the overall delivery patterns.

1.6.3 Regulatory Issues

FERC Order 636 created open access for storage and allowed users to manage their own storage accounts (within operational rules of the storage services). Equally important, Order 636 opened the door to third party independent storage operators. FERC has also set up procedures whereby operators can seek to charge market-based rates instead of traditional cost-based rates. It is felt that allowing operators to charge market rates may encourage greater investment in new storage. But, as implemented, FERC set the bar to qualify for market-based rates high—applicants have had to demonstrate that they have no market power under a relatively tight definition of the relevant storage service market. Investment in new storage has increased, but at a pace at which policymakers hoped would occur.

The Energy Policy Act of 2005 contains provisions that amend the Natural Gas Act to allow FERC to authorize market-based rates for new storage projects even in cases where the applicants cannot demonstrate that they lack market power. Accordingly, FERC issued Order 678 in 2006 to establish rules for making it easier to show that a storage facility would not have market power by expanding the definition of the relevant product market. Further, Order 678

establishes that even where applicants cannot show a lack of market power, FERC can nevertheless authorize market-based rates under certain conditions.

In California, the California Public Utilities Commission (CPUC) regulates storage services. Storage services provided by LDCs are subject to cost-based rates for storage used to provide service to core customers. Non-core services are subject to rate caps and revenue sharing. Independent, third-party storage services are allowed market-based rates and are subject to reporting requirements and prohibitions against engaging in hub services or other trading services with affiliates or parent companies.

The major issue for regulators is whether a storage operator can exert market power, and if the regulators should monitor and place some restrictions on storage operations under market-based rates. This has been balanced against the understanding that increasing storage ameliorates gas price volatility, and that there are externalities associated with storage operations. Presently, it is not clear if FERC or CPUC policies present barriers to storage development.

1.6.4 Regulation and the Development of New Storage Capacity

In the United States, storage field development is regulated, with both new storage fields and expansions of existing storage fields subject to approval by a variety of regulatory agencies. FERC regulates natural gas storage capacity used in, or contracted for, interstate natural gas commerce, while individual state public service commissions regulate storage capacity used for intrastate commerce. Generally (but not exclusively), the state public service commissions regulate storage capacity owned and used by LDC customers to serve the needs of their own in-franchise customers, while FERC regulates storage capacity owned by, or connected directly to, the interstate natural gas pipeline system.

As mentioned above, most natural gas storage capacity regulated by FERC is subject to cost-based rates. The rates at which this storage capacity can be contracted are set based upon the cost of providing the storage service, plus a “reasonable” rate of return on investment as determined by FERC. Almost all of the natural gas storage owned by an interstate natural gas pipeline is regulated by FERC as cost-based storage.

Current FERC policy promotes development of storage. FERC has established a significant incentive for independent storage in terms of a substantially lower threshold analysis required to obtain market-based rates. Recent changes allow for both existing storage facilities to apply for market-based rates under a relaxed standard that allows for a much broader product definition as well as the granting of market-based rates for new storage even in instances where the storage provider is deemed to have market power, so long as the facility is in the public interest and FERC concludes that it would not be built under a cost-based rate regime.

Generally, market-based rates create the opportunity for upside potential in storage asset investment. Cost-based rates limit upside potential without reducing downside risk. The application of market-based rates has an impact on the allocation of risks between the buyer and seller of storage services. The buyer must rely on contracts exclusively to address price risk because there is no “backstop” price determined by regulation. Conversely, the seller has no

regulated recourse assuring the "opportunity to recover prudently incurred costs" granted by regulation. FERC is more likely to approve market-based rates in markets with major competitors that are capable of expanding and increasing available storage service, thereby providing additional alternative capacity to thwart any potential effort by the applicant to exercise market power.[22]

Market-based rates have been granted for facilities that are able to show, through traditional market concentration analysis, that they lack market power. So far, the majority of FERC's allowances of market-based rates have been to independent storage operators without a significant pipeline ownership share in the market served by the storage facility.

FERC has applied its market power analysis in a number of cases. Applications involving both production and market area storage have been approved. However, when the geographical market is defined very broadly, for example to include both production and market areas, an unfavorable decision can result.

In response to changes in United States law included in the 2005 Energy Policy Act, and to concerns related to the relatively slow development of new storage capacity in the United States, FERC is in the process of reviewing the process by which a storage developer may seek market-based rates for new storage facilities, and has recently announced new proposed rules on market-based rates for interstate natural gas storage facilities.

As previously mentioned, in June 2006, FERC in Order 678 expanded the conditions under which market-based rates could be applied by issuing regulations to implement Section 312 of the Energy Policy Act of 2005. FERC expanded the definition of the "relevant product market" to be used in market concentration analysis. This action will likely increase the number of instances in which market-based rates are found to be appropriate for new storage capacity.

If approved, the new rules proposed by the FERC would increase the opportunities by which a storage provider can demonstrate that market-based rates would not harm consumers by expanding the definition of storage competitors to include close substitutes for gas storage services, such as available pipeline capacity, local gas production and LNG terminals. The proposed rules would apply to all storage facilities, including both new and existing storage fields. This change reflects the reality that gas in storage currently competes with these substitutes, and adopting this approach would provide a more accurate analysis of whether a storage provider can exercise significant market power in a relevant market.

The proposed rules would also provide an opportunity for FERC to approve market-based rates for storage facilities completed after August 8, 2005 "notwithstanding the fact that the applicant is unable to demonstrate that it lacks market power"[23] if the Commission determines that

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[22] 94 FERC 61,194 (2001), p. 24. Also OneOk Gas Storage, 90 FERC 61, 283 (2000), where the Commission relied on the existence of idle capacity and ease of entry for its finding of no market power concern, notwithstanding the applicant's market share of 13.5%.

[23] FERC *Rate Regulation of Certain Underground Storage Facilities Notice of Proposed Rulemaking*. December 22, 2005. 18 CFR Part 284, p. 22.

market-based rates are in the public interest and necessary to encourage the construction of new storage capacity, and that customers are adequately protected.

1.7 Implications for Public Policy

Even a cursory examination of gas industry trade publications indicates the importance of storage inventories on natural gas price levels. Natural gas prices rise or fall, sometimes dramatically, if natural gas storage injections or withdrawals differ from market expectations.

Natural gas market prices are extremely volatile because of underlying supply and demand conditions. Supply is relatively fixed—inelastic—in the short to medium term as the basic supply infrastructure (wells and pipelines) cannot rapidly increase output in the face of increasing prices. Demand is also relatively price-insensitive in the short to medium term. With the exception of dual-fuel users, most customers, particularly residential consumers, cannot substitute other products or do without gas in response to price increases. In addition, natural gas prices are still generally regulated at the retail level for most residential and commercial customers. Prices to these customers are adjusted over the longer term to reflect average commodity prices but there is not an immediate price signal reflecting changes in market prices to these customers.

Importantly, demand fluctuates substantially seasonally and daily with changes in the weather. Inelastic supply and demand coupled with significant shifts in demand generate price volatility. Use of gas storage can potentially reduce this volatility.

Given the influence of storage on prevailing natural gas prices, there is a natural tendency to consider policy tools regarding gas storage in an attempt to influence natural gas prices. However, intervention into the operation of the market, if the market is workably competitive and reflects thoroughly defined property rights, can ultimately do damage in terms of economic efficiency and consumer benefits regardless of how well-intentioned the motives for intervention are.

1.7.1 Policy Justification of Intervention

The issue of *externalities* and differences in private sector and societal costs create implications for public policy and decision-makers in California and in other jurisdictions. To the extent that private sector costs and benefits equate to social costs and benefits and there are not barriers to the development of storage, the market will develop an appropriate amount of storage without interference. The degree to which there remain externalities that are not incorporated into private market decisions should be the fundamental question addressed by any analysis made by policymakers when considering intervention in the market.

1.7.2 Identification, Quantification, and Capture of Benefits through Private Transactions

As discussed in Section 5, private sector participants in the market for storage are not a homogeneous group. They reflect diversity in terms of market segment and objectives for activity in the storage market. As a result of these differences, participants may value elements

of storage service differently. Indeed, different storage customers may attach fundamentally different values to storage in total.

However, the analysis indicates that different customers are not attaching different values to storage without justification. Each customer type has different needs and the way that storage provides an economic substitute for the other economic alternatives (for example, pipeline capacity, dual-fuel capability, financial derivatives, etc.) provides a rational framework for assessing value. And while complicated, the analysis and data needed to quantity the value of storage are available to participants. The information available to market participants, while not perfect and symmetrical, allows the providers and consumers of storage service to conduct the analysis.

Transparency in the broader natural gas market in California, the western states and North America is a critical feature fostering the efficient investment in the "right" amount of storage. Regulatory proceedings at the Federal and state levels to improve transparency are under consideration. In this area, California has been and continues to be a leader. A number of the aspects of regulations to improve market information and transparency currently being considered at the Federal level were modeled on existing reporting on some California gas utility systems.[24]

1.7.3 Barriers to Entry and Construction of New Storage Facilities

Siting of gas storage fields and accesses to transportation and distribution systems present a potential barrier. Land use, environmental permitting, and other siting issues present major, if not the most significant, challenges to storage development. In order to ensure that adequate storage is developed, public policy should balance land use objectives and consider how procedures could be used to thwart development.

The effects of removing barriers to entry go beyond assuring adequate supply of storage services. Potential competition will maintain economic pressures on existing storage providers even before alternative fields are built.

Robust competition in providing storage services is important to maintain the appropriate capacity and price of California storage services. In order to maintain and create incentives for the appropriate capacity of natural gas storage, California government and regulatory agencies should commit to maintaining market flexibility and cost accountability. Uncertainty in the market can delay investment, especially in such assets as natural gas storage fields, which are costly and have significant lead times for construction.

1.7.4 Innovation and Customization of Service

Flexibility of natural gas storage customers can be increased in several ways. Restrictions on storage contract terms and conditions should be minimal. Shippers on the transmission and

[24] FERC Notice of Proposed Rulemaking regarding Pipeline Posting Requirements under Section 23 of the Natural Gas Act, Docket No. RM08-2-000

distribution system should be able to switch among competing storage providers and pipeline transportation capacity with reasonable costs. Customers should not have mandated contract terms that unduly lock them into a single storage provider. Innovation and customization are important contributors to economic efficiency in workably competitive markets.

The public policy issues become more complex when juxtaposed with concerns regarding undue discrimination. Traditional utility regulation requires that all *similarly situated* customers be offered identical (or as nearly identical as possible) service and be charged the same rate. However, the application of this requirement can be problematic in a rapidly changing market. At its core are the questions, "What is a 'similarly situated' customer?" and "Can customers that seem similar be offered different services at different prices because the negotiations for the services were conducted at different points in time?"

There is no simple "cookie cutter" solution to this tension between regulatory protection and economic efficiency. It inherently reflects a balance. But it should be recognized in the course of creating the balance that a restrictive policy framework can adversely result in an under investment in storage.

1.7.5 Internalization of Network Reliability Costs and Benefits

Most importantly, all costs need to be internalized, especially for users of the gas network that do not contract for the reliability and flexibility that gas storage creates. Fees and penalties for gas consumption load variation and gas imbalances must at least reflect the full unit costs for storage assets. If the market allows free riding of the operational benefits and flexibility that storage provides, too little storage capacity will be built.

It is the issue of creating free-riders that may limit the benefits of a strategic natural gas reserve. A state-operated strategic natural gas reserve would be a direct substitute for reliability offered by private natural gas storage fields. If costs are borne directly by all market participants, some gas consumers would pay for neither network reliability that they do not necessarily want nor need. Those gas consumers or shippers would end up subsidizing shippers that demand a high degree of reliability. This would allow the high reliability shippers to contract for less gas storage and still receive the desired level of reliability. The main impact of a strategic natural gas reserve would be to reduce the amount of natural gas storage capacity that is privately built in the market.

By contrast, investment in basic research and development that improves storage technology and reduces operating costs creates benefits that result in lower consumer costs and increased storage development in a competitive storage market. Public/private research programs that produce improvements that are in the public domain propagate benefits that produce private sector and public sector benefits and ultimately provide lower costs for delivered gas than would exist without such investment.

Finally, constraints on utility gas portfolio management practices that limit the ability of a utility to recognize the full value of storage, including arbitrage value, limit the incentive for the utility to acquire and construct additional storage capacity. Utility regulation should consider creating appropriate incentives for portfolio management.

CHAPTER 2:
Project Results: The Impacts of Weather on the West Coast and California's Natural Gas Storage Infrastructure

2.1 Introduction

This section documents the development of 10 alternative weather cases prepared by ICF to evaluate the value of natural gas storage in California. The 10 alternative weather cases presented here were developed from the models and analytical techniques used in the Base Case analysis previously presented to the California Energy Commission (Energy Commission). This modeling work began in 2007 and was completed in 2008. This section also provides a description of the Base Case natural gas market outlook that provides the foundation for the analysis of the impact of the different weather cases.[25]

2.1.1 Relationship Between Storage and Weather

Historically, storage has served two relatively simple functions. Pipelines and LDCs have invested in storage to fulfill their obligation to provide a reliable supply of gas. Storage has also provided consumers and suppliers the operational flexibility to balance supply and demand on a seasonal, weekly, and daily basis. Thus, historically the value of gas storage has been in its ability to match production, which is generally at steady rates, with consumption. That is, storage capacity provides value because it is used to satisfy demand during peak consumption periods in winter. Storage also increases the reliability of natural gas flowing through natural gas pipelines.

Storage provides a balancing function in the short-term (for example, daily and even hourly balancing). In the deregulated environment and with the increase in reliance on natural gas for power generation, pipelines have had to implement policies to manage imbalances on the system (what is injected into the pipe must equal what is withdrawn from the pipe) when hundreds of shippers on any one pipeline are making independent decisions about gas purchases and deliveries. Pipelines have instituted a system of fees and penalties[26] to incentivize shippers to balance their injections and withdrawals.

As a result, natural gas storage creates value for consumers by its ability to manage seasonal and short-term imbalances between natural gas supply and natural gas demand.

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[25] ICF previously delivered the Base Case results for the West Coast Modeling effort.

[26] The fees and penalties charged to meet hourly fluctuations have become a central issue on the El Paso Pipeline, which serves Southern California and the rapidly growing requirements of Phoenix and Southwest.

Natural gas supply tends to be relatively stable.[27] However, consumption of natural gas fluctuates substantially seasonally and daily, in response to weather changes. These changes are the result of both changes in heating/cooling load brought about by changes in temperature and changes in gas-fire power generation requirements that are influenced by hydropower generation that is sensitive to seasonal precipitation and snowpack.

The relative lack of supply elasticity and the significant swings in consumption that are influenced by weather create gas price volatility. The use of gas storage can help to reduce that volatility by managing the deliveries of natural gas to consumers to meet short-term demand for gas. Storage can also enhance supply security by making gas available when other supplies may fail or become too costly. Finally, storage serves a balancing function within the delivery system and helps minimize operating costs and rationalize overall investment in pipeline infrastructure. As a result, storage usage and value vary widely as weather changes.

2.2.2 Overview of Alternative Weather Cases Section

The 10 alternative weather cases documented in this section are designed to facilitate an assessment of how storage utilization and marginal prices are affected by weather. The weather cases alter assumptions for temperatures and conditions that drive levels of hydroelectric generation in the Western United States (for example, rainfall and snowpack). The cases combine different assumptions for temperature (for example, colder winter and hotter summer) with different levels of hydroelectric generation. Each case, like the Base Case, produces daily load, flow, and storage utilization results, along with marginal prices, for a variety of locations in California and the Western Region.

Case studies #1 through #9 focus on assessing the value of the expected storage infrastructure included in the Base Case with different weather, that is, temperatures and levels of precipitation. Storage would likely have the highest marginal value and the market would be most supply constrained and subject to shortages in Case Study #9, which assumes a very cold winter and low precipitation levels. Conversely, storage would likely exhibit the lowest marginal value and the market would be least constrained and most unlikely to experience any shortages in Case Study #1, which assumes mild temperatures with above average precipitation levels. Scenario 10 provides a more extreme weather/hydro case based on similar conditions to those that occurred during the 2000-2001 California energy crisis.

2.2.3 Structure of Alternative Weather Cases Section

The basic analytical modeling approach used in this study is summarized in Section 2.2. Section 2.3 provides a summary of the Base Case Outlook for North American, Western United States, and California natural gas markets used as the basis for the 10 weather cases, and Section 2.4 provides a detailed explanation of the development of the 10 weather scenarios. Section 2.5 compares the basic results of the 10 weather cases.

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[27] In the absence of major supply disruptions such as hurricanes and pipeline outages.

2.2 Analytical Approach

Our analysis is based on a multi-step process that makes use of three different model developed by ICF: (1) the Gas Market Model (GMM), (2) the Daily Gas Load Model (DGLM), and (3) the Regional Infrastructure Assessment Modeling System (RIAMS). Each of these models and their role in the analysis are explained below.

2.2.1 Gas Market Model

The GMM is a full supply/demand equilibrium model of the North American gas market, which solves for monthly natural gas prices throughout North America, given different supply/demand conditions. Overall, the model solves for market clearing prices by considering the interaction between supply and demand curves at each of the model's nodes. On the supply side of the equation, prices are determined by production and storage price curves that reflect prices as a function of production and storage utilization (Figure 15). Prices are also influenced by *pipeline discount* curves, which reflect the change in basis or the marginal value of gas transmission as a function of load factor. On the demand side of the equation, prices are represented by a curve that captures the fuel-switching behavior of end-users at different price levels. The model balances supply and demand at all nodes in the model at the market clearing prices determined by the shape of the supply and demand curves.

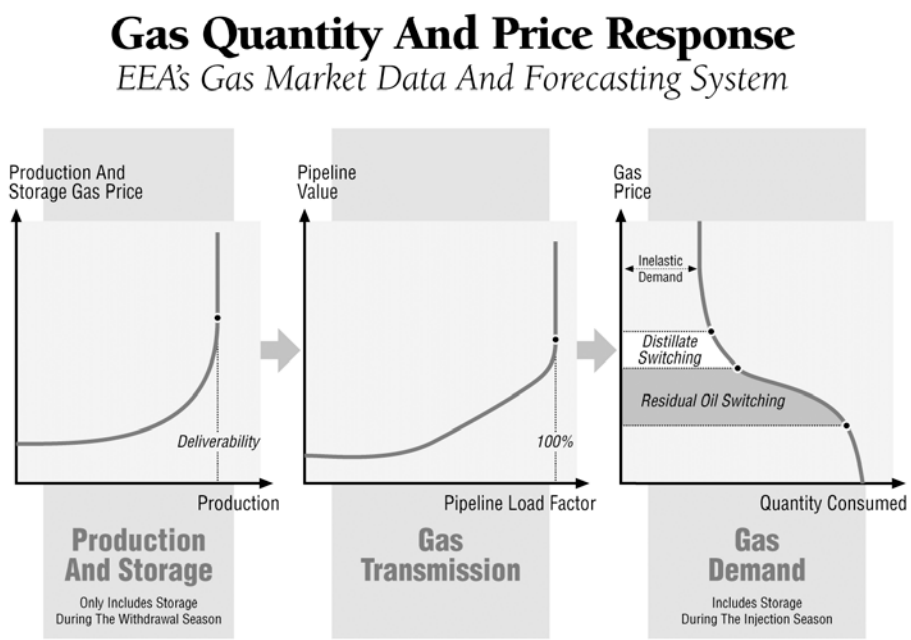

Figure 15: Supply/Demand Curves

Source: ICF International

There are nine different components of the GMM, as shown in Figure 16. The user specifies input for the model, including assumptions for weather, economic growth, oil prices, and gas supply deliverability, among other variables. ICF's market reconnaissance keeps the model up to date with generating capacity, storage and pipeline expansions, and the impact of regulatory

changes in gas transmission. This is important to maintaining model credibility and confidence of results.

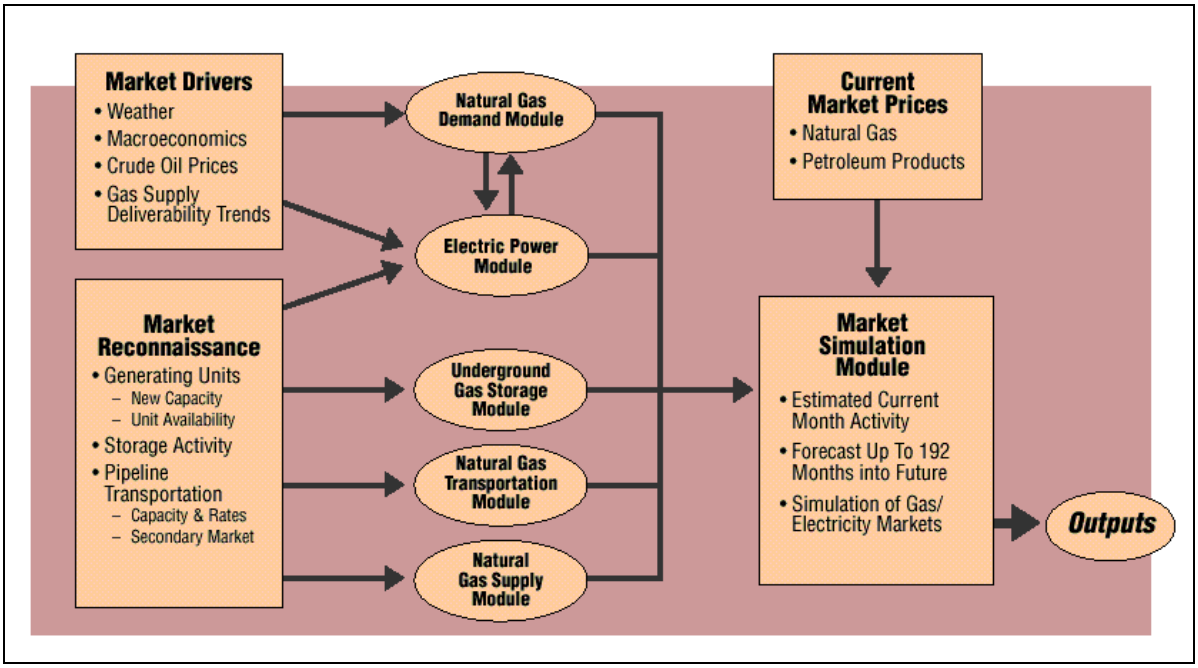

Figure 16: GMM Structure

Source: ICF International

The first GMM routine solves for gas demand across different sectors, given economic growth, weather, and the level of price competition between gas and oil. The second routine solves the power generation dispatch on a regional basis to determine the amount of gas used in power generation, which is allocated along with end-use gas demand to model nodes. The gas supply component of the model solves for node-level natural gas deliverability or supply capability, including LNG import levels. The last routine in the model solves for gas storage injections and withdrawals at different gas prices. The model nodes are tied together by a series of network links in the gas transportation module. The structure of the transmission network is shown in Figure 17. The components of supply (for example, gas deliverability, storage withdrawals, supplemental gas, LNG imports, and pipeline imports) are balanced against demand (for example, end-use demand, power generation gas demand, LNG exports, and pipeline exports) at each of the nodes and gas prices are solved in the market simulation module.

The GMM solves the market in monthly increments, and can be run through 2035. Each month is solved incrementally; that is, without any foresight on future gas prices and demands, and only limited foresight on supply development.[28] Monthly storage activity is governed by an

[28] The GMM has the ability to look ahead 6 to 12 month to see major supply developments such as the onset of LNG deliveries and the development of new Arctic gas supplies. In the "look-ahead" logic,

algorithm designed to mimic "reasonable" management of storage assets, based on long-run average patterns of injections and withdrawals. For example, storage may not be drawn down aggressively in December even if prices are relatively high, because the owners of storage capacity (primarily LDCs) are concerned with system reliability and want to have adequate storage in reserve for the remainder of the winter. Likewise, gas maybe injected into storage even when prices are relatively high in the summer because storage operators generally build working gas to desired levels for the coming winter.

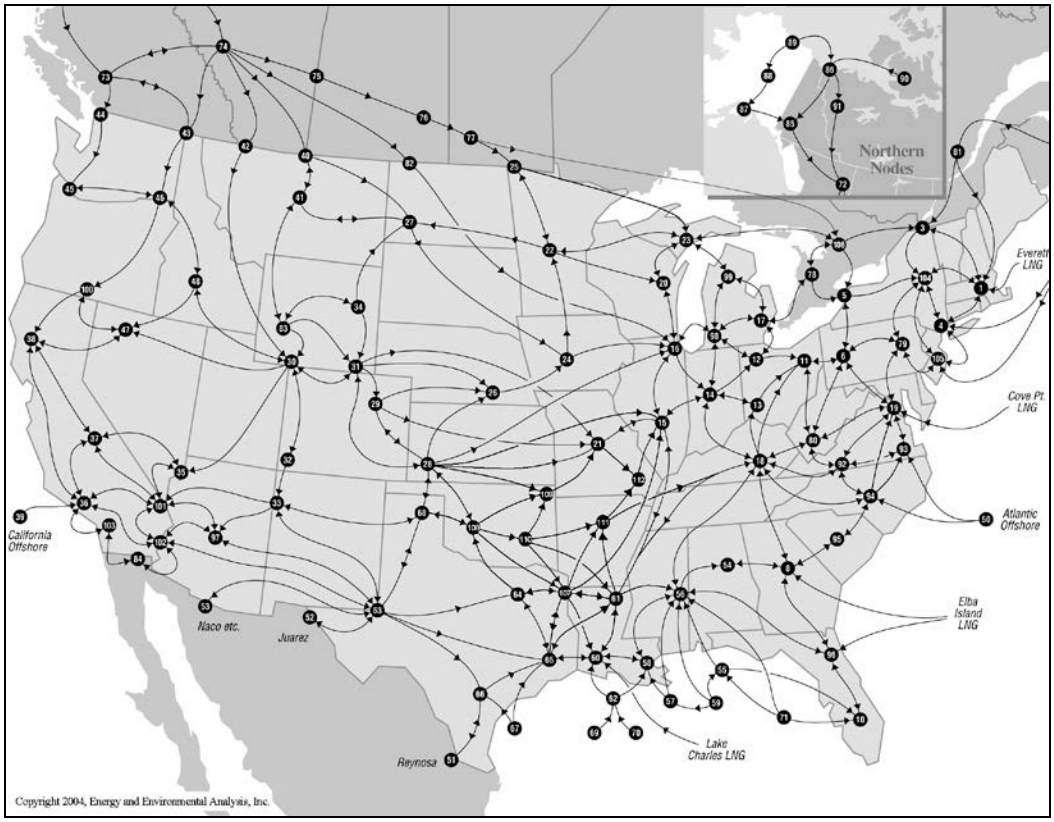

Figure 17: GMM Transmission Network

Source: ICF International

Since GMM covers the entire United States and Canadian natural gas network, each of the GMM's nodes covers a relatively large geographic area. For example, California is divided into four market areas: Northern California (38), Central California (37), Southern California (36), and the San Diego area (103), as shown in Figure 18. California also has four additional nodes that represent pipeline transit points, but have no supply, demand, or storage assigned to them: Malin (100), Topock (101), Ehrenberg (102), and the Baja border (84).

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the GMM does not factor in smaller supply developments since the timing of those supplies is not known with certainty.

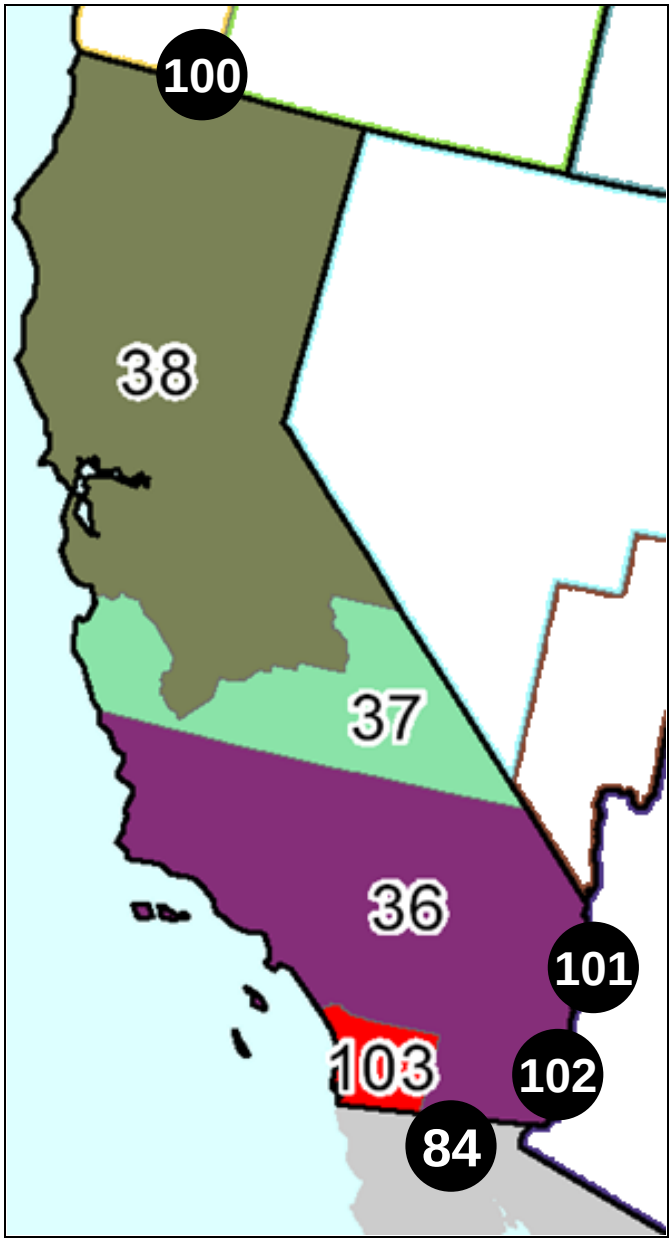


Figure 18: Gas Market Model's Representation of California Gas Markets

Source: ICF International

2.2.2 Daily Gas Load Model

The DGLM is an adaptation of the same gas demand algorithms used in the GMM. In contrast to the GMM, which projects monthly average demands at each market node, the DGLM projects daily loads for the same nodes as used in the GMM. The daily variability in demand is determined by a daily temperature series which is input for each demand region. For this

analysis, the research team used a daily temperature series that came closest to the average temperature variability observed during the past 30 years.

2.2.3 Regional Infrastructure Assessment and Modeling System

The RIAMS is used to provide a more detailed view of regional pipeline flows and storage activity than that provided by the GMM. RIAMS is based on a county-level assessment of gas consumption, production, and infrastructure (pipeline capacity, storage fields, and gas processing plants). This data is used to create a detailed regional network problem which is solved using CPLEX optimization software. The model's objective is to find the least-cost means of meeting a balanced solution for demand and production for a given time period at each node in the system by moving gas on the pipeline network, while staying within defined bounds for storage activity and pipeline flows. RIAMS can be run for a series of months, determining average monthly values, or for every day in a month, to determine daily variability.

Within RIAMS, a natural gas pipeline is described as a series of contiguous links between points, or *hubs*, in each county it passes through, as shown in Figure 19. Each pipeline hub can be connected to demand, production, or storage nodes within that county (or occasionally a neighboring county) by a pipeline link. If a pipeline has deliveries in a given county, it will also have a delivery hub; the link between the pipeline hub and the delivery hub represents any constraint on the total pipeline deliveries to that county. Some demand nodes, such as those representing gas-fired power plants or large industrial consumers, are connected directly to delivery hubs. LDC hubs act as intermediate point between delivery hubs and residential/commercial (R/C) demand nodes. If two pipelines have interconnected capacity in a given county, it is represented by a link between the two pipeline hubs. The Western United States version of RIAMS covers eleven western states and 38 distinct pipeline systems, and it includes 37 storage fields, as shown in Figure 20.[29]

In contrast to the GMM, RIAMS solves for every time period in its projection simultaneously, optimizing the use of storage across all time periods. For example, if RIAMS is given a problem with relatively cold weather in December and mild weather for the rest of the winter, RIAMS will increase December withdrawals much more than GMM would project, as RIAMS effectively "knows" that the gas in storage will not be needed for later in the heating season. Because of this intertemporal optimization of storage, RIAMS results show less seasonal variation in prices. Therefore, estimates of storage valuation based on RIAMS results are inherently conservative.

[29] Figure 20 shows only interstate pipelines; other components of the Western United States pipeline system (gathering pipe, LCDs, etc.) are not shown.

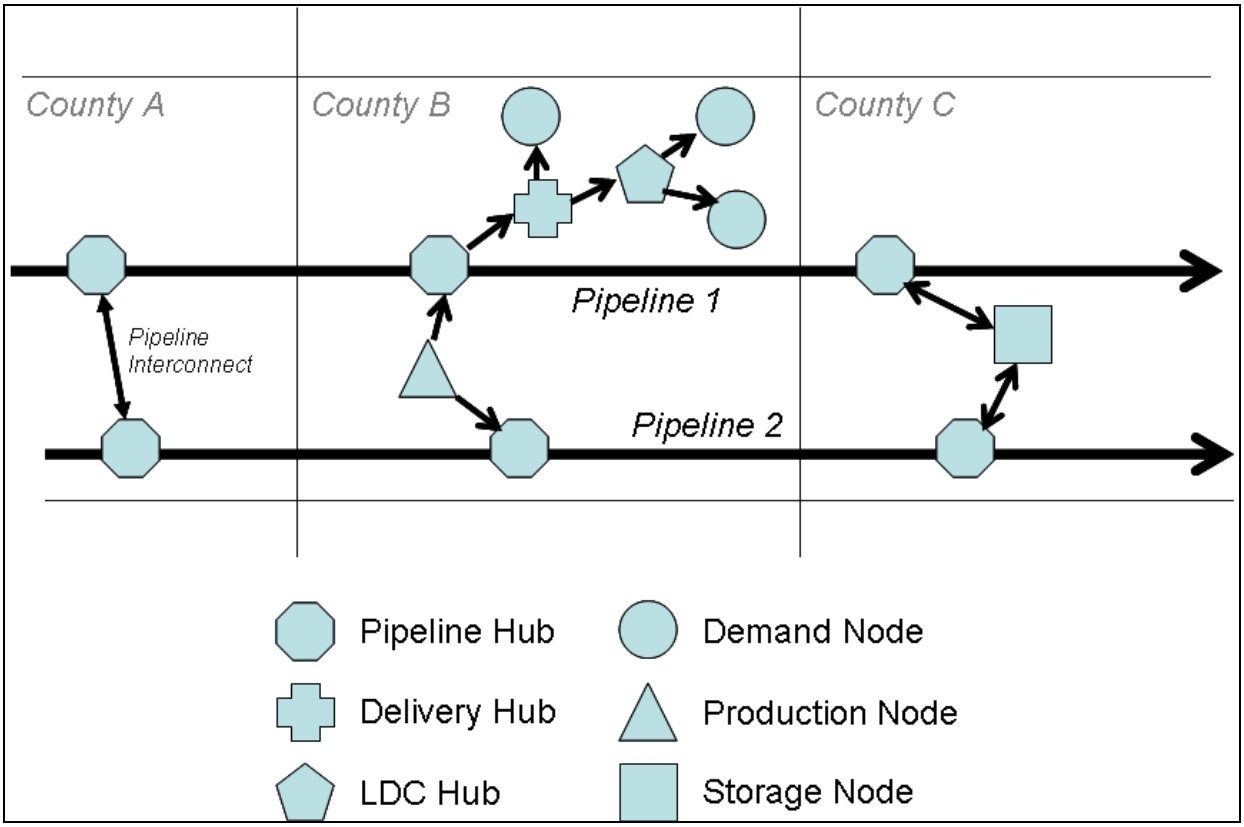


Figure 19: Conceptual Layout of RIAMS Pipeline Network

Source: ICF International

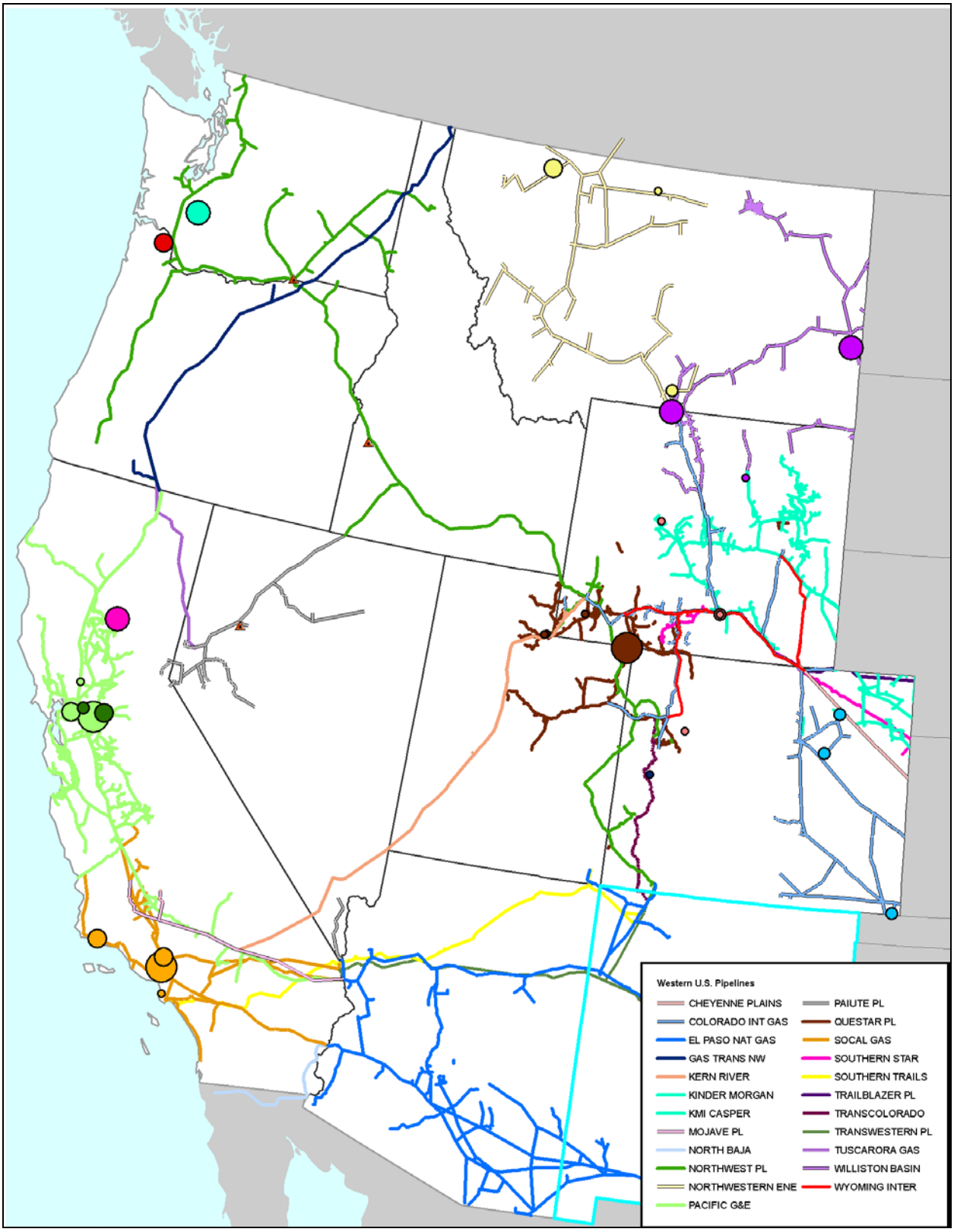


Figure 20: RIAMS Western United States Pipeline Network and Storage Fields

Source: ICF International

2.2.4 Integrating the Three Models

The process of integrating the three models is shown in Figure 21. First, GMM is run to create a monthly projection for the entire North American market. The GMM's projections for gas demand, production, regional pipeline imports and exports, and beginning- and end-of-year working gas levels for the region as a whole are passed to the RIAMS model. RIAMS then creates a detailed projection of gas market activity for the Western United States, including a projection of monthly activity at each storage field in the region. Monthly gas consumption and prices are also passed from the GMM to the DGLM, which is used to create a daily load projection for the same time period. The daily load projections from DGLM and the projected beginning- and end-of-month working gas levels for each field from the monthly version of RIAMS are then passed into the daily version of RIAMS to determine daily variability in field-level storage activity.

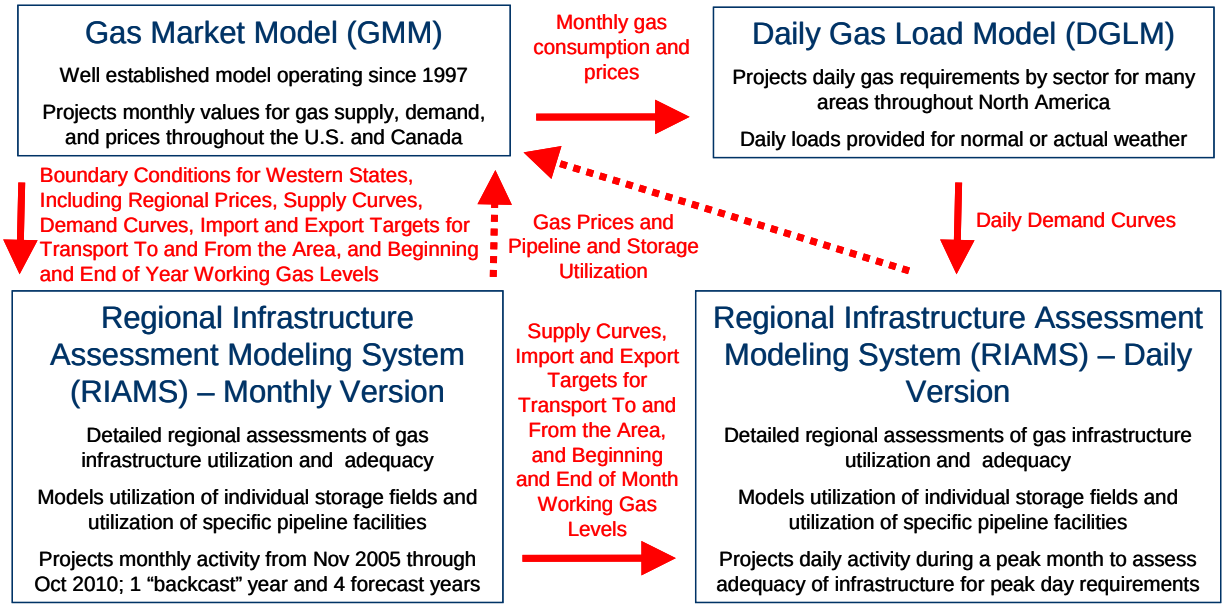


Figure 21: Model Integration

Source: ICF International

2.3 General Natural Gas Market Conditions Reflected in the West Coast Storage Modeling Effort

The starting point for the analysis is a Base Case forecast of natural gas markets. All of the analysis focuses on future value of storage during the 2009–2010 time period. Even though this period is in the near future, there remains significant uncertainty associated with any forecast. Particularly under current energy market conditions, with rapidly changing energy prices, a rapidly evolving LNG market, and changes in public perceptions related to energy markets, it is important to specify the starting point of the analysis. For this analysis, the Base Case was

developed based on the best available assumptions at the end of 2007. The assumptions behind the Base Case forecast are discussed below.

2.3.1 North American Gas Market Outlook

While this research effort is focused on evaluating the value of California natural gas storage in the context of the Western natural gas markets, the impact of the broader North American market cannot be ignored. The North American market sets the boundary conditions impacting California gas markets and natural gas storage value. The basic assumptions underlying North American markets are summarized below:

Economic Assumptions

The assumed United States Gross Domestic Product (GDP) growth rate for the projection is constant at 3.1 percent, which is consistent with the observed long-run average growth rate. Within the GMM, United States GDP growth drives electricity demand growth and (to a lesser extent) residential and commercial gas demand growth.

Industrial sector gas demand growth is driven by growth in output, which is represented by industrial production indices for major industrial categories, such as chemicals, petroleum refining, iron and steel, etc. Across all industries, the weighted average production growth rate is for the projection is constant at 2.6 percent. Historically, industrial production growth rates have been more volatile than GDP growth and generally have been trending downward over the past 30 years.

Projected Canadian GDP growth is constant at 2.5 percent per year, consistent with the long-run average growth rate. Canadian GDP growth assumptions drive industrial and power generation gas demand growth, and (to a lesser extent) residential and commercial gas demand growth in Canada.

The Base Case oil price projection is based on ICF's third quarter 2007 oil price forecast (Figure 22). The GMM oil price inputs are based on Refiner Acquisition Cost of Crude (RACC), which equates to about 90 percent of the West Texas Intermediate (WTI) price. In nominal dollars, RACC is projected to average $76 per barrel (bbl) in 2008, but declines to $59 per bbl by 2010. The prices for oil products (residual and distillate fuel oils) are based on recent historic relationships to RACC in dollars per MMBtu—the price of residual fuel oil is 83 percent of the RACC price, and distillate fuel oil is 130 percent of the RACC price.

In the short term, oil prices have an impact on gas prices and consumption due to oil-to-gas switching in the industrial and power generation sectors. When oil prices rise relative to natural gas, industrial and power consumers who can switch to natural gas will do so. Currently, oil prices are much higher than natural gas on a dollar-per-Btu basis. In this environment, all industrial and power consumers that can switch have already switched to gas, so further increases in oil prices are unlikely to encourage any additional short-term gas consumption.

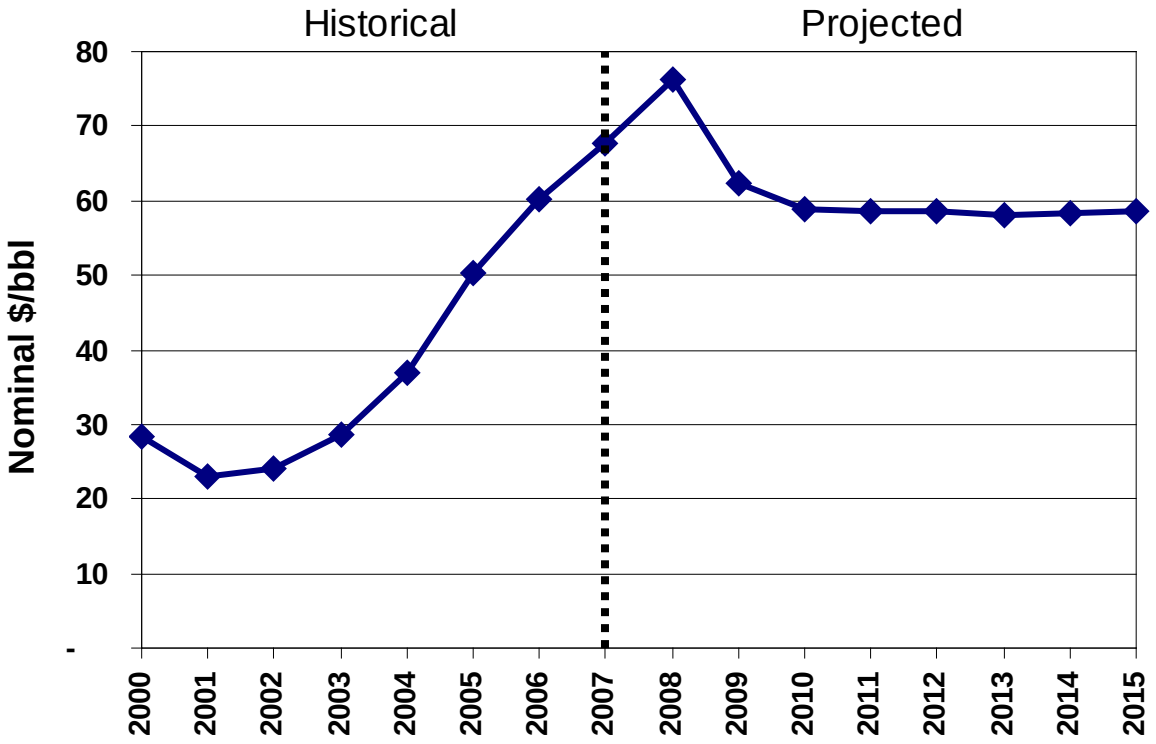


Figure 22: Assumed Oil (RACC) Prices

Source: ICF International

United States Gas Demand Outlook

Total United States gas demand is projected to increase from 22.6 Tcf in 2007 to 24.2 Tcf in 2010, and to 26.7 Tcf by 2015 (Figure 23). The greatest amount of growth is in the electric power sector. Since 1997, over 200 gigawatts (GW) of new gas-fired capacity has been constructed in the United States. As electricity demand increases, it is likely that the utilization of these new gas plants will grow, thereby increasing gas consumption. Gas consumption in the power sector is projected to increase from 5.8 Tcf in 2007 to 6.8 Tcf by 2010 and to 8.6 Tcf by 2015.

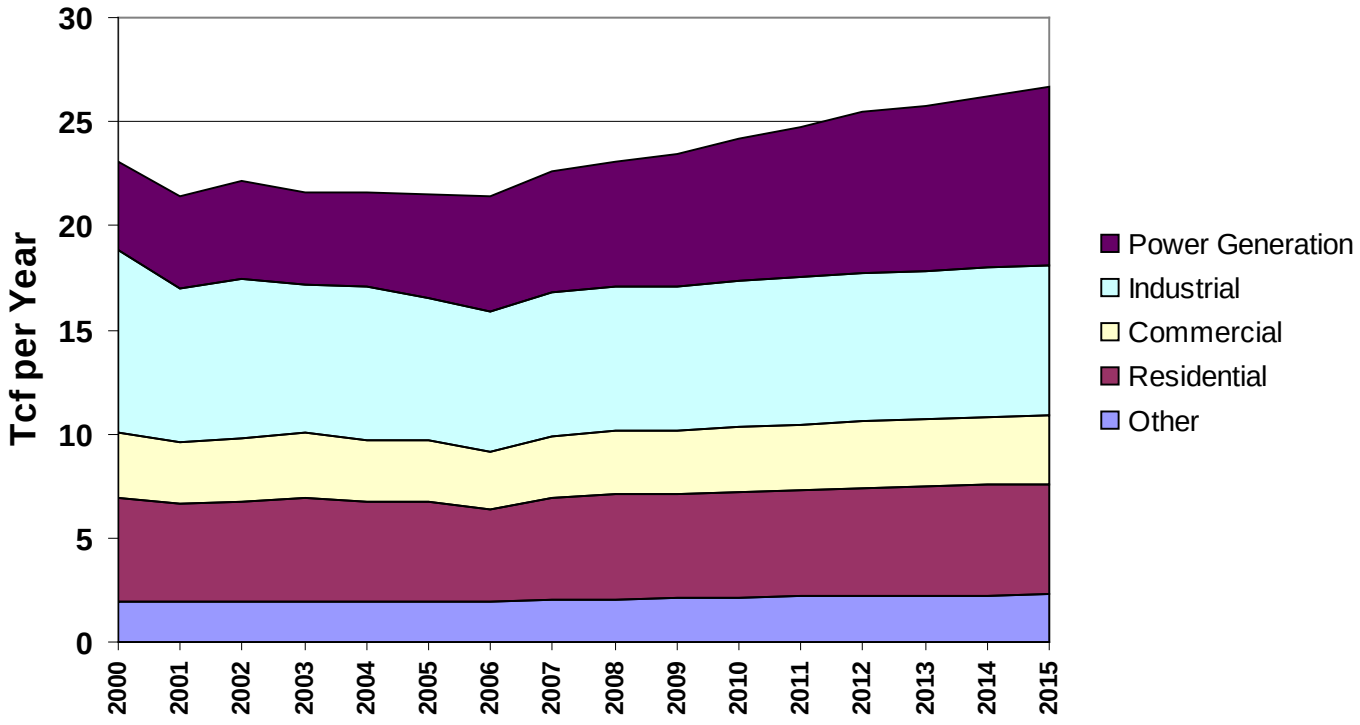


Figure 23: Projected United States Gas Demand by Sector

Source: ICF International

Gas consumption in the industrial sector, which is down from its peak in the mid-1990s, will grow at a modest pace. There was significant demand destruction in the early 2000s, as gas prices rose dramatically. Most of this demand destruction occurred in two industries, ammonia production and petrochemicals, where the cost of natural gas makes up a high percentage of the total cost of production (Table 7). United States consumption in the industrial sector is projected to increase from 6.9 Tcf in 2007 to 7.0 Tcf by 2010 and to 7.2 Tcf by 2015. About 16 percent of gas use in the industrial sector is attributed to industrial cogeneration facilities, which produce both process heat and electricity.

Table 7: Gas as a Share of Value Added in Various Industries

Industry	*Gas Use in 2003 (Bcf)*	*Percent of Total Industrial Gas Use (%)*	*Gas Share of Value Added (%)*
Chemicals (all chemicals except ammonia production)	2,134	30	20
Ammonia Production	329	5	90
Refining	1,307	18	8
Pulp and Paper Products	596	8	9
Food Processing and Manufacturing	585	8	5
Iron, Steel, Aluminum, Other Metals	337	5	9
Stone, Clay, and Glass	339	5	3
All Other Manufacturing and Non Manufacturing	1,576	22	3

Source: ICF International

Gas consumption in the residential and commercial sectors is also project to increase at a modest pace, driven primarily by demographics. Residential and commercial gas consumption is projected to increase from 7.9 Tcf in 2007 to 8.1 Tcf by 2010, and grows to 8.6 Tcf by 2015.

United States Electric Generation Outlook

Within the GMM, electricity demand growth is driven by the projected GDP growth rate and the electricity sales-to-GDP elasticity. The electricity sales-to-GDP elasticity is the ratio of the rate of growth in electricity sales to the rate of growth in GDP. Over the past fifty years, this elasticity has been steadily decreasing, and ICF projects that trend will continue. The projected United States electricity sales growth rate averages 1.9 percent per year, which is slightly lower than the average growth rate for the past thirty years. United States electricity sales are projected to increase from 3,700 terawatt hours (TWh) in 2007 to over 3,900 TWh by 2010, and grow to 4,400 TWh by 2015 (Figure 24).

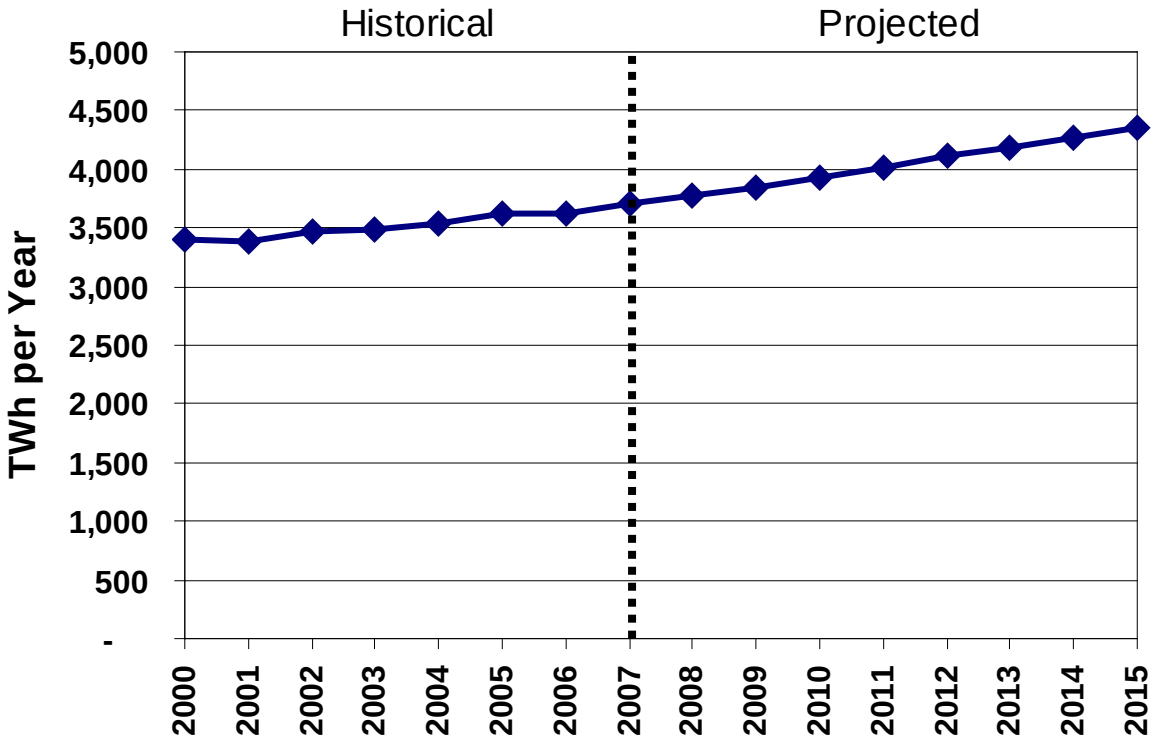


Figure 24: Projected United States Lower-48 Electricity Sales

Source: ICF International

In the near term, increases in gas-fired generation meet most of the increases in electricity demand. Gas-fired generation is projected to increase from 840 TWh in 2007 to 975 TWh in 2010, and grows to nearly 1,200 TWh by 2015 (Figure 25).

Coal-fired generation is expected to increase, but not nearly as quickly as the increase in electricity demand. Increases at existing coal plants are limited by environmental regulations, and concern over regulations on carbon emissions are likely to limit growth in coal capacity. Nuclear generation is expected to increase slightly through 2015 due to capacity *uprates* at existing units. No new nuclear plants are projected to come online until 2019.

United States non-hydro renewable generation increases by about 10 TWh per year by 2010, growing to about 2.5 percent of total United States generation. By 2015, annual renewable generation is projected to increase to nearly 140 TWh per year, and make up about 2.9 percent of total United States generation. Hydroelectric generation is assumed to remain constant throughout the projection.

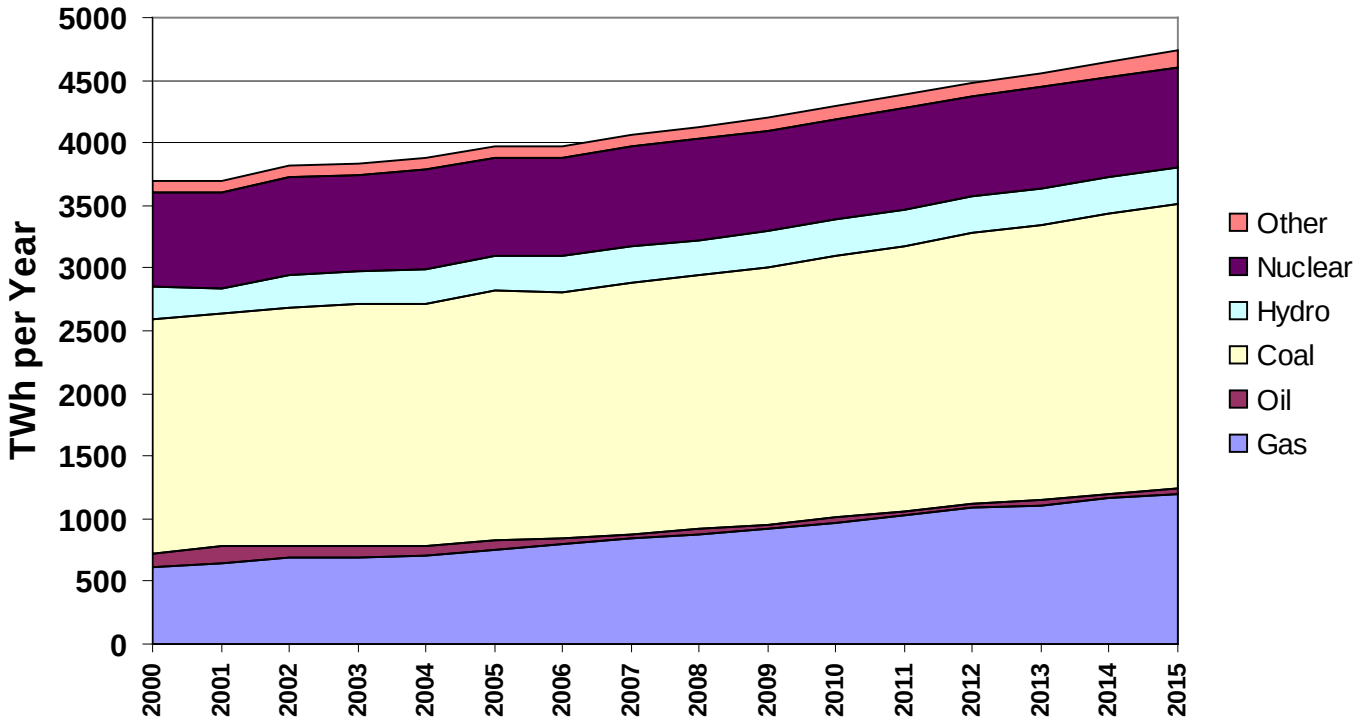


Figure 25: Projected United States Lower-48 Electricity Generation by Fuel Type

Sources: Historic data from United States Energy Information Administration (EIA), projection from ICF International

Gas Production and LNG Imports

Production from mature producing areas such as Western Canada, Gulf Coast onshore and the Permian Basin will continue to decline. United States and Canadian production from these traditional supply areas is projected to decline from 19.5 Tcf in 2007 to 18.9 Tcf by 2010, and to 18.6 Tcf by 2025 (Figure 26). New frontier supplies, which include LNG imports, the Northern Rockies, Mid-continent Shales, Gulf of Mexico deep water, and Alaska and Mackenzie Delta gas, will account for about one-third of United States and Canada gas supply by 2010, versus only 25 percent today. By 2015, new frontier supplies will make up 40 percent of United States and Canadian supplies. Notable changes in these new supply areas are:

- United States and Canadian LNG imports increase from about 0.8 Tcf in 2007 to 1.5 Tcf by 2010, and 3.5 Tcf by 2015.
- Production in the Northern Rockies increases from 2.5 Tcf in 2007 to 3.0 Tcf by 2010 and to 3.9 Tcf by 2015.
- Production in the Mid-continent Shales increases from 1.8 Tcf in 2007 to 2.5 Tcf by 2010 and to 2.7 Tcf by 2015.
- Production in the deeper waters of the Gulf of Mexico increases from 1.2 Tcf in 2007 to 1.8 Tcf by 2010 and to 2.0 Tcf by 2015.

The Alaska Gas Pipeline will not be built until well after 2015. We assume it will be built in 2020 with an initial capacity of 4.0 Bcfd, and will be expanded in 2023 to 6.0 Bcfd. We assume the Mackenzie Delta Gas Pipeline will be operational in late 2015 with a capacity of 1.0 Bcfd.

In total, North American gas supplies are projected to increase from 25.8 Tcf in 2007 to 28.4 Tcf by 2010, and reach 31.1 Tcf by 2015.

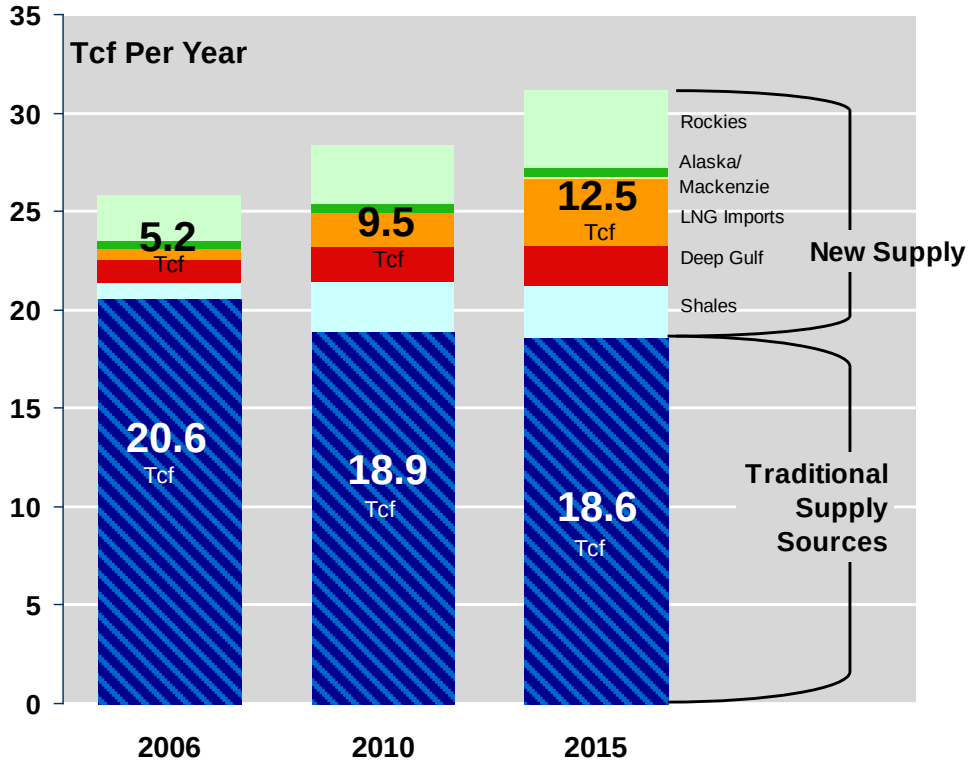


Figure 26: Projected North American Gas Supplies

Source: ICF International

Pipeline Capacity and Flows

Through 2012, over 20 Bcfd of new pipeline capacity from the Rockies, Gulf Coast, and Mid-continent will bring new supplies to markets further east (Figure 27). As mentioned above, exports from Western Canada are expected to decline through 2015 due to declining production, as well as from increased gas consumption in Western Canada for oil sands development. Exports from the Rockies, Mid-continent, and Gulf Coast are up due to increases in production in the Rockies and Mid-continent shales, and increases in Gulf Coast LNG imports. Utilization of the pipelines in the Western United States, other than the pipelines transporting gas eastward out of the Rockies, is not projected to change significantly through 2010. Other notable changes in pipeline flows include:

- Flows on GTN from Canada to California are projected to decline as a result of declining production in Western Canada.
- Exports from the United States to Mexico are projected to decline, as a result of deliveries at the Costa Azul LNG import facility. However, slow growth in LNG deliveries (due to lack of supply) will not significantly change California's import/export activity until 2010.
- Kern River Pipeline, El Paso Pipeline, and Transwestern Pipeline flows are projected to remain fairly close to today's levels throughout this near-term projection.
- Most of the major gas pipeline interconnects within California (for example, Kramer Junction, Wheeler Ridge, the Cadiz crossover, etc.) continue to be utilized at levels that are similar to today's levels. The exception is PG&E deliveries to SoCal Gas at Kern River Station, which are likely to decline during the next few years due to a decline in deliveries from GTN to PG&E at Malin, Oregon.

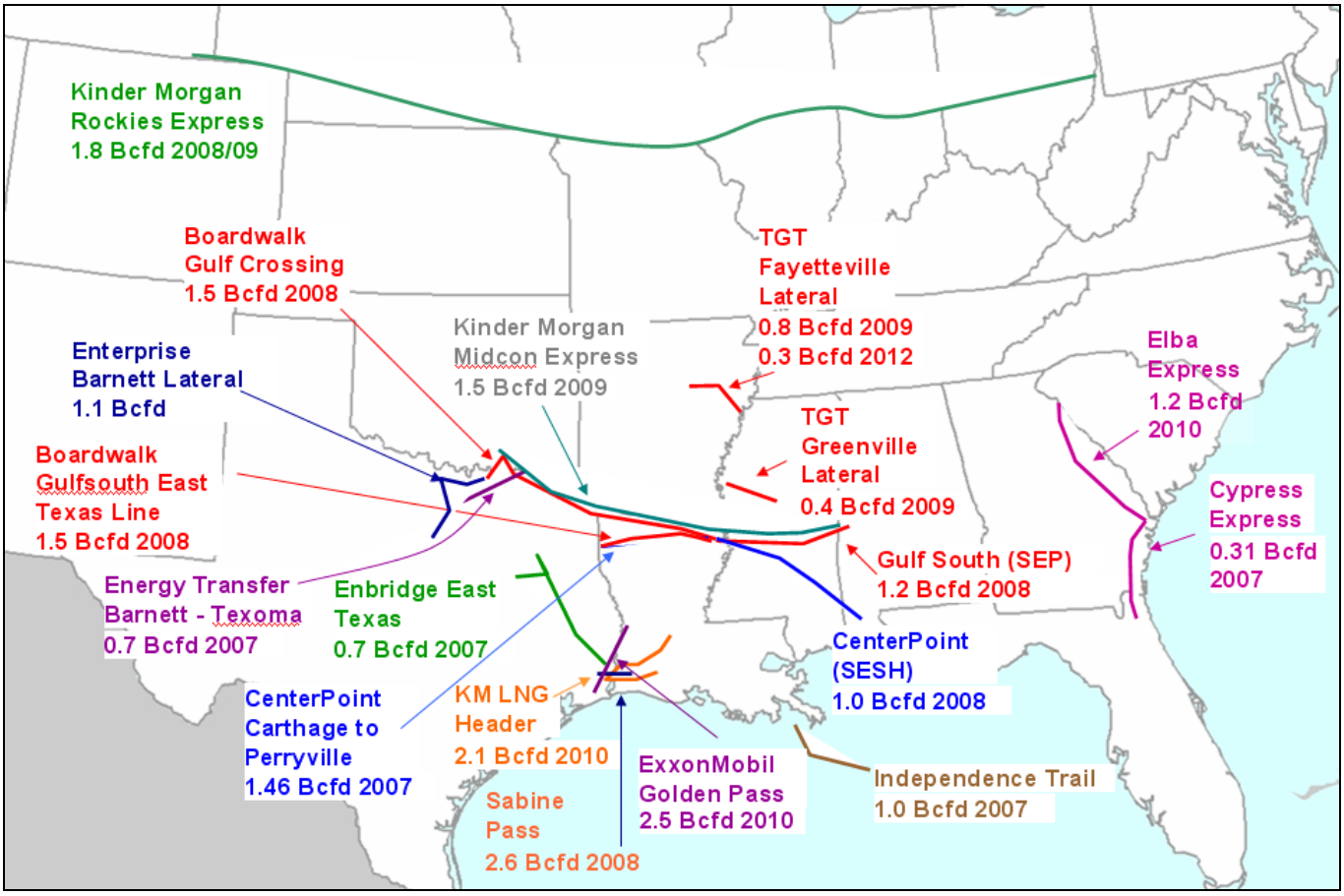


Figure 27: Notable Near-term Pipeline Expansions

Source: ICF International

Gas Storage

Through 2010, ICF projects that about 240 Bcf of new working gas capacity will be added in North America (195 Bcf in the United States and 47 Bcf in Canada), an increase of about 5 percent over 2007 capacity. Of the 195 Bcf added in the United States, about three-fourths of the new capacity is expected to be added in the Gulf Coast region.

Versus the past few years, storage turnover in the Western United States is projected to increase through 2010 by approximately 40 Bcf; withdrawals increase by about 270 million cubic feet per day (MMcfd) and injections increase by about 200 MMcfd. Storage turnover in California is projected to increase by over 20 Bcf; withdrawals increase by about 140 MMcfd and injections increase by about 100 MMcfd. The Rockies Express (REX) pipeline is the primary driver behind the change in Western United States storage withdrawals. After both the West and East segments of the REX pipeline come online, Rocky Mountain production can be delivered to higher-priced markets in the east, thereby reducing supplies in the west.

Storage utilization for the United States as a whole is also projected to increase, partly due to the seasonal pattern of LNG imports. Given the nature of world LNG markets, ICF is projecting a growth in LNG deliveries to North America during the summer months, with winter deliveries rerouted to higher-priced markets in Europe and Asia. Since the majority of North America's LNG imports will be delivered during the summer, the gas will need to be stored for the winter when demand is greater.

2.3.2 California Gas Market Demand and Supply Outlook

California Gas Demand Outlook

California's total gas consumption is projected to increase from 2,250 Bcf in 2007 to 2,360 Bcf by 2010, and by 2015 to reach 2,450 Bcf (Figure 28). As with the United States as a whole, California gas demand growth is lead by growth in the power sector. California's gas consumption in the power sector is projected to increase from 700 Bcf in 2007 to nearly 800 Bcf by 2010 and to 840 Bcf by 2015.

Gas consumption in California's industrial sector is expected to grow somewhat faster than the United States average. The chemicals industry makes up a relatively small portion of the State's industrial gas demand, so California has experienced less industrial demand destruction over the past 10 years than some other areas, such as the Gulf Coast. Gas consumption in the industrial sector is projected to increase from 750 Bcf in 2007 to 760 Bcf by 2010 and to about 790 Bcf by 2015. Together, petroleum refining and enhanced oil recovery account for about 60 percent of California's industrial gas use. Cogeneration makes up a high percentage of gas use in both of these industries. About 40 percent of California's current and projected gas use in the industrial sector is attributed to industrial cogeneration facilities.

Gas consumption in the residential and commercial sectors increases at modest pace, driven primarily by demographics. Residential and commercial gas consumption is projected remain

flat at around 740 Bcf through 2010. By 2015, R/C gas consumption is projected to increase to 760 Bcf, an average growth rate of 0.4 percent per year.

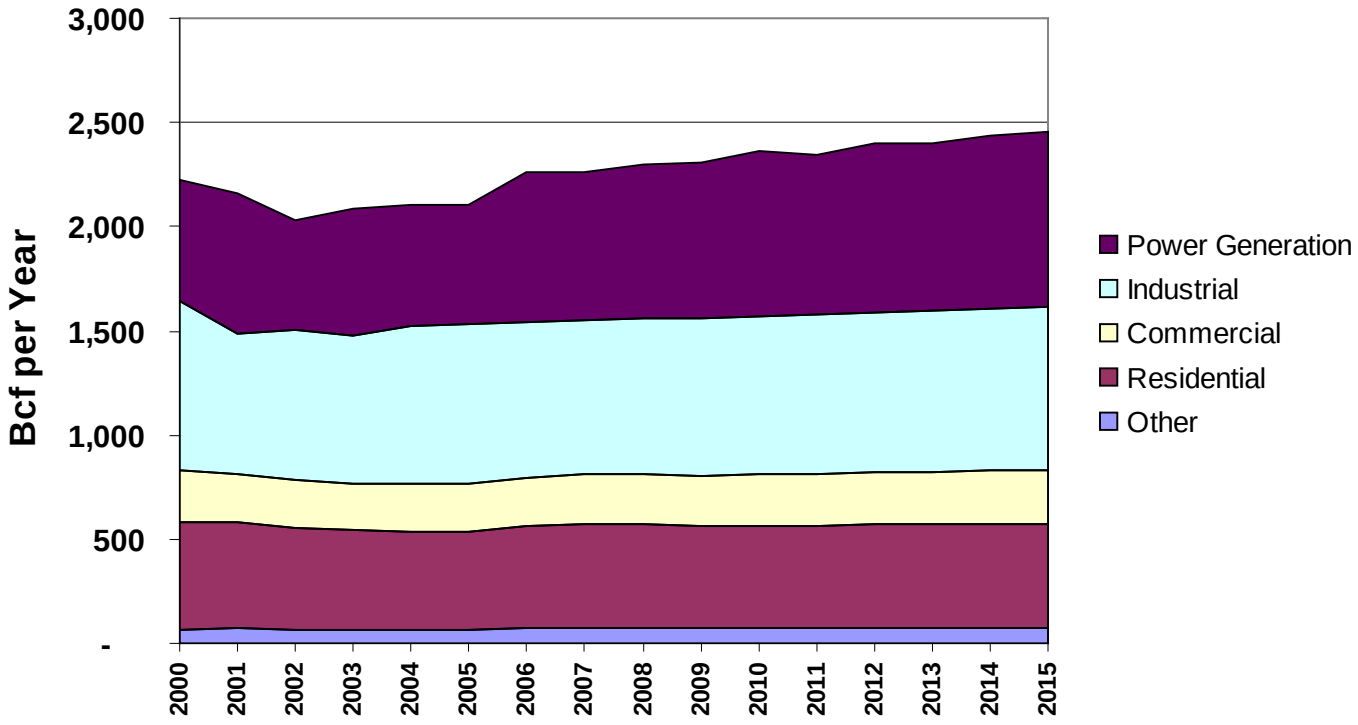


Figure 28: Projected California Gas Demand by Sector

Source: ICF International

California Electric Generation Outlook

California's annual electricity demand is projected to increase from 265 TWh in 2007 to 283 TWh by 2010, and reach 320 TWh by 2015 (Figure 29). This equates to an average annual growth rate of 2.5 percent per year, significantly higher than the United States average growth rate for the same period of 2.0 percent.

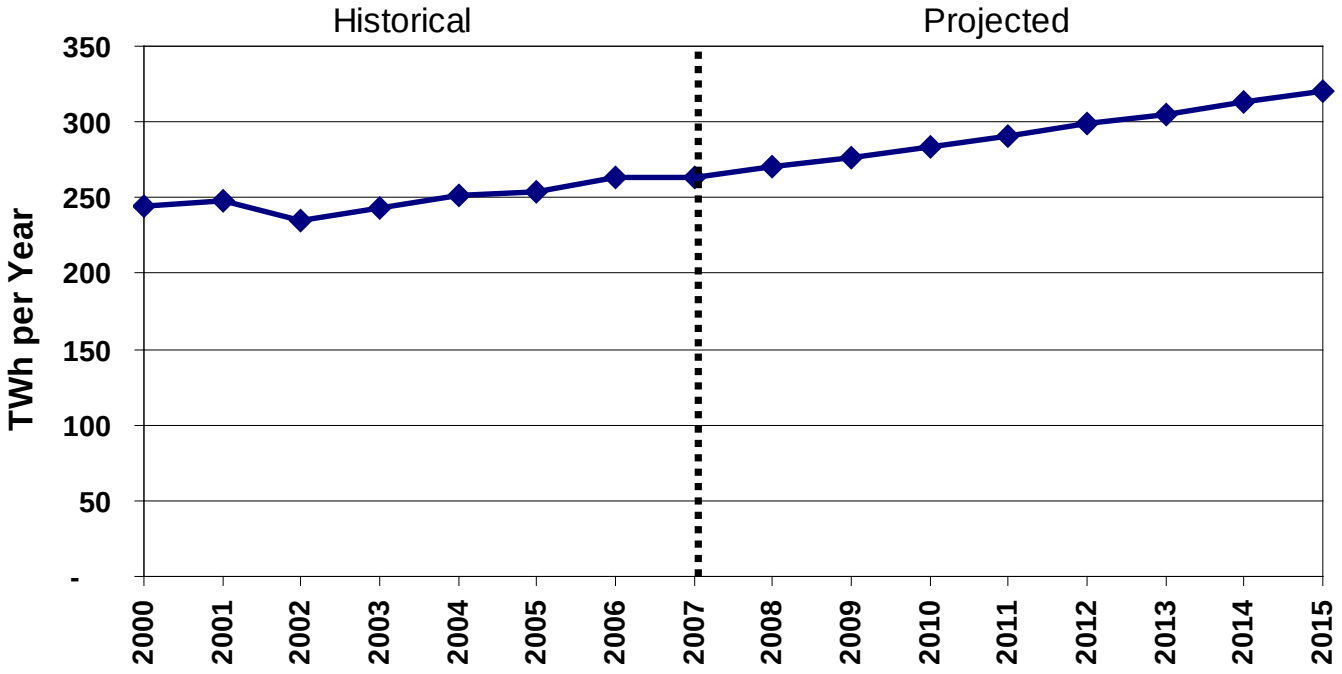


Figure 29: Projected California Electricity Sales

Sources: Historic data from United States EIA, projection from ICF International

Currently, California imports a total of 65 TWh per year, or roughly 25 percent of its electricity needs, from neighboring states in the Pacific Northwest and Southwest. Through 2010, electricity imports are expected to remain fairly constant. Beyond 2010, electricity imports are expected to decline slightly as electric load growth in other regions reduces their exports to California.

In the near term, increases in gas-fired generation meet most of the increase in California's electricity demand. Gas-fired capacity makes up about 60 percent of California's total in-state generating capacity. Gas-fired generation is projected to increase from 117 TWh in 2007 to 137 TWh in 2010, and grows to 150 TWh by 2015 (Figure 30).

Coal-fired generation within California is expected to be fairly flat through 2010. The Mohave plant in Southern Nevada, which provided power to California until its shutdown in 2006, is projected to come back online in 2011. Other new coal plants are anticipated in Nevada through 2015, but these will serve load within Nevada, not California. California nuclear generation increases slightly by 2010 due to capacity *uprates* at existing units, but no new nuclear plants are projected for California.

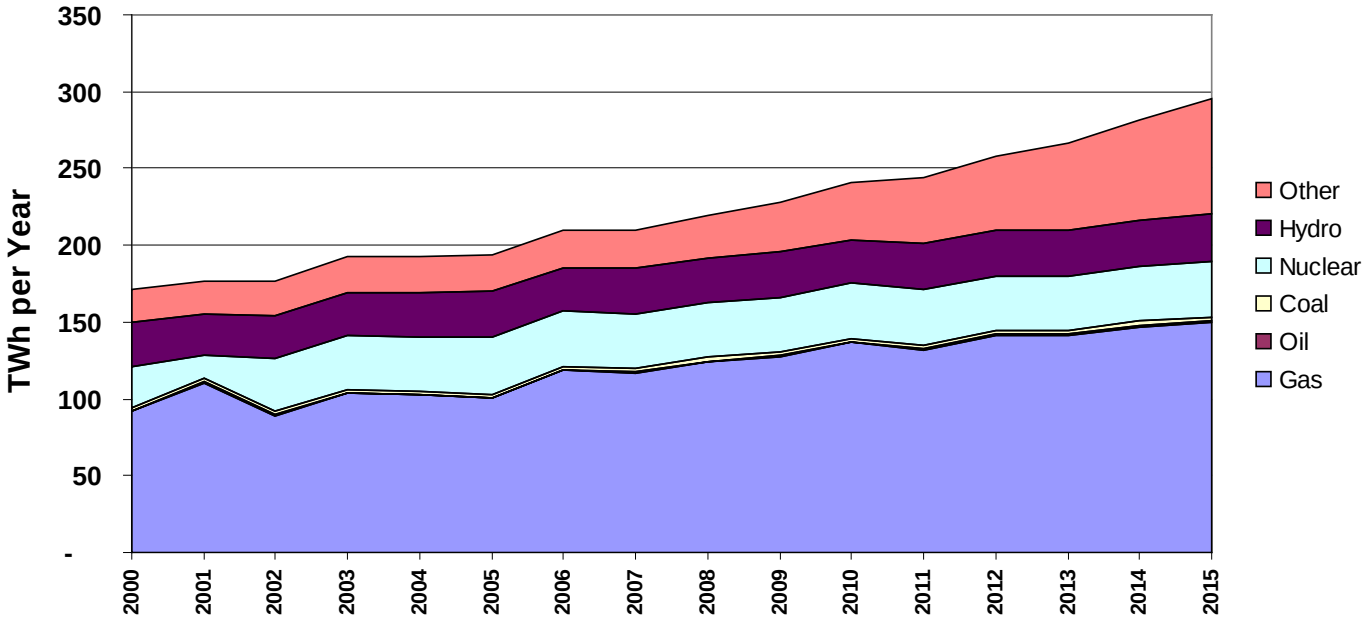


Figure 30: Projected California Electricity Generation by Fuel Type

Sources: Historic data from United States EIA, projection from ICF International

California's non-hydro renewable generation is projected to increase from 25 TWh in 2007 to 37 TWh in 2010, accounting for 15 percent of total in-state generation. By 2025, California's renewable generation is projected to increase to about 75 TWh per year. In the Base Case, California's hydroelectric generation is projected to remain constant through the projection. The alternate scenarios examine the impact of increased and reduced hydroelectric generation, both within California and in those states that export power to California.

California Gas Production and LNG Imports

California in-state production makes up about 13 percent of the state's total gas supply. California gas production is expected to remain fairly constant at around 330 Bcf per year (0.9 Bcfd) through 2010. Annual production is expected to decline to about 300 Bcf (0.7 Bcfd) by 2015, as mature fields are depleted.

There are no LNG import facilities assumed for California throughout the projection. However, some of the LNG imported to Costa Azul, Mexico (projected to come online in 2008) is expected to be exported to California.

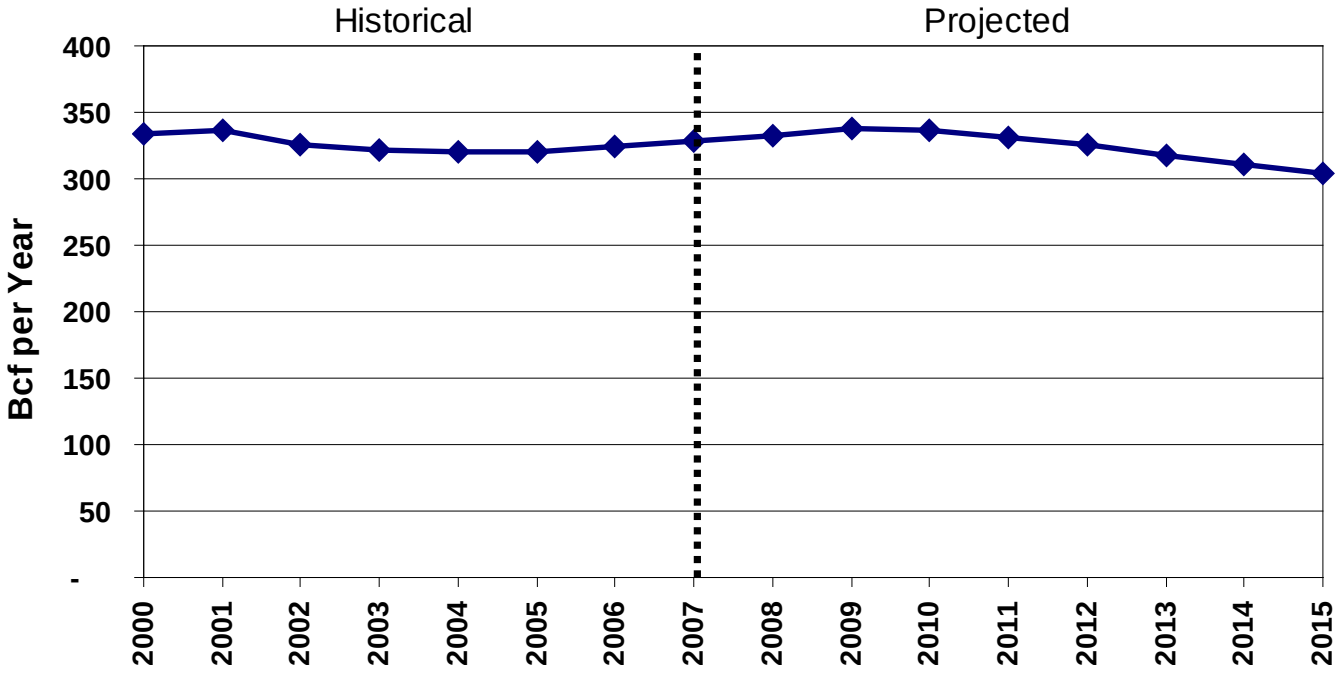


Figure 31: Projected California Natural Gas Production

Source: ICF International

2.3.3 California Natural Gas and Power Generation Infrastructure Outlook

The California natural gas market infrastructure has changed substantially since 2001. Pipeline capacity into the State has increased, pipeline interconnects within the state have been improved, and storage holders have changed operational behavior, with storage injection patterns less sensitive to short-term price trends. In addition, updates to power generation capacity in the State have reduced the impact of volatility in hydro generation on natural gas demand in the region. While not the only reason for both import/export and storage capacity additions in the area, the 2000-2001 energy crisis in California was a major catalyst for these additions. One of the objectives of the weather analysis conducted as part of this study is to determine if the changes have made the California market better prepared to adjust to extreme weather and hydro conditions than it was during the 2000-2001 period.

The major changes in California natural gas and power generation markets influencing the impact of the alternative weather scenarios are discussed below.

Natural Gas Pipeline Capacity

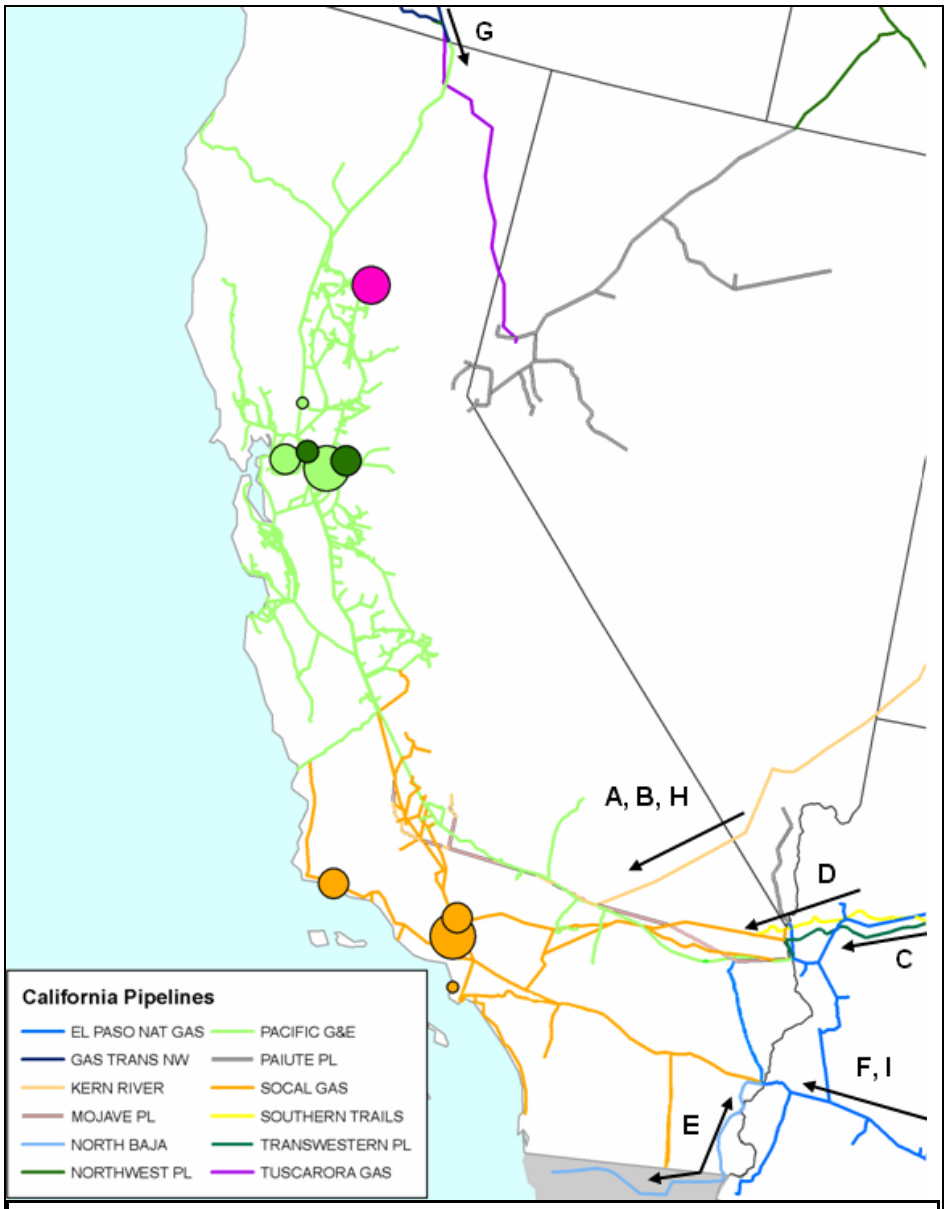
Interstate pipelines can currently deliver almost 10 Bcfd of natural gas into California. Between 2001 and 2007, interstate pipeline delivery capacity to California increased by about 30 percent from around 7 Bcfd in 2001 (Table 8 and Figure 32). This growth in import capacity was achieved first through small emergency expansions in response to the California energy crisis, followed by bigger expansions required to meet growing electric power demand.

The North Baja pipeline provides capacity that will be used in the future to import LNG from the Costa Azul facility. Currently, natural gas flows south and west along the North Baja/Baja Norte/TGN path to deliver gas to the President Juarez power plant in Rosartio, Baja California. The only new pipeline capacity into California that is anticipated before 2010 is the expansion of the North Baja pipeline, which will allow LNG from Costa Azul to be exported to California.

Table 8: California Pipeline Import Capacity

Pipeline	2001 Capacity	Capacity Additions	2007 Capacity
Gas Transmission Northwest (Malin)	1,930	220	2,150
Kern River Gas Transmission	750	1,250	2,000
El Paso Natural Gas (Topock)	1,925	0	1,925
Southern Trails (Needles)	0	80	80
Transwestern Pipeline (Needles)	1,060	150	1,210
El Paso Natural Gas (Ehrenberg)	1,210	550	1,760
North Baja Pipeline (Ehrenberg)	0	500	500
Total	**6,875**	**2,750**	**9,625**

Source: ICF International



	Pipeline	Year	Expansion Name	Capacity Added
A	Kern River Pipeline	2001	Emergency expansion	135
B	Kern River Pipeline	2002	Permanent expansion	220
C	Transwestern Pipeline	2002	Red Rock Emergency Expansion	150
D	Southern Trails Pipeline	2002	Questar Southern Trails oil line conversion	80
E	North Baja Pipeline	2002	Baja Norte	500
F	El Paso Natual Gas	2002	All American oil pipeline conversion	230
G	Gas Transmision Northwest	2002	Compression expanision	220
H	Kern River Pipeline	2003	Parallel line expansion	895
I	El Paso Natual Gas	2004	El Paso Power Up expansion	320
	Total			**2,750**

Figure 32: California Natural Gas Pipeline Expansions Since 2001

Source: ICF Representation of American Gas Association (AGA) and IHS Energy Group Data

Power Generation

As of 2007, the total generating capacity for the California Independent System Operator (California ISO) was approximately 47 GW. In the 1990's very little new generation was built within California, and the State started to rely more heavily on imports from neighboring states to meet incremental power generation growth. Resource constraints during the 2000-2001 energy crisis prompted a boom of new generation construction at the same time that much of older generating units were nearing retirement.

Between 2001 and 2007, over 15 GW of new generation capacity was added to California at the same time that over 5 GW were retired, moth-balled or re-powered. Approximately 96 percent of the new units are using natural gas as their primarily fuel (Table 9). Even though California now has greater gas generation capacity than in 2001, power sector gas consumption in California has not increased significantly. Rather, average California power sector gas consumption from 2002 to 2007 is about 200 Bcf or 20 percent lower than the high mark observed in 2001. This is because many of the units that were retired were older steam units with very high heat rates. The new units which have been added since 2001 are combined cycle and single cycle turbines, which have much lower heat rates than the old steam units they replaced. As a result, the marginal generating units called on-line in periods of high electricity demand now have much lower gas consumption, which places less demand on gas pipeline and storage capacity. The lower gas demand from power is equivalent to an average of 550 MMcfd of pipeline or storage capacity that was not needed in the 2002 to 2007 period (Figure 33).

Table 9: Change in California Generation Capacity (Megawatts)

	New Generating Units	Retirements	Net Capacity Added	Percent of New Units Using Gas
2001	1,967	28	1,939	91%
2002	2,878	1,170	1,708	96%
2003	4,830	2,152	2,678	96%
2004	748	180	568	97%
2005	2,231	450	1,781	96%
2006	1,895	1,535	360	99%
2007	724	0	724	93%
2001- 2007	**15,273**	**5,515**	**9,758**	**96%**

Source: California ISO

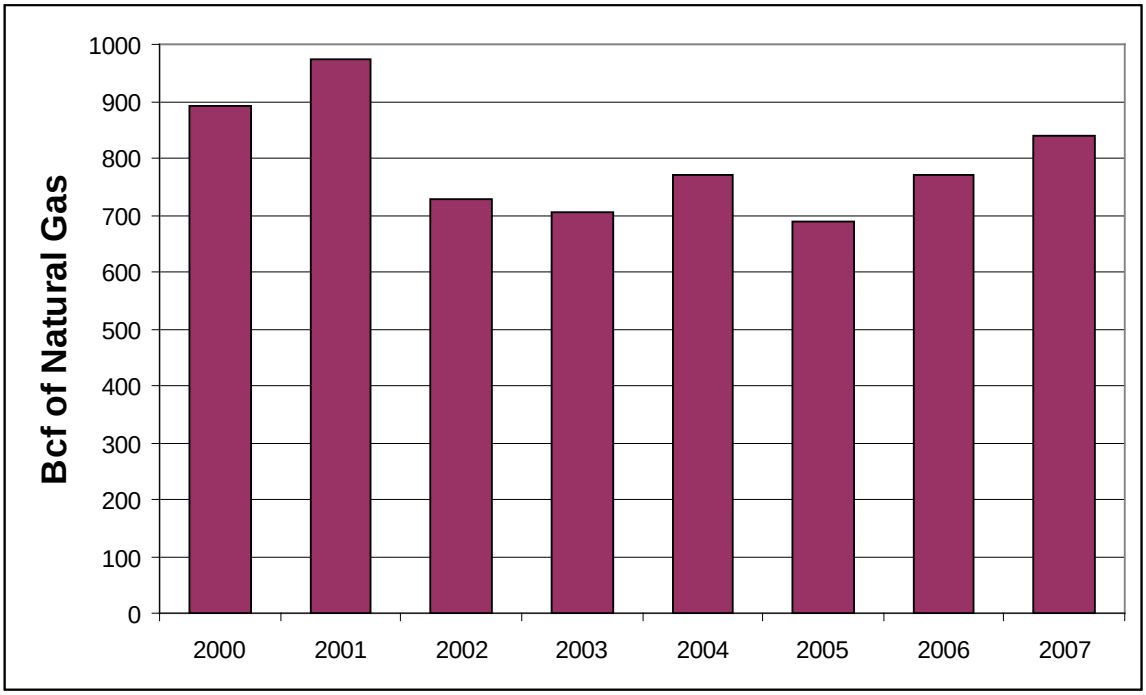


Figure 33: California Electric Power Natural Gas Consumption

Source: United States EIA Natural Gas Annual and Natural Gas Monthly

Natural Gas Storage

California currently has 10 active storage fields with a storage working gas capacity of almost 268 Bcf and deliverability of 6.5 Bcfd. In 2005 and 2006, end-of-refill-season working gas levels approached 260 Bcf in California, or over 97 percent of total capacity (Figure 34).

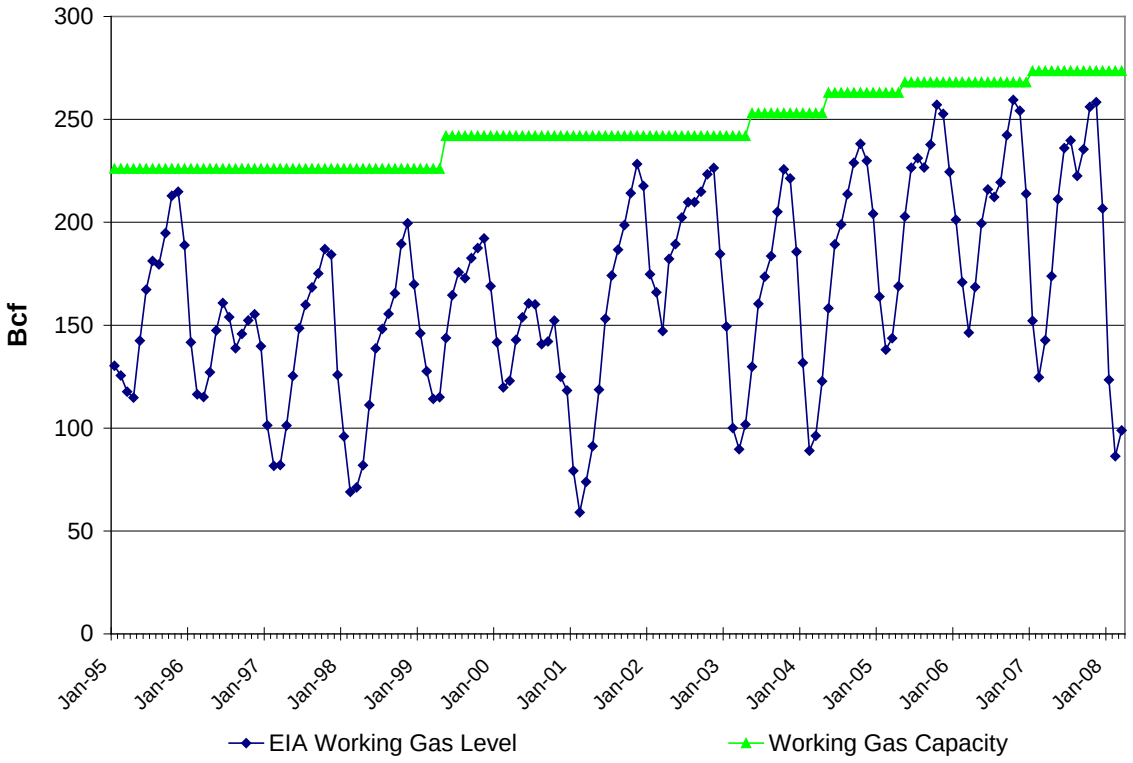


Figure 34: California Working Gas Storage Levels and Capacity 1995 – 2007

Sources: United States EIA and ICF

All the storage in California is connected to the pipelines of two large gas utilities, SoCal Gas and PG&E (Figure 35). The four fields in Southern California are all owned and operated by SoCal Gas and have a combined capacity of about 120 Bcf and deliverability of almost 3.8 Bcfd (Table 10). Northern California has six fields with three fields owned and operated by PG&E and three fields owned and operated by the independent operators Wild Goose Storage and Lodi Gas Storage. Total Northern California storage capacity is approximately 148 Bcf with almost 2.8 Bcfd of deliverability.

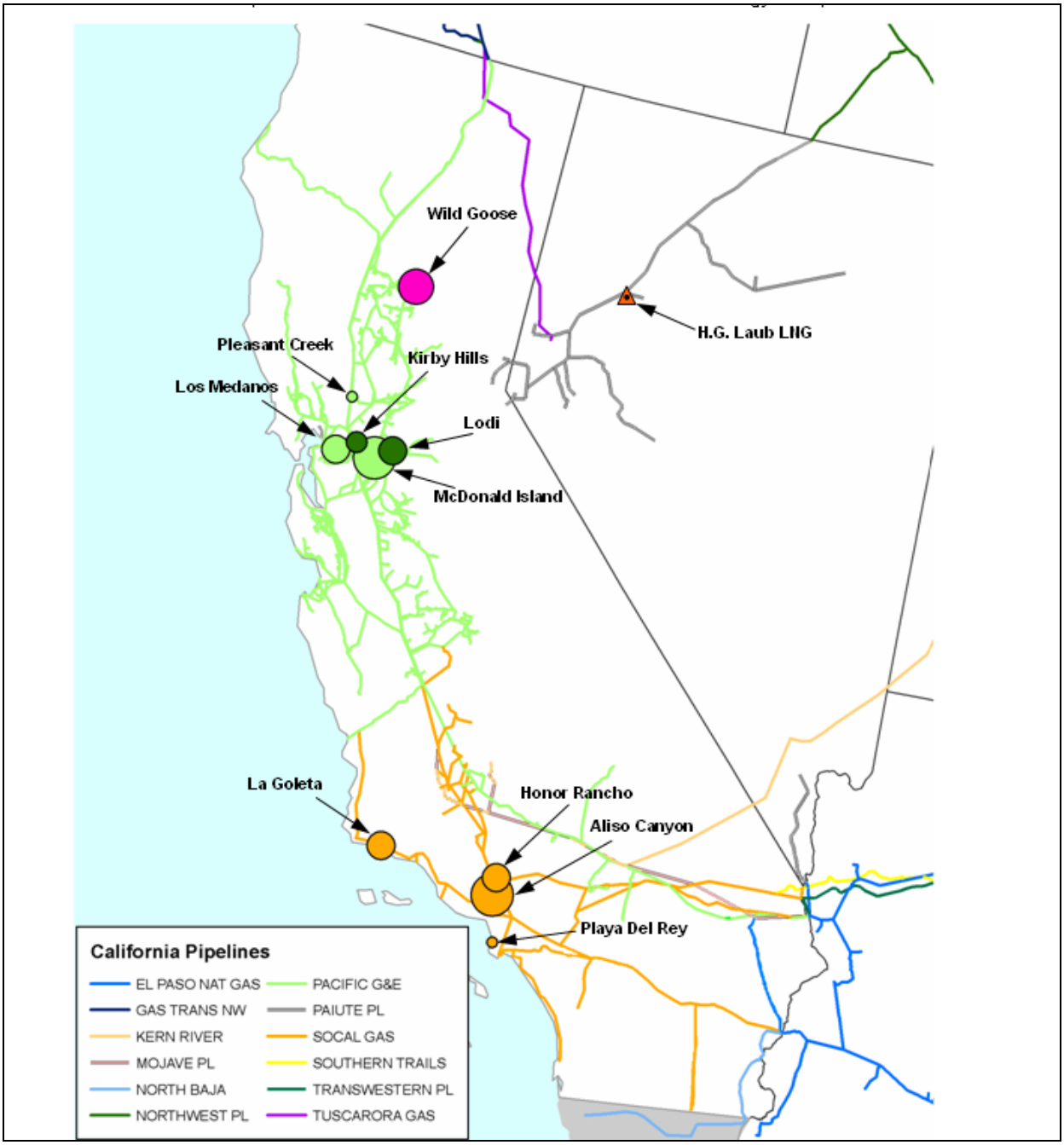


Figure 35: California Storage Fields

Source: ICF Representation of AGA and IHS Energy Group Data

Table 10: California Storage Capacity and Deliverability by Field

Operator State	Field_Name	Field_Type	Working Gas Capacity (MMcf)	Maximum Deliverability (MMcf)	Working Capacity Deliverability Ratio (Days)
Assets Associated with Intrastate Pipelines or Gas Distribution Opperations					
Southern California Gas Co.			**120,000**	**3,760**	**32**
California	*Aliso Canyon*	Depleted Reservoir	76,000	1,650	46
	Honor Rancho	Depleted Reservoir	21,500	1,170	18
	La Goleta	Depleted Reservoir	20,000	410	49
	Playa del Ray	Depleted Reservoir	2,500	530	5
Pacific Gas and Electric Co.			**102,000**	**1,720**	**59**
California	*Los Medanos*	Depleted Reservoir	16,300	400	41
	McDonald Island	Depleted Reservoir	83,400	1,250	67
	Pleasant Creek	Depleted Reservoir	2,300	70	33
Total Associated Operators			**222,000**	**5,480**	**41**
Percent of Total			**83%**	**84%**	
Independent Operators					
Lodi Gas Storage - ArcLight Energy Partners			**22,000**	**550**	**40**
California	*Kirby Hills*	Depleted Reservoir	5,000	50	100
	Lodi	Depleted Reservoir	17,000	500	34
Wild Goose Storage Inc.			**24,000**	**480**	**50**
California	*Wild Goose*	Depleted Reservoir	24,000	480	50
Total Independent Operators			**46,000**	**1,030**	**45**
Percent of Total			**17%**	**16%**	
Total of California Storage			**268,000**	**6,510**	**41**

Source: United States EIA

Of the California storage fields, Kirby Hills is the newest, completed in early 2007. Table 11 lists the additions to California storage capacity over the past six years. California storage capacity has increased by 46.0 Bcf or over 20 percent since 2001 (Table 11). Most of this capacity has been added by independent storage operators.

Table 11: California Underground Storage Capacity Additions

Storage Field	Year	Storage Capacity Added (Bcf)	
Lodi Gas	2002	12.0	New Field
Aliso Canyon	2003	7.0	Re-clasify base gas to working gas
La Goleta	2003	7.0	Re-clasify base gas to working gas
Wild Goose	2004	10.0	Expansion
Lodi Gas	2005	5.0	Expansion
Kirby Hills	2007	5.0	New Field
Total		**46.0**	

Source: ICF International

There are two planned storage projects expected to increase capacity by 2010:

1. There is a planned expansion of the Kirby Hills facility in 2008 which will increase its working gas capacity from 5.0 Bcf to 12.0 Bcf.
2. The new Sacramento Natural Gas Storage facility is expected to come online in 2009 with a working gas capacity of 7.0 Bcf.

California working capacity is expected to total 287 Bcf by 2010. After 2010, another 20 Bcf of working capacity will be added in California, bringing the total capacity to 307 Bcf by 2025.

Summary of California Infrastructure Outlook

Overall, the changes in California's energy infrastructure since 2001 have combined to create less stress on the State's natural gas infrastructure. Increased efficiency in gas-fired power generating capacity has reduced peak demand on the gas pipelines and storage fields. At the same time, expansions in pipeline and storage capacity have lead to greater flexibility in the gas market. As a result, it is unlikely that the conditions which precipitated the 2000-2001 energy crisis would cause the same level of market disruptions, given the current state of California's energy infrastructure.

2.4 Alternative Weather Cases Selection and Description

This section provides an overview of how the set of cases analyzed in the Alternative Weather Cases section were selected. It describes the set of possible scenarios, the way in which all of the cases were compared, and the criteria by which the final scenario selections were made.

2.4.1 Goal for the First Set of Cases

The goal set forth for this set of cases was to "focus primarily on changing weather conditions in California and the broader Western United States to assess how storage utilization and marginal prices are affected by weather."[30] The Base Case assumed 30-year average temperatures and 20-year average hydroelectric generation for the entire projection. The cases developed for this stage of the analysis manipulate the inputs for both the temperature and hydroelectric generation in order to see what effects different levels of these two variables (for example, warmer temperatures vs. colder temperatures, high hydroelectric generation vs. low hydroelectric generation) would have on natural gas storage use and marginal gas prices in California and the Western United States.

2.4.2 Historical Data Used for Analysis

The initial analysis of weather patterns was based on United States temperature data for the 74 years from 1932–2005 and hydroelectric generation data for the 24 years from 1980–2004.

The 74 years of chosen temperature data reflected all of the temperature data available to ICF. Unfortunately, the available data for hydroelectric generation over the same time period was not consistent. Hydroelectric generation capacity in the West was expanding in the 1970s. We

[30] This goal was laid out in ICF's letter to Mr. Steve Schiller on August 22, 2006 under Topic Area #1.

were unable to normalize data from before 1980 due the significant differences in capacity. Since hydroelectric capacity has been relatively constant since 1980, the data on hydroelectric generation was limited to this shorter time period.

In order to determine which temperature and hydro years would best suit the purposes of the analysis, the research team ran each of these situations independently using the GMM. For each of the 74 temperature cases, the temperature inputted into the GMM starting in April 2009 was set equal the same month's temperature from a specific year of historical data. The historical temperature data was then carried forward through December 2010. For example, the temperature case representing 1932 temperature would reflect, for the months April 2009 to December 2010 in the GMM, the temperature data for April 1932 to December 1933. As the goal was to normalize the initial temperature and hydro runs for comparison, hydroelectric generation levels were kept at ICF's normal level throughout each case run during the forecast period. Each of the hydroelectric generation cases were run in a similar fashion, with each hydro case's generation being used in the model from April 2009 through December 2010 and normal temperature assumed for the duration of the run during the forecast period.

2.4.3 Methodology for Comparing Cases

To select which temperature and hydroelectric generation cases to use for our impact analysis, the research team decided to use the end-of-withdrawal season (March) working gas level in California as a barometer for storage utilization and marginal prices. As the GMM assumes a 90 percent of capacity storage fill during forecast injection seasons, the March working gas level adequately reflects storage turnover during the withdrawal season, and thus storage utilization. Additionally, as all other factors are kept constant in each case, the March working gas level can be used to measure the effect on marginal prices, as a lower level would imply more storage usage, and thus higher demand and higher prices.

Figure 36 shows the combined frequency distribution of March 2010 working gas levels in California for each of the 98 cases of temperature and hydroelectric generation run using the GMM. The distribution of these levels is roughly normal, with a mean of 131 Bcf. There is an accumulation of cases at the upper end of the distribution, as the maximum working gas level is constrained by the amount of available storage capacity. Under the assumption that the distribution is normal, Figure 37 represents the combined cumulative probability chart used to determine which temperature and hydroelectric generation cases would be used to conduct the analysis.

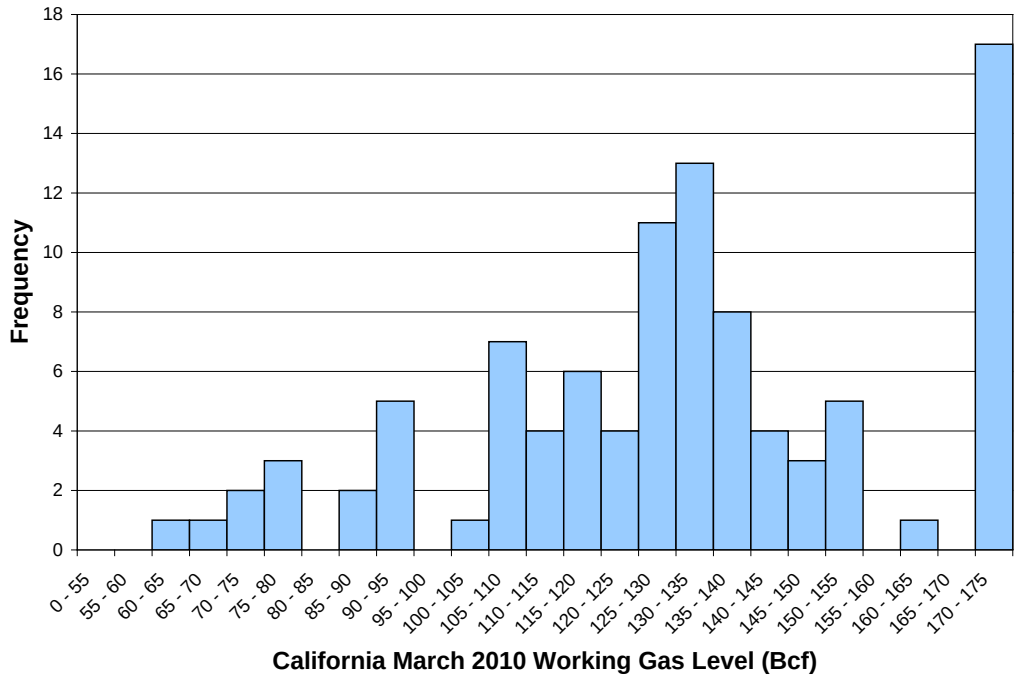


Figure 36: Frequency Distribution Chart of Temperature and Hydroelectric Generation Cases

Source: ICF International

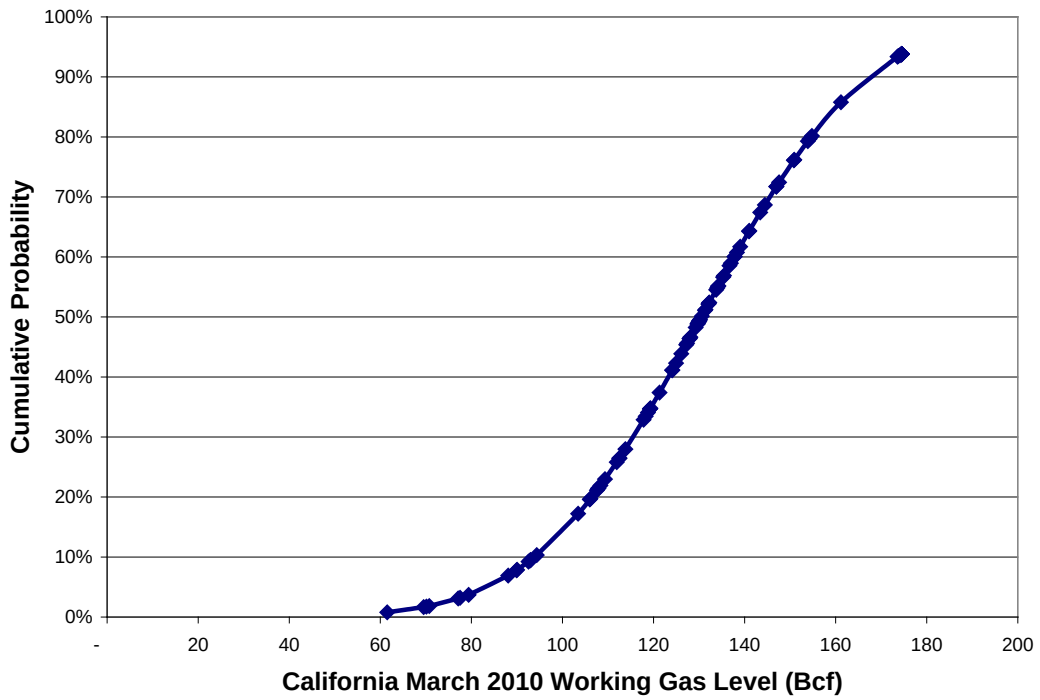


Figure 37: Cumulative Normal Distribution of Temperature and Hydroelectric Generation Cases

Source: ICF International

2.4.4 Selection of Cases for Scenario Analysis

Based on an outline of scenarios previously agreed upon[31] and the distribution represented in Figure 37 as guides, the research team next went about selecting combined temperature and hydro generation cases to use in order to measure the total effect of both on storage utilization and marginal prices. This section will detail which of these cases were included in the matrix and how the specific cases were chosen.

The Base Case versus the Midpoint Case

The original suggested matrix of temperature and hydroelectric cases is shown in Figure 38. During the initial phases of case development, it was discovered that using the Base Case as the midpoint case for the matrix would constrain the weather cases inappropriately. The Base Case used the 30-year average temperatures (average of the years 1977–2006) for the forecast period, which is significantly warmer than the midpoint of distribution of all cases. In the Base Case, March 2010 California working gas level is 152 Bcf, over 20 Bcf higher than the mean of the distribution (Figure 39). Instead of using the Base Case as the midpoint of the matrix, the research team decided to instead run a separate midpoint case, reflecting temperature and hydro cases that ended with March working gas levels in California closest to the mean of the distribution (Figure 39).

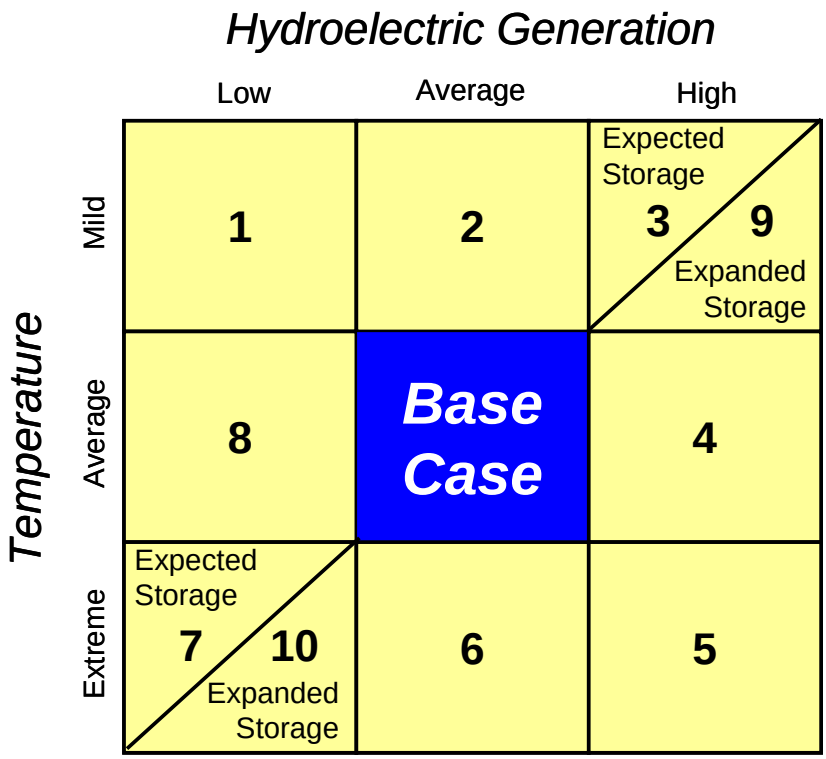


Figure 38: Original Suggested Weather Case Studies

Source: ICF International

[31] ICF letter to California Energy Commission, August 22, 2006.

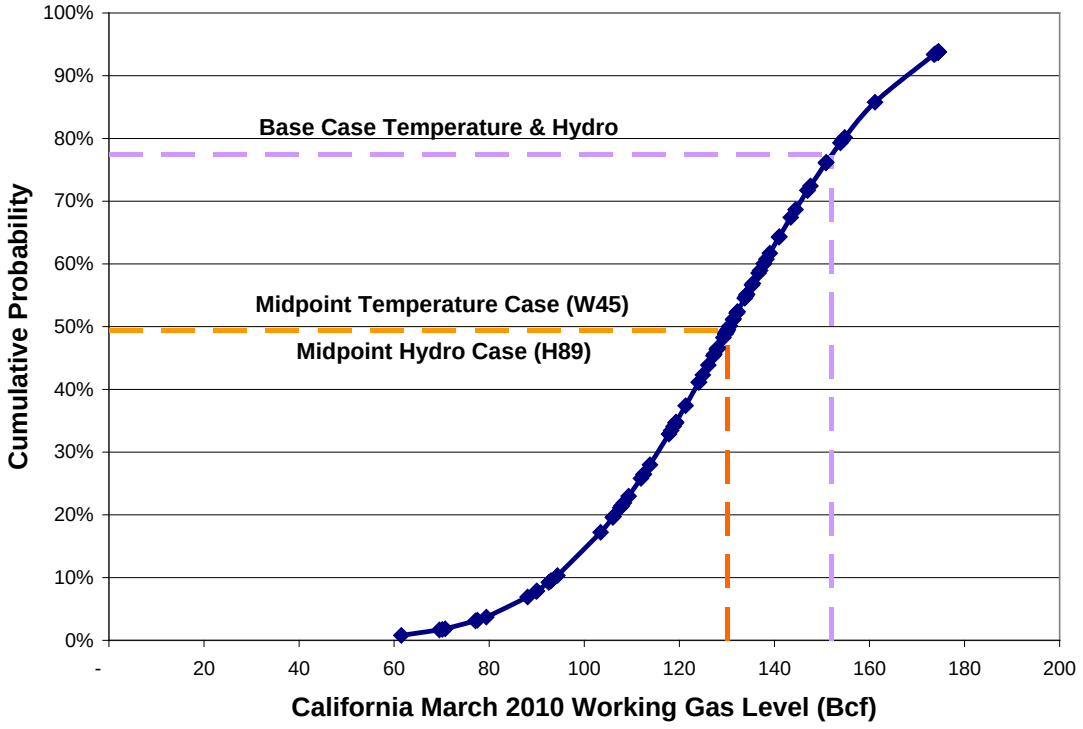


Figure 39: March 2010 Working Gas Level, Base Cases versus Midpoint Case

Source: ICF International

Mild/Extreme Temperature and High/Low Hydroelectric generation Scenario Selections

Given that this distribution is normal, the research team wanted to capture the most significant portion of it in our case selection. To this end, temperature and hydroelectric generation cases near the 20 and 80 percent probability points along Figure 37 were selected to be classified as "extreme" temperature and "low" hydro, and "mild" temperature and "high" hydro, respectively. Doing so sets boundaries for what storage utilization and marginal prices would most likely be observed. Figure 40 shows the specific cases selected and where these cases fall on the distribution.

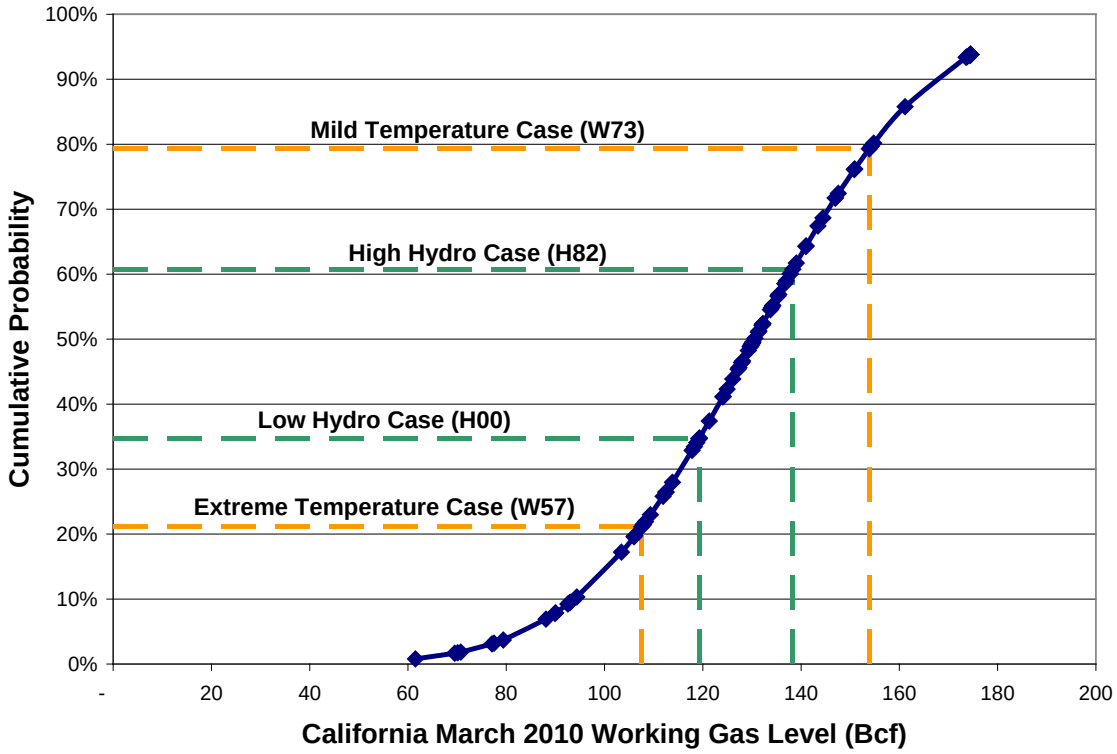


Figure 40: Cases Selected as "Extreme" and "Mild" Temperature and "Low" and "High" Hydroelectric Generation

Source: ICF International

For the temperature cases, determining which cases to use was fairly straightforward. As these cases stretched the entire band of the distribution, the research team chose the case utilizing 1957–58 and 1973–74 temperature data to be used as the "extreme" and "mild" temperature cases, respectively. The case using 1957–58 temperatures ended the withdrawal season in 2010 with 107.5 Bcf in storage in California, placing it at around the 21st percentile. The case using 1973–74 temperatures had 154.9 Bcf left in storage in March 2010, placing it in the 79th percentile.

Determining which hydroelectric generation cases to use proved a bit tougher. Due to changes in California's energy markets (discussed previously in Section 2.3.3), variations in hydroelectric generation had a smaller impact on the end-of-season storage level in California in our projection for 2010 than it did in 2000-2001. As such, the variance in the end-of-season California working gas level was only about 19 Bcf, ranging from 119 Bcf to 138 Bcf. Thus, it was impossible to choose cases that were near the 20th or 80th percentile of the distribution. Instead, the ends of the hydroelectric generation case band were used, leading to classification of the 2000-2001 hydroelectric generation data as the "low" hydro case and the 1982–83 hydroelectric generation data as the "high" hydro case. Along the distribution, these two cases fell into the 35th and 61st percentiles, respectively.

Very Extreme Weather Scenario Selection

The research team determined it was also important to look at what might happen in an extremely severe, yet unlikely scenario. To this end, the research team wanted to see how California would look if end-of-withdrawal season storage levels in California got as low as they did during the California energy crisis of 2000-2001.

In determining which case combinations would best replicate this scenario, a couple of combinations of temperature and hydroelectric generation data were chosen to test and see how closely the 2000-2001 storage situations could be replicated. Since hydroelectric generation has little impact on the working gas levels, the primary focus was on choosing a temperature case below 10 percent probability on the distribution. The 1947–48 temperatures and 1986–87 hydroelectric generation cases were selected. This combination yielded an end-of-withdrawal season storage level of 82 Bcf in California, which is very similar to the draw-down of storage observed in 2000-2001. These results will be expounded upon in more detail later in this section.

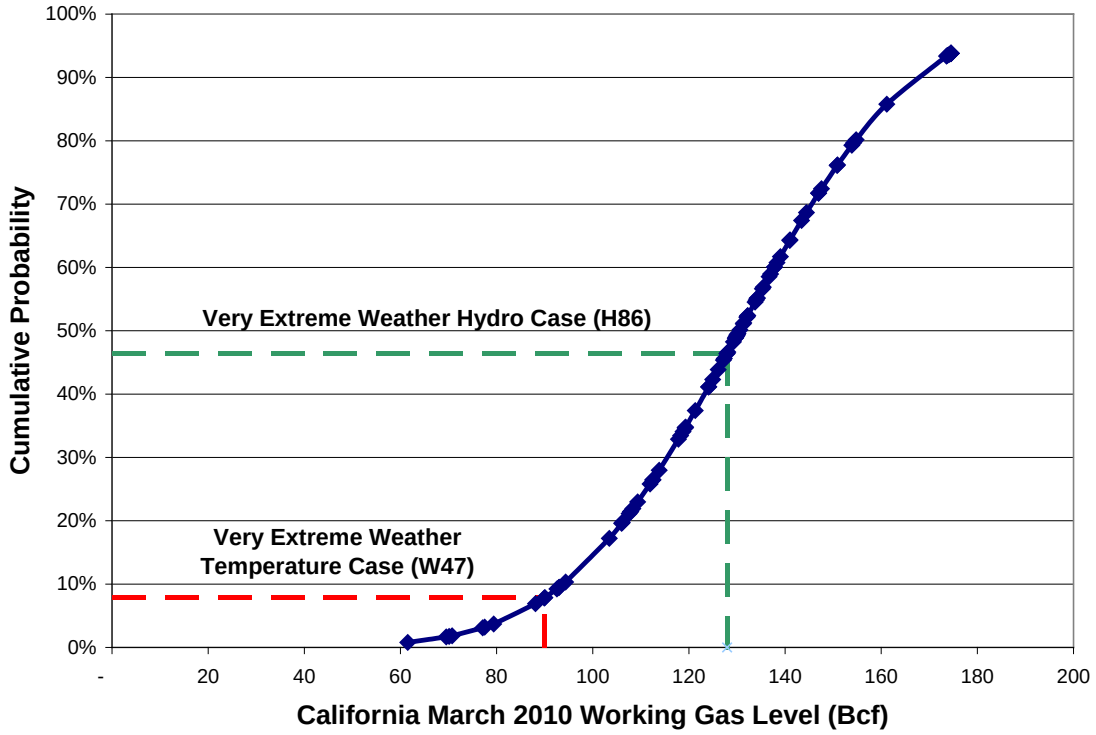


Figure 41: "Very Extreme" Weather Case Temperature and Hydroelectric Generation Scenario Selections

Source: ICF International

Final Case Matrix

The final matrix of cases used in this stage of the analysis is shown in Figure 42.

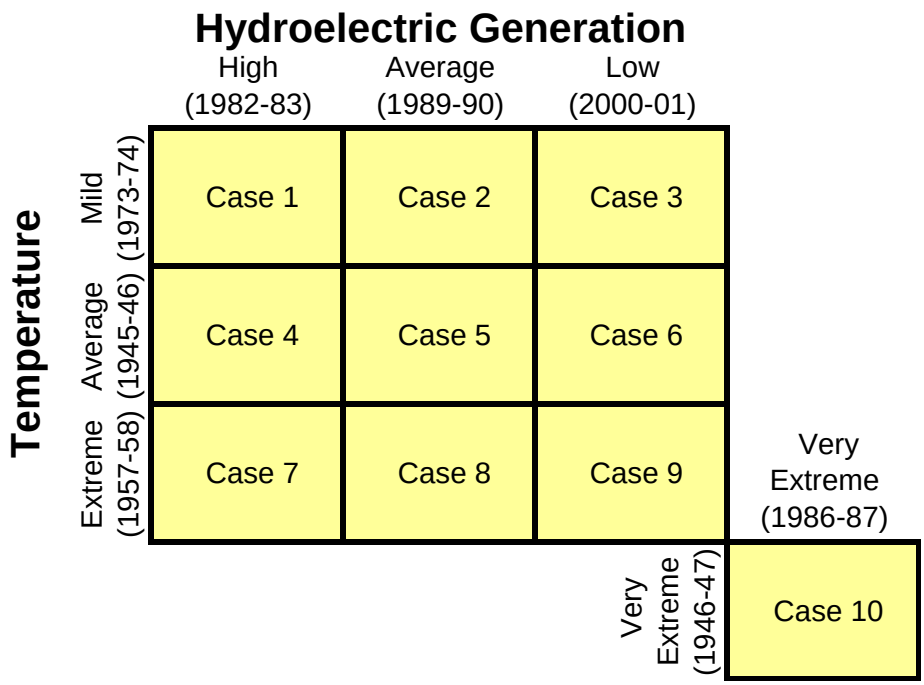


Figure 42: Final Case Matrix

Source: ICF International

2.5 Alternative Weather Cases Results and Conclusions

The 10 alternative weather cases developed for this project result in substantially different natural gas demand, supply, and storage utilization patterns, as well as storage value assessments. This section of the report provides a look at the impacts of the different weather cases on storage operations and value, and draws initial conclusions from the analysis.

2.5.1 Impact of Alternative Weather Cases On California Storage Requirements

As discussed in Section 2.4 of this report, the 10 weather cases were developed primarily to test the impacts of weather on California storage requirements. Figure 43 illustrates the impact of the 10 weather cases on end-of-season working gas inventory levels by storage field. As expected, the weather cases substantially impact end-of-season storage levels, with the mild weather cases resulting in much higher end-of-season inventory levels than more extreme weather cases. In Case 1, the mildest weather case, end-of-March inventories are at 161 Bcf, which is slightly higher than observed in recent history. The most extreme weather case, Case 10, results in March working gas inventories of about 80 Bcf, similar to the levels observed during 2001 after accounting for growth in overall storage capacity in the state.

The impact of the different weather cases on California natural gas demand, shown in Figure 44, does not necessarily track the impact on working gas inventories. For example, Case 6 actually results in higher California gas demand than the more extreme weather cases. This is due to use of actual weather data throughout the Western region, where weather in other areas included in the analysis is more extreme than the weather in California.

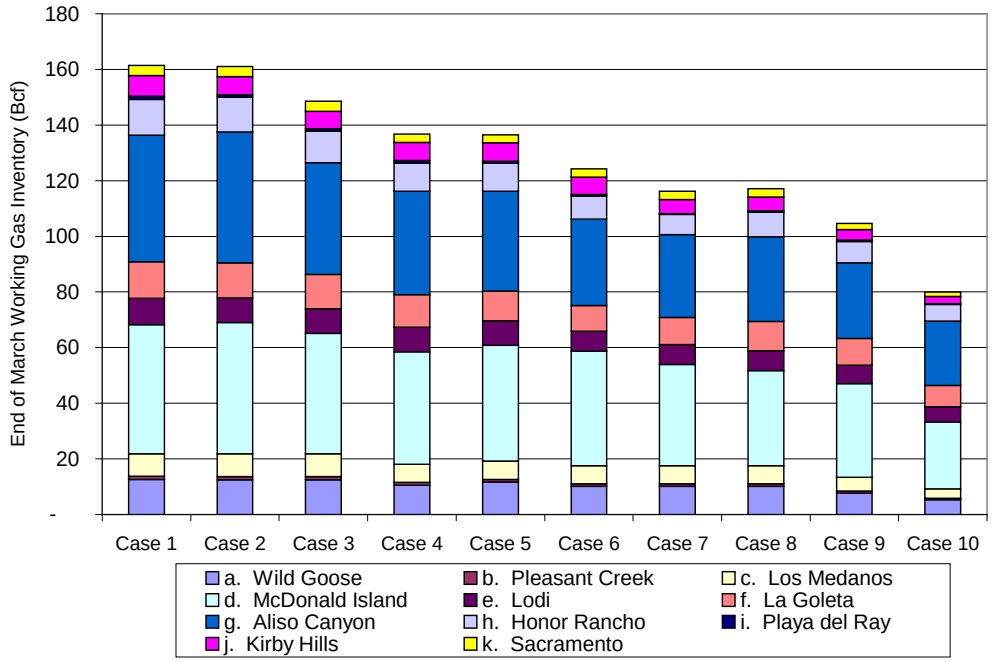


Figure 43: March 2010 Storage Inventories by Facility

Source: ICF International

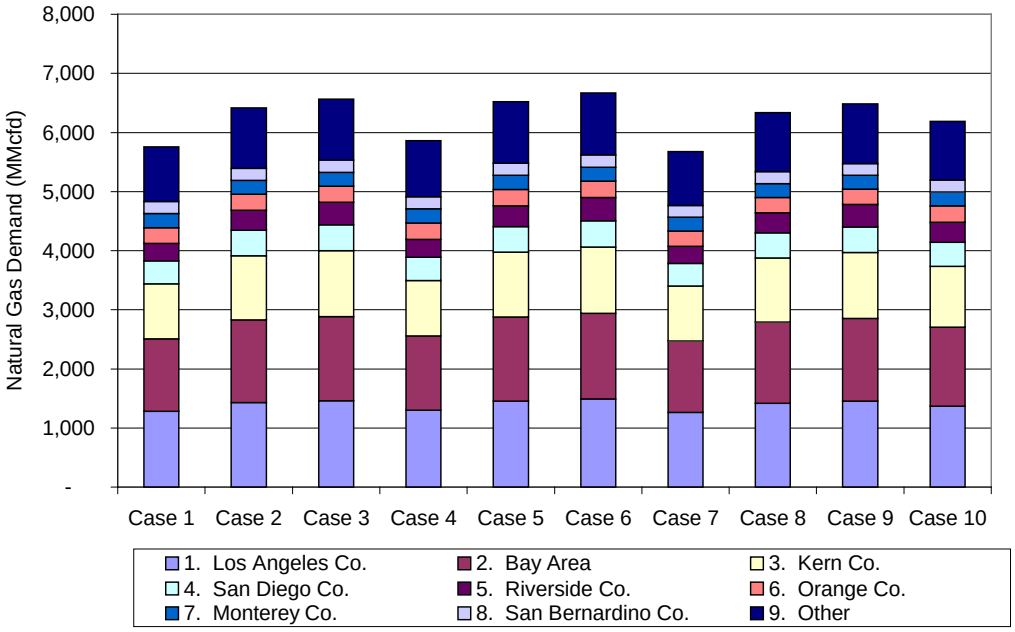


Figure 44: Projected California Natural Gas Demand, April 2009 to March 2010

Source: ICF International

The impact of the 10 different weather scenarios on the different storage facilities is relatively symmetrical, with minor differences due to differences in physical characteristics of the

different fields that limit storage field flexibility in some cases, with Wild Goose providing the most relative flexibility in the extreme case. As expected, the largest fields in the State, McDonald Island and Aliso Canyon, have the largest differences in end-of-March working gas inventories.

The monthly differences in working gas levels for the different weather cases are shown in Figure 45, and net injections and withdrawals by month for the different weather cases are shown in Figure 46. It is worth noting that the differences in the injection and withdrawal patterns for the different weather cases are not necessarily consistent from month to month due to the use of actual weather data for all of North America to develop the weather cases. For example, December storage withdrawals in the extreme weather case are much lower than December storage withdrawals in many of the other cases. However, as expected, January and February withdrawals for the extreme case are much greater than the other cases.

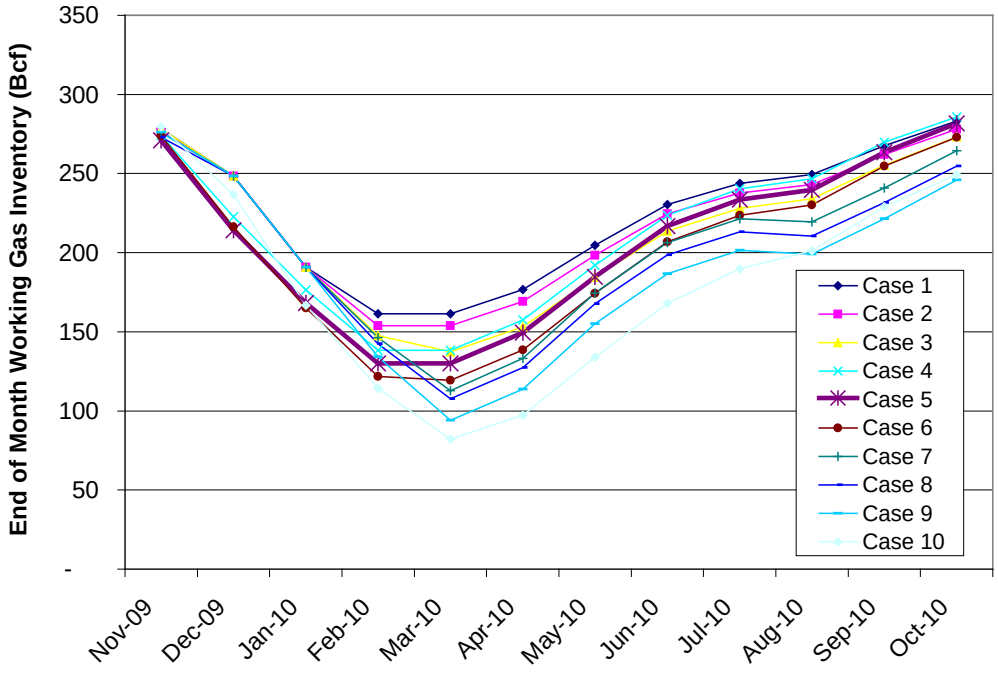


Figure 45: California Storage Working Gas Levels

Source: ICF International

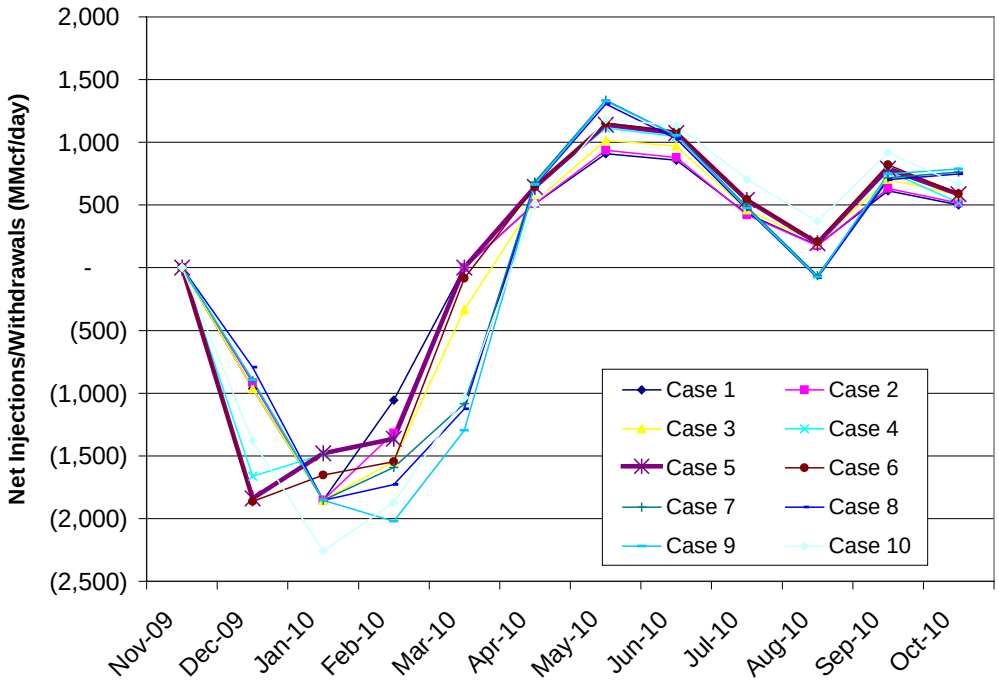


Figure 46: California Storage Net Injections (+) and Withdrawals (-), based on GMM Results

Source: ICF International

2.5.2 Incremental Value of California Storage to California Consumers

The ICF GMM provides a forecast of the expected seasonal value of natural gas in California. These forecasts include consideration of the full range of impacts of all of the factors influencing North American natural gas markets, including factors such as East Coast LNG imports, pipeline construction from the Rockies to East Coast markets, and other factors that do not have a direct linkage or direct impact on California markets.

RIAMS estimates the seasonal value of natural gas storage to Western United States and California consumers. In these initial weather sensitivity cases, the boundary conditions for RIAMS have been set to ensure that the RIAMS results reflect the value of California storage to meet different weather scenarios within the Western Region, rather than reflecting all of the gas market factors throughout North America that might impact storage values. The seasonal value of storage from RIAMS for each of the 10 weather cases is shown in Figure 47. This figure shows the estimated injection season and withdrawal season natural gas prices for the 2009–2010 storage season (April 2009 through March 2010) on the primary axis, as well as the seasonal value of natural gas (withdrawal season price minus injection season price) on the secondary axis. As indicated in this chart, the seasonal value of natural gas ranges from about $0.62 per MMbtu in Case 1 to $1.09 in Case 9.

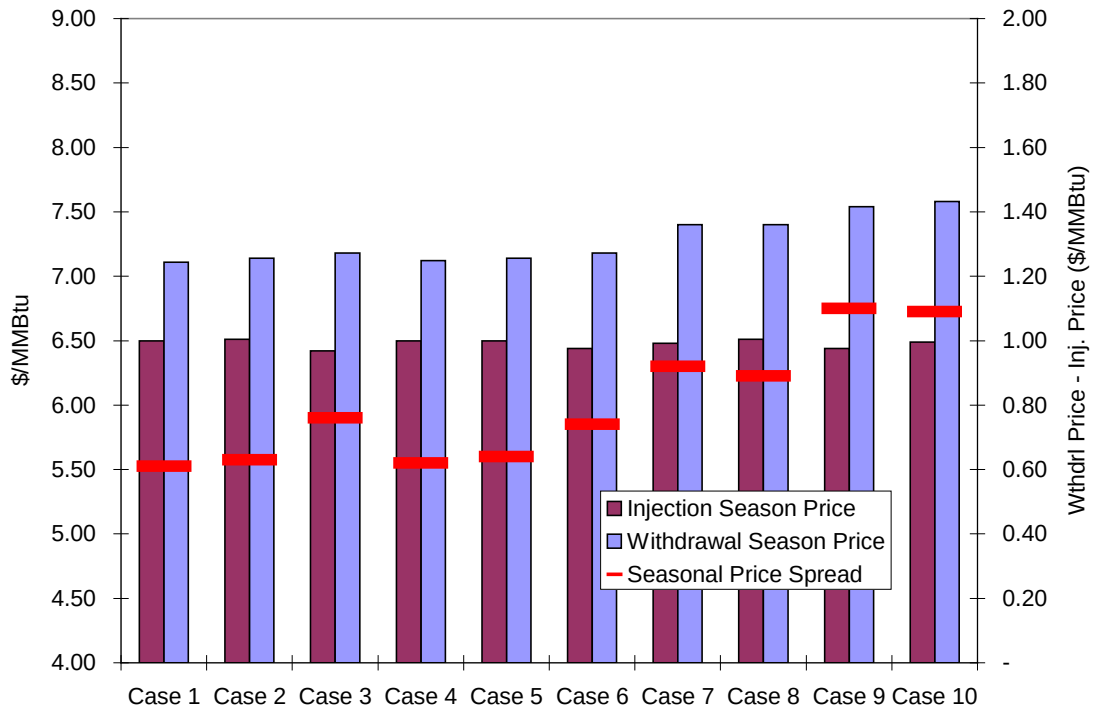


Figure 47: Impact of Alternative Weather Scenarios on Natural Gas Prices and Seasonal Spreads, RIAMS Results

Source: ICF International

The values of storage estimated from the RIAMS analysis scenarios discussed here represent a subset of the value of natural gas storage related to factors within the Western Region. The scenario results do not represent the full market value of storage, which is heavily influenced by factors outside of the Western United States. In addition, the RIAMS model provides the best or lowest cost mix of storage, production, and pipeline imports to meet California demand based on the *intertemporal* optimization of the different gas supply, demand, and price over the forecast period. The model is based on a perfect foresight, including future weather, future demand and future natural gas prices. As a result, the model projections represent the optimal usage of natural gas storage. This solution is not a forecast of actual natural gas storage usage or the actual cost/benefits of using natural gas storage. The use of the *intertemporal* optimization approach provides a very powerful tool for evaluating the potential changes in costs and value of storage under different weather and demand scenarios. However, the results need to be used with caution, as the market will actually operate without perfect foresight, and will not be capable of reaching the optimal solution. In the evaluation of natural gas storage, the use of a perfect foresight optimization approach understates the true value of storage, as a significant element of the value of natural gas storage is based on the use of storage to meet unexpected changes in natural gas demand and supply, and to hedge against uncertainty in natural gas prices.

As a result, the research team has looked at both the results of the RIAMS model and the GMM model when evaluating storage value. Figure 48 shows the full seasonal value of California storage for each weather case when evaluated in the context of the overall North American market. This figure shows the estimated injection season and withdrawal season natural gas prices for the 2009–2010 storage season (April 2009 through March 2010) on the primary axis, as well as the seasonal value of natural gas (withdrawal season price minus injection season price) on the secondary axis. As indicated in this chart, the seasonal value of natural gas ranges from about ($0.07) per MMbtu in Case 1 to $2.33 in Case 10. In Case 1 and Case 2, mild winter weather and low hydro demand result in withdrawal season prices that are equal to or below injection season prices.

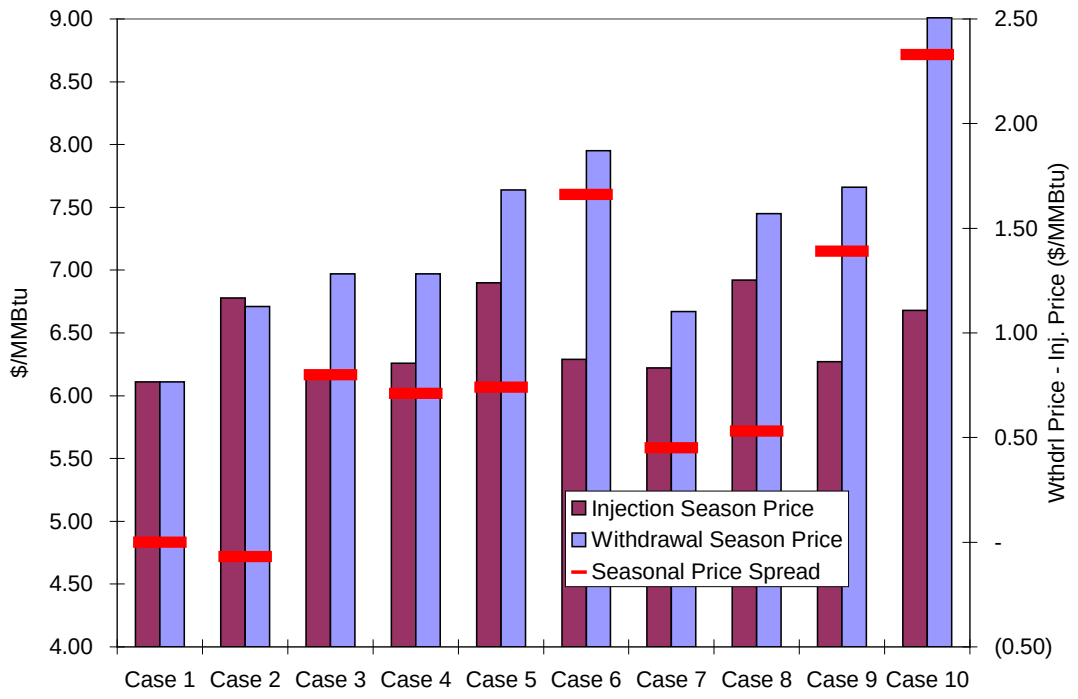


Figure 48: Impact of Alternative Weather Scenarios on Natural Gas Prices and Seasonal Spreads, GMM Results

Source: ICF International

2.5.3 Differences in Gas Prices and Seasonal Storage Value Within California

The RIAMS analysis indicates that the different weather cases are likely to have very similar impacts on natural gas prices and seasonal storage values in most of the storage regions and demand regions within California. Based on the regional analysis, prices are likely to differ by about $0.50 per MMBtu, ranging from $6.60 to $6.95 per MMBtu at different storage fields in Case 1 (Mild Weather, High Hydro Generation) to $7.00 to $7.38 per MMBtu at different storage fields in Case 10 (Extreme Weather and Hydro Generation). The price impact of weather is

generally somewhat smaller in the demand regions, with the difference between the lowest price case (typically Case 1), and the highest price case (typically Case 10) averaging about $0.30 at most demand locations.

The one exception to this range is Los Angeles County, where the highest price case exceeds the lowest price case by about $0.45 per MMBtu.

The RIAMS analysis indicates that the alternative weather scenarios create larger differences in storage value (Table 12 and Table 13) than in annual average natural gas prices. Seasonal price spreads at the field level range from $0.57 to $0.54 per MMBtu in Case 1 (Mild Weather, High Hydro Generation) to $1.07 to $1.13 per MMBtu in Case 10 (Extreme Weather and Hydro Generation).

Table 12: Average Annual Natural Gas Prices At Different Points Within California (RIAMS Analysis), April 2009 through March 2010 ($/MMBtu)

	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7	Case 8	Case 9	Case 10
Storage Facilities										
a. Wild Goose	6.95	6.89	6.86	6.98	6.91	6.91	7.15	7.09	7.19	7.36
b. Pleasant Creek	6.92	6.89	6.88	6.95	6.93	6.91	7.09	7.10	7.21	7.29
c. Los Medanos	6.91	6.91	6.87	6.95	6.94	6.92	7.09	7.10	7.20	7.29
d. McDonald Island	6.91	6.91	6.86	6.96	6.94	6.90	7.11	7.10	7.15	7.31
e. Lodi	6.95	6.90	6.87	6.93	6.90	6.92	7.09	7.09	7.16	7.29
f. La Goleta	6.60	6.65	6.65	6.62	6.71	6.75	6.82	6.89	6.94	7.00
g. Aliso Canyon	6.67	6.75	6.77	6.71	6.80	6.83	6.95	7.01	7.07	7.07
h. Honor Rancho	6.67	6.77	6.76	6.71	6.79	6.84	6.95	7.01	7.05	7.06
i. Playa del Ray	6.65	6.77	6.75	6.67	6.76	6.78	6.96	6.97	7.01	7.00
j. Kirby Hills	6.93	6.92	6.90	6.97	6.94	6.91	7.15	7.13	7.22	7.38
k. Sacramento	6.91	6.91	6.87	6.95	6.94	6.93	7.10	7.09	7.21	7.30
Demand Regions										
1. Los Angeles Co.	6.72	6.83	7.17	6.76	6.82	7.01	6.87	6.95	7.09	7.09
2. Bay Area	6.79	6.82	6.82	6.79	6.78	6.79	6.95	6.98	7.01	7.08
3. Kern Co.	6.59	6.67	6.68	6.60	6.65	6.67	6.80	6.85	6.90	6.90
4. San Diego Co.	6.68	6.75	6.76	6.68	6.73	6.75	6.88	6.93	6.98	6.99
5. Riverside Co.	6.65	6.71	6.71	6.65	6.68	6.71	6.84	6.89	6.93	6.95
6. Orange Co.	6.68	6.75	6.76	6.68	6.73	6.75	6.88	6.93	6.98	6.98
7. Monterey Co.	6.79	6.82	6.82	6.79	6.78	6.79	6.95	6.97	7.00	7.08
8. San Bernardino Co.	6.66	6.73	6.73	6.66	6.70	6.73	6.86	6.91	6.96	6.96

Source: ICF International

Table 13: Seasonal Difference in Natural Gas Prices At Different Points Within California ($/MMBtu)

	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7	Case 8	Case 9	Case 10
Storage Facilities										
a. Wild Goose	0.63	0.66	0.76	0.65	0.66	0.73	0.96	0.89	1.10	1.07
b. Pleasant Creek	0.64	0.66	0.77	0.65	0.66	0.74	0.96	0.89	1.11	1.08
c. Los Medanos	0.64	0.66	0.77	0.65	0.66	0.74	0.96	0.89	1.11	1.08
d. McDonald Island	0.63	0.66	0.77	0.65	0.66	0.73	0.95	0.89	1.10	1.08
e. Lodi	0.63	0.66	0.77	0.65	0.66	0.73	0.95	0.89	1.10	1.08
f. La Goleta	0.57	0.61	0.78	0.56	0.60	0.77	0.90	0.92	1.11	1.11
g. Aliso Canyon	0.60	0.61	0.79	0.59	0.61	0.79	0.91	0.93	1.12	1.14
h. Honor Rancho	0.60	0.61	0.80	0.60	0.61	0.79	0.91	0.93	1.12	1.15
i. Playa del Ray	0.62	0.63	0.82	0.62	0.64	0.81	0.94	0.95	1.15	1.17
j. Kirby Hills	0.64	0.66	0.77	0.65	0.66	0.73	0.96	0.89	1.11	1.08
k. Sacramento	0.64	0.66	0.77	0.65	0.66	0.74	0.96	0.89	1.11	1.08
Demand Regions										
1. Los Angeles Co.	0.62	0.73	1.59	0.67	0.69	1.20	0.89	0.94	1.36	1.39
2. Bay Area	0.48	0.58	0.76	0.49	0.50	0.65	0.89	0.89	1.10	1.07
3. Kern Co.	0.49	0.52	0.74	0.48	0.47	0.66	0.87	0.87	1.11	1.12
4. San Diego Co.	0.49	0.52	0.73	0.48	0.47	0.66	0.87	0.87	1.10	1.13
5. Riverside Co.	0.49	0.53	0.73	0.48	0.47	0.65	0.88	0.88	1.10	1.12
6. Orange Co.	0.49	0.52	0.73	0.49	0.47	0.66	0.87	0.87	1.10	1.13
7. Monterey Co.	0.48	0.58	0.76	0.49	0.50	0.65	0.89	0.89	1.10	1.07
8. San Bernardino Co.	0.49	0.52	0.73	0.48	0.47	0.65	0.87	0.87	1.10	1.12

Source: ICF International

As with the impact on annual prices, the regional analysis suggests that weather will have a much larger impact on the seasonal value of natural gas in Los Angeles County than in the rest of the State.

2.5.4 Daily Analysis

The monthly analysis provides an evaluation of general market trends and conditions, and captures the basic seasonality of the natural gas markets. However, the natural gas infrastructure system, including pipeline and storage capacity, is designed to meet peak day loads. In order to evaluate storage value during these peak demand periods, the RIAMS model is also run on a daily basis for January. Monthly gas consumption and prices are passed from the GMM to the DGLM, which is used to create a daily load projection for the same time period. The daily load projections from DGLM and the projected beginning- and end-of-month working gas levels for each field from the RIAMS monthly period run are then passed into the daily version of RIAMS to determine daily variability in field-level storage activity.

Figure 49 compares the peak period demand for California regions for the five highest demand days in January 2010 for each of the weather scenarios.

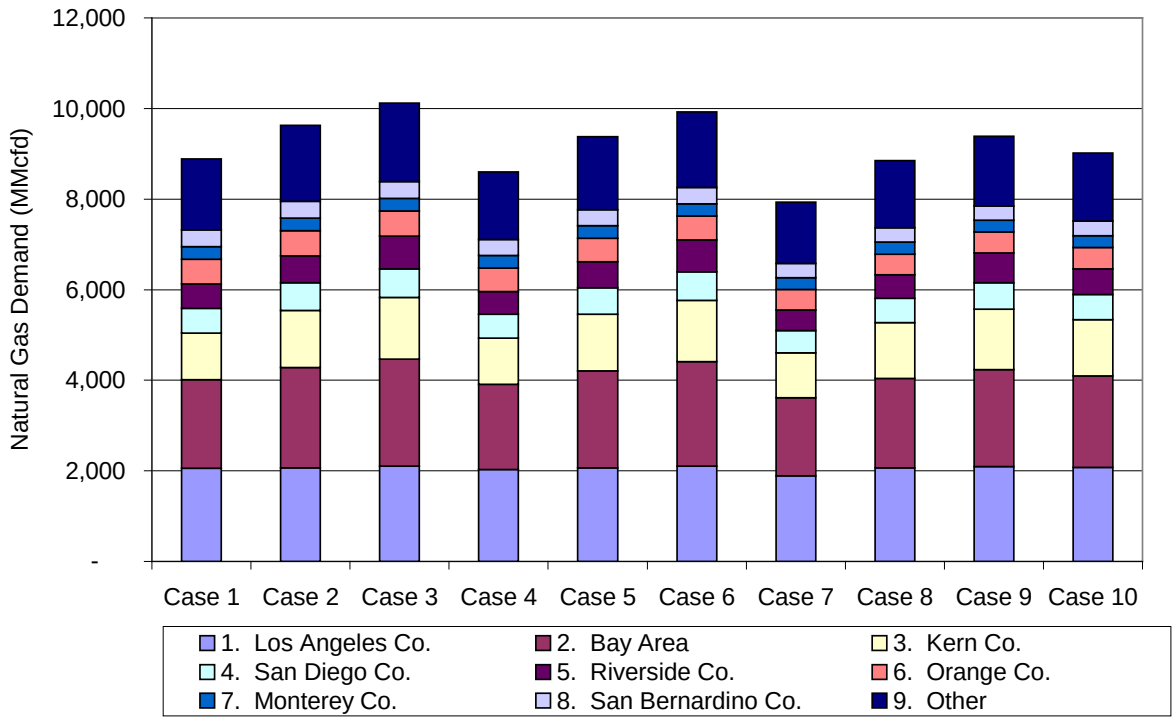


Figure 49: California Peak Period Natural Gas Demand (5 Peak Days in January 2010)

Source: ICF International

It is worth noting that the extreme weather cases, which were developed to reflect annual weather patterns with the greatest impact on California storage requirements, do not necessarily include the periods with the highest January peak day demand requirements.

The average prices for the same five day period are shown by location in Table 14. This table indicates that prices during peak periods are relatively stable at each of the California storage fields, but can vary widely in the major demand regions. Peak prices at the 11 storage fields modeled vary by $0.52 to $0.57 per MMBtu between the weather case with the lowest peak period prices (Case 6), and the weather case with the highest peak period prices (Cases 7 and 8). However, in the demand regions modeled, peak period prices in Los Angeles County diverge widely from the rest of the State due to transmission constraints into the County, while prices in the Bay Area region also diverge due to transmission constraints, although to a much smaller degree than observed in Los Angeles County.

Table 14: Natural Gas Prices at Different Points Within California (RIAMS Analysis), Five Peak Demand Days in January 2010

	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7	Case 8	Case 9	Case 10
Storage Facilities										
a. Wild Goose	7.06	6.99	6.95	7.07	7.14	6.78	7.34	7.32	7.17	7.31
b. Pleasant Creek	7.07	7.00	6.96	7.08	7.15	6.79	7.34	7.33	7.18	7.32
c. Los Medanos	7.07	7.00	6.97	7.08	7.16	6.80	7.35	7.33	7.19	7.32
d. McDonald Island	7.07	7.00	6.97	7.08	7.15	6.79	7.34	7.33	7.18	7.32
e. Lodi	7.07	7.00	6.97	7.08	7.15	6.79	7.34	7.33	7.18	7.32
f. La Goleta	6.87	6.89	6.86	6.88	6.96	6.60	7.23	7.22	7.07	7.12
g. Aliso Canyon	6.97	6.99	6.96	6.98	7.05	6.69	7.33	7.32	7.17	7.26
h. Honor Rancho	6.97	6.99	6.96	6.98	7.05	6.69	7.33	7.32	7.17	7.26
i. Playa del Ray	6.97	6.99	6.96	6.98	7.05	6.69	7.33	7.32	7.17	7.26
j. Kirby Hills	7.07	7.00	6.97	7.08	7.15	6.79	7.34	7.33	7.19	7.32
k. Sacramento	7.07	7.00	6.97	7.08	7.15	6.80	7.35	7.33	7.19	7.32
Demand Regions										
1. Los Angeles Co.	8.54	18.37	29.04	7.51	13.65	25.22	7.38	8.29	15.91	9.22
2. Bay Area	8.29	8.09	8.11	7.44	7.51	7.19	7.35	7.33	7.19	7.32
3. Kern Co.	6.89	6.91	7.18	6.89	6.97	6.89	7.25	7.24	7.31	7.18
4. San Diego Co.	6.97	7.00	8.20	6.98	7.06	7.02	7.33	7.32	7.18	7.27
5. Riverside Co.	6.94	6.95	6.91	6.94	7.02	6.66	7.29	7.27	7.13	7.23
6. Orange Co.	6.97	6.99	6.96	6.98	7.06	6.70	7.33	7.32	7.18	7.26
7. Monterey Co.	7.07	7.00	6.97	7.08	7.16	6.80	7.34	7.33	7.19	7.32
8. San Bernardino Co.	6.95	6.97	6.94	6.96	7.03	6.67	7.31	7.30	7.15	7.24

Source: ICF International

2.5.5 Conclusions Based Upon Evaluation of Weather Cases

Regional vs. North American Storage Value

The alternative weather scenarios have significantly different impacts on the seasonal value of natural gas storage depending on whether the analysis includes the full range of weather impacts across North America, or is limited to the impacts in the Western Region of the United States. As indicated in Figure 50, the North American analysis generates much larger changes in storage value due to weather than does the Western Region analysis. In the milder weather cases, withdrawal season prices can be below injection season prices in the mild weather scenarios, but increase substantially in the extreme weather cases, with seasonal price differences ranging from ($0.07) to $2.33 per MMBtu. However, when the analysis is limited to the Western Region, storage value is much more stable, with seasonal price differences ranging from $0.61 to $1.09.

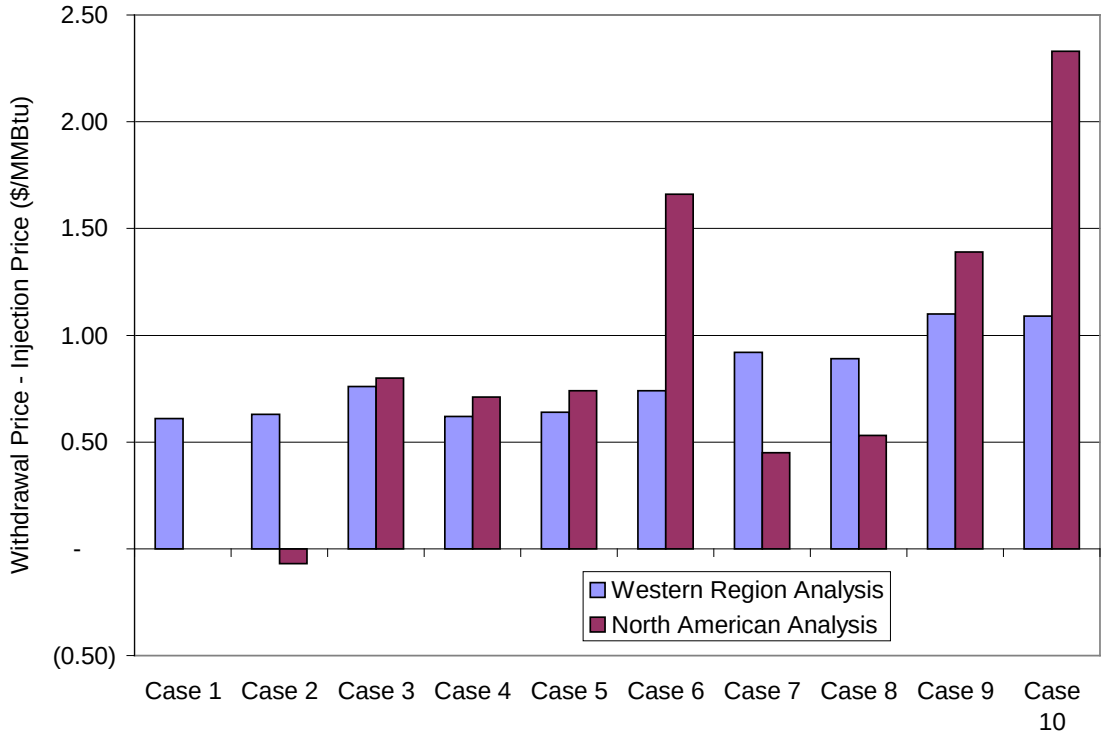


Figure 50: Comparison of 2009–2010 Seasonal Storage Values From North American and Western Regional Analysis for 10 Alternative Weather Cases

Source: ICF International

Relationship between California Demand and California Storage Utilization

The analysis of alternative weather scenarios indicates that the relationship between California natural gas demand and total demand for California natural gas storage services is not linear. The weather conditions leading to the greatest demand for natural gas within California do not necessarily result in the greatest utilization and greatest value of California storage capacity. Instead, factors outside of California also have a significant impact on California storage inventory levels.

Regional Capacity Constraints

The California storage modeling effort revealed significant constraints on pipeline capacity and storage availability into the Los Angeles area during peak demand days in the time period modeled. The results suggest that these constraints into the Los Angeles area are not coincident with the overall level of working gas inventories in California natural gas storage.

Changes in California Energy Infrastructure have Reduced Vulnerability to Alternative Weather Cases Since 2000-2001

Based on historical market behavior in California during the 2000-2001 period, the storage value assessments may seem somewhat lower than anticipated for the extreme weather scenarios.

Even though the nature of the demand disturbances that occurred during the 2000-2001 period is roughly equivalent to the demand disturbances in Cases 9 and 10, the impact on working gas in storage, gas prices, and storage values projected in the current analysis for the 2009-2010 time period is substantially less than observed in the market during the 2000-2001 time period.

However, as discussed earlier the infrastructure and gas supply situation for California has changed substantially since 2001. Pipeline capacity into the State has increased, pipeline interconnects within the State have been improved, and storage holders have changed operational behavior, with storage injection patterns less sensitive to short-term price trends. Our initial analysis appears to confirm that the California market is better prepared to adjust to extreme weather and hydro conditions than it was during the 2000-2001 period, and the price impacts of an extreme weather/hydro scenario are expected to be much lower than observed during that historical period.

CHAPTER 3:
Project Results: The Impact of Variations in Renewable Generation on California's Natural Gas Infrastructure

3.1 Introduction

This section of the report documents the development of five scenarios aimed at investigating the impacts of variations in renewable generation on California's gas infrastructure.

The modeling work in Section 2 assessed the use and value of gas storage in California. In the original work plan for the subcontract, the next set of scenarios was to focus on the impact of LNG imports, disruptions to gas infrastructure, and/or increased gas-fired power generation. However, the Energy Commission expressed a desire to redirect the effort to focus on the impact of California's increasing use of renewable energy on gas infrastructure, since gas-fired generation serves as a back-up to renewable generation.

In the revised work plan, the focus for the remaining scenarios has been shifted to the potential impacts of variations in renewable generation on California's natural gas infrastructure, assuming the adoption of a 33 percent Renewables Portfolio Standard (RPS). The modeling work for the renewable generation scenarios was performed in 2009.

3.1.1 California's Renewable Portfolio Standard

Due to increasing interest in controlling carbon emissions, many states have begun to focus their attention not only on reducing the emissions from fossil fuel plants, but also on developing clean sources of energy. To this end, 29 states have established renewables portfolio standards, which set goals of meeting a certain percentage of the states' electricity demand with renewable generation.

In 2002, California established its own Renewables Portfolio Standard Program, with the goal of increasing the percentage of renewable energy in the State's electricity mix to 20 percent by 2017. The *2003 Integrated Energy Policy Report* recommended accelerating that goal to 20 percent by 2010, and the *2004 Energy Report Update* further recommended increasing the target to 33 percent by 2020. The State's *Energy Action Plan* also supported this goal.

In 2006, California State Senate Bill 107 (Simitian) codified the 20 percent by 2010 goal. Under the 2006 law, electric utilities and others entities with retail electricity sales are required to increase their procurement of electricity from eligible renewable energy resources by at least 1 percent of their retail sales annually, until they reach 20 percent by 2010. On September 15, 2009, Governor Arnold Schwarzenegger signed Executive Order S-21-09, directing the California Air Resources Board (ARB) to adopt regulations increasing California's RPS to 33 percent by 2020.

3.2 Overview of Task

By definition, several technologies can contribute to meeting the 33 percent RPS, including wind, photovoltaic (PV), solar thermal, biogas, biomass, geothermal, and small hydroelectric. Some renewable technologies, such as wind, PV, and solar thermal, have variability in their output due to weather conditions. The variability of generation from wind and solar technologies is different, so different mixes of technologies result in different degrees of variability in total RPS generation. Reductions in renewable generation can create a corresponding increase in gas demand for electricity generation, and potentially could stress California's natural gas pipeline and storage infrastructure. This study focuses on the potential impact of variation in renewable generation on California's gas pipelines and storage capacity in 2020, the year when the proposed 33 percent RPS is to be met.

3.3 Overview of Modeling Approach

As with the earlier modeling work that examined the impact of weather and hydroelectric generation on gas storage, this analysis is based on a multi-step process that makes use of three different models to analyze changes in natural gas demand, supply, and the utilization of gas infrastructure under different scenarios.

- Gas Market Model (GMM) – GMM creates a monthly projection for the entire North American natural gas market through 2020, including regional supply, demand, storage activity, inter-regional pipeline flows, and gas prices.
- Regional Infrastructure Assessment Modeling System (RIAMS) – RIAMS provides a much more detailed analysis of pipeline flows and storage activity within California for the forecast period 2019-2020 (when the 33 percent RPS target is met).
- Daily Gas Load Model (DGLM) – DGLM is used to create a daily load profile for January 2020, California's peak gas demand month. The daily load profile is input into RIAMS to project peak day pipeline flows and storage activity. The results are critical to assessing the adequacy of gas infrastructure to satisfy peak day loads.

The renewable generation cases we modeled were based on several 33 percent RPS scenarios developed for the CPUC by Energy and Environmental Economics, Incorporated for the 33 percent Implementation Analysis Working Group Meeting on January 15, 2009.[32] After discussions with Energy Commission staff, we chose the following three scenarios from the workgroup presentation: the 33 percent Reference Case, the High Wind Case, and the High Central Station Solar case. While the total annual RPS generation is the same in each of these three scenarios, they have different mixes of renewable technologies to meet the standard. When implemented in the natural gas models, the different technology mix represented in each scenario results in both different seasonal generation patterns and different projections for reduced levels of generation from renewables that could result from variability in weather.

[32] California Public Utility Commission 33% Implementation Analysis Working Group presentation, provided via email by Michael Magaletti, February 9, 2009.

A total of five renewable generation cases were modeled:

- Case 1: 33 percent RPS Reference Scenario, Expected Renewable Generation, Normal Weather. This case assumes California's RPS is 33 percent of electricity sales by 2020, renewable capacity is sufficient to meet this standard, and renewable generation in 2020 is at the expected level. The mix of technologies used to meet the RPS is consistent with the CPUC's 33 percent Reference scenario. This case also assumes normal weather conditions.
- Case 2: 33 percent RPS Reference Scenario, Expected Renewable Generation, Adverse Weather. This case assumes the same level of renewable generation as in Case 1, but instead of normal weather it assumes adverse temperatures conditions (that is, hot summer and cold winter) and reduced generation from large hydroelectric facilities. This case is needed to differentiate the impact of temperature and hydroelectric conditions on gas demand from the impact of changes in renewable generation in Cases 3, 4, and 5.
- Case 3: 33 percent RPS Reference Scenario, Reduced Renewable Generation, Adverse Weather. This case assumes the same RPS and technology mix as Case 1, but wind and solar generation are assumed to be below expected levels in 2020, and this deficit is replaced solely with gas-fired generation. This case also assumes the same adverse temperature and hydroelectric conditions as in Case 2.
- Case 4: 33 percent RPS High Wind Scenario, Reduced Renewable Generation, Adverse Weather. In this case, the mix of technologies used to meet the 33 percent RPS is consistent with the CPUC's High Wind scenario. Wind and solar generation are assumed to be below expected levels in 2020, and this deficit is replaced solely with gas-fired generation. This case also assumes the same adverse temperature and hydroelectric conditions as in Case 2.
- Case 5: 33 percent RPS Solar Scenario, Reduced Renewable Generation, Adverse Weather.
  In this case, the mix of technologies used to meet the 33 percent RPS is consistent with the CPUC's High Central Station Solar scenario. Wind and solar generation are assumed to be below expected levels in 2020, and this deficit is replaced solely with gas-fired generation. This case also assumes the same adverse temperature and hydroelectric conditions as in Case 2.

The procedure used to model the cases is outlined in Figure 51. For each of the five cases, we first ran the GMM with the assumed level of renewable generation in California to determine changes in regional gas consumption, production, storage injections and withdrawals, gas prices, and inter-regional pipeline flows. Data from the GMM was then passed to the monthly version of the RIAMS model, which was used to project changes in the utilization of pipeline and storage capacity in California and surrounding states as gas demand at specific power plants changed in response to the change in renewable generation. The monthly version of RIAMS was run for the 12 months from November 2019 to October 2020. Data from the

monthly version of RIAMS, along with the daily gas load projection from the DGLM, was passed to the daily version of RIAMS, which was used to project the utilization of California's gas pipelines and storage facilities for each day of January 2020. Of particular interest is the RIAMS solution for the peak day of January, which is typically the highest demand day of the year in California. If California's natural gas infrastructure is not capable of meeting changes in gas load caused by variations in renewable generation, deficiencies in the infrastructure would show up on the peak gas demand day.

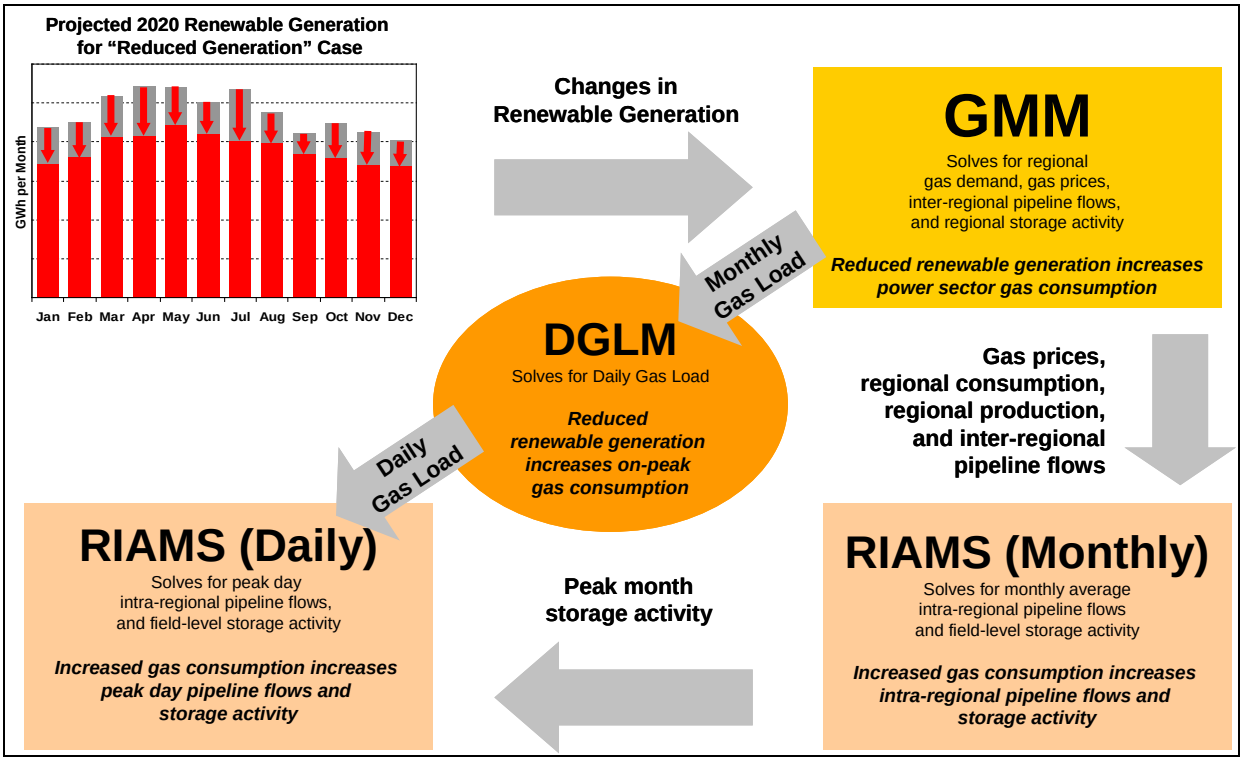


Figure 51: Modeling of Renewable Generation Cases

Source: ICF International

3.3.1 Common Assumptions in All Cases

The earlier temperature/hydroelectric modeling work performed under this contract was based on ICF's January 2008 Base Case. ICF updates its gas market Base Case projection each month to reflect recent developments in the gas market, so we adopted our January 2009 Base Case as the starting point for the renewables analysis. The January 2009 Base Case projection includes historical macroeconomic inputs for 2008 (which are lower than our January 2008 projection) and our latest macroeconomic projection, which assumes a recession lasting through the end of 2009. The recession reduces demand for natural gas over the next year, but United States GDP growth returns to the long-run expected average of 3.0 percent per year by 2010. The January 2009 Base Case also includes ICF's most recent reconnaissance on natural gas pipeline and storage additions throughout North America.

Assumptions for the United States Natural Gas Market

Annual gas consumption in the United States is expected to increase by 2.2 Tcf by 2020, as shown in Table 15. Most of the increase in United States gas consumption is due to increased gas demand for electricity generation. Over the same period, net exports to Mexico are expected to increase by 0.4 Tcf per year, yielding an increase in total annual demand of 2.6 Tcf.

Most of the increase in United States gas supply comes from domestic production, which is projected to increase by 2.3 Tcf. Gas production increases are concentrated in the Rockies, Mid-continent shales, and Marcellus Shale. Net LNG imports are also up by 1.2 Tcf, which more than offsets the 0.9 Tcf decline in net imports from Canada.

Obviously, California benefits directly from growing gas production in the Rockies, as more gas will be available on Kern River Pipeline, and the new Ruby Pipeline will allow additional supplies from the Rockies to flow west. But California also benefits indirectly from increasing production east of the Rockies in areas such as the Mid-continent shales. Increasing production east of the Rockies means more natural gas from Texas could be available to markets in the West.

Table 15: United States Natural Gas Supply and Demand through 2020

U.S. Natural Gas Balance, Bcf per Year	2007	2008	2009	2010	2015	2020	2008-20 Delta	2008-20 CAGR
Total Consumption	23,189	22,996	22,703	22,405	24,675	25,175	2,179	0.8%
+ Net Storage Injections (+) or Withdrawals (-)	(177)	(43)	172	(88)	(153)	87	130	n/a
+ Net Exports to Mexico	277	357	409	298	536	759	402	6.5%
Total Demand	23,289	23,310	23,284	22,615	25,058	26,021	2,711	0.9%
Total Production	19,875	20,503	20,621	19,489	22,331	22,815	2,312	0.9%
+ Net LNG Imports	702	287	324	1,002	1,050	1,524	1,237	14.9%
+ Net Imports from Canada	3,062	2,827	2,588	2,324	1,912	1,890	(937)	-3.3%
Total Supply	23,639	23,617	23,533	22,816	25,293	26,230	2,613	0.9%
Balancing Item*	350	307	249	201	235	209	(97)	-3.1%

* Total Supply less Total Demand; also referred to as unaccounted for gas.

Source: ICF International

Assumptions for California's Electric Power Sector

For the cases used in the renewables analysis, we modified some of the model input assumptions to be consistent with other Energy Commission assumptions about California's electricity market. In renewables cases, California's electricity demand growth rate is consistent

with the Energy Commission's 2007 projection of 1.1 percent per year growth through 2020.[33] We used the Energy Commission's 2007 load growth projection because the updated projection was still being developed when we were conducting this study. Because of the 2008-2009 Recession, electricity demand in the Base Case does not match the Energy Commission's 2007 projection for every year, but it does match the average long-run growth rate and the total level of electricity demand reached by 2020.

We also modify the ICF Base Case assumptions for renewable generation growth so it would be consistent with the 33 percent RPS standard. Using the Energy Commission's 2007 load projection, ICF estimates that net energy for load would be 353 TWh in 2020, and retail electricity sales would be 309 TWh. To meet a 33 percent RPS, California would have to generate or import a total of 103 TWh of electricity from qualified renewable generators in 2020. Both Cases 1 and 2 assume there is 103 TWh of renewable generation in 2020, while the other three cases assumed reduced levels of renewable generation.

All three of the CPUC's 33 percent RPS scenarios reach 103 TWh of RPS generation by 2020, but each has a unique mix of technologies, as shown in Table 16.[34] The Reference scenario assumes that wind generation provides about 37 percent of RPS generation, with 25 percent coming from solar technologies, and the remaining 38 percent coming from other technologies (biogas, biomass, geothermal and small hydroelectric). The High Wind scenario assumes that wind makes up 47 percent of RPS generation, solar technologies 12 percent, and other technologies 41 percent. The Solar scenario assumes that solar technologies make up 26 percent of RPS generation, wind 36 percent, and other technologies 38 percent.

Table 16: Expected Renewable Generation by 2020 for Each 33% RPS Scenario

Generation in GWh per Year	2008 Base Generation*	Reference Incremental Increase	Reference Total Generation	High Wind Incremental Increase	High Wind Total Generation	Solar Incremental Increase	Solar Total Generation
Wind	5,724	32,685	38,409	42,849	48,573	31,057	36,781
Solar (PV and Thermal)	724	24,815	25,539	11,448	12,172	26,383	27,107
Biomass	5,696	3,050	8,746	4,756	10,452	3,110	8,806
Biogas	-	2,078	2,078	2,078	2,078	2,078	2,078
Geothermal	12,951	11,520	24,471	13,034	25,985	11,520	24,471
Small Hydro	3,761	116	3,877	100	3,861	116	3,877
Total RPS Generation	28,856	74,264	103,120	74,264	103,120	74,264	103,120

* 2008 Base Generation - http://energyalmanac.ca.gov/electricity/total_system_power.html

Source: ICF International

[33] *California Energy Demand 2008 - 2018*: Staff Revised Forecast, CEC-200-2007-015-SF2. Forecast extended to 2020 by Energy Commission staff.

[34] The incremental increases for each of the scenarios shown in Table 16 are slightly different from those shown in the CPUC presentation, which totaled 74,650 GWh for each case. For this study, the increases in each type of generation were scaled down slightly so the expected level of RPS generation in 2020 in each scenario would total exactly one-third of electricity sales.

As of 2009, California has over 370 gas-fueled electric generating facilities with a total capacity of 40 GW.[35] About 52 percent of the existing gas-fueled capacity is located in southern California, 33 percent in northern California, and 15 percent in central California, as shown in Figure 52. In all the renewable cases, gas-fueled capacity is expected to increase by 3 GW to 43 GW by 2020, with about two-thirds of the new capacity being combustion turbines to serve peak-demand needs. The additions of new capacity are assumed to be distributed within the State roughly in proportion to the location of existing gas-fueled capacity.

In all our cases, ICF assumes that new regulations on water discharge from plants using once-through cooling will not have any significant impact on power sector gas demand in California. It is unlikely that new regulations would force the retirement of nuclear plants, and any gas-fired plants that may be retired would likely be replaced with new gas-fired capacity, which would cause very little net change in gas consumption.

[35] Nearly all these units use natural gas exclusively, but a small number (less than 2%) are dual-fueled (oil and gas) units. New capacity additions are expected to operate on gas only.

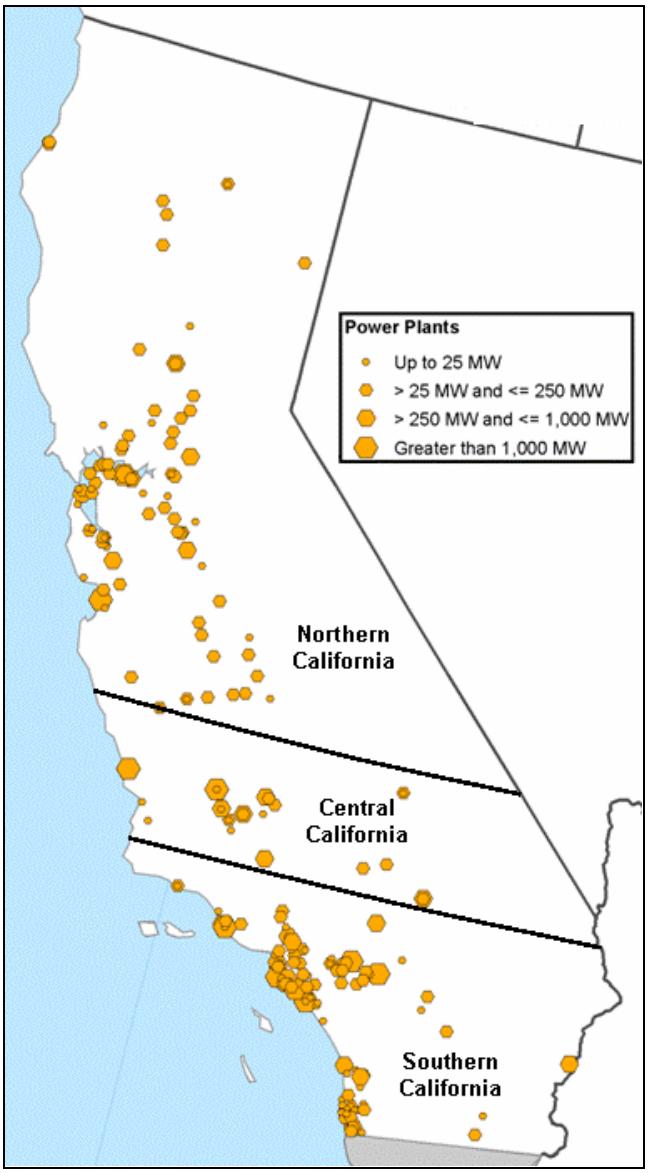


Figure 52: Existing Gas-fueled Electric Power Plants in California

Source: ICF International, based on California Energy Commission database of existing power plants

Assumptions for California's Natural Gas Infrastructure

All cases used in the renewables analysis used the same assumptions for North American gas pipeline and storage capacity. ICF's assumptions for current and projected changes to natural gas infrastructure are based on publicly available information, such as pipeline bulletin boards, FERC filings, trade publications, and press releases. The Energy Commission has reviewed our assumptions that have a direct impact on California's gas infrastructure and did not provided any information to the contrary.

Maps outlining our assumptions for central/southern and northern California's natural gas infrastructure are shown in Figure 53 and Figure 54, respectively. Southern/Central California has 7.6 Bcfd of in-bound pipeline capacity on interstate pipelines, and about 130 Bcf of storage capacity with a maximum withdrawal capability of 3,200 million cubic feet per day (MMcfd).

Based on announce plans, we assume that two compression and looping expansions on Kern River Pipeline in 2010 and 2011 will increase capacity on Kern's mainline by a total of 411 MMcfd. These expansions are concentrated on the northern half of Kern's system. While they will increase the amount of gas available to the California market, they will not directly increase capacity crossing the California/Nevada border.

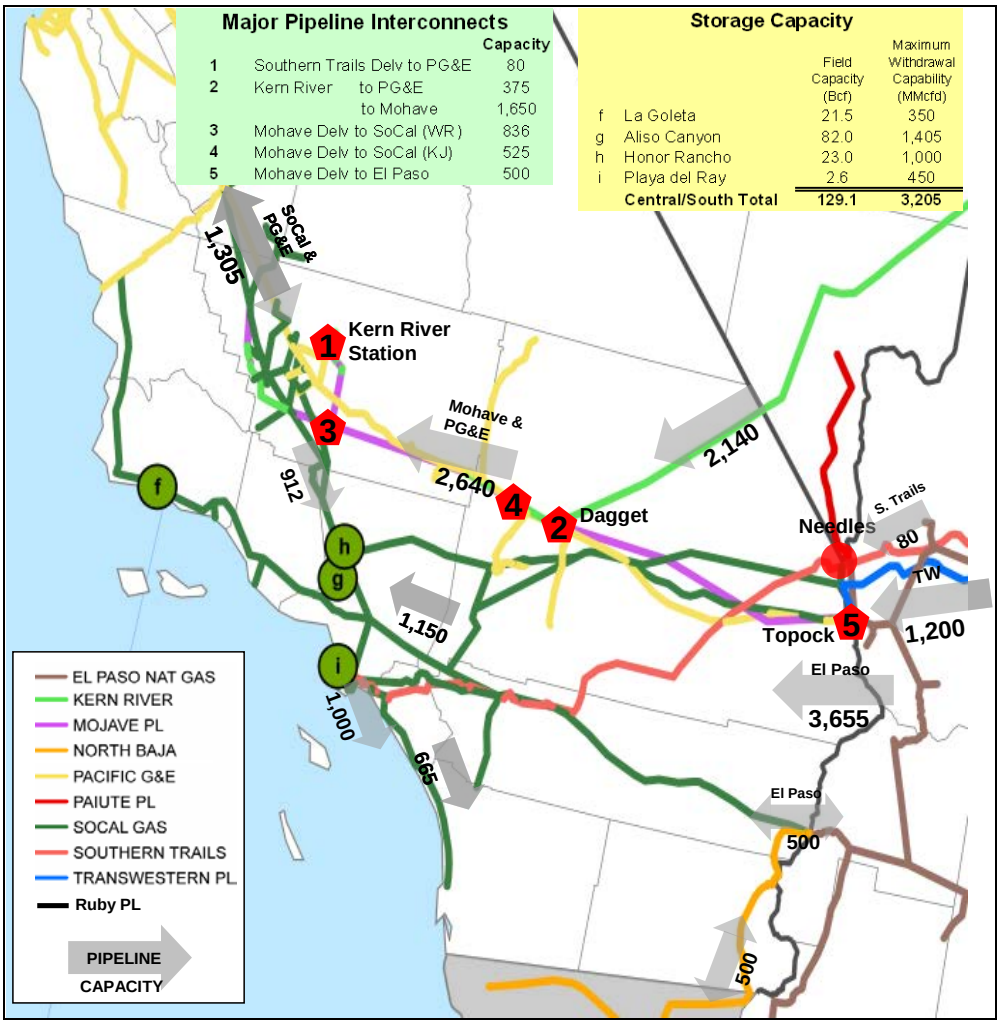


Figure 53: Central/Southern California Natural Gas Infrastructure in 2020

Source: ICF International, based on publicly available information

Though not technically part of southern California's natural gas infrastructure, the Costa Azul LNG terminal in Baja, Mexico will benefit the State indirectly. Costa Azul began operation in 2008 with a receipt capacity of 1 Bcfd. Because of an apparent lack of firmly committed supplies, ICF projects that LNG imports at Costa Azul are likely to be far less than the facility's capacity. In all the renewable cases, Costa Azul imports average about 0.45 Bcfd in 2020. While the facility is not expected to provide much gas for export to the United States, it still helps the California gas market by displacing demand for United States gas exports to Mexico.

In Northern California, PG&E has over 2 Bcfd of receipt capability at the Malin border crossing. The new Ruby Pipeline, scheduled for 2011, will provide an additional 1.3 Bcfd of pipeline capacity from Opal to Malin. A planned 42-inch line connecting Ruby to PG&E will provide additional capacity crossing the California/Oregon border, but at this time there are no publicly announced plans for additional capacity expansions on PG&E's system.

There are also two new storage fields and one field expansion planned by 2011 for Northern California. Sacramento Natural Gas Storage is scheduled to begin operation in 2010 with a working gas capacity of 7 Bcf and maximum withdrawal capacity of 200 MMcfd. Gill Ranch is scheduled to begin operation in 2011 with a working gas capacity of 20 Bcf and maximum withdrawal capacity of 300 MMcfd. Kirby Hills is scheduled to expand its working gas capacity by 6.5 Bcf to 12 Bcf in 2011; maximum withdrawal capacity will increase from 50 to 100 MMcfd. Including these expansions, Northern California's storage working gas capacity will total nearly 180 Bcf by 2020, with a maximum withdrawal capability of over 3,200 MMcfd.

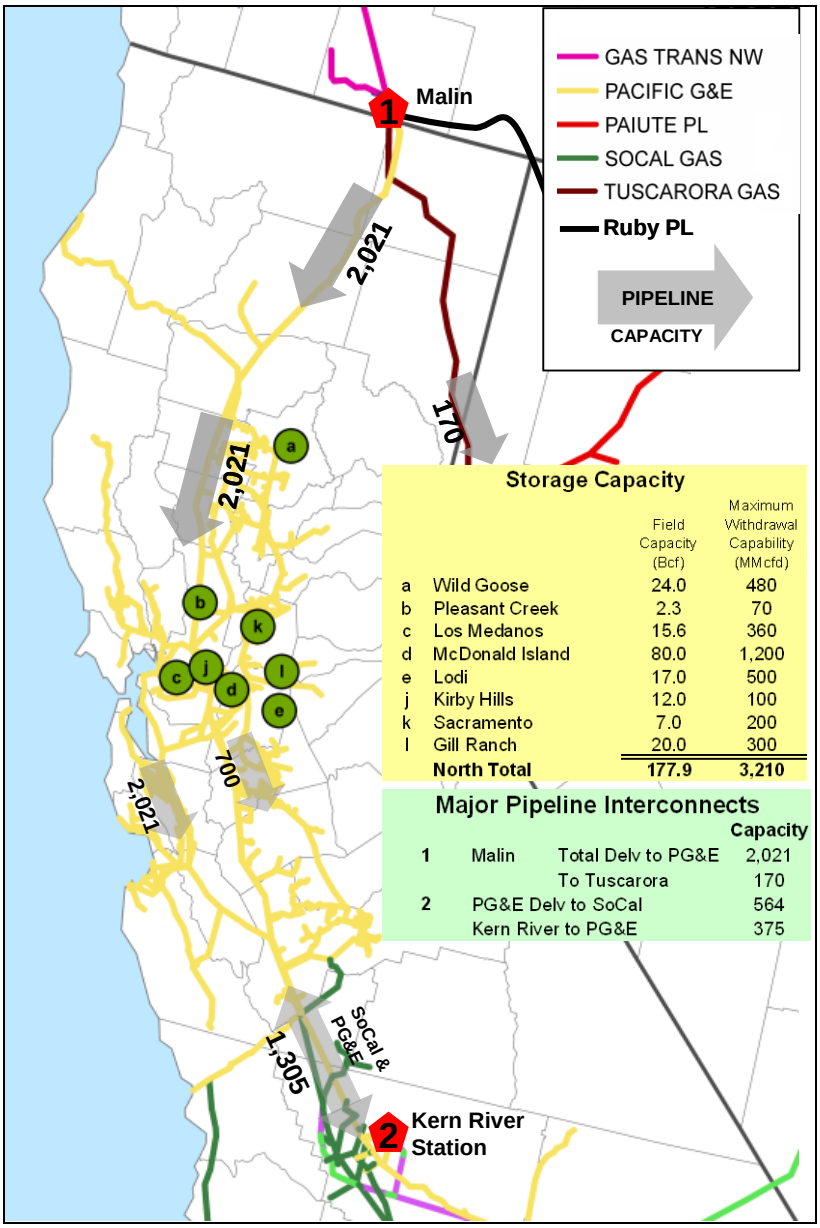


Figure 54: Northern California Natural Gas Infrastructure in 2020

Source: ICF International, based on publicly available information

3.4 Methodology for Constructing the Renewable Generation Cases

At the time this study was being conducted, the Energy Commission had not developed any independent estimates for the seasonal patterns in RPS generation or potential reductions in RPS generation due to variability in weather. Therefore, ICF developed its own estimates for the seasonality and potential reductions in RPS generation, which were applied to the 2020 RPS generation targets derived from the CPUC scenarios. ICF provided its estimates to Commission staff for review in March 2009, and there were no changes recommended.

3.4.1 Assumptions for Wind Generation

Monthly wind generation profiles are based on NREL wind shape files that were provided to ICF by Energy Commission staff. The National Renewable Energy Laboratory (NREL) data includes hourly wind generation for each region of California for the years 2004, 2005 and 2006. This data has been used to determine the percentage of the total annual wind generation assigned in each month of the year to each area within California. The NREL wind shape data was also used to determine the distribution of daily wind generation for the month of January, which is the peak month for natural gas demand.

For purposes of determining where wind generation would be located, California is divided into three areas: Northern (above 36 degrees latitude), Central (between 34.75 degrees and 36 degrees latitude), and Southern (below 34.75 degrees latitude). These areas roughly correspond to both the GMM's California gas demand regions and regional division in the NREL wind data.

Under the Reference RPS scenarios (as used in Case 1), the expected annual wind generation in 2020 is 38,409 gigawatt-hours (GWh). Based on the NREL data, a portion of the annual generation was assigned to each month, as shown in Figure 55. For the State as a whole, monthly wind generation ranges from a high of 4 TWh (40 percent capacity utilization) in May to a low of 2.5 TWh (25 percent capacity utilization) in September.

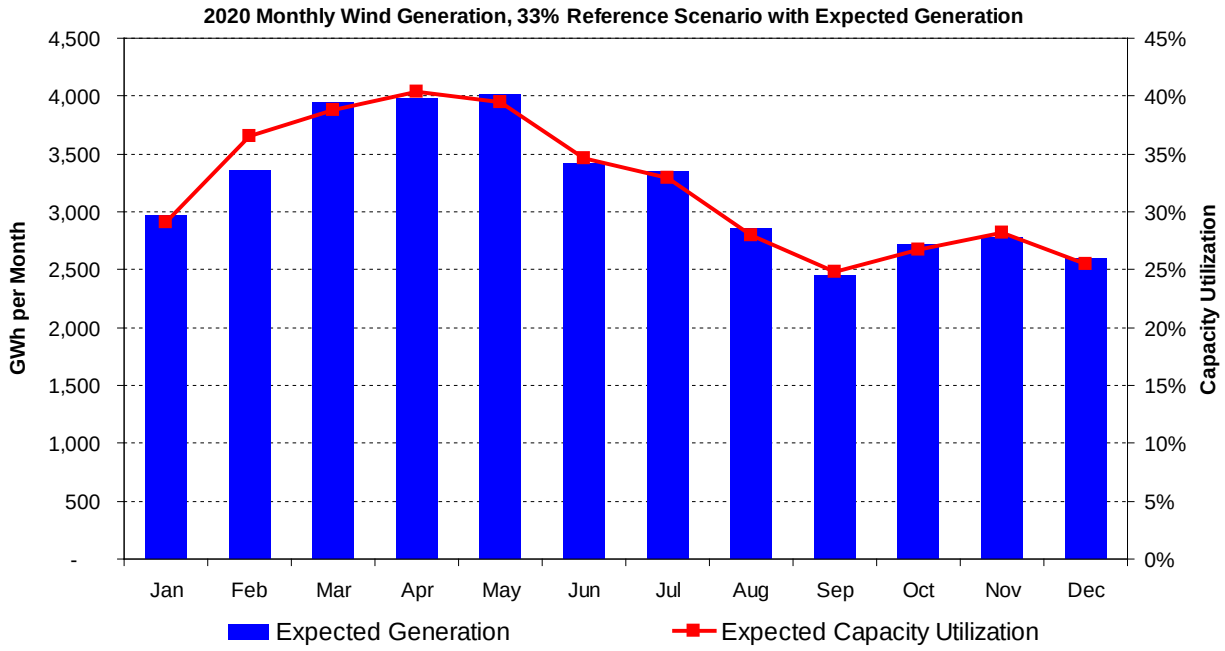


Figure 55: Example of Monthly Wind Generation in 2020

Source: ICF International

Daily wind generation in January 2020 is shown in Figure 56. For the month of January, daily generation ranges from a low of 30 GWh (9 percent capacity utilization) to a high of 153 GWh (47 percent capacity utilization. This is the range of daily values for the State as a whole, summed across all regions for each calendar day. Regionally, daily capacity utilization for January ranges from a low of 6 percent to a high of 57 percent.

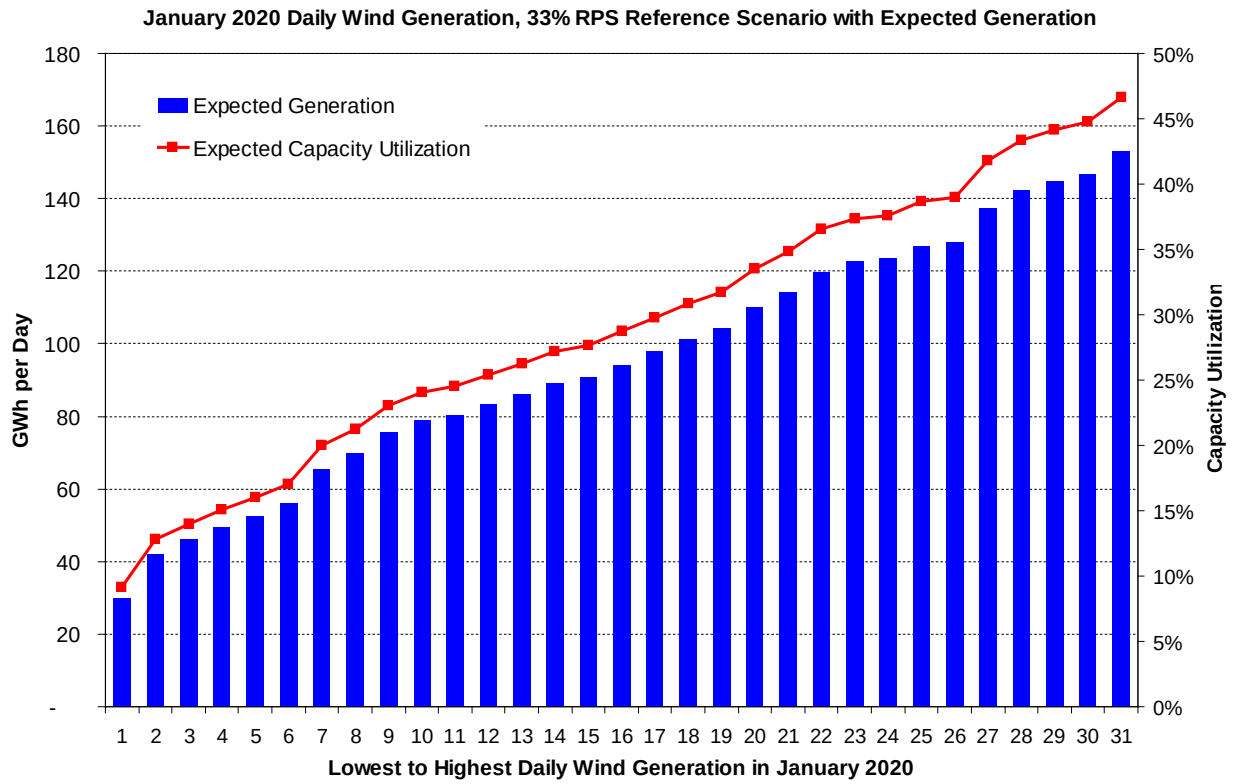


Figure 56: Example of Daily Wind Generation in 2020

Source: ICF International

Estimates for reduced wind generation are based on 20 to 30 years[36] of daily average wind speed data from the National Oceanic and Atmospheric Administration's (NOAA) National Climate Data Center for 12 weather stations throughout the State (six in northern California, two in central California, and four in southern California). For each weather station, NOAA reports average daily wind speed, to which ICF applied a wind power function to arrive at estimated potential generation for turbines located in that area of California.[37]

To estimate what the generation would be in a low wind year, ICF summed the potential wind generation across all areas of the State for each year of historic data and picked the lowest coincidental historical year. We chose this approach, rather than summing minimum levels of generation from different years for each area would exaggerate the degree of variability in

[36] The number of years of data available varies by weather station.

[37] Since the weather station anemometers are usually at a height of only 10 meters above the surrounding terrain, ICF applied an adjustment factor of 1.4 to the reported wind speed to arrive at an estimated wind speed at 100 meters, which is a typical hub height for a large wind turbine.

generation, since low average wind speeds in one area of the state may be offset by higher wind speeds in another. Based on the historical wind speed data, ICF estimated that in a low wind year, total annual wind generation could be as much as 24 percent below the expected annual generation.

An example of the reduced level of wind generation used for the Reference Scenario with Reduced Generation (Case 3) is shown in Figure 57. For the year in total, wind generation in the reduced case is 24 percent below expected level. July has the greatest reduction in wind generation, with the estimated low being 37 percent (or about 1,200 GWh) below the expected level of generation. In January, wind generation in the reduced case is 25 percent below the expected level of generation.

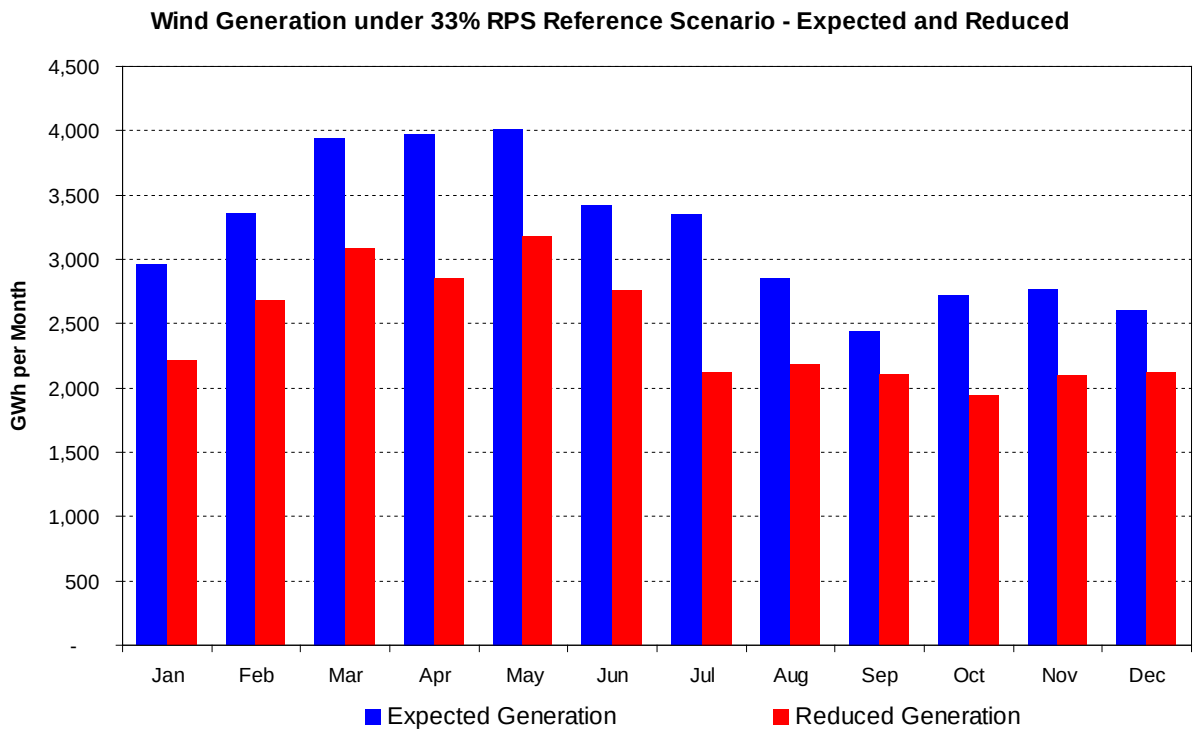


Figure 57: Example of Expected versus Reduced Monthly Wind Generation

Source: ICF International

To arrive at reduced daily generation values for January, we applied the percentage reduction in monthly generation (25 percent) to all days of the month as shown in Figure 58. Under the 33 percent Reference Scenario with Reduced Generation (Case 3), wind generation is only 20 GWh on the lowest wind generation day in January. When running the Reduced Generation cases, we assume a "stress" scenario, in which the lowest wind generation day in January occurs on the highest gas demand day in January. This increases peak day gas demand during the highest gas demand month of the year.

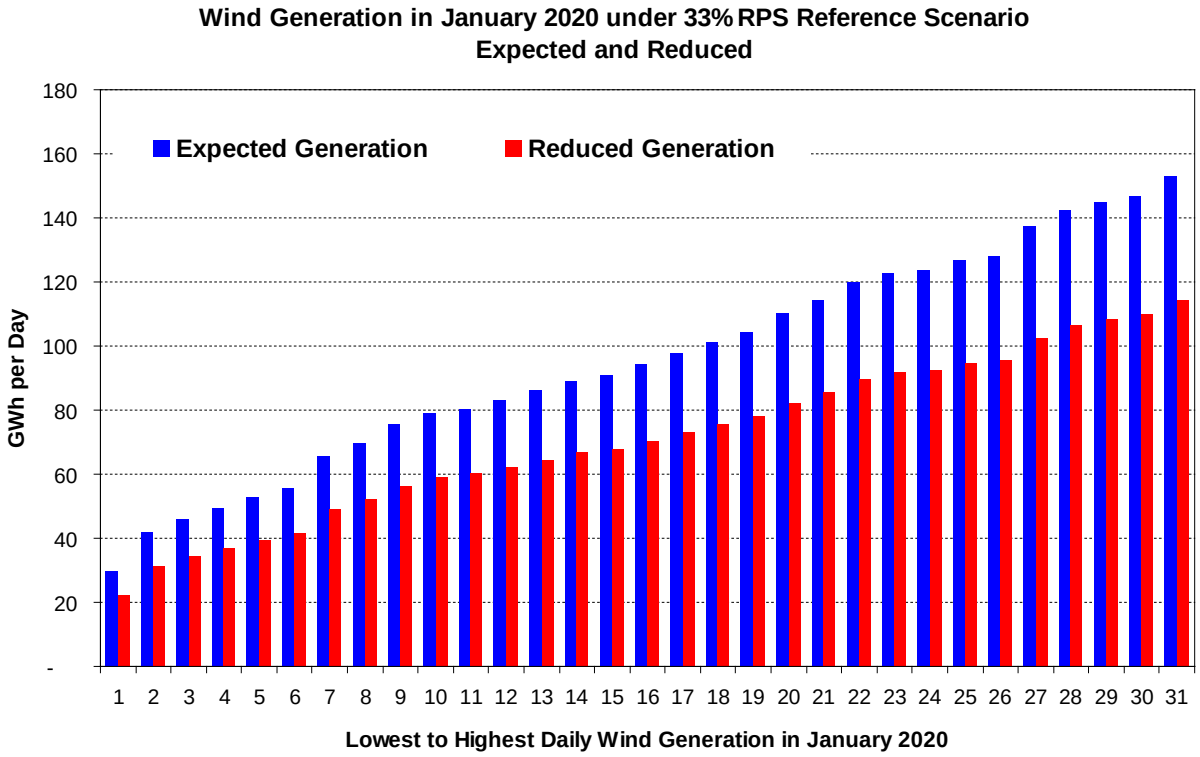


Figure 58: Example of Expected versus Reduced Daily Wind Generation

Source: ICF International

3.4.2 Assumptions for Solar Generation

Assumptions for solar generation were based on 30 years of NREL data on solar radiation for six weather stations in Southern California.[38] The NREL data reports average daily solar radiation each month for the years 1961 to 1990; it does not include any data on daily variability within each month. Since the vast majority of California's solar resource is located below 34.75 degrees latitude, for modeling purposes ICF assumed all solar generation is located in Southern California.

This data has been used to determine how much of the total annual generation should be assigned to each month of the year and the potential reductions in solar generation. Solar thermal and PV generation are assumed to have the same seasonal pattern and variability in generation. Minimum generation levels are based on the observed annual minimums in the historical solar radiation data across all six weather stations. The daily generation profile for January 2020 is based on the assumption that solar generation is distributed normally within the month.

Seasonally, California's solar generation potential is typically highest in the summer and lowest in winter, as shown in Figure 59. In Case 1 (Reference 33 percent RPS scenario with expected

[38] National Solar Radiation Data Base (1961-1990), prepared by the National Renewable Energy Laboratory, 1617 Cole Blvd., Golden, Colorado, 80401.

generation), monthly solar generation ranges from a high of 2.7 TWh (33 percent capacity utilization) to a low of 1.5 TWh (18 percent capacity utilization). Since we have assumed all solar generation is located in Southern California, this distribution applies to both the region and the State as a whole.

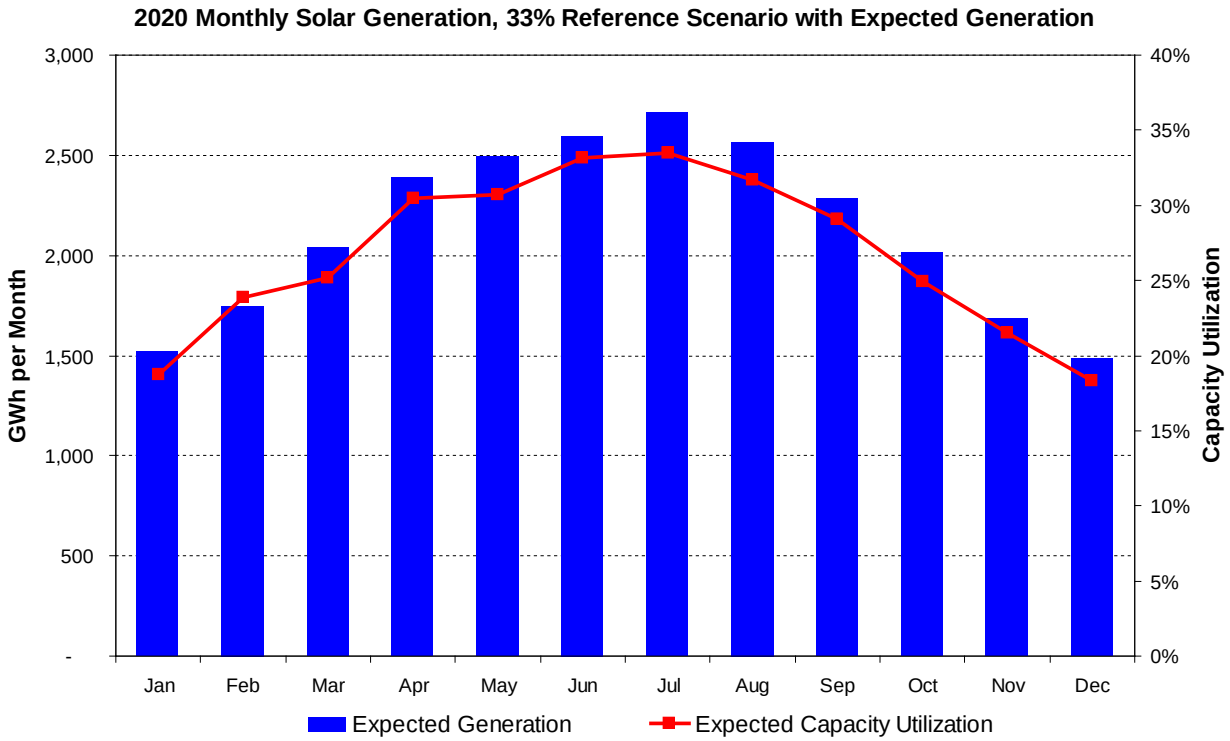


Figure 59: Example of Monthly Solar Generation in 2020

Source: ICF International

To arrive at a daily pattern for solar generation in January 2020, we assumed that the total generation for January was distributed normally across the days of the month, as shown in Figure 60. As with the monthly variability, we also assume that solar thermal and PV have the same daily variability. For Case 1, daily solar generation in January 2020 is assumed to range from a low of 8 GWh (3 percent capacity utilization) to a high of 98 GWh (38 percent capacity utilization).

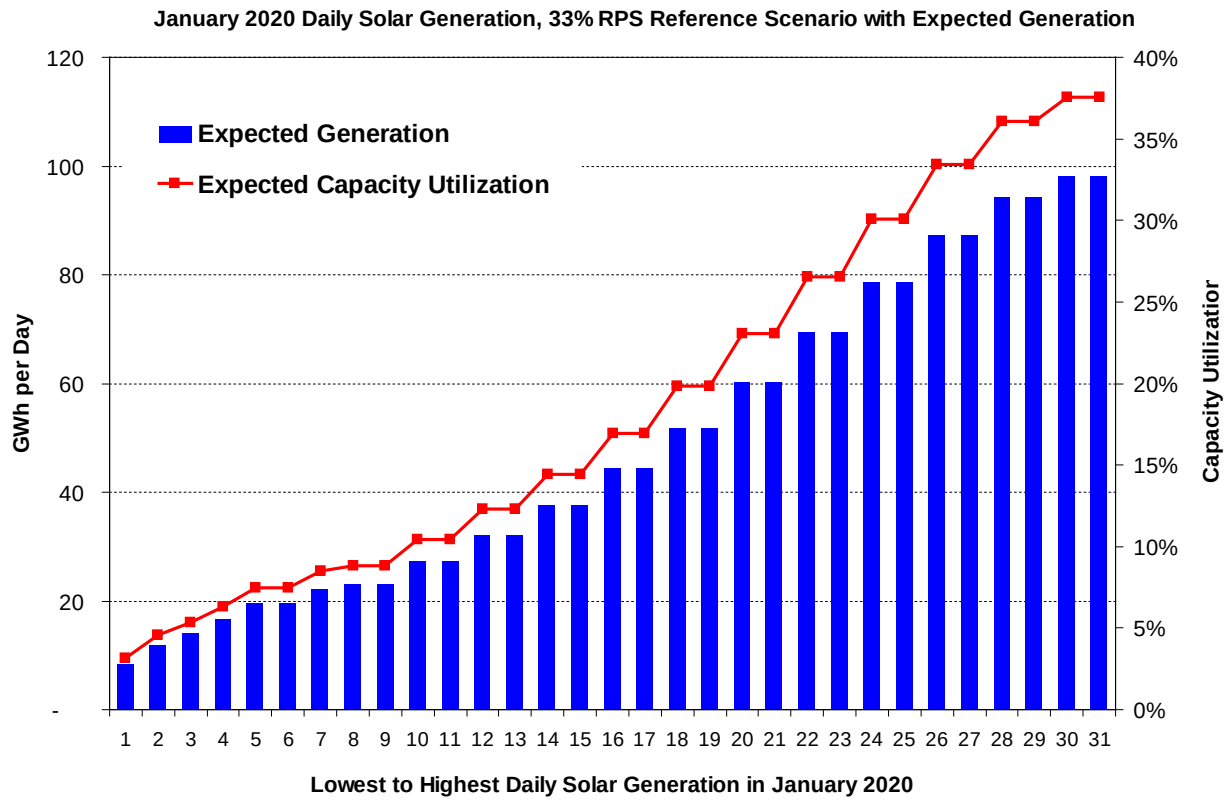


Figure 60: Example of Daily Solar Generation in 2020

Source: ICF International

Based on the historic solar radiation data, we estimate that in a low solar year total annual solar generation could be as much as 8 percent below the expected annual generation. This is based on the lowest observed annual solar radiation levels across Southern California for the 30 years from 1961 through 1990. Solar generation is most variable in the winter months, with the estimated low for January being 13 percent below the expected level of generation, as shown in Figure 61. In the Reference Case with Reduced Generation (Case 3), solar generation in January 2020 is 200 GWh below the expected monthly total.

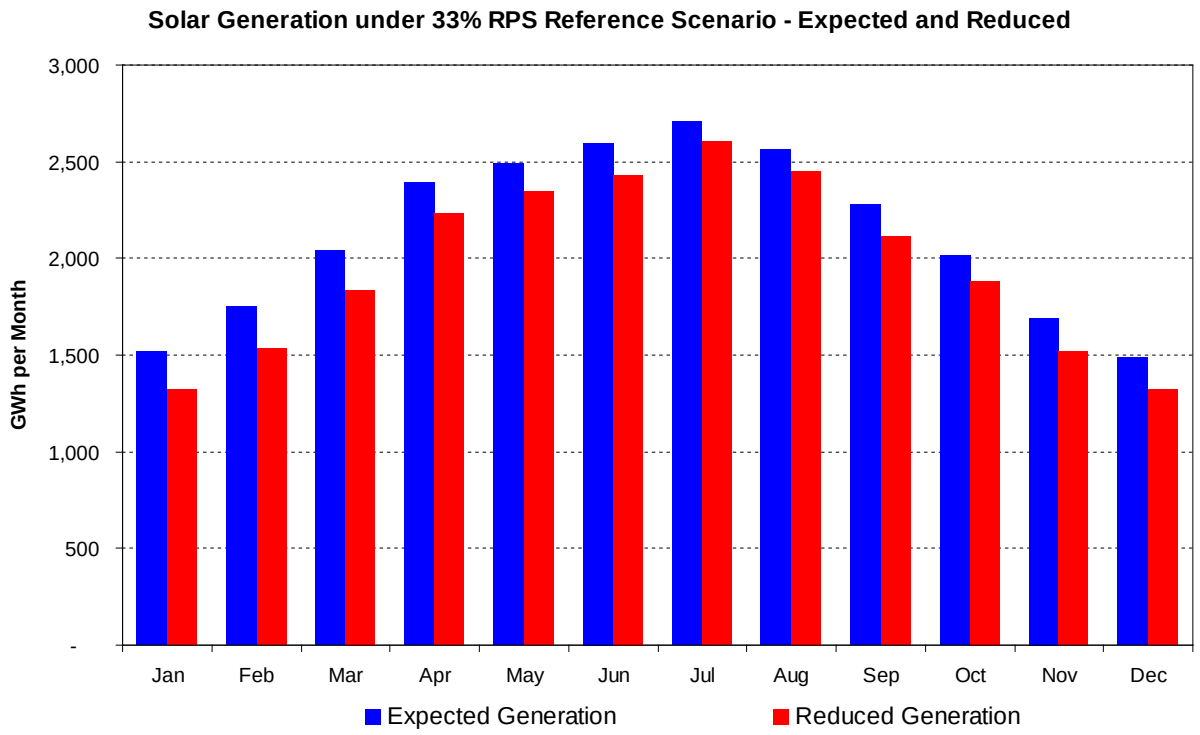


Figure 61: Example of Expected versus Reduced Monthly Solar Generation

Source: ICF International

To arrive at the reduced daily solar generation values for January, we have applied the percentage reduction in monthly generation (13 percent) to all days of the month, as shown in Figure 62. In the Reference Case with Reduced Generation (Case 3), solar generation is only 7 GWh on the lowest day of January. For all the Reduced Generation cases, we assume a "stress" scenario, in which the lowest solar generation day in January occurs on the highest gas demand day in January. This increases peak day gas demand during the highest gas demand month of the year.

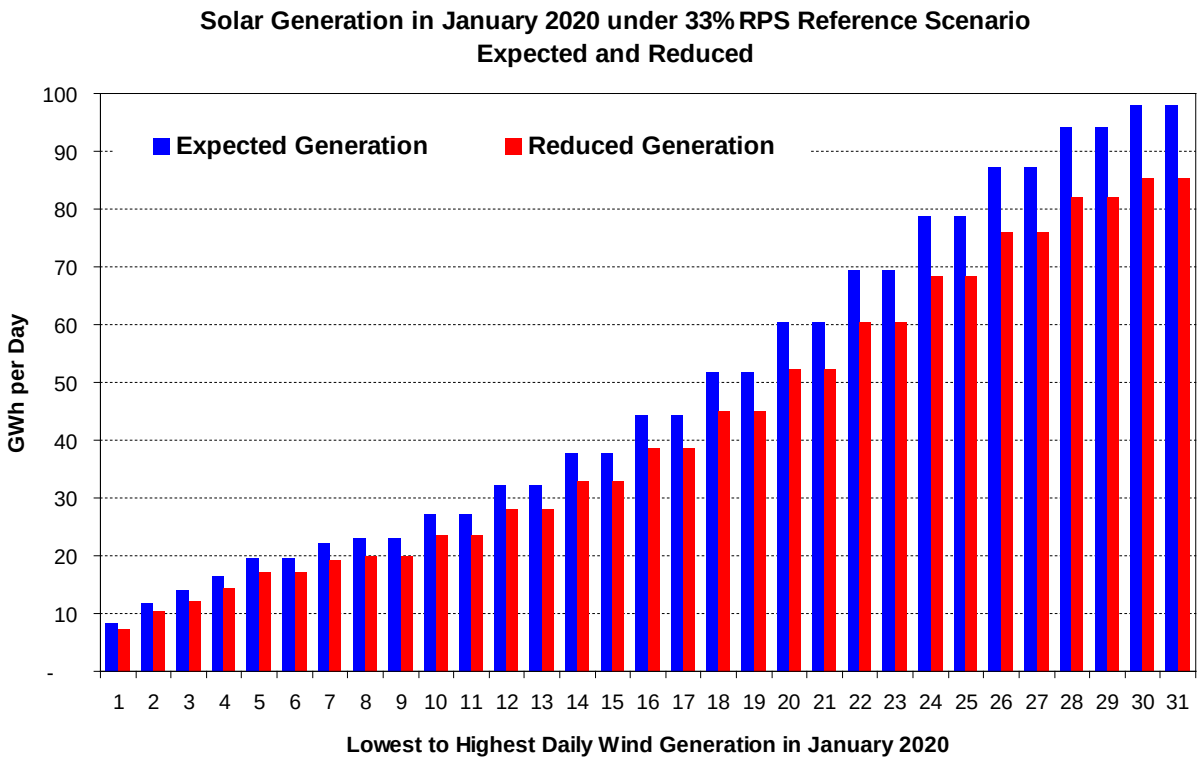


Figure 62: Example of Expected versus Reduced Daily Solar Generation

Source: ICF International

3.4.3 Assumptions for Biomass, Biogas, Geothermal, and Small Hydroelectric Generation

Unlike wind and solar technologies, biomass, biogas, and geothermal generation do not vary with changing weather conditions. Therefore, we have assumed that the annual generation from these technologies is evenly distributed throughout the year, and that there is no variation from the expected level of generation in the reduced generation cases.

As a simplifying assumption, we have also kept small hydroelectric generation constant throughout the year. Small hydroelectric generation comprises only about 4 percent of the 2020 RPS generation total and less than 0.3 percent of the incremental increase in renewable generation through 2020. Variation in large hydroelectric generation, which makes up a much greater percentage of California's total electricity supply, is considered with the assumption of adverse temperature/hydroelectric conditions in Cases 2 through 5.

3.4.4 Assumed Reductions in Renewable Generation

For the reduced generation cases, total annual wind generation has been reduced by 24 percent and total annual solar generation has been reduced by 8 percent, compared to the expected values for each scenario, as shown in Table 17. As discussed above, biomass, biogas, geothermal, and small hydroelectric generation are all assumed to be constant. In total, annual RPS generation was reduced by between 10 percent and 12 percent, depending on the scenario.

Table 17: Reduced Renewable Generation by 2020 for Each 33% Scenario

	Reference		High Wind		Solar	
	GWh	% Reduction	GWh	% Reduction	GWh	% Reduction
Wind	29,352	-24%	37,119	-24%	28,108	-24%
Solar (PV and Thermal)	23,594	-8%	11,245	-8%	25,043	-8%
Biomass	8,746	0%	10,452	0%	8,806	0%
Biogas	2,078	0%	2,078	0%	2,078	0%
Geothermal	24,471	0%	25,985	0%	24,471	0%
Small Hydro	3,877	0%	3,861	0%	3,877	0%
Total RPS Generation	**92,119**	**-11%**	**90,741**	**-12%**	**92,383**	**-10%**

Source: ICF International

In all the reduced generation cases, total RPS generation is lowest in the winter, when wind and solar generation are generally at their lowest levels, as shown in Figure 63. Since generation from renewable technologies other than wind and solar are assumed to be constant, all the reductions in RPS generation are due to the assumed reductions in wind and solar generation.

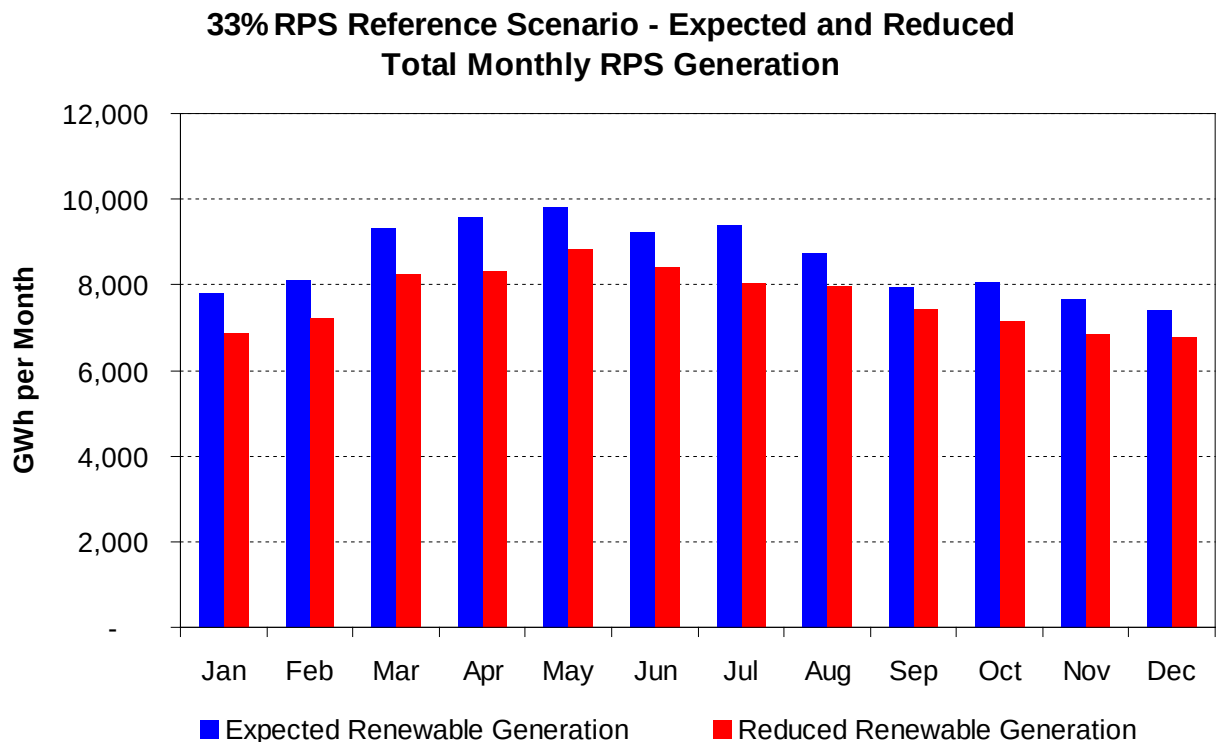


Figure 63: Example of Expected versus Reduced Monthly Total RPS Generation

Source: ICF International

3.4.5 Seasonal Impacts of Reduced Renewable Generation on Natural Gas Demand and Infrastructure

In terms of the deficit in electricity generation, the potential for a reduction in renewables is greatest in the summer. In the reduced generation cases, RPS generation in July 2020 is down by 1,300 to 1,600 GWh (14 percent to 18 percent). Assuming this deficit is replaced entirely with gas-fired generation, this would increase gas demand for power generation by an average of 0.3 to 0.4 Bcfd.

However, residential/commercial gas demand is much lower in the summer than in the winter. In Case 1 (Reference RPS with Expected Generation), residential/commercial is about 1.8 Bcfd lower in July than in January. The normal variation in seasonal residential/commercial gas load is much greater than the potential variation caused by a reduction in renewable generation. The seasonality of gas storage also makes it easier to respond to increases in power generation gas demand in the summer. Natural gas is normally injected into storage in the summer. These injections could be avoided on peak summer days, and gas could even be withdrawn if needed to meet demand. Therefore, due to normal seasonal variation in residential/commercial gas demand and the seasonality of gas storage, reductions in renewable generation have less of an impact on California's gas infrastructure in the summer months.

In contrast, reductions in RPS generation have a much greater impact on gas pipeline loads and storage withdrawals in the winter months. Due to normal seasonal variations in wind and solar generation, expected levels of RPS generation are lowest in the winter months. Also, California gas demand peaks in January, due to increased residential and commercial loads. Therefore, any reductions in renewable generation in January add additional gas demand at a time when gas demand is already at its highest. This is why we have focused the daily gas load analysis on the January peak gas demand day.

3.4.6 Assumptions for Adverse Temperatures and Hydroelectric Generation

In Case 1, we assumed that seasonal temperatures and hydroelectric generation are normal throughout the United States and Canada for all years of the projection. For temperatures, normal is defined as the average monthly heating and cooling degree days for the past 30 years (1979 to 2008). For hydroelectric generation, normal is the average monthly generation for the 25-year period 1980 to 2004. In the daily analysis, the pattern of peak month (January) temperatures is representative of average variability in January weather.

Cases 2 through 5 assume adverse temperatures (hotter summer and colder winter) and reduced hydroelectric generation in the years 2019 and 2020. This is done to test the robustness of California's gas infrastructure if the reductions in renewable generation occur during a year similar to the 2000-2001 energy crisis, when gas demand was unusually high due to the adverse temperature and hydroelectric conditions. The assumptions for adverse temperatures and hydroelectric generation are based on our earlier analysis of the impact of temperature and hydroelectric generation on natural gas storage utilization in California. For this analysis, we chose temperatures from 1957-1958 and hydroelectric generation from 2000-2001, which was the combination referred to as the "extreme" case in the temperature/hydro analysis. In the adverse

temperature/hydro cases, the changes to weather and hydroelectric generation are applied throughout the United States and Canada.

For the daily analysis, we have chosen a temperature pattern for January that includes the coldest day in California from the past 30 years of daily temperature data. In the daily analysis for the Reduced Generation cases (Case 3 through 5), we also placed the lowest renewable generation day on the coldest January day, which further increases gas demand and places additional stress on the natural gas infrastructure.

3.5 Case Results

This section details the results of the five renewable generation cases run by ICF International. For each case we provide an overview of the gas demand projections annual, seasonally, and for the January peak gas demand day, as well as an analysis of how demand is met through pipeline imports and storage withdrawals.

3.5.1 Case 1: 33 percent RPS Reference Scenario with Expected Generation and Normal Weather

Case Results Overview

Given normal weather and expected renewable generation output, California demand for natural gas is expected to decline to 5.4 Bcfd by 2020, a decrease of 900 MMcfd (Table 18). The majority of this decline is due to decreasing demand for natural gas in the power sector, where demand declines by 800 MMcfd through 2020. The decline in power sector gas demand is due to modest electric load growth coupled with the increase in renewable generation to meet the 33 percent RPS. The rest of the decline is in the residential sector, where increasing efficiency leads to a decline of 100 MMcfd by 2020. Commercial and industrial gas demands both remain relatively flat through 2020.

Table 18: California's Natural Gas Balance, Case 1

Bcfd	2008	2009	2010	2015	2019	2020	2008-20 Delta	2008-20 CAGR
Consumption	**6.29**	**5.58**	**5.69**	**5.66**	**5.44**	**5.39**	(0.9)	-1.3%
Residential	1.43	1.31	1.34	1.30	1.29	1.29	(0.1)	-0.8%
Commercial	0.67	0.66	0.66	0.65	0.65	0.66	(0.0)	-0.2%
Industrial	1.48	1.35	1.45	1.48	1.50	1.50	0.0	0.1%
Power Generation	2.58	2.13	2.11	2.10	1.86	1.81	(0.8)	-2.9%
Other	0.13	0.13	0.12	0.13	0.13	0.13	(0.0)	-0.4%
Pipeline Exports	**0.07**	**0.08**	**0.10**	**0.03**	**0.09**	**0.09**	0.0	1.6%
To Northern Nevada	0.07	0.08	0.10	0.02	0.02	0.02	(0.1)	-10.4%
To Mexico	-	-	-	0.02	0.07	0.07	0.1	n/a
Production	**0.88**	**0.87**	**0.84**	**0.83**	**0.85**	**0.85**	(0.0)	-0.4%
Pipeline Imports	**5.61**	**4.94**	**5.03**	**4.91**	**4.72**	**4.67**	(0.9)	-1.5%
via Southern Nevada (Kern River)	1.54	1.52	1.53	1.87	1.87	1.87	0.3	1.7%
via Arizona (El Paso, Transwestern)	2.82	1.93	2.01	1.84	1.60	1.58	(1.2)	-4.7%
via Malin	1.23	1.48	1.45	1.18	1.25	1.21	(0.0)	-0.2%
via Mexico (Costa Azul LNG)	0.02	-	0.04	0.02	0.00	0.01	(0.0)	-7.0%
Storage Net Injections / (Withdrawals)	**0.02**	**0.09**	**0.02**	**-**	**-**	**-**	(0.0)	-100.0%
Balancing Item	**0.11**	**0.07**	**0.06**	**0.05**	**0.04**	**0.04**	(0.1)	-8.8%

Source: ICF International

Natural gas production in California remains relatively flat through 2020, decreasing by about 30 MMcfd during the period. As a result, imports of natural gas to California decrease by about the same amount as the decrease in gas demand. Most of the declines are on the El Paso Natural Gas and Transwestern Pipeline systems, which together are down by roughly 1.2 Bcfd from 2008 to 2020. Imports along Kern River Pipeline in central California increase by about 300 MMcfd through 2020, driven by growth in gas production in the Rockies and increased pipeline capacity on the Kern River system. Imports at the Malin Interchange and from Mexico remain relatively flat throughout the projection period.

As in most of the rest of the United States, California's peak gas demand month is January (Figure 64). In Case 1, which has normal weather and expected renewable generation, California will consume an average of 6.9 Bcfd in January 2020. California's electricity demand peaks in July and August, which creates a secondary peak in gas demand due to increased demand in the power sector. However, the summer gas demand peak is much lower than the winter peak.

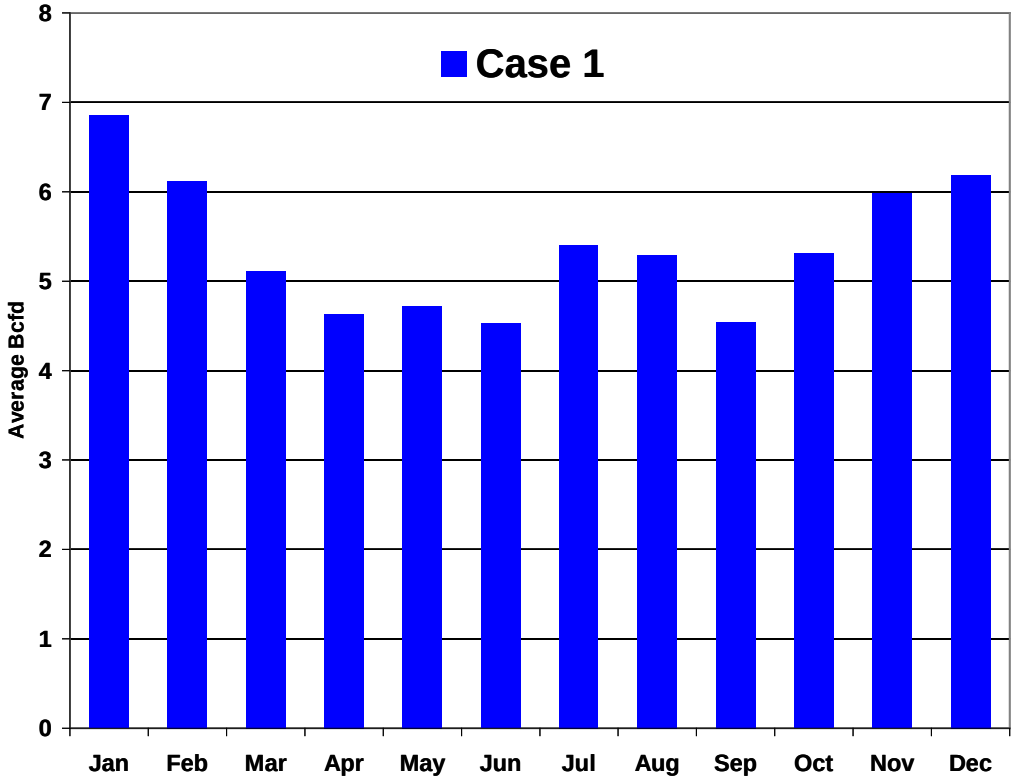


Figure 64: California Monthly Gas Consumption in 2020, Case 1

Source: ICF International

California's total storage working gas capacity is projected to be in excess of 300 Bcf by 2020. Under normal weather and hydroelectric conditions, the working gas fill level at the end of March 2020 (the end of the storage withdrawal season) is about 120 Bcf, or close about 40 percent of available capacity (Figure 65). To put this into historical perspective, during the 2000-2001 energy crisis in California, working gas levels dropped down to around 60 Bcf in February 2001 out of a total capacity of about 240 Bcf, or roughly 24 percent of working gas capacity.

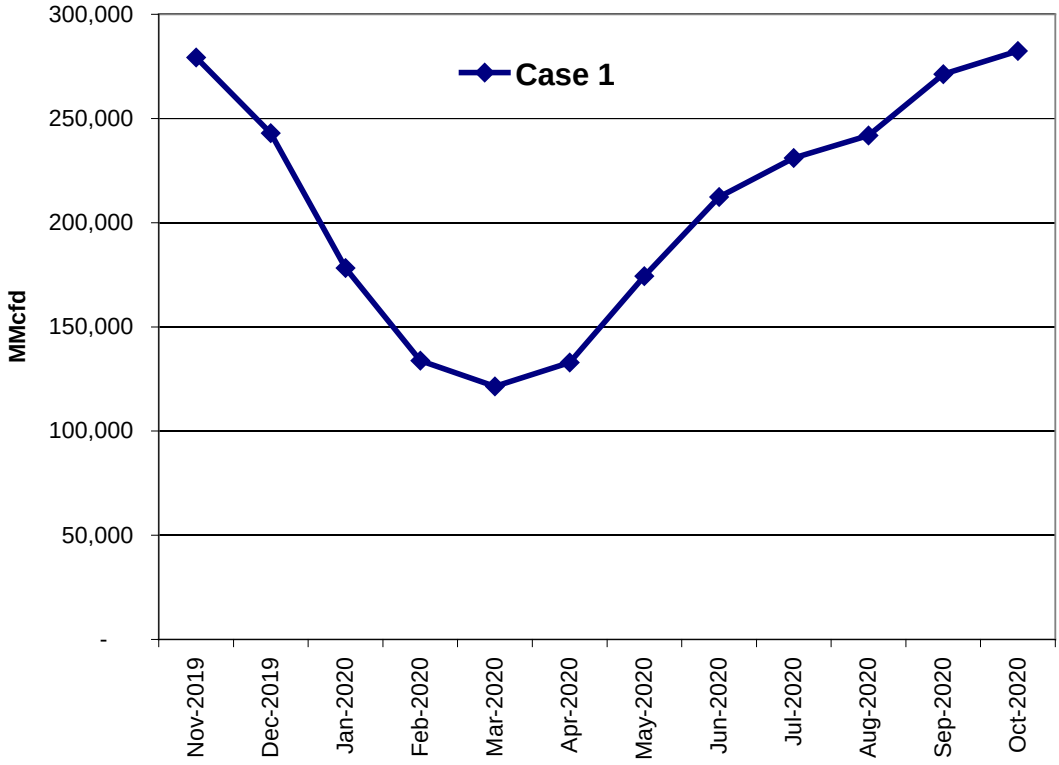


Figure 65: California Storage End-of-Month Working Gas Levels, Case 1

Source: ICF International

Peak Analysis

In Case 1, January 2020 peak gas demand day is projected to be 8.2 Bcf. The majority of the demand is in the residential/commercial sectors, which account for roughly 4.2 Bcf, or about 50 percent, of total demand for the day (Figure 66). The power sector is the next largest sector, accounting for 2.5 Bcf, or around 30 percent. The industrial sector accounts for only 1.6 Bcf, or about 20 percent, of peak day consumption.

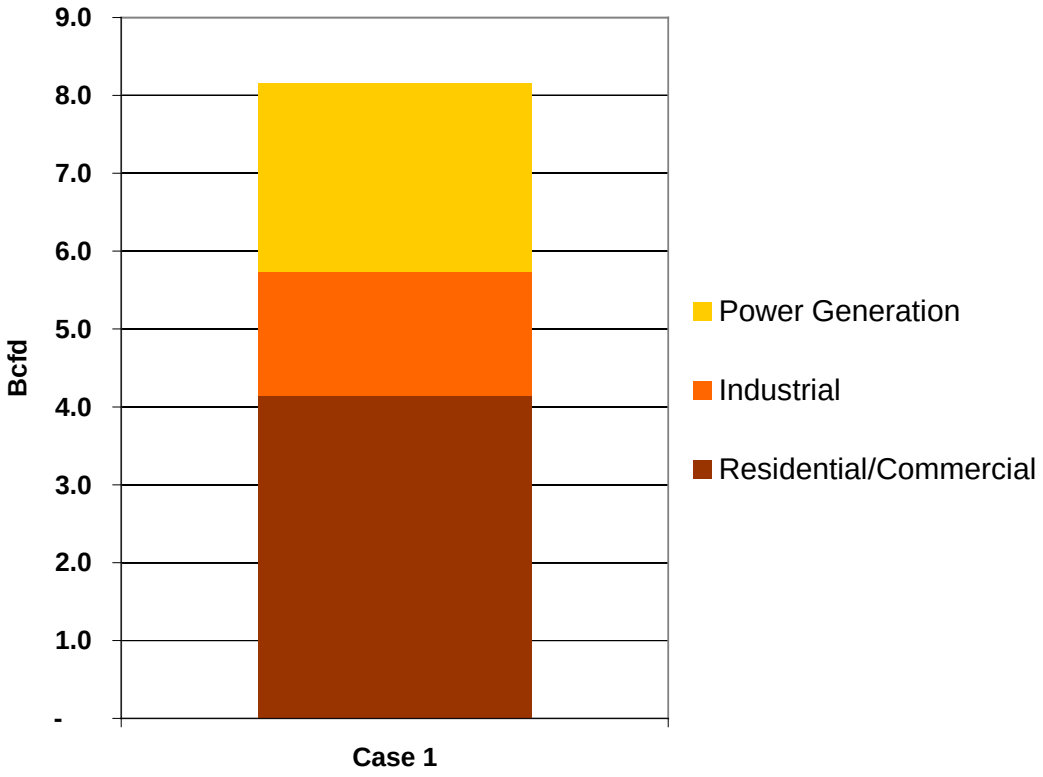


Figure 66: California January 2020 Peak Day Gas Consumption, Case 1

Source: ICF International

Most of the State's peak day demand is in Southern California. Given normal weather and expected renewable generation, Southern California consumes almost 4.1 Bcf of natural gas, or close to 50 percent of total peak daily demand for the State (Figure 67). Northern California is the second highest demand area, consuming over 2.7 Bcf of gas, or roughly 33 percent of peak day demand. Central California demand is only about 1.3 Bcf on the peak demand day.

California's peak day demand is met primarily with a combination of pipeline imports (3.8 Bcf) and natural gas storage withdrawals (3.6 Bcf). The balance, about 0.8 Bcf, is met with in-state gas production.

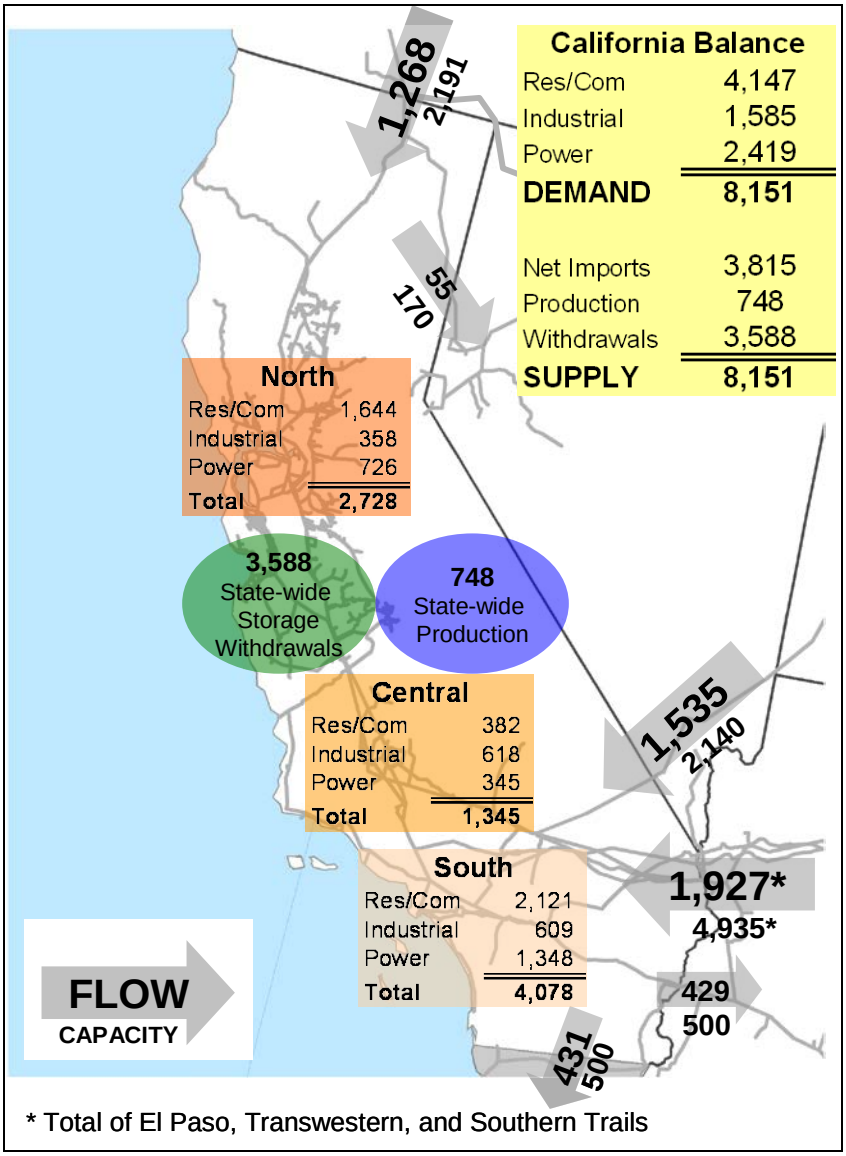


Figure 67: January 2020 Peak Day Balance (MMcfd), Case 1

Source: ICF International

In southern and central California, natural gas pipelines do not appear to be a constraining factor on supply in Case 1. Of the three major pipelines entering the area – Kern River, Transwestern, and El Paso – the highest load factor observed is on Kern River, which has a load factor of just over 70 percent on the 2020 peak demand day. In total, importing pipelines to the area have unused capacity of over 3.6 Bcf (Figure 68). Storage is also similarly unconstrained. On the peak demand day, the four storage fields in southern and central California withdraw a total of around 2.1 Bcf, or about 64 percent of total 3.2 Bcf of withdrawal capability of the four fields.

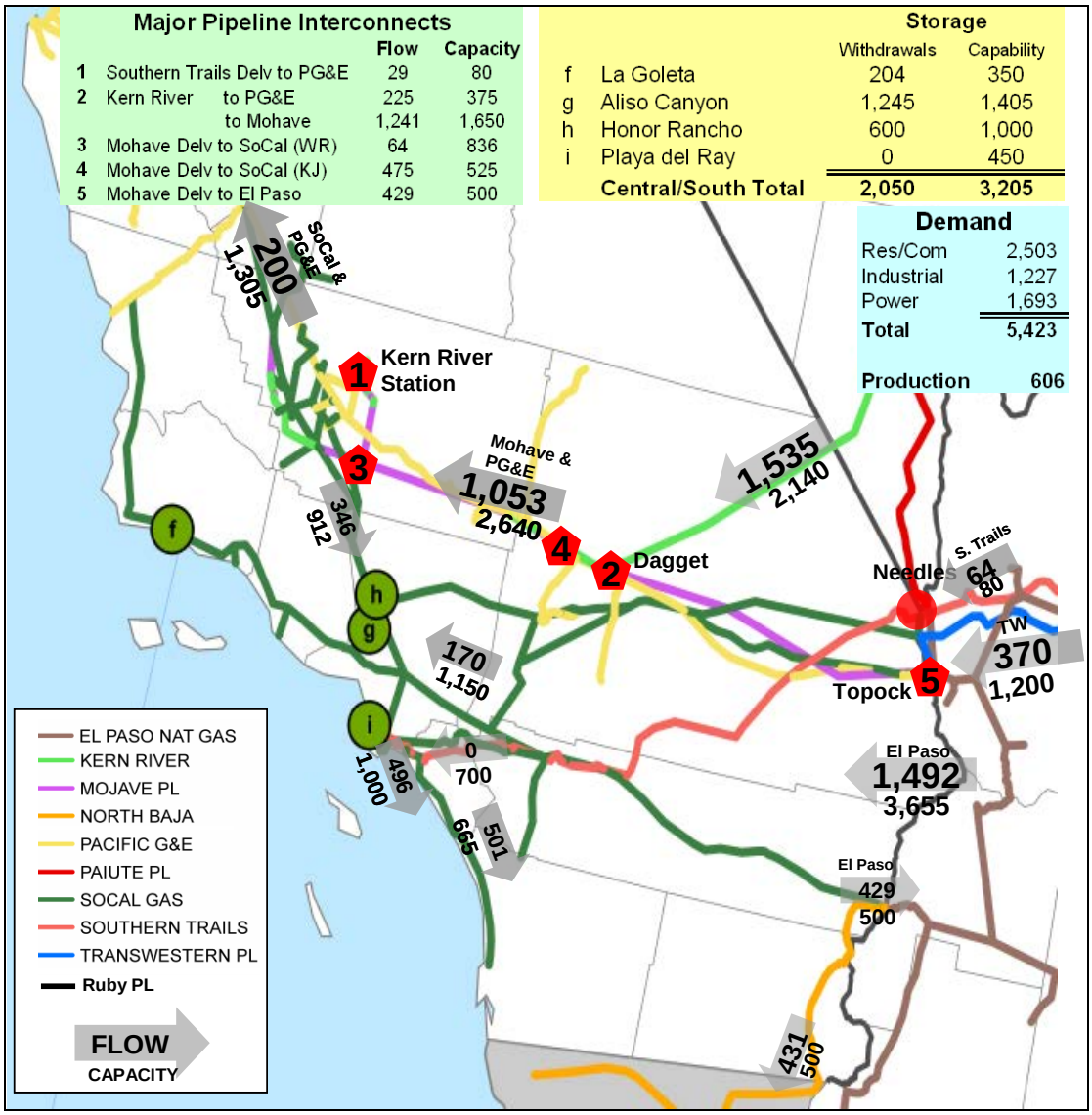


Figure 68: January 2020 Peak Day Flows in Southern/Central California (MMcfd), Case 1

Source: ICF International

Total demand in southern and central California on an average January day is about 830 MMcf lower than on a peak day. All of incremental demand is met by regional storage. Close to 950 MMcf of additional gas is withdrawn from regional storage on a peak day; about 2.1 Bcf is withdrawn from storage on a peak day while only about 1.1 Bcf is withdrawn on an average day. On the other hand, peak day pipeline imports of natural gas are almost the same, with about 140 MMcf less gas being imported than on an average day. Similarly to imports, pipeline exports on a peak day are about the same as on an average day, with a negligible amount of additional gas being export to northern California on a peak day to help fill demand in that region.

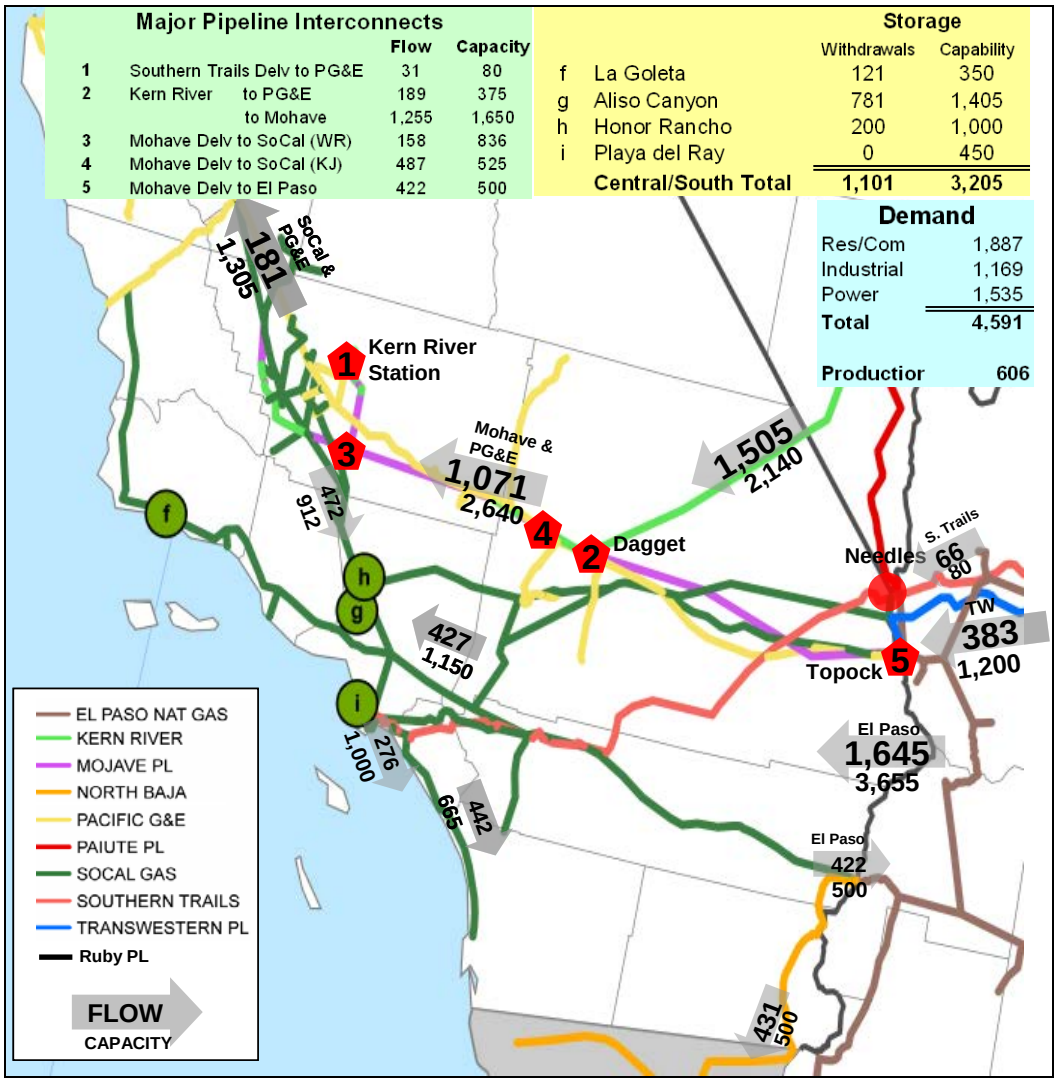


Figure 69: January 2020 Average Flows in Southern/Central California (MMcfd), Case 1

Source: ICF International

The peak day flows on PG&E south of Malin is 1.2 Bcf, or less than 60 percent of the system's capacity (Figure 70). In-state deliveries to northern California from southern and central California are relatively small at 200 MMcf, or about 7 percent of total demand for the day. Storage fields in the area are also unconstrained on the peak day, at less than 50 percent of the total storage withdrawal capability in northern California.

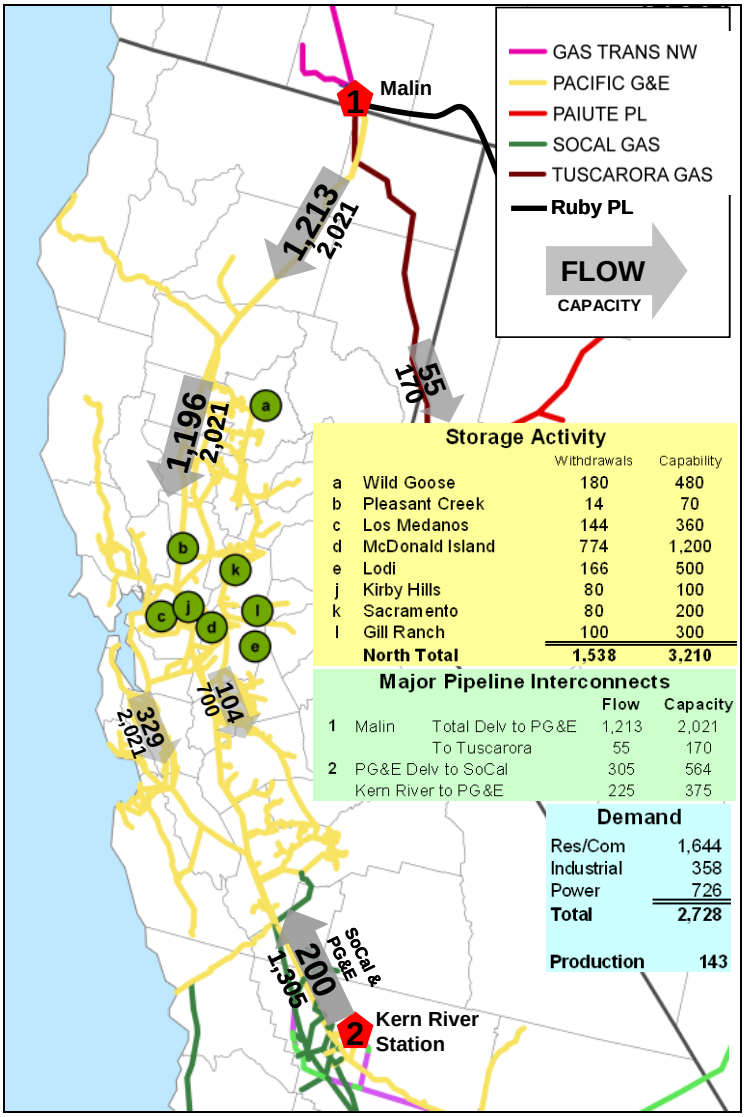


Figure 70: January 2020 Peak Day Flows in Northern California (MMcfd), Case 1

Source ICF International

On a peak January demand day, northern California consumes about 490 MMcf more than on an average day. As in southern and central California, the entirety of this incremental demand is met by increased storage withdrawals. Compared to the peak day, storage withdrawals on an average January day are roughly 550 MMcf lower (Figure 71). Intrastate pipeline imports from southern and central California are slightly higher on a peak day, but this increase is offset by slightly lower imports at Malin.

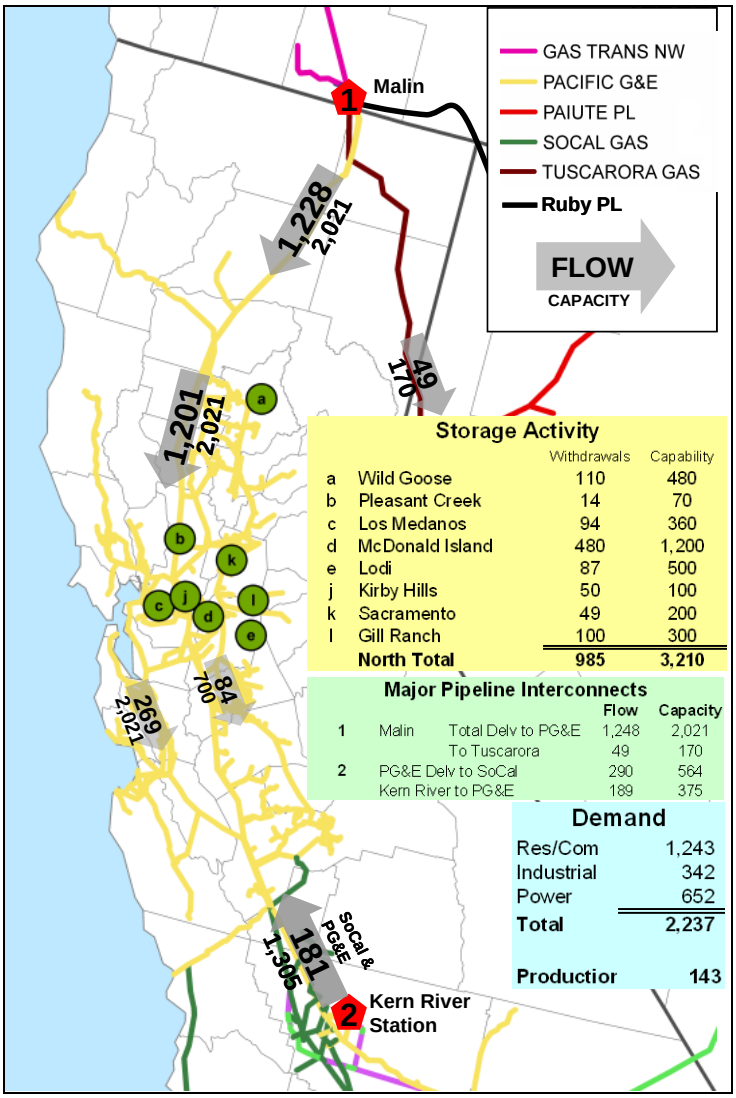


Figure 71: January 2020 Average Flows in Northern California (MMcfd), Case 1

Source: ICF International

3.5.2 Case 2: 33 percent RPS Reference Scenario with Expected Generation and Adverse Weather

Case Results Overview

Case 2 adds adverse temperatures and reduced hydroelectric generation in 2020, but still assumes that renewable generation is at expected levels. In Case 2, average annual gas consumption in 2020 is 6.1 Bcfd, or about 670 MMcfd higher than in Case 1 (Table 19). However, despite the addition of adverse temperature/hydroelectric conditions in Case 2, the projected gas demand in 2020 is still lower than 2008 demand by almost 240 MMcfd.

Table 19: California's Natural Gas Balance, Case 2 vs. Case 1

	2019		2020	
		Delta vs		*Delta vs*
Bcfd	Case 2	*Case 1*	Case 2	*Case 1*
Consumption	**5.61**	***0.17***	**6.06**	***0.67***
Residential	1.32	*0.03*	1.24	*(0.05)*
Commercial	0.66	*0.00*	0.65	*(0.01)*
Industrial	1.50	*(0.00)*	1.48	*(0.02)*
Power Generation	2.00	*0.14*	2.56	*0.75*
Other	0.13	*0.00*	0.13	*0.00*
Pipeline Exports	**0.08**	***(0.01)***	**0.06**	***(0.03)***
To Northern Nevada	0.02	-	0.01	*(0.01)*
To Mexico	0.06	*(0.01)*	0.05	*(0.02)*
Production	**0.85**	***0.00***	**0.85**	***0.00***
Pipeline Imports	**4.88**	***0.16***	**5.32**	***0.65***
via Southern Nevada (Kern River)	1.85	*(0.02)*	1.79	*(0.09)*
via Arizona (El Paso, Transwestern)	1.75	*0.15*	2.11	*0.53*
via Malin	1.27	*0.02*	1.39	*0.18*
via Mexico (Costa Azul LNG)	0.01	*0.01*	0.04	*0.03*
Storage Net Injections / (Withdrawals)	**-**		**-**	*0*
Balancing Item	**0.04**	***0.00***	**0.04**	***0.01***

Source: ICF International

Increased flows on El Paso and Transwestern meet most of the incremental demand increase in Case 2. In total, flows on these two pipelines are up by 530 MMcfd, compared to Case 1. In northern California, imports at Malin are up by 180 MMcfd compared to Case 1.

Figure 72 shows a comparison of average monthly demand in California between Case 1 and Case 2. With the exception of December, monthly average gas demand in California is higher under adverse weather conditions by between 300 MMcfd to 1500 MMcfd. In January (the peak gas demand month), average daily demand is around 7.4 Bcfd, an increase of about 500 MMcfd over Case 1. A combination of hot summer weather and poor hydroelectric generation leads to an increase in August demand of over 1 Bcfd, but the average daily gas demand in August is still about 1 Bcfd lower than in January.

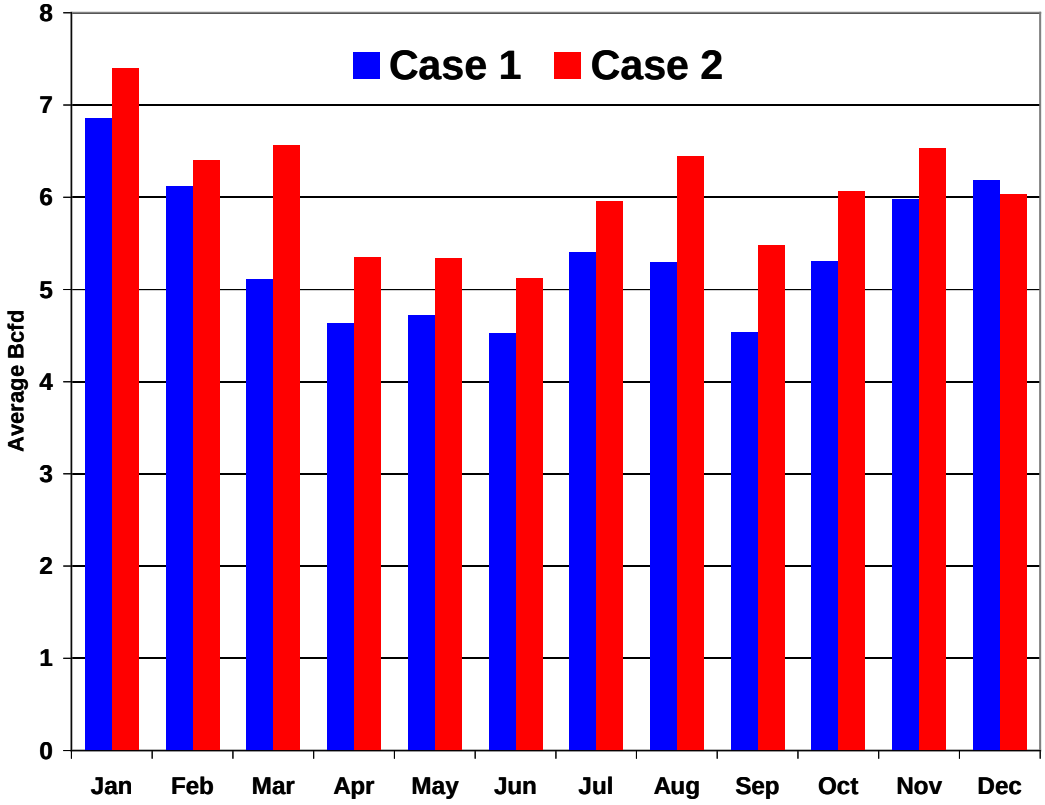


Figure 72: California Monthly Gas Consumption in 2020, Case 2 vs. Case 1

Source: ICF International

Despite the adverse temperature and hydroelectric generation conditions in Case 2, monthly storage withdrawals through January 2020 are not significantly different than in Case 1. As the withdrawal season continues, though, California relies more heavily upon storage to meet the increased demand. By the end of March, storage working gas levels are down to 70 Bcf, or roughly 22 percent of the State's total storage capacity by 2020. Still, there is sufficient pipeline capacity and available gas supplies to allow California's storage fields to refill to the same level as in Case 1 by October 2020 (the beginning of the next storage withdrawal season).

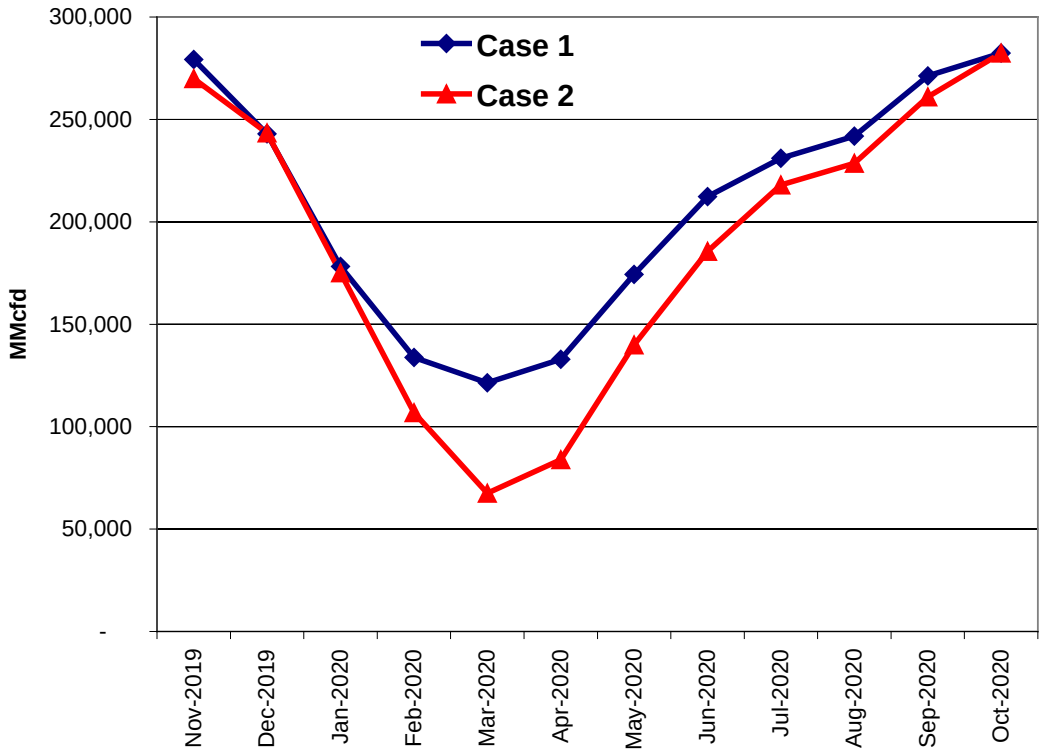


Figure 73: California Storage End-of-Month Working Gas Levels, Case 2 vs. Case 1

Source: ICF International

Peak Analysis

January 2020 peak day consumption in Case 2 totals about 9.3 Bcf, or about 1.2 Bcf greater than in Case 1 (Figure 74). About 60 percent (700 MMcf) of the increase is in the power sector. Residential and commercial demands are up about 500 MMcf over Case 1, accounting for the remaining 40 percent of the total increase. There is no significant change in industrial gas demand between the two cases.

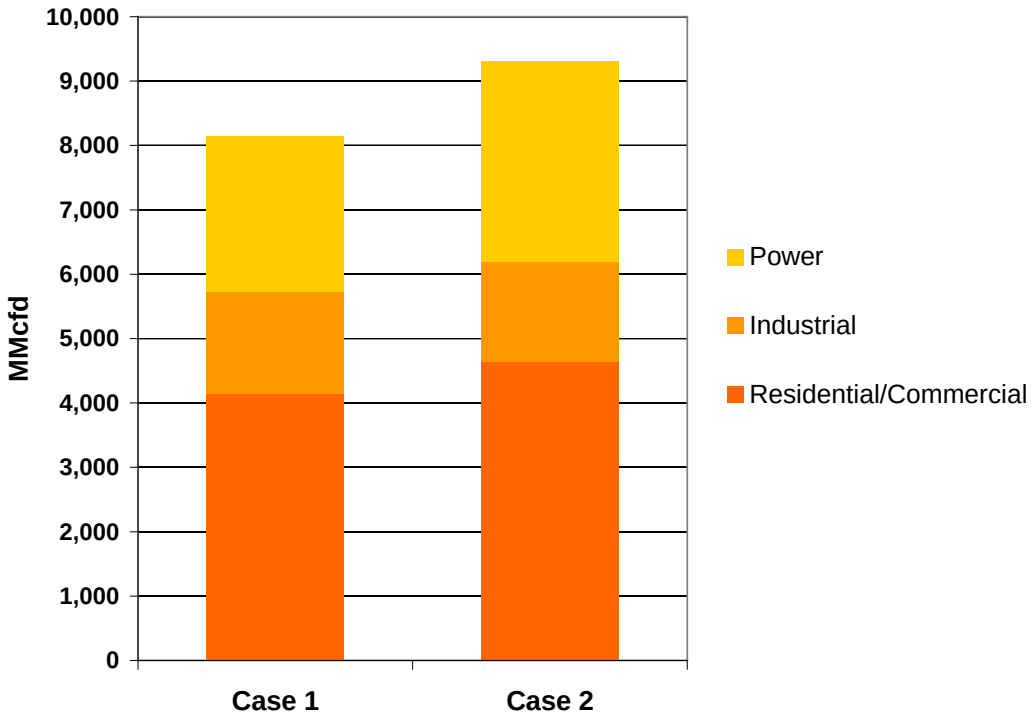


Figure 74: California January 2020 Peak Day Gas Consumption, Case 2 vs. Case 1

Source: ICF International

The adverse conditions in Case 2 increase January peak day natural gas consumption throughout California, with the most significant increase occurring in southern California (Figure 75). In southern California gas consumption is up by nearly 570 MMcf, compared to Case 1. Of this increase, roughly 63 percent is in the power sector. Northern California's peak day consumption is about 480 MMcf greater than in Case 1, and central California is about 110 MMcf greater than in Case 1.

Most of the increase in peak day demand Case 2 is met by increased storage withdrawals. In total, peak day withdrawals are up 750 MMcf, compared to Case 1. Pipeline imports into California are up a by 410 MMcf. Most of the increase in pipeline imports occurs along the El Paso system into southern California. Despite the additional 1.2 Bcf of supply necessary to fulfill demand on a January peak day under adverse temperature and hydroelectric conditions, both pipeline flows and storage field withdrawals are well within their infrastructure capabilities.

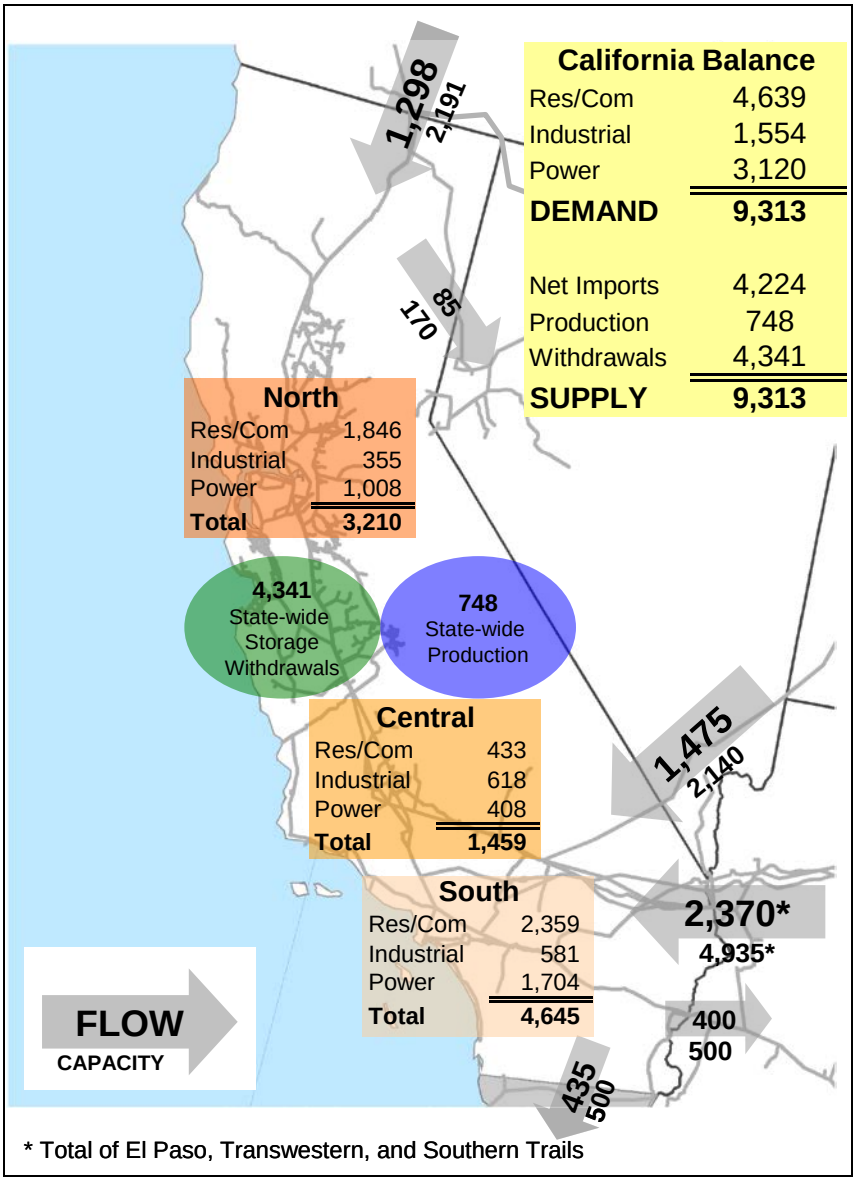


Figure 75: January 2020 Peak Day Balance (MMcfd), Case 2

Source: ICF International

Compared to Case 1, peak day demand in southern and central California in Case 2 is about 680 MMcf higher (Figure 76). Power sector demand in the area increases the most, by about 420 MMcf. The residential and commercial sectors account for the remainder of the increase; they are up by about 290 MMcf compared to Case 1.

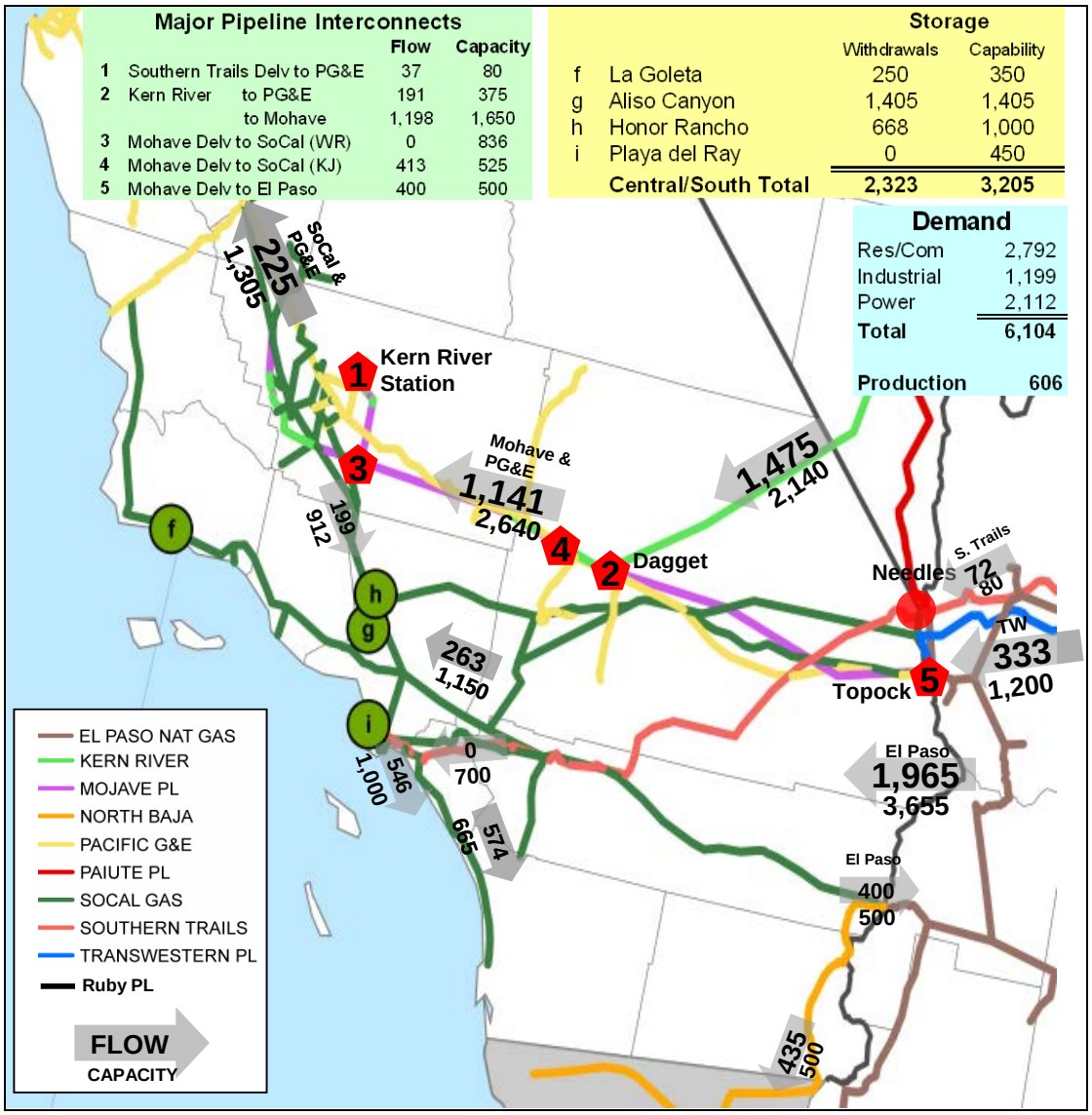


Figure 76: January 2020 Peak day Flows in Southern/Central California (MMcfd), Case 2

Source: ICF International

Area pipeline imports are up by around 380 MMcf, while storage withdrawals are up by close to 270 MMcf. Most of pipelines and storage fields within the area are well within system constraints, although load factors on pipelines into San Diego counties are near 90 percent. Under adverse conditions in both the winter and summer months (when power generation gas use peaks), pipelines into San Diego could become constrained due to the lack of storage availability and limited pipeline options into the region.

Southern/central California's average daily demand in January in Case 2 is up by around 330 MMcf compared to Case 1 (Figure 77). Average monthly pipeline flows are higher than in Case 1, but average daily storage withdrawals are similar.

Compared to the peak day of demand for Case 2, the average daily demand in January is almost 1.2 Bcf lower. All of the additional peak day demand is met by additional storage withdrawals, which are about 1.3 Bcf higher on the peak day.

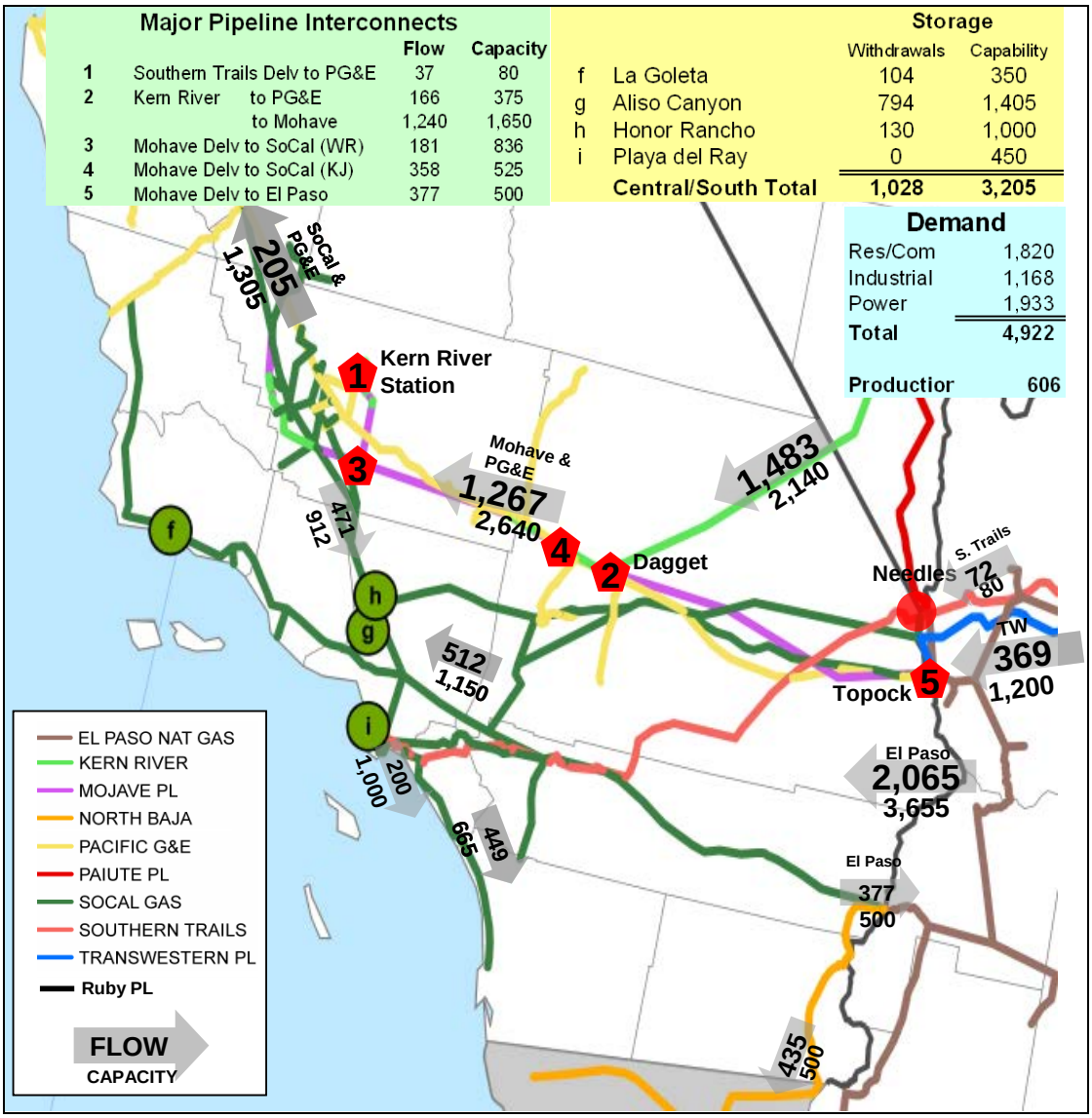


Figure 77: January 2020 Average Flows in Southern/Central California (MMcfd), Case 2

Source: ICF International

Northern California peak day gas consumption in January is about 480 MMcf higher in Case 2 compared to Case 1 (Figure 78). This increased demand is split between the residential/commercial and power sectors. The increased demand in northern California is met by additional storage withdrawals. This result may not reflect what would happen in reality accurately since the RIAMS model uses intertemporal optimization methods in order to solve for each scenario. In reality, it is likely that pipeline flows into northern California would

increase somewhat given this scenario and storage withdrawals would not cover the entire increase in demand. However, even if storage withdrawals were lower, there is still ample pipeline capacity into the region to meet the January peak day demand.

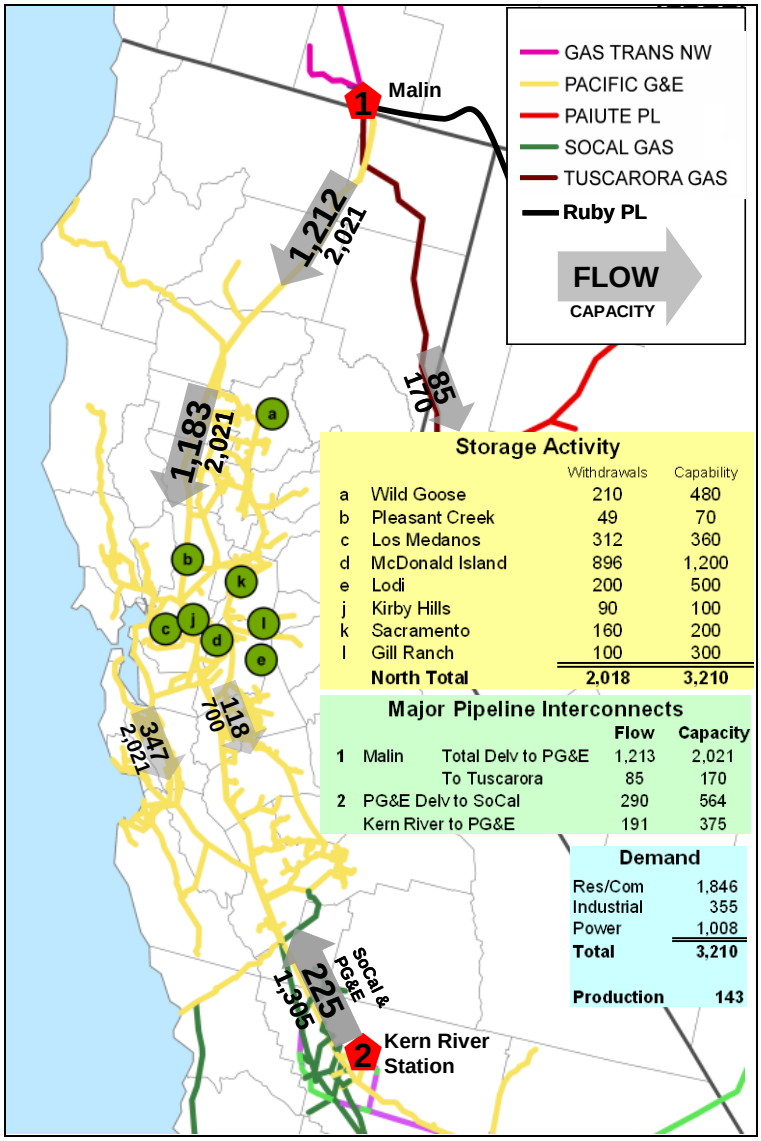


Figure 78: January 2020 Peak Day Flows in Northern California (MMcfd), Case 2

Source: ICF International

Compared to Case 1, average daily January gas consumption in northern California is up by over 210 MMcf in Case 2 (Figure 79). The power sector accounts for all of the additional demand compared to Case 1. All of the incremental demand is met by increased natural gas storage withdrawals in the region.

In northern California, demand on the average day in January is about 760 MMcf lower than the peak day. Unlike in southern California, the majority of additional peak day demand in northern California occurs in the residential and commercial sectors. Compared to the average day, peak day power sector demand is about 100 MMcf higher, while residential/commercial demand is up by almost 650 MMcf. All the additional peak day demand is met by additional storage withdrawals.

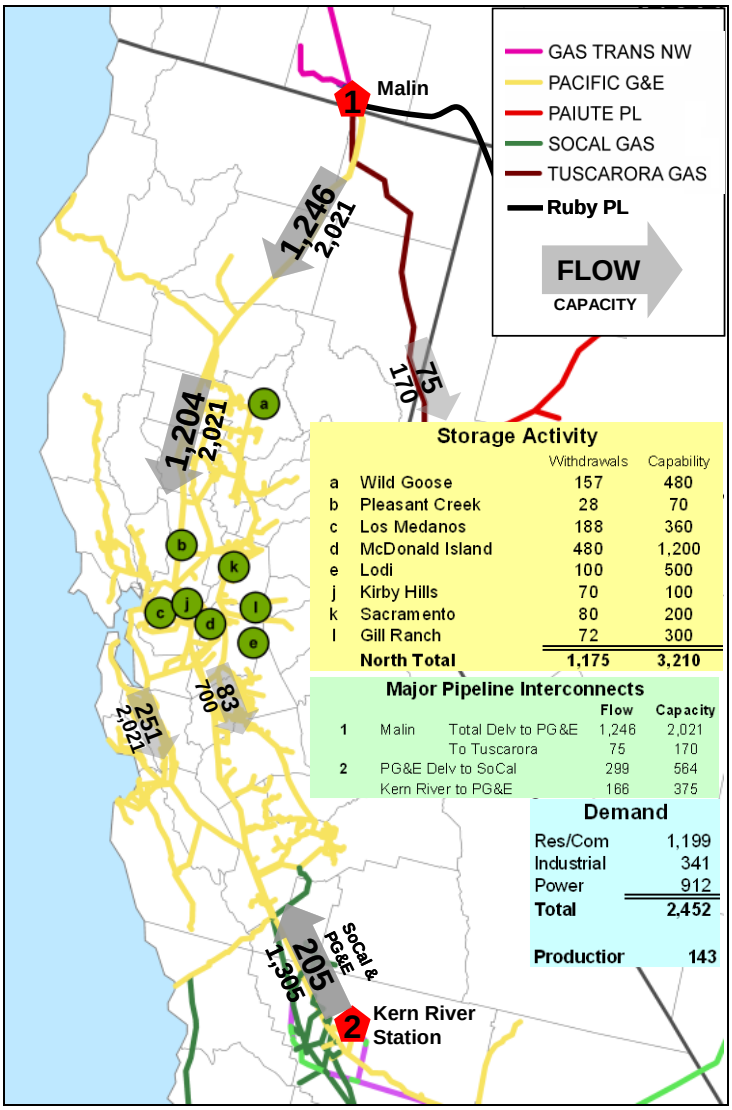


Figure 79: January 2020 Average Flows in Northern California (MMcfd), Case 2

Source: ICF International

3.5.3 Case 3: 33 percent RPS Reference Scenario with Reduced Renewable Generation and Adverse Weather

Case Results Overview

In addition to the adverse weather and hydroelectric generation conditions, Case 3 tests the ability of California's natural gas system to cope with a reduction in renewable generation in 2020, based on the 33 percent RPS Reference scenario. Case 3 reduces California's annual renewable generation in 2020 by 11 TWh, or about 11 percent. As a result of the reduction in renewable generation, California's annual gas consumption in 2020 is 0.2 Bcfd greater than in Case 2 (Table 20).

Table 20: California's Natural Gas Balance, Case 3 vs. Case 2

	2020	
Bcfd	Case 3	*Delta vs Case 2*
Consumption	**6.26**	***0.20***
Residential	1.24	*(0.00)*
Commercial	0.65	*(0.00)*
Industrial	1.48	*(0.00)*
Power Generation	2.76	*0.21*
Other	0.13	*0.00*
Pipeline Exports	**0.06**	***(0.00)***
To Northern Nevada	0.01	*0.00*
To Mexico	0.05	*(0.00)*
Production	**0.85**	***0.00***
Pipeline Imports	**5.52**	***0.20***
via Southern Nevada (Kern River)	1.76	*(0.03)*
via Arizona (El Paso, Transwestern)	2.27	*0.16*
via Malin	1.45	*0.06*
via Mexico (Costa Azul LNG)	0.04	*0.01*
Storage Net Injections / (Withdrawals)	**-**	-
Balancing Item	**0.04**	***0.00***

Source: ICF International

As would be expected, all of the increase in demand for natural gas is in the power generation sector, as gas is used to fill the gap in renewable generation for the year. To fulfill the increased demand, imports along the El Paso/Transwestern corridor and at the Malin interchange are up by about 160 MMcfd and 60 MMcfd, respectively. Imports along the Kern River pipeline are down relative to Case 2 by about 30 MMcfd.

As shown in Figure 80, compared to Case 2, average monthly gas consumption in the reduced renewable generation scenario is up by between 100 and 300 MMcfd throughout 2020. In the winter peak month of January average gas consumption is up by about 200 MMcfd, equal to

about the same as the annual average increase. In August, the summer peak demand month, gas demand is up only by about 100 MMcfd, mainly due to the reductions in wind and solar generation.

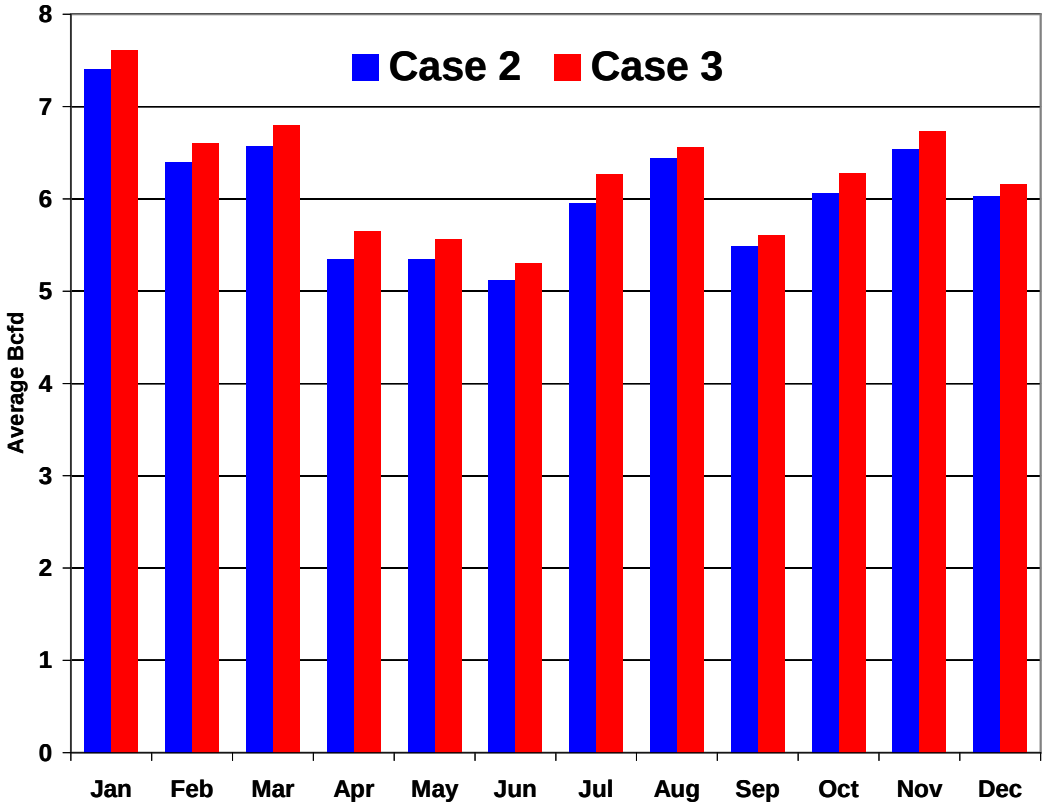


Figure 80: California Monthly Gas Consumption in 2020, Case 3 vs. Case 2

Source: ICF International

Despite the necessity of additional gas supplies for the state of California due to the reduction in renewable generation, gas storage withdrawals within the State are very close to those observed in Case 2 (Figure 81). Through January, storage withdrawals in both cases are almost identical. By the end of the withdrawal season in March, 2020, the difference in withdrawals between the two cases is still barely noticeable. In the reduced renewable generation scenario, only an additional 1.4 Bcf is withdrawn from storage by March compared to Case 2, with a little more than 66 Bcf of gas left in storage by the end of the season.

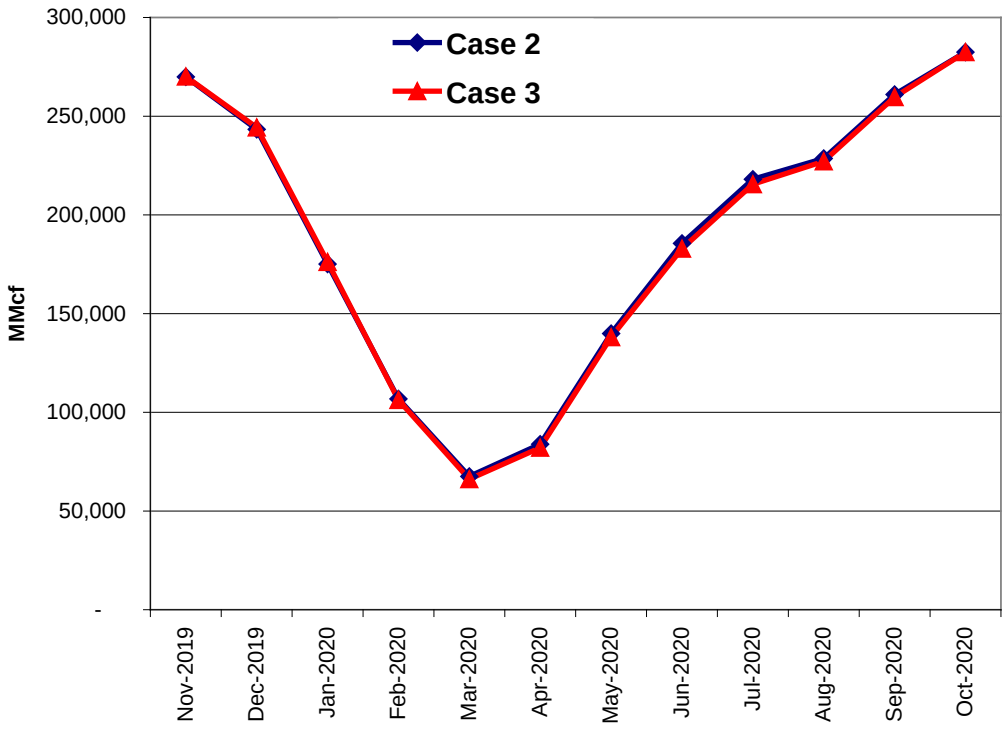


Figure 81: California Storage End-of-Month Working Gas Levels, Case 3 vs. Case 2

Source: ICF International

Peak Analysis

Peak day gas consumption in January in Case 3 is about 460 MMcf higher than in Case 2 (Figure 82). As Case 3 assumes the same weather conditions as Case 2, all of the additional gas demand occurs in the power generation sector.

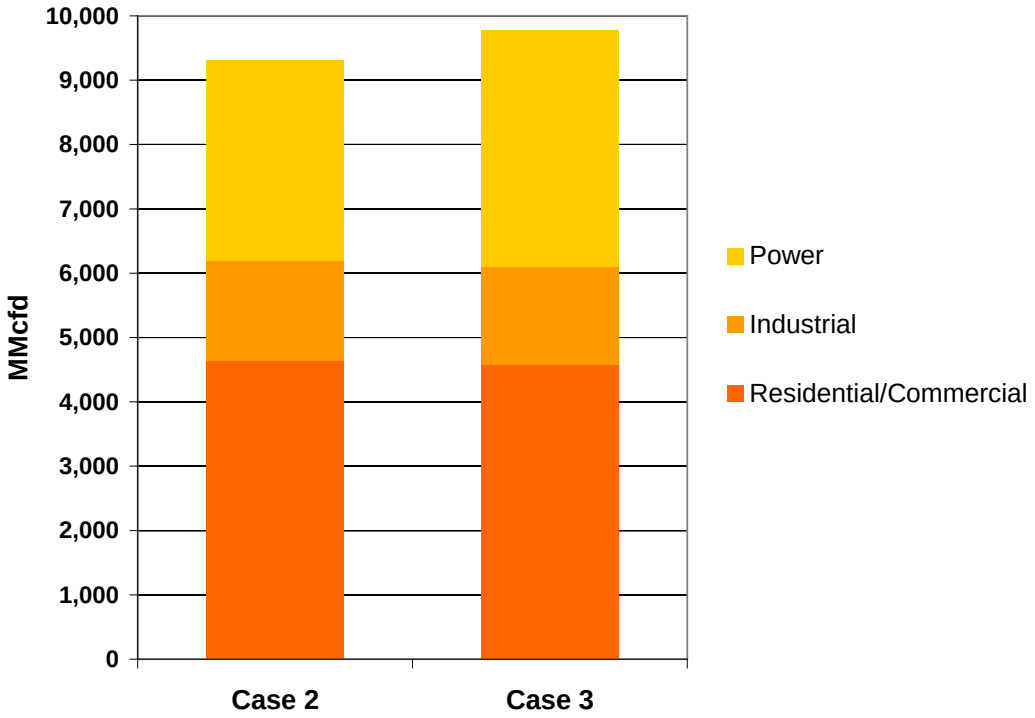


Figure 82: California January 2020 Peak Day Gas Consumption,

Case 3 vs. Case 2

Source: ICF International

Due to the reduced renewable generation on the peak day, gas consumption is up in the power sector throughout California, with southern California requiring the most additional gas supply, with nearly an additional 270 MMcf of gas needed in the region. In northern California, an additional 220 MMcf of gas is required to fill the additional power demand, while only about 60 MMcf is needed in central California (Figure 83). In both central and northern California, industrial and residential/commercial demand is relatively flat, but in southern California demand in both sectors is down slightly.

The majority of this increased demand is filled by increased pipeline imports. In total, an additional 330 MMcf of gas is imported to California on the peak day in Case 3 over Case 2. Most of the additional gas is imported along the El Paso line in southern California. Additional storage withdrawals account for about an additional 150 MMcf of supply. Most of the increase in storage withdrawals is concentrated at the Aliso Canyon and Honor Rancho fields near Los Angeles. In this scenario, storage withdrawals on the peak day in January are at or near capacity at many fields within the State.

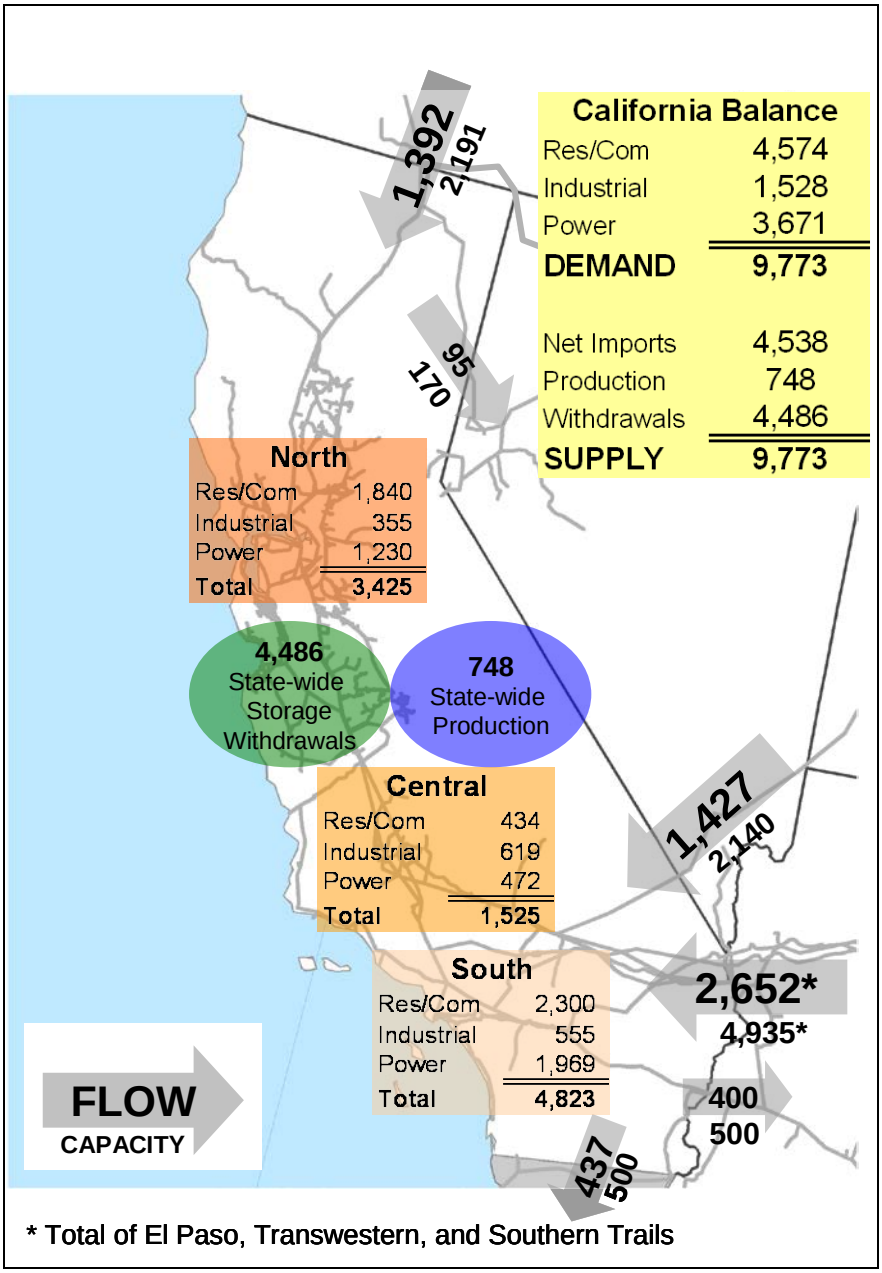


Figure 83: January 2020 Peak Day Balance (MMcfd), Case 3

Source: ICF International

In southern and central California, the reduced generation available from renewable power sources causes a demand increase for natural gas of about 250 MMcf compared to Case 2 (Figure 84). This increase in demand is met primarily by an increase in pipeline imports along the El Paso corridor, which are about 280 MMcf higher than in Case 2 at around 2,250 MMcf. Storage withdrawals in the region are about the same as in Case 2, only up by about 10 MMcf.

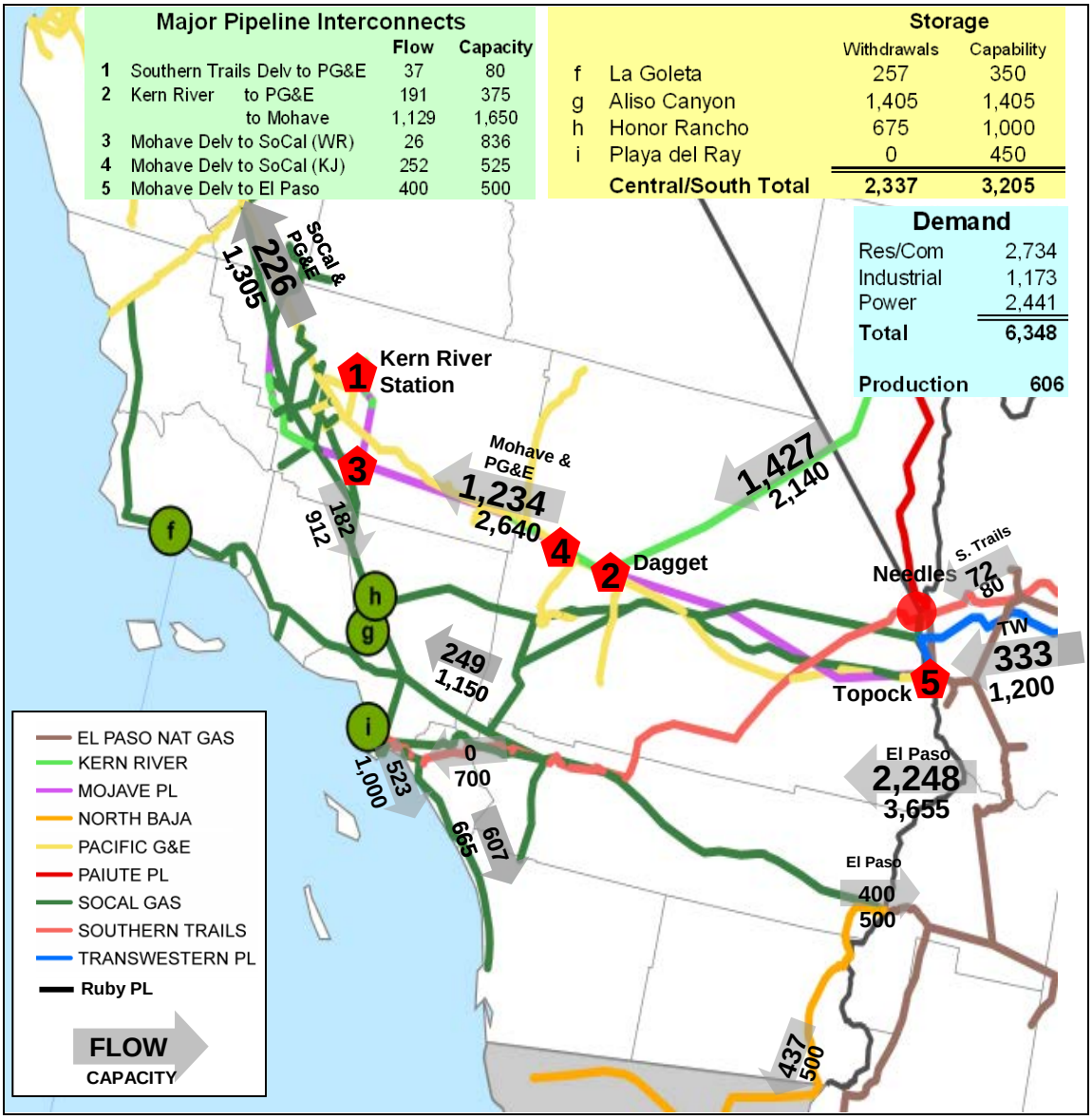


Figure 84: January Peak Day Flows in Southern/Central California (MMcfd), Case 3

Source: ICF International

For the majority of southern and central California, pipeline and storage capacity is adequate to meet the increased demand levels brought on by the lower renewable generation levels in Case 3. As in Case 2, the one area where potential problems could arise is in the San Diego area since, unlike the Los Angeles Basin, San Diego has no storage fields in its immediate vicinity. In this scenario, load factors on pipeline serving San Diego are over 90 percent, almost at the constraining point. In a peak power generation demand month like August, the city would most likely be constrained if renewable generation were to be as low as it is in Case 3.

Average daily gas demand in southern and central California in January is only about 90 MMcf higher than in Case 2 (Figure 85). Almost all of this additional demand is met by increased

imports along El Paso's system, which is up by about 150 MMcf at around 2.2 Bcf. Imports along Kern River's line are about 70 MMcf lower, and intrastate flows from central California to northern California are up by about 25 MMcf.

Compared to the average January day, peak day gas demand is about 1.3 Bcf higher in Case 3, with residential/commercial demand about 920 MMcf higher and power sector demand about 420 MMcf higher. Industrial sector demand is roughly the same on a peak day and on an average day. All of the additional gas required to fill peak day demand is met by additional storage withdrawals.

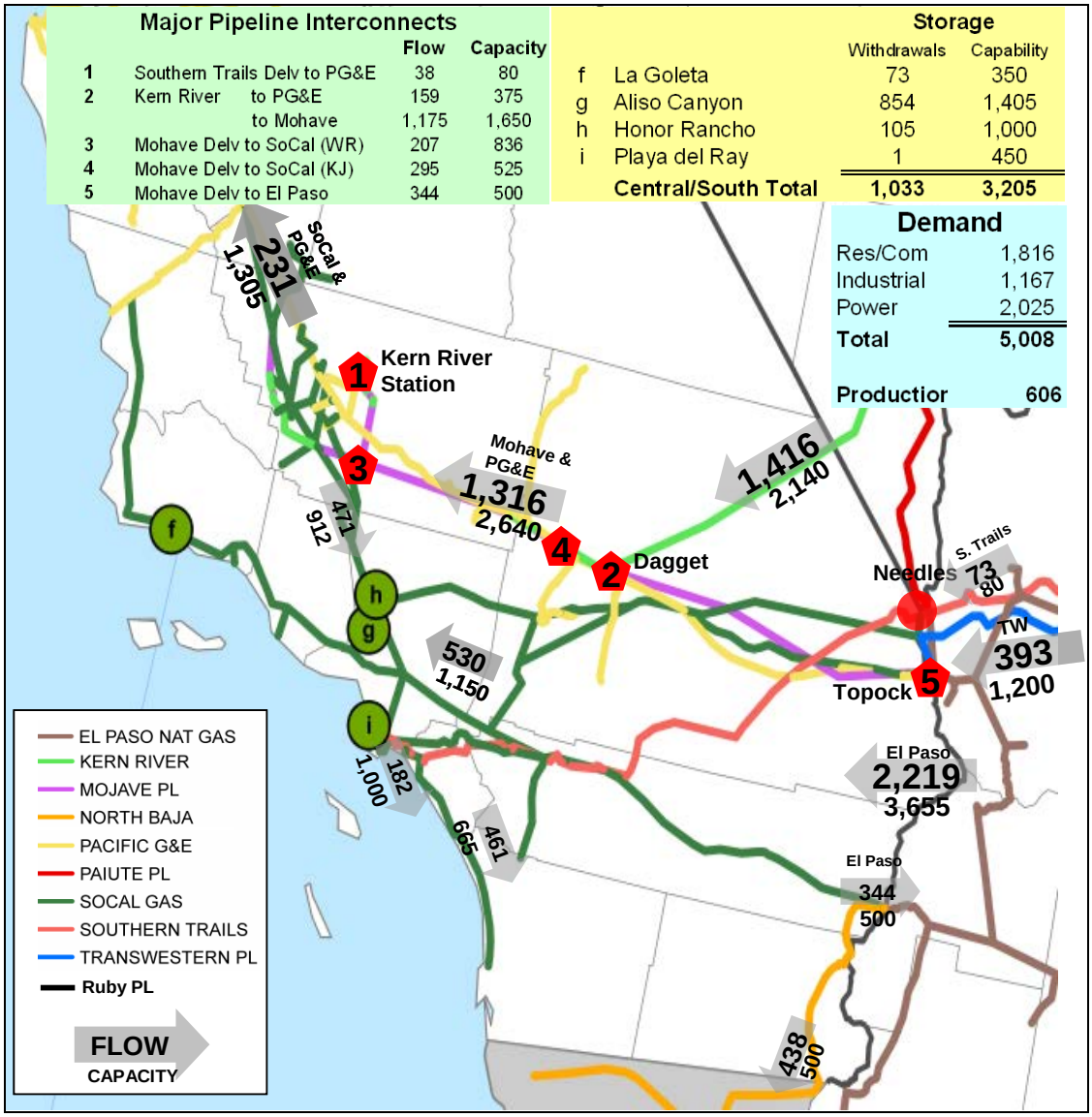


Figure 85: January 2020 Average Flows in Southern/Central California (MMcfd), Case 3

Source: ICF International

In northern California, the reduced renewable generation in Case 3 creates an additional 220 MMcf of gas for the power sector on the peak demand day in January 2020 (Figure 86). About

90 MMcf of the increase is met by increased imports at Malin, and 130 MMcf is met by additional storage withdrawals within the region. Four of the area's eight storage fields – Pleasant Creek, Los Medanos, Kirby Hills, and Sacramento – are withdrawing at their full capability on the peak day. This reflects a tendency of the RIAMS to maximize withdrawals from particular fields due to their proximity to load centers. However, even if withdrawals at these four fields were lower, there are ample remaining pipeline capacity and storage withdrawal capability at other fields to meet peak day demand.

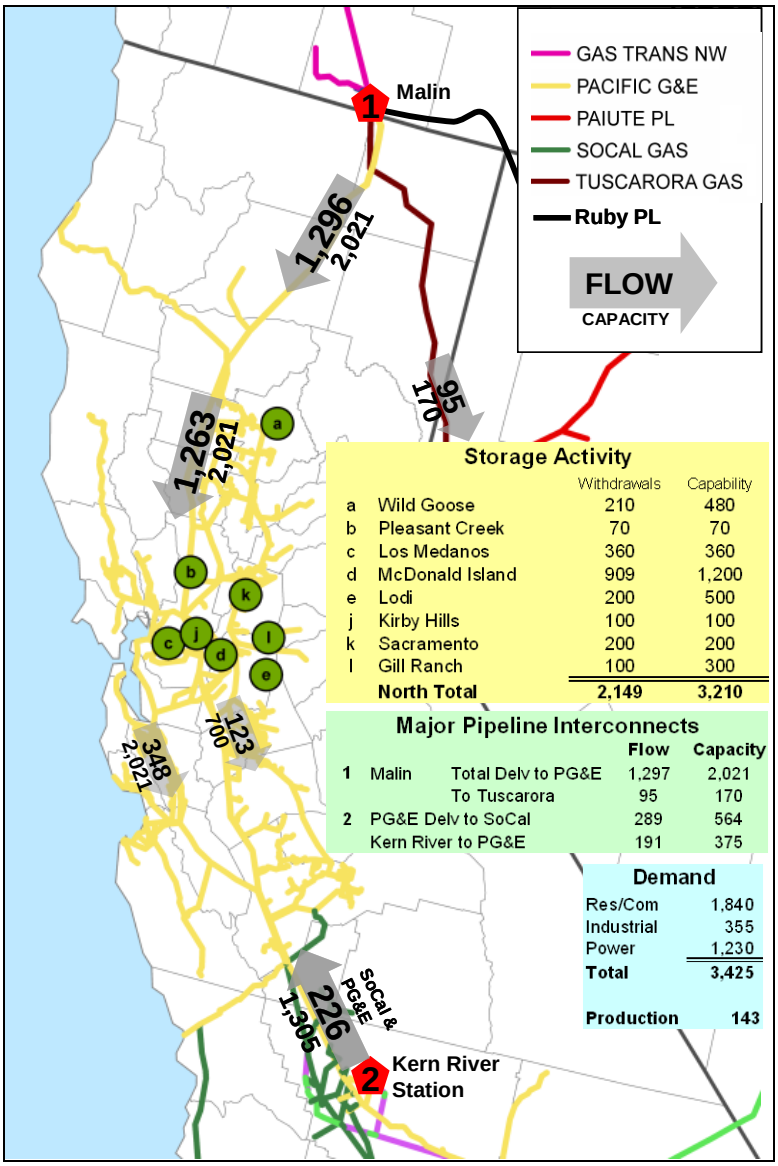


Figure 86: January Peak Day Flows in Northern California (MMcfd), Case 3

Source: ICF International

Despite the increased need for gas-fired generation in Case 3 over Case 2, northern California average daily demand in January is only about 50 MMcf greater in Case 3 (Figure 87). All of the

additional demand is concentrated in the power sector. The incremental demand increase is met by a combination of additional imports at Malin and storage withdrawals within the region.

January average daily demand in northern California is about 700 MMcf less than on the peak day. Residential/commercial gas demand is about 650 MMcf higher on a peak day, while power sector demand is about 40 MMcf higher. All of the supply needed to fill peak day demand compared to average daily demand in the region comes from additional storage withdrawals.

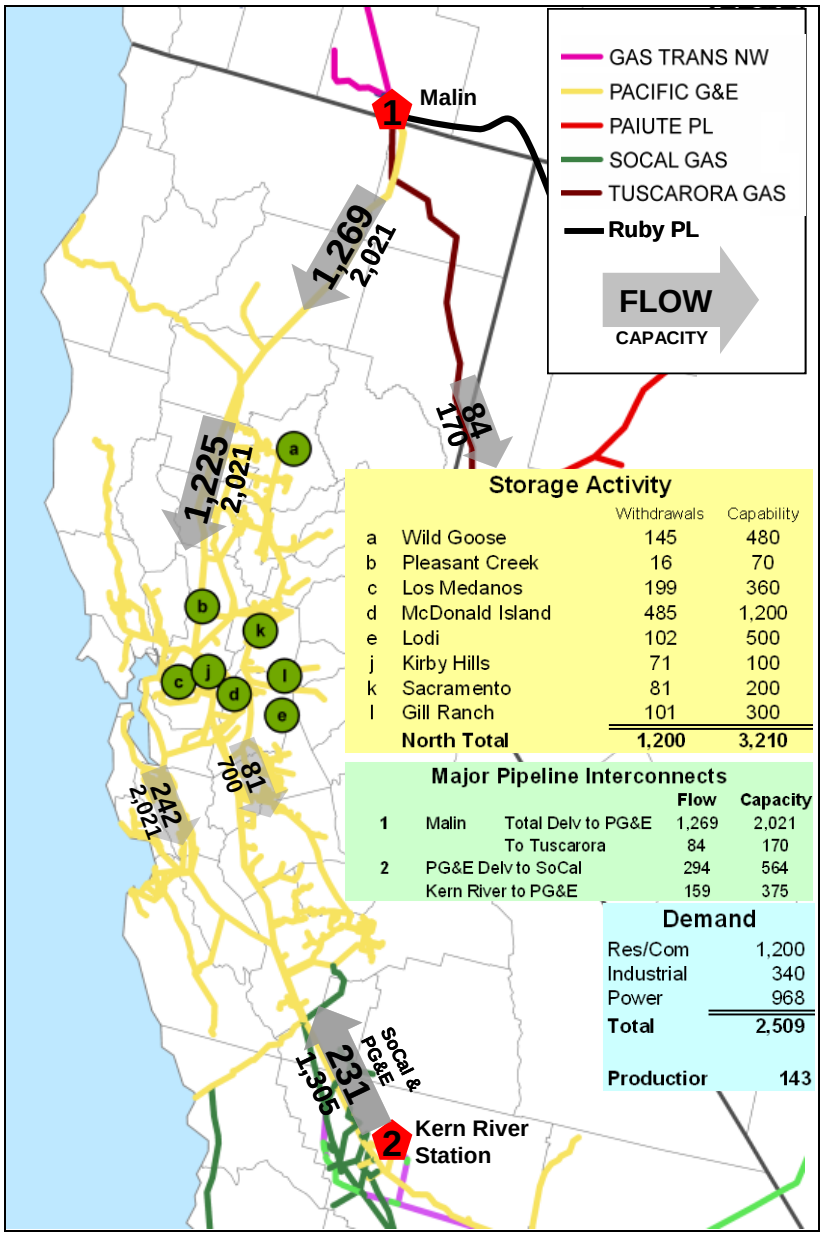


Figure 87: January 2020 Average Flows in Northern California (MMcfd), Case 3

Source: ICF International

3.5.4 Case 4: 33 percent RPS High Wind Scenario with Reduced Renewable Generation and Adverse Weather

Case Results Overview

Case 4 assumes the same adverse weather and hydroelectric generation conditions as Case 2 and a reduction in renewable generation in 2020 similar to Case 3, but the seasonal pattern of renewable generation is based on the High Wind RPS scenario. In Case 4, annual renewable generation is reduced by 12 TWh in 2020. Among all of the outage cases, Case 4 has the greatest reduction in renewable generation, but only by about 1 TWh compared to Case 3.

The reduced renewable generation leads to an increase in average annual power generation gas demand of about 220 MMcfd, just slightly higher than the increase observed in Case 3 (Table 21). And, similar to Case 3, the gas imports along the El Paso/Transwestern corridor and at Malin act as the primary sources of the additional supply needed.

Table 21: California's Natural Gas Balance, Case 4 vs. Case 2

	2020	
Bcfd	Case 4	*Delta vs Case 2*
Consumption	**6.28**	***0.22***
Residential	1.24	*(0.00)*
Commercial	0.65	*(0.00)*
Industrial	1.48	*(0.00)*
Power Generation	2.78	*0.22*
Other	0.13	*0.00*
Pipeline Exports	**0.06**	***(0.00)***
To Northern Nevada	0.01	*0.00*
To Mexico	0.05	*(0.00)*
Production	**0.85**	***0.00***
Pipeline Imports	**5.54**	***0.22***
via Southern Nevada (Kern River)	1.76	*(0.03)*
via Arizona (El Paso, Transwestern)	2.28	*0.18*
via Malin	1.46	*0.07*
via Mexico (Costa Azul LNG)	0.04	*0.01*
Storage Net Injections / (Withdrawals)	**-**	-
Balancing Item	**0.04**	***0.00***

Source: ICF International

Comparing Case 2 with Case 4, monthly average gas consumption in 2020 is up between 110 MMcfd and 370 MMcfd (Figure 88). In January, average consumption is up by about 220

MMcfd, which is about equal to the average annual increase. Consumption in the peak summer month of August is up by about 120 MMcfd.

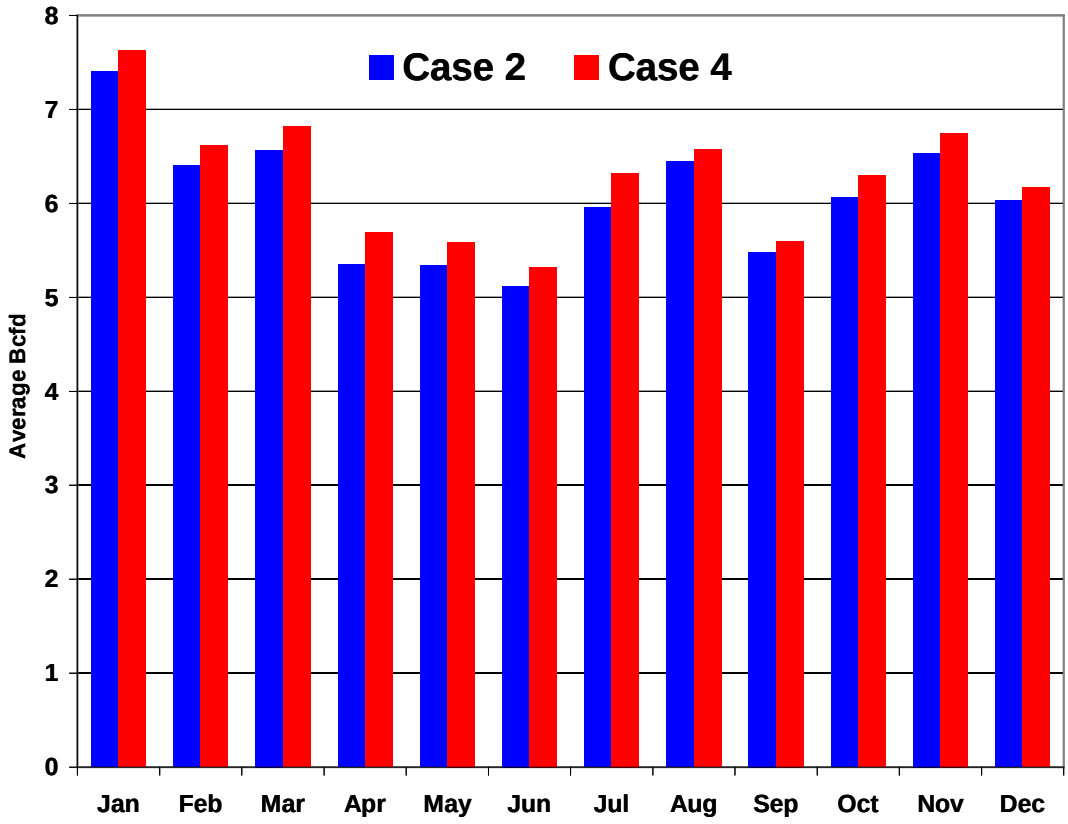


Figure 88: California Monthly Gas Consumption in 2020, Case 4 vs. Case 2

Source: ICF International

Monthly storage withdrawals within California in Case 4 are very similar those observed in Case 2 (Figure 89). By the end of the withdrawal season in March 2020, the amount of gas left in storage in Case 4 is about 1.4 Bcf lower than the level in Case 2, an incremental decrease of about 2 percent.

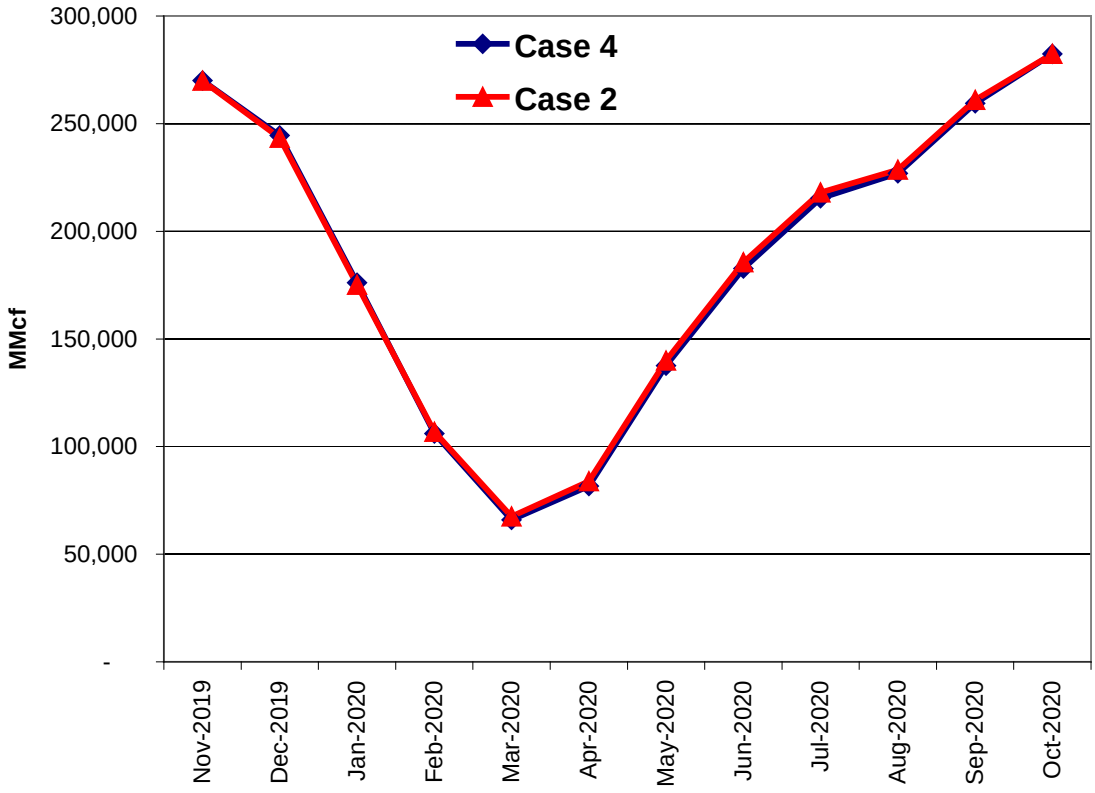


Figure 89: California Storage End-of-Month Working Gas Levels, Case 5 vs. Case 2

Source: ICF International

Peak Analysis

In January 2020, peak day consumption in Case 4 is 9.9 Bcf, or about 570 MMcf greater than in Case 2 (Figure 90). Compared to Case 2, all of the additional peak day demand in this scenario is in power sector.

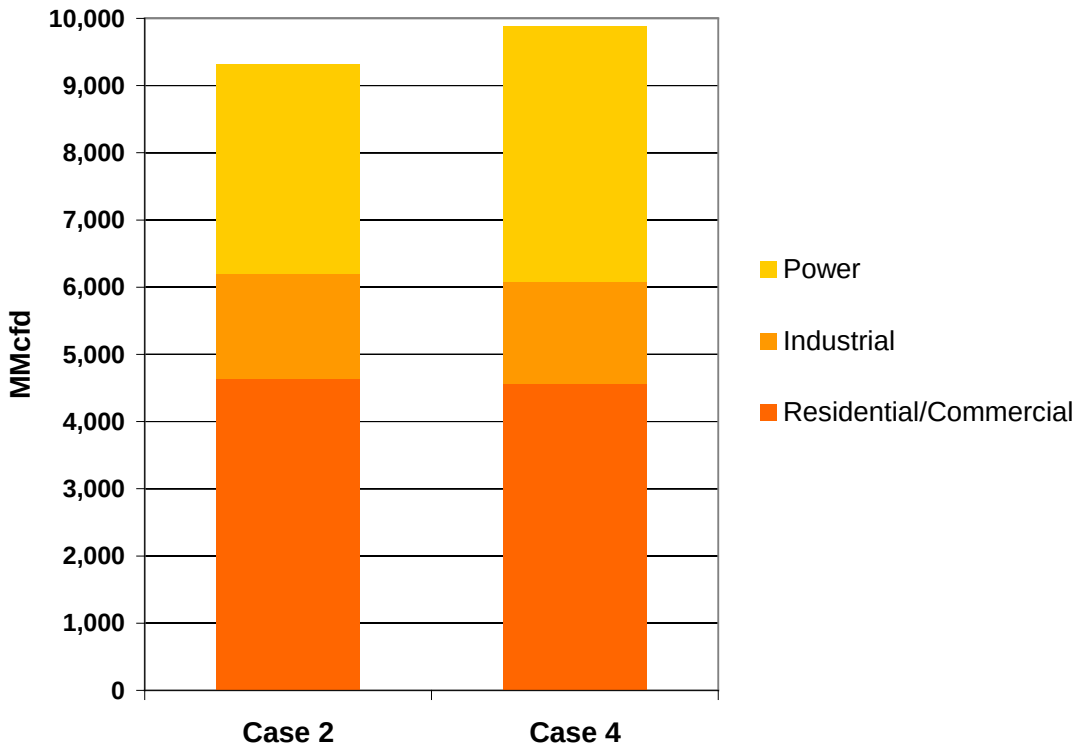


Figure 90: California January 2020 Peak Day Gas Consumption, Case 4 vs. Case 2

Source: ICF International

Southern California shows a slightly larger increase in power generation demand than other areas in the State (Figure 91). In southern California, peak day power generation demand is up by about 330 MMcf, while demand in northern California is up by about 270 MMcf and only by about 80 MMcf in central California. The additional demand is met by a combination of additional pipeline imports and storage withdrawals. Compared to Case 2, pipeline imports are up by 300 MMcf, while an additional 280 MMcf is withdrawn from storage on a peak day. The majority of the additional pipeline imports enter the state via the El Paso/Transwestern corridor. Similar to in Case 3, storage withdrawals are at, or near, capacity at many fields within California.

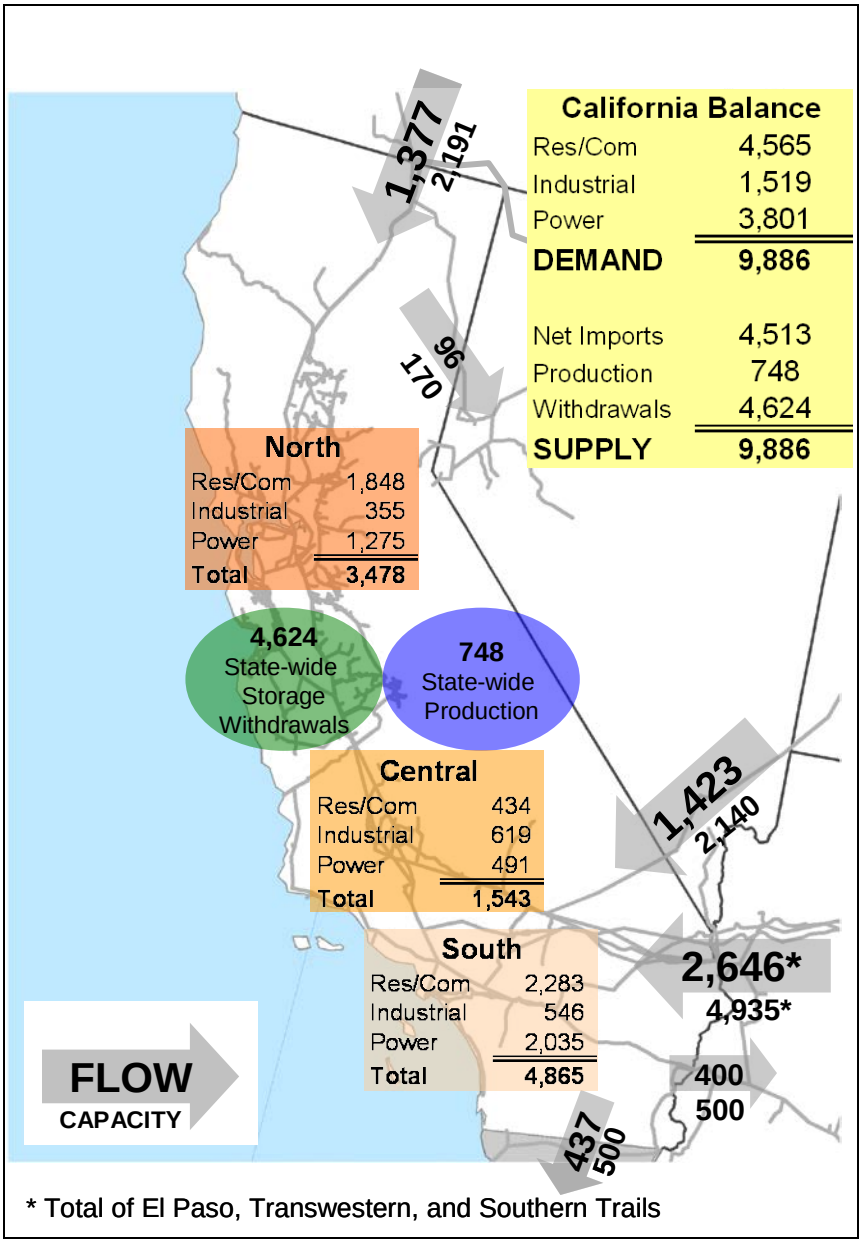


Figure 91: January 2020 Peak Day Balance (MMcfd), Case 4

Source: ICF International

The reduction in renewable generation causes a demand increase of about 300 MMcf in southern and central California compared to Case 2 (Figure 92). Most of this increase in demand is met by increased imports of gas along El Paso's system (280 MMcf). Additional storage withdrawals account for the remaining supply needed. For the most part, pipeline and storage capacity in the region is adequate to meet demand. Similar to in Case 3, load factors on the January peak day along pipelines serving San Diego County are over 90 percent. This is an indication that during both winter and summer peak gas demand periods it is likely that pipelines into San Diego would be constrained.

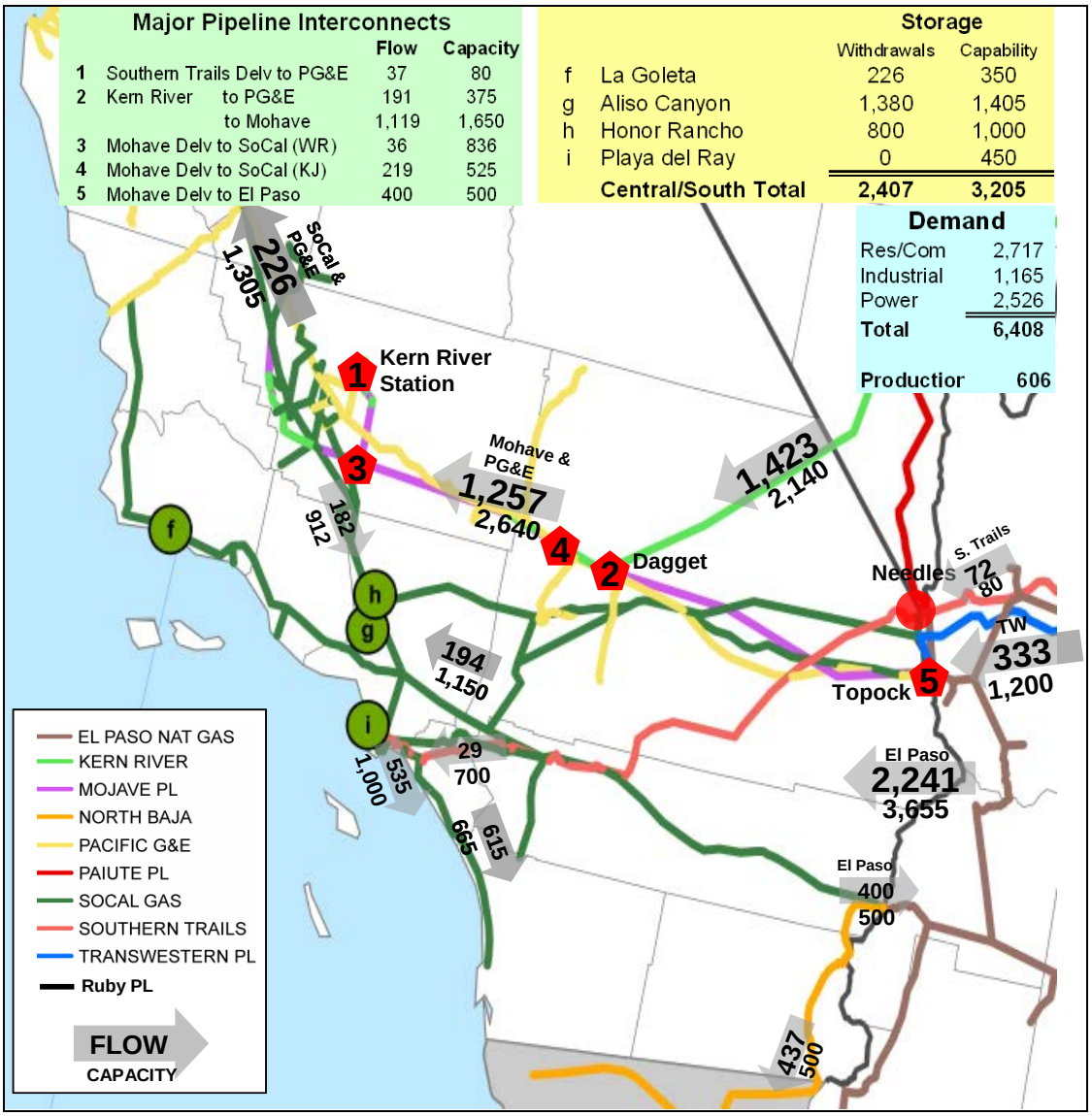


Figure 92: January 2020 Peak Day Flows in Southern/Central California (MMcfd), Case 4

Source: ICF International

The January daily average demand in central/southern California increases by 80 MMcf, compared to Case 2 (Figure 93). Pipeline imports on the El Paso system meet most the incremental demand increase on the average day in Case 4.

Compared to an average day in January 2020, demand on a peak day is about 1.4 Bcf higher. Residential/commercial demand is about 900 MMcf higher on the peak day, while power sector demand is about 500 MMcfd higher. Compared to the average day, all of the incremental demand on the peak day comes from additional storage withdrawals.

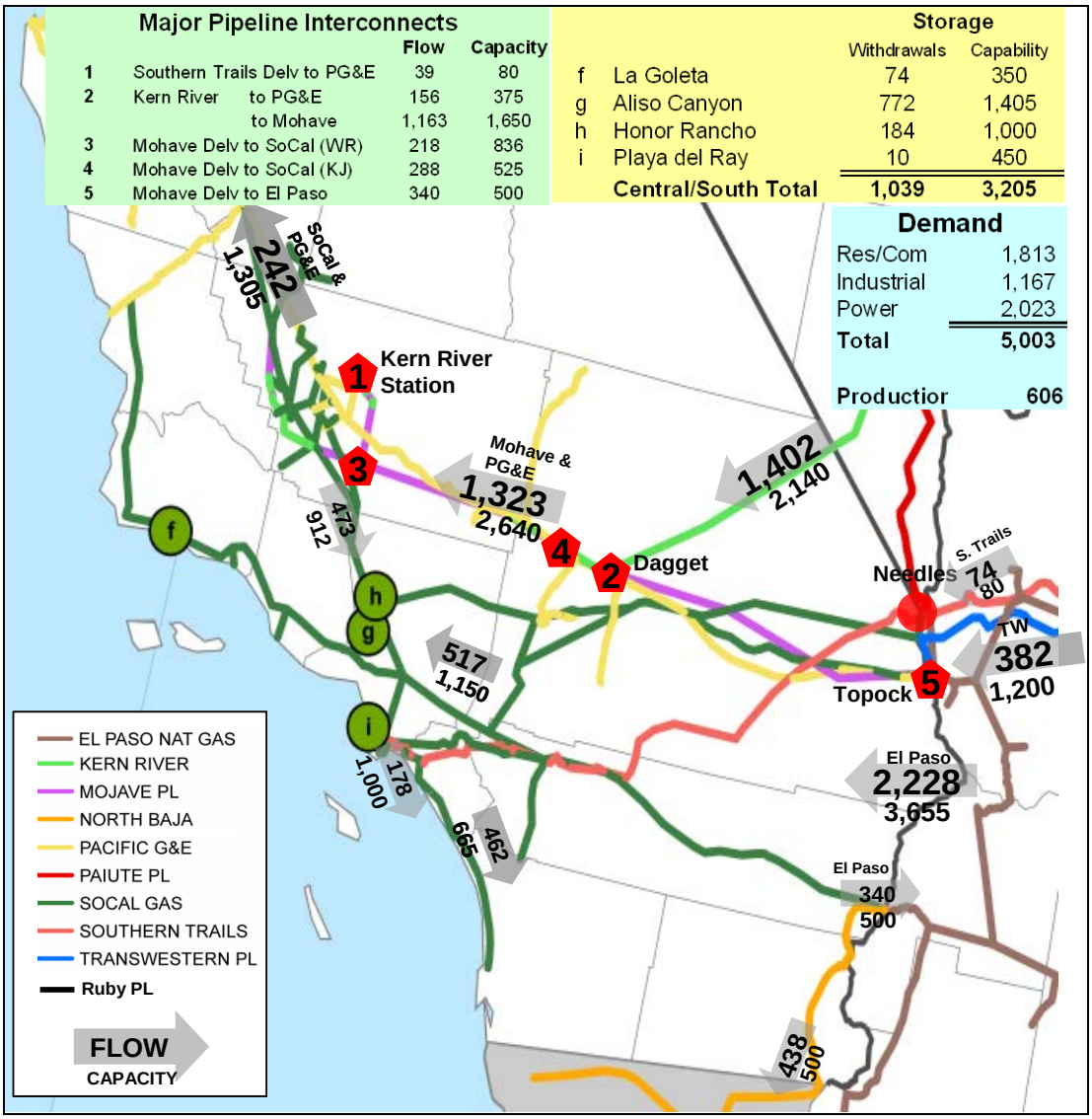


Figure 93: January 2020 Average Flows in Southern/Central California (MMcfd), Case 4

Source: ICF International

Compared to Case 2, January peak day demand in northern California is up by about 270 MMcf in Case 4 (Figure 94). Most of the incremental demand increase is met by increased storage withdrawals, with the remainder being met by increased imports at Malin. As in Case 3, four of the eight storage fields in the region are withdrawing at their full capability. Even if withdrawals at these fields were lower, there is more than enough unused pipeline capacity and storage withdrawal capability to adequately meet the case's demand levels.

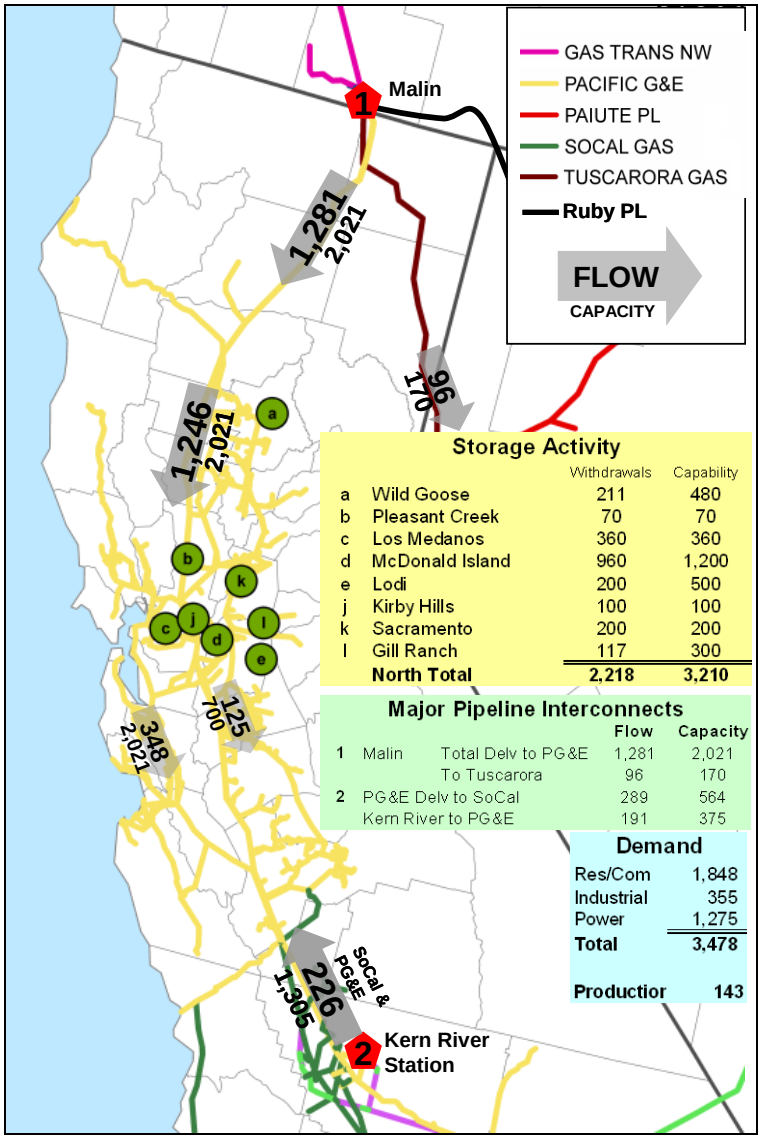


Figure 94: January 2020 Peak Day Flows in Northern California (MMcfd), Case 4

Source: ICF International

January average daily demand in the northern California is about 60 MMcf higher than in Case 2 (Figure 95). The additional demand is met by slight increases in both pipeline imports at Malin and storage withdrawals.

Compared to the January average day demand in Case 4, the peak demand day is about 1,000 MMcf higher. About 650 MMcfd of the increase is in residential/commercial demand, while the remainder of the increase is in the power sector. Compared to the average January day, storage withdrawals are about 1,000 MMcf higher to meet the demand increase.

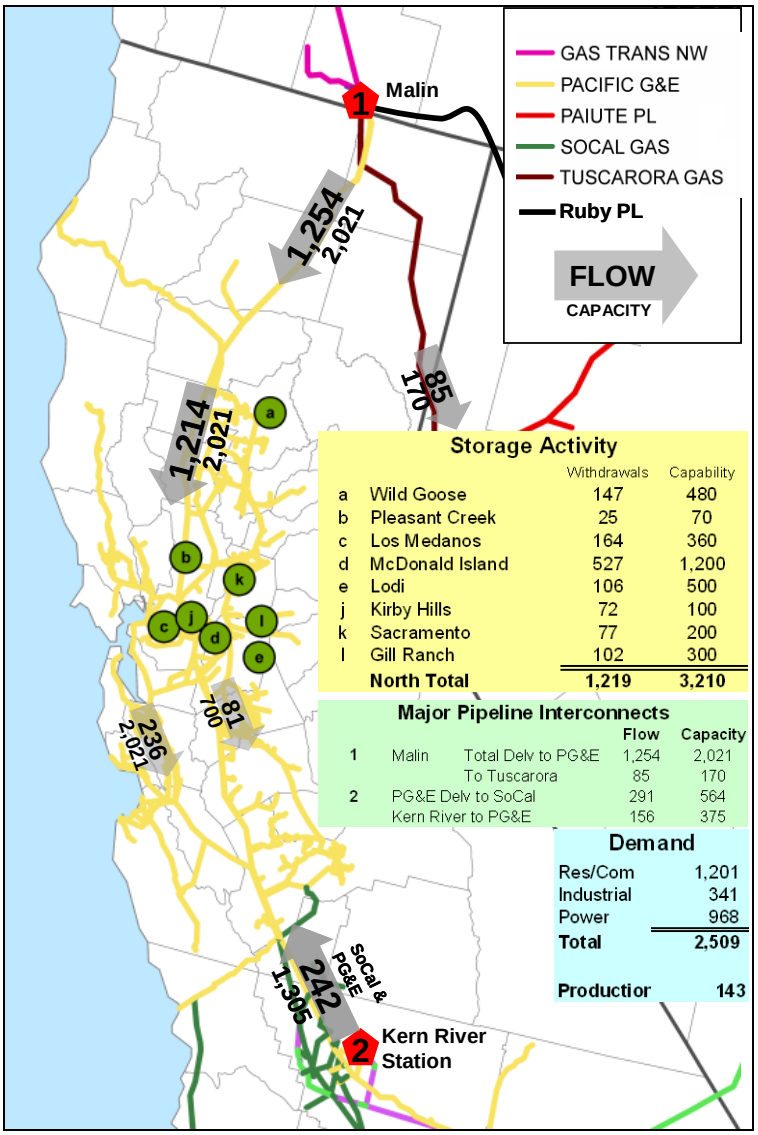


Figure 95: January 2020 Average Flows in Northern California (MMcfd), Case 4

Source: ICF International

3.5.5 Case 5: 33 percent RPS Solar Scenario with Reduced Renewable Generation and Adverse Weather

Case Results Overview

Case 5 reduces annual renewable generation in 2020 by about 10 TWh, or roughly 10 percent, compared to the expected annual renewable generation. Of the three reduced renewable generation cases, this scenario has the smallest reduction in annual generation, though it only difference from Case 3 by about 0.2 TWh. The reductions in renewable generation lead to an average annual increase in power generation gas consumption of about 190 MMcfd (Table 22). As in Cases 3 and 4, this additional demand is met by increased imports of natural gas along the

El Paso/Transwestern corridor in southern California and at the Malin interchange in northern California.

Table 22: California's Natural Gas Balance, Case 5 vs. Case 2

	2020	
Bcfd	Case 5	*Delta vs Case 2*
Consumption	**6.26**	***0.19***
Residential	1.24	*(0.00)*
Commercial	0.65	*(0.00)*
Industrial	1.48	*(0.00)*
Power Generation	2.76	*0.20*
Other	0.13	*0.00*
Pipeline Exports	**0.06**	***(0.00)***
To Northern Nevada	0.01	*0.00*
To Mexico	0.05	*(0.00)*
Production	**0.85**	***0.00***
Pipeline Imports	**5.51**	***0.19***
via Southern Nevada (Kern River)	1.76	*(0.02)*
via Arizona (El Paso, Transwestern)	2.26	*0.15*
via Malin	1.45	*0.06*
via Mexico (Costa Azul LNG)	0.04	*0.00*
Storage Net Injections / (Withdrawals)	**-**	-
Balancing Item	**0.04**	***0.00***

Source: ICF International

Compared to Case 2, average gas consumption in Case 5 is up by 100 MMcfd to 300 MMcfd each month in 2020 (Figure 96). This differential is very similar to Case 3 since the renewable generation levels are very similar in both cases. In January, the winter peak month, average consumption is up by about 210 MMcfd, which is about the same as the annual average increase. In the summer peak month of August gas consumption is up by 110 MMcfd.

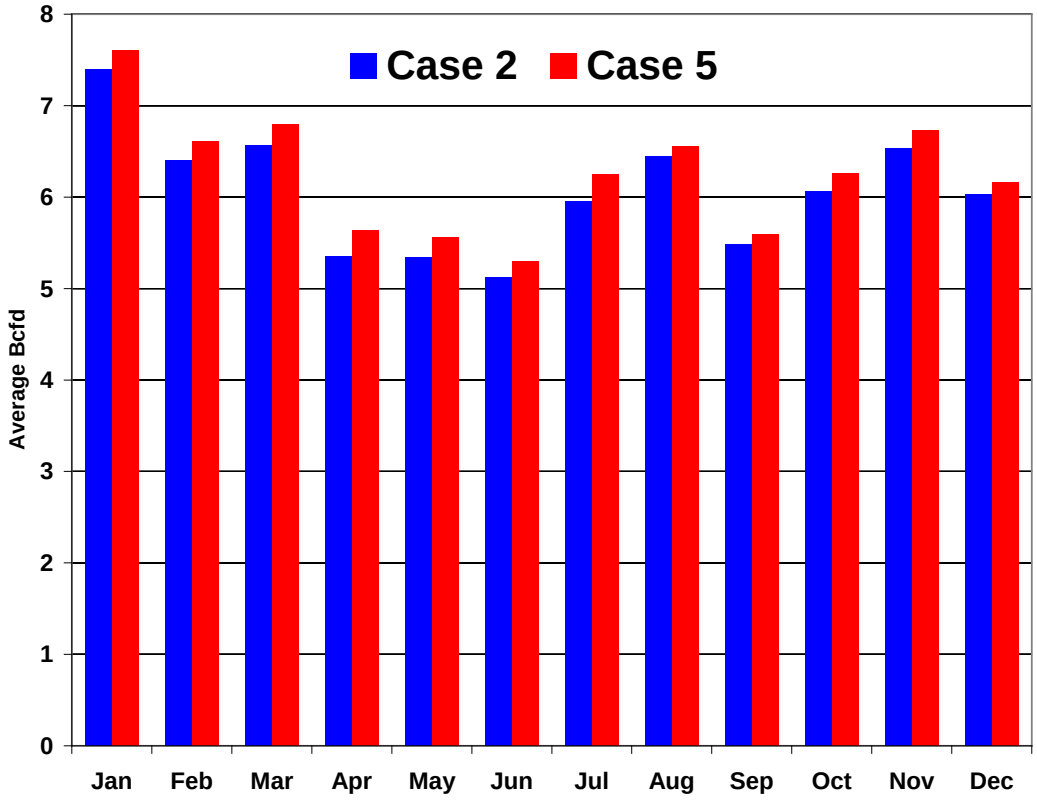


Figure 96: California Monthly Gas Consumption in 2020, Case 5 vs. Case 2

Source: ICF International

As in the other reduced renewable generation cases, monthly storage withdrawals in Case 5 are very similar to those in Case 2 (Figure 97). By the end of the storage withdrawal season in March 2020 the working gas level in Case 5 is only about 1.2 Bcf lower than in Case 2.

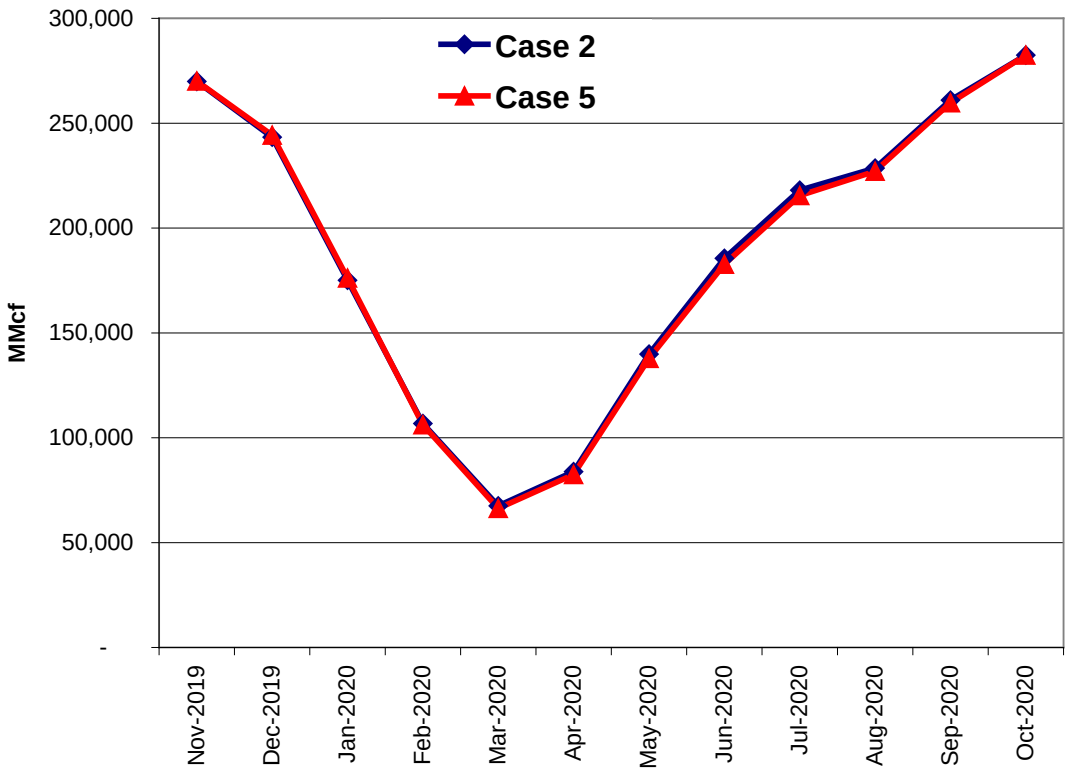


Figure 97: California Storage End-of-Month Working Gas Levels, Case 5 vs. Case 2

Source: ICF International

Peak Analysis

On the peak demand day in January 2020, total gas demand within California is about 9.8 Bcf (Figure 98). This demand level is about 500 MMcf higher than that in Case 2 and all of the demand increase are in the power sector. Peak day demand in this scenario is about 70 MMcf less than in Case 4 (the High Wind RPS Reduced Generation case) and about 40 MMcf greater than in Case 3 (the Reference RPS Reduced Generation case).

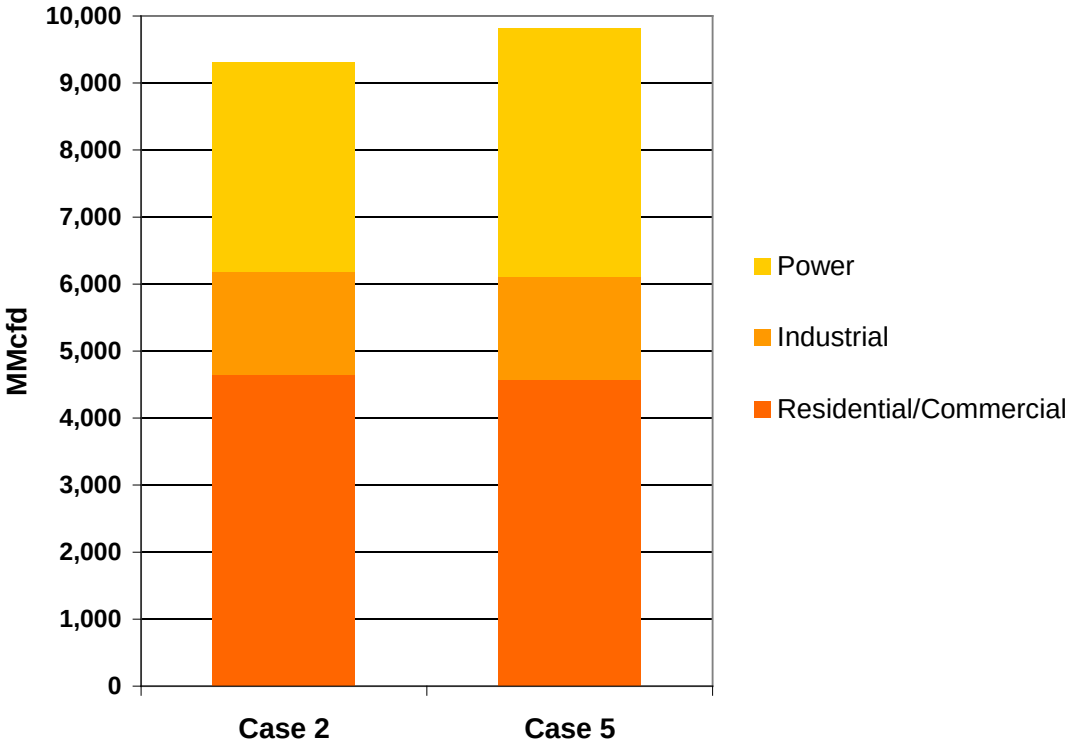


Figure 98: California January 2020 Peak Day Gas Consumption, Case 5 vs. Case 2

Source: ICF International

As in the other reduced renewable generation scenarios, January peak day gas consumption in the power sector is up throughout the State. The increase in southern California is somewhat greater than that in central or northern California. Power generation demand in southern California is up by 290 MMcf, while in northern California demand is up by about 230 MMcf and in central California demand is up by 70 MMcf (Figure 99). This increased demand is met by increased imports of natural gas into California and increased storage withdrawals. Most of the increase in pipeline imports is along the El Paso system in southern California. Most of the increase in storage withdrawals is concentrated at the Aliso Canyon and Honor Rancho fields near Los Angeles. Throughout the State, storage withdrawals are at or near capacity at many fields.

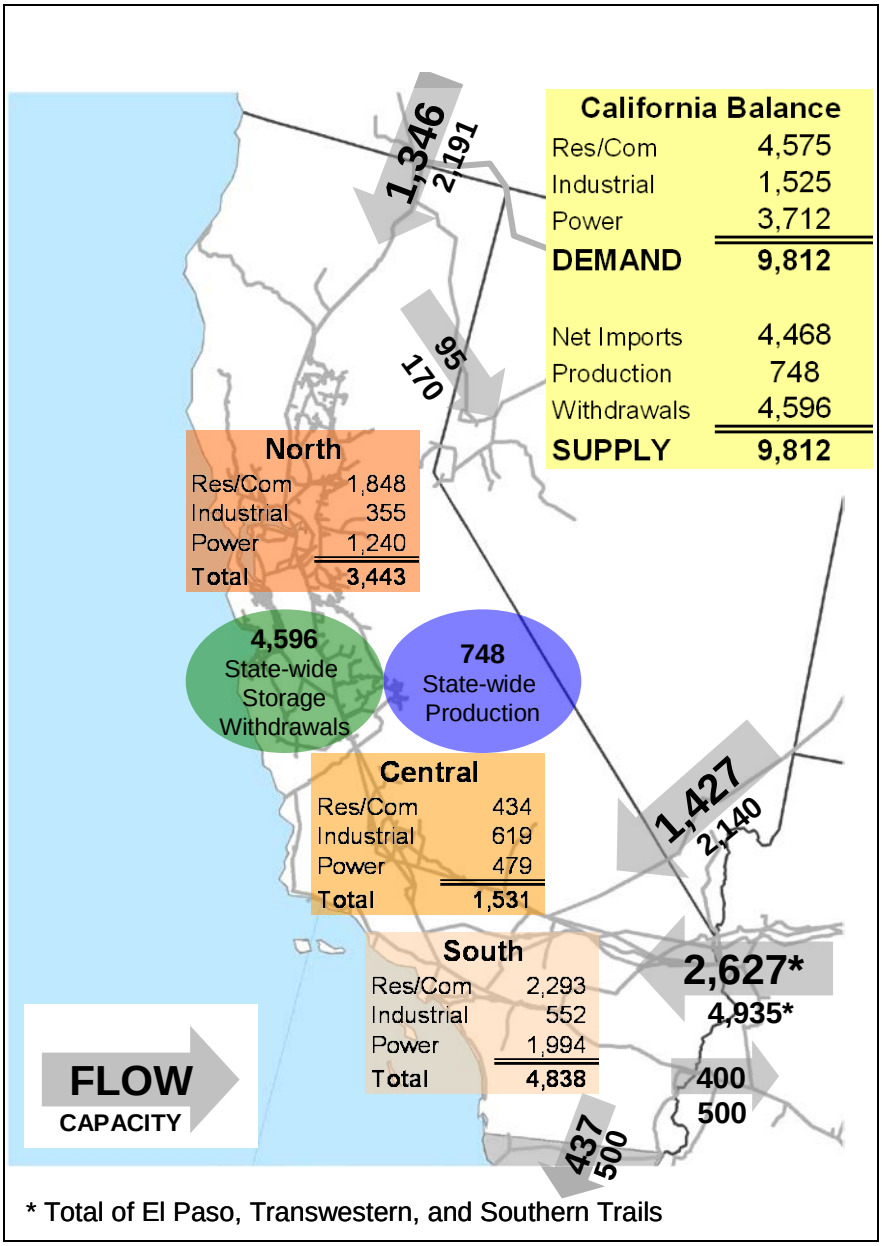


Figure 99: January 2020 Peak Day Balance (MMcfd), Case 5

Source: ICF International

The reduction in renewable generation in Case 5 causes a demand increase of about 270 MMcf in southern and central California compared to Case 2 (Figure 100). About 230 MMcf of the demand increase is met by increased natural gas pipeline imports on the El Paso system. The remainder of the demand increase is met with additional storage withdrawals within the area. As in the other reduced renewable generation scenarios, both pipeline and storage capacity appears to be adequate to meet peak day demand in the area. However, load factors along pipelines serving San Diego are over 90 percent. As in the other reduced renewable generation

cases, these results indicate that pipelines serving the San Diego area may become constrained during peak gas demand periods in both the winter and summer months.

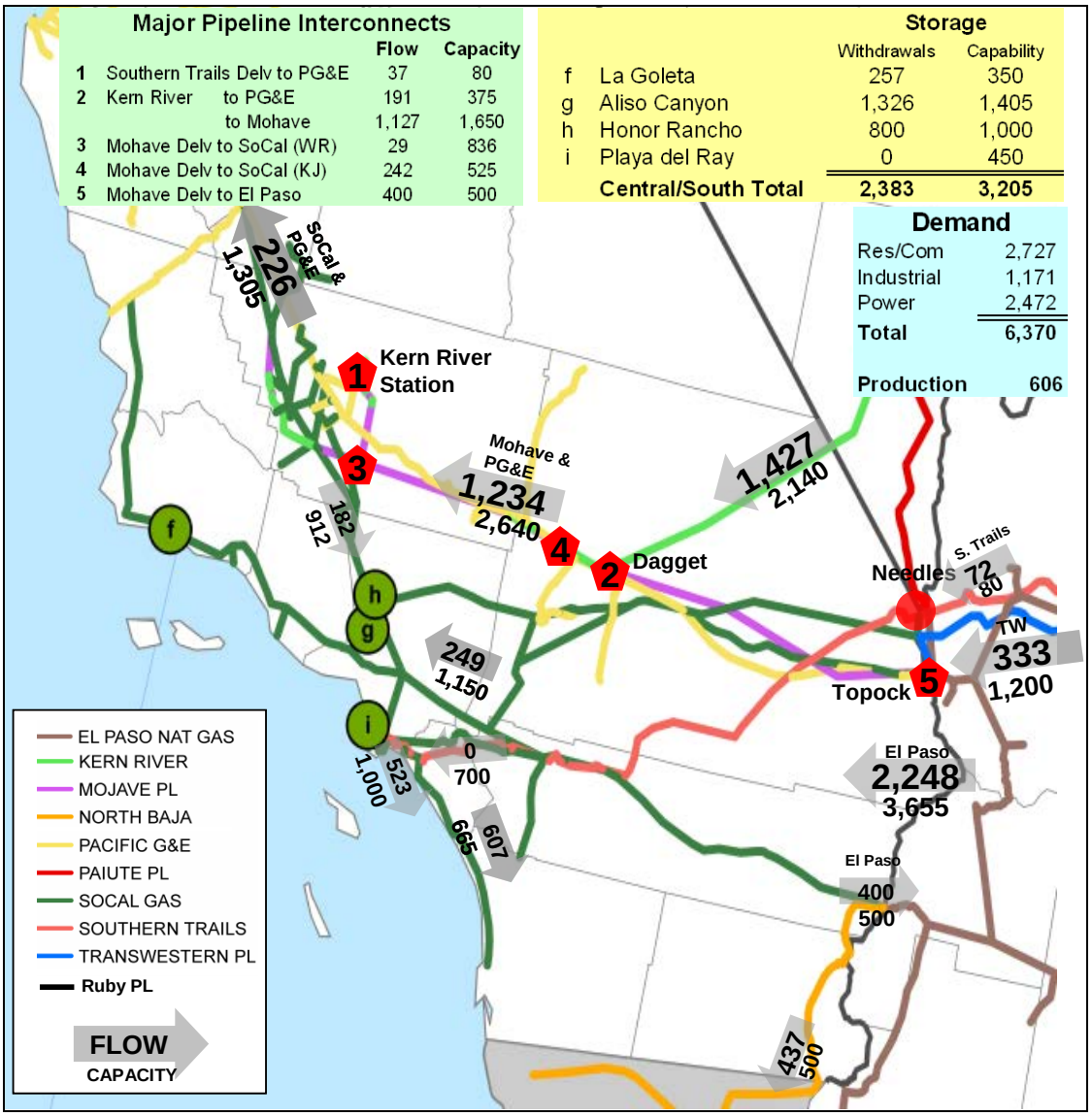


Figure 100: January 2020 Peak day Flows in Southern/Central California (MMcfd), Case 5

Source: ICF International

Comparing Case 2 with Case 5, average January demand in southern and central California is up by about 80 MMcf (Figure 101). Almost all of the incremental demand is met by increased imports on the El Paso system.

Compared to the peak day demand in Case 5, average January demand is about 1.4 Bcf lower. Of the additional demand on a peak day, over 900 MMcf is in the residential/commercial sector. The remaining 450 MMcf is in the power sector. All of the additional supply needed to meet peak day demand is supplied by additional storage withdrawals within the area.

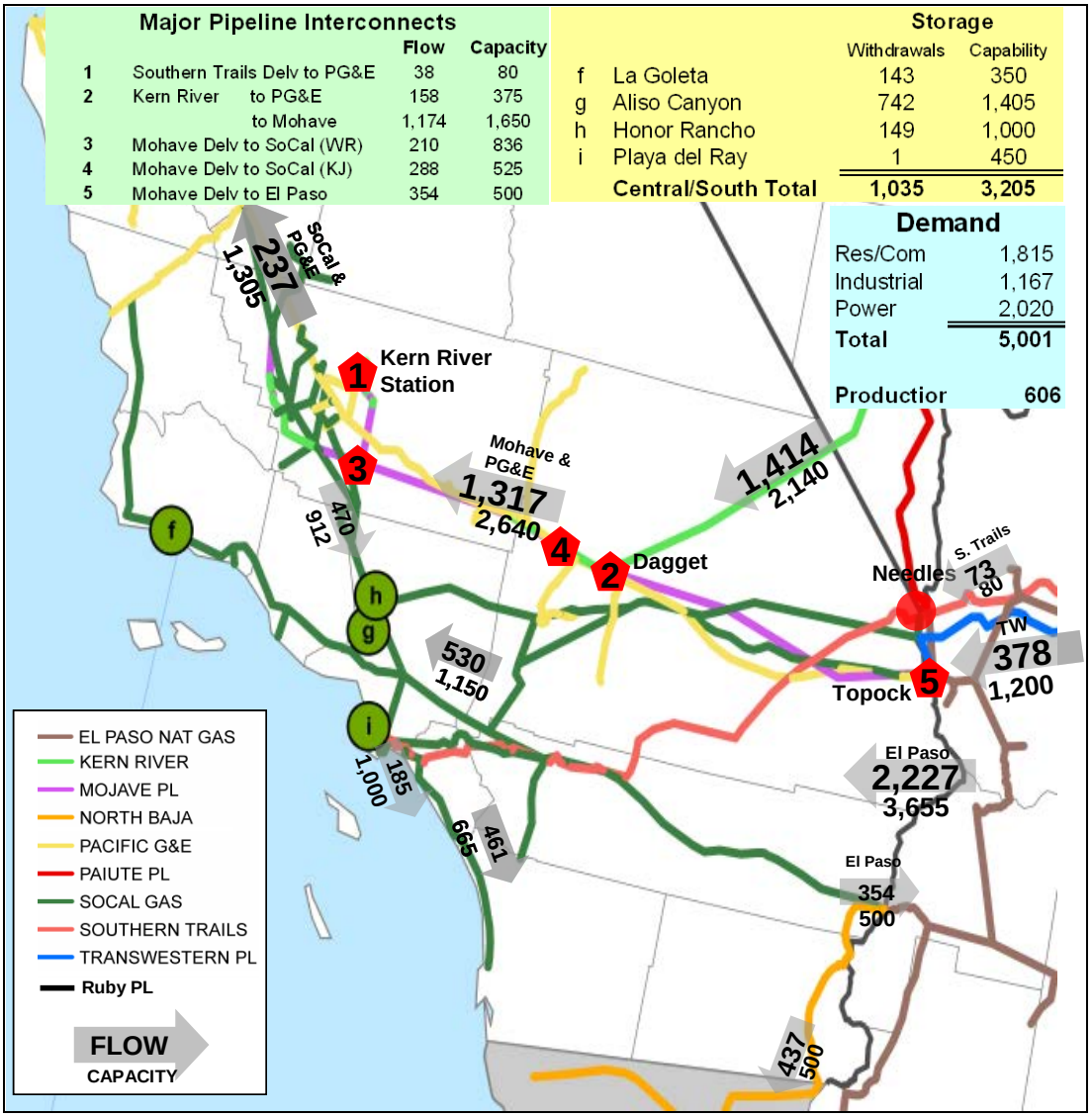


Figure 101: January 2020 Average Flows in Southern/Central California (MMcfd), Case 5

Source: ICF International

Peak day demand in northern California in Case 5 is up by about 230 MMcf over Case 2 (Figure 102). About 190 MMcf of the increase is met by additional storage withdrawals and about 40 MMcf comes from additional imports at Malin. Similarly to the other two reduced renewable generation cases, four of the eight storage fields in northern California are withdrawing at their full capability on the peak day. However, even if the withdrawal capability at these fields is being overestimated, there are still remaining unused pipeline import capacity and storage withdrawal capability at other fields to help meet peak day demand.

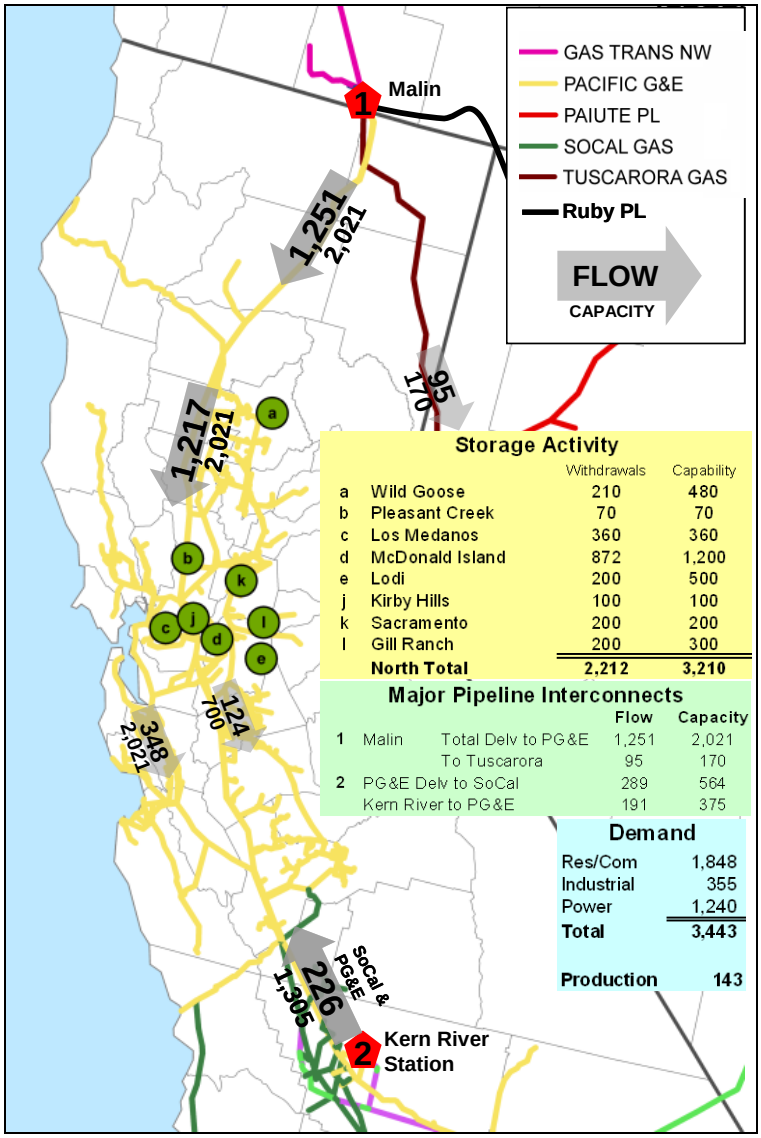


Figure 102: January 2020 Peak Day Flows in Northern California (MMcfd), Case 5

Source: ICF International

In northern California, average January demand is up only slightly compared to Case 2; demand in Case 5 is only about 50 MMcf higher than in Case 2 (Figure 103). The increase in demand is met by increased in both pipeline imports at Malin and regional storage withdrawals.

Compared to the peak day in Case 2, the average January demand in northern California in Case 5 is lower by about 940 MMcf. Compared to the average day, gas demand on the peak day is 650 MMcf higher in the residential/commercials sector, and 280 MMcf higher in the power sector, with a slight increase in industrial demand. All of the additional peak day demand is met with additional storage withdrawal.

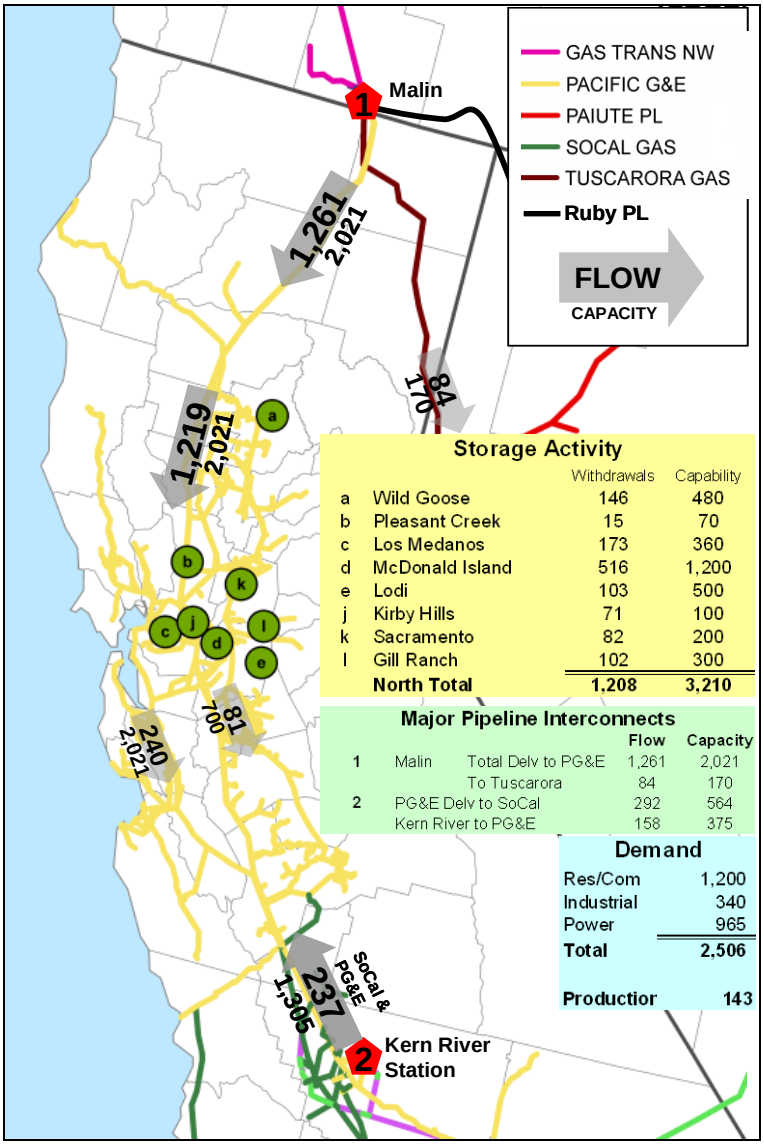


Figure 103: January 2020 Average Flows in Northern California (MMcfd), Case 5

Source: ICF International

3.6 Summary and Conclusions

3.6.1 Key Assumptions Driving Case Results

As with any modeling analysis, the results of this study are dependent on the underlying assumptions. This section of the report highlights what we have identified as the key assumptions that could cause the outlook for California's natural gas market to deviate from this study's projections.

1. *Electric Load Growth.* This analysis used the Energy Commission's 2007 projection of 1.1 percent per year growth in California's electric load. Many factors, such as the rate of economic growth and the impacts of energy efficiency and demand-side management (DSM) programs, can affect the rate of growth in electricity demand. If the rate of

electric load growth is greater than assumed, then incremental growth in gas-fired generation and power generation gas demand will most likely be more than projected. Likewise, if electric load growth is lower, then incremental growth in gas-fired generation and power generation gas demand will most likely be less than projected.

2. *Wind and Solar Variability.* Historical data on actual wind and solar generation are very limited. While data on historical wind speed and solar radiation are more extensive, they have other limitations, such as the limited number of weather stations located near prime wind and solar locations. Since the estimates for wind and solar variability used in this study are based on a limited amount of data, the potential variability in generation (and the consequential variations in gas demand for power generation) may be more or less than represented in this study.

3. *Electric Transmission Constraints.* A detailed analysis of California's electric transmission network was outside of the scope of this study. Consequently, we assumed that reductions in RPS generation within an area (northern, central, or southern California) will be met with increased gas-fired generation in the same area. Limitations on the ability to transmit electricity within each area could result in a different dispatch pattern for gas-fired power plants, and therefore different loads on the natural gas infrastructure. However, it the electric grid is more robust than represented, power generation gas consumption in areas with pipeline constraints (such as San Diego) may be lower than projected.

4. *Representation of the Natural Gas Infrastructure*. The analysis is based on a county-level assessment of mainline capacities, storage field locations, and gas demand. There could be potential constraints within counties and in local distribution systems that are not apparent in this analysis.

5. *Hourly versus Daily Variations in Generation*. This analysis focuses on seasonal and daily variations in renewable generation; the impact of hourly variations has not been assessed. Hourly variations in wind and solar generation could create additional variability in demand for gas-fired generation. However, since pipeline and distribution companies have flexibility in their infrastructure (through line pack and storage) to respond to hourly variability in gas use, we feel that hour variations in renewable generation would have a minimal impact on gas infrastructure.

6. *Optimization of Storage Withdrawals*. The RIAMS model, which was used to project intra-state pipeline flows and storage activity, optimizes the use of storage within the month of January to meet peak day demands. That is, the model knows the exact level of gas demand for each day, and will forgo withdrawal on lower demand days to make more gas available on higher demand days. It is possible that on peak gas demand days, actual pipeline flows would be higher and storage withdrawals would be lower than levels projected by RIAMS. However, the results still suggest that there is ample inter- and intra-state pipeline capacity available on peak days.

3.6.2 Conclusions

A 33% RPS Results in an Incremental Reduction in California's Gas Demand

Using the Energy Commission's 2007 electric load projection, a 33 percent RPS would result in greater incremental growth in renewable generation than there is growth in electric load. As a result, gas-fired generation is displaced, and gas consumption for power generation decreases over time. With expected levels of renewable generation and normal weather and hydroelectric conditions, California's power sector gas consumption is projected to decline by 0.8 Bcfd by 2020. Since projected gas demand in the residential, commercial, and industrial sectors is flat to down, California's total gas demand is projected to decline by 0.9 Bcfd by 2020. Even with adverse weather and hydroelectric conditions, which increases average annual gas demand by 0.7 Bcfd, gas consumption in 2020 is still projected to be lower than in 2008.

Even if average annual gas consumption does decrease, the natural gas infrastructure must be maintained to meet peak demand periods, which could indicate a significant change in natural gas customer rate structures. However, this issue was not studied in this project.

California's Natural Gas Infrastructure is Adequate to Handle Increases in Peak Day Gas Demand Caused by Reduced Renewable Generation

All of the cases with reduced renewable generation cause an incremental increase in January 2020 peak day gas demand of about 0.5 Bcfd, but these increases were not enough to cause significant problems for the State's gas pipeline or gas storage infrastructure. All the reduced generation cases show similar results. The High Wind scenario (Case 4) has the greatest generation reductions, but still shows no signs of demand curtailments, pipeline congestion, or storage constraints on the January peak gas demand day. In all cases there was ample pipeline capacity entering the State to meet the increased load on a peak demand day. While high, gas storage withdrawals were within the estimated operational limits at all fields, and working gas in storage was not pushed to unreliably low levels.

Gas infrastructure within the State is generally adequate to meet the increased January peak day gas demands in all the reduced generation cases, with one possible exception. The San Diego area distribution lines appeared to be congested in both winter and summer peak gas demand periods. Additional pipeline and/or storage infrastructure may be required in this area to ensure system reliability.

Hourly flows have not been investigated in our study. We understand that on an hourly basis, localized congestion may result from a variety of factors depending on the interplay between renewables and gas generation in various locations. Such localized congestion may require incremental expansion of gas facilities in specific areas. Investigation of hourly flows and localized congestion was beyond the scope and budget for this work.

California's Natural Gas Supply Options and Infrastructure Improve Over Time

United States gas supplies are expected to increase by over 7 Bcfd by 2020, mainly due to increases in domestic production. Growth in Rockies gas production has a direct benefit to California, providing more gas supplies via the Kern River Pipeline and the new Ruby Pipeline

planned for 2011. Increases in production in other areas can also have a positive impact on California's gas supply outlook by making more gas available throughout the U.S.

Several planned projects will increase the supply of natural gas available to California. Ruby Pipeline will provide an addition 1.3 Bcfd of pipeline capacity from the Rockies to Malin. Additional compression and looping on Kern River Pipeline will allow for additional flows on that system. While the Costa Azul LNG terminal may not receive enough gas to become a significant supply source for Southern California, those imports will displace the need for some United States gas exports to Mexico, and therefore make more gas available to the California market.

New storage capacity in California provides additional flexibility for meeting peak demand. Two new storage fields and one field expansion are planned within the next several years, adding over 33 Bcf of storage capacity and 550 MMcfd of maximum withdrawal capability.

Technology Mix and Geographic Diversity in Renewables Minimizes the Potential Impact of Reduced Renewable Generation

While wind and solar generation varies due to changes in weather, other renewable technologies, such as biomass, biogas, and geothermal, do not. All the scenarios assumed between 38 percent and 41 percent of future RPS generation come from non-intermittent technologies, which dampens the potential for variability in total renewable generation.

While both wind and solar technologies have distinct seasonal patterns to their output, to some extent these normal seasonal patterns complement each other. In the summer months, when electric load is highest, wind generation is at its lowest but solar generation is at its highest. Having a mix of both wind and solar generation helps dampen out the seasonal variations of each technology.

Seasonal variations in wind and solar technologies also compliment the seasonal patterns in electricity demand and gas demand. Both wind and solar generation are relatively low in the winter months, when electricity demand is also relatively low. In the summer, when electricity demand peaks, residential and commercial gas demands are at their lowest levels. This means that in the summer, more gas supplies and pipeline capacity are available to meet increased power sector gas demand should renewable generation fall short of expected values.

Geographic diversity also enhances the reliability of intermittent renewable technologies. For example, wind generation can be highly variable at any particular site in California. However, based on historic weather data, it appears unlikely that there would be unfavorable wind conditions simultaneously throughout the State. Having wind farms at many different locations reduces the variability of California's total supply of wind generation.

CHAPTER 4:
Recommendations and Benefits for California

4.1 Recommendations Based Upon Conceptual Analysis of Natural Gas Storage in California

The natural gas market in California is integrated with the broader gas market of the Western states and, indeed, of the whole of North America. As such, the California gas market is influenced by approximately 490 Bcf of storage capacity, with peak deliverability of 9.8 Bcfd. Moreover, there have been proposals for new storage facilities and expansions to existing fields. Nevertheless, it is a legitimate question to consider whether the structure of the market for natural gas storage is such that the "right amount" of storage is available to the gas market in California. The analysis presented provides a way to structure this important question:

- Does the current market provide private sector market participants with the opportunity to identify, quantify, and capture benefits from the value created from natural gas storage transactions?
- Does regulation inhibit innovation and customization of storage service in California in a manner that limits the creation of additional value? If so, is the limitation necessary to prevent undue discrimination in access to service? Is this tradeoff inherent or are there alternatives that can foster improved innovation and customization while maintaining protection from discrimination?
- Are there barriers to entry and expansion that could be reduced while protecting other public policy objectives (for example, land use planning and environmental protection)?
- Are the costs and benefits associated with network reliability internalized to the greatest degree possible without regulatory intervention that creates dead weight efficiency losses?

4.2 Recommendations Based Upon the California Natural Gas Storage Modeling Effort

The regional capacity constraints revealed during the process of this modeling effort present a potential issue going into the future. As the Los Angeles area presented a significant bottleneck as a result of the modeling effort, a potential future study focusing on this area could help to better understand the source of the congestion. The study could determine the level of extreme weather necessary to cause the bottleneck and then focus on the infrastructure necessary to mitigate the problem.

4.3 Recommendations Based Upon the California 2020 33 percent RPS Modeling Effort

Similar to the storage modeling effort, the renewable generation modeling effort revealed a localized bottleneck in the San Diego area during both the winter and summer peak gas demand periods. A future study focusing in on this area could help understand the necessary additional infrastructure in the area, whether it is additional pipeline capacity into the region or storage infrastructure in the area, needed in order to mitigate these peak demand congestions.

4.4 Benefits for California

Using the analysis presented within this report, California can enhance its ability to maintain a healthy, functioning natural gas storage marketplace. The knowledge gained with respect to public and private party interest can ensure that policy decisions don't heavily favor one side of the equation more than the other. Additionally, the information presented regarding determining the optimal level of natural gas storage infrastructure needed by California can be used to enhance future storage siting policies and decisions. Finally, in understanding how innovation and research and development are properly incentivized within the industry, California can work together with private partners to further progress in the development of new and improved natural gas storage technologies and techniques in an efficient manner.

Based upon the findings of the California natural gas storage modeling effort, it can be seen that, since the energy crisis of 2000-2001, the changes made to California's natural gas infrastructure have significantly enhanced the State's ability to cope with similar situations that may occur. In none of the cases run did California's system put up any red flags that would lead to a conclusion that the system was unable to handle the extreme weather scenarios being run.

Based upon the results of the cases run for the 33 percent RPS modeling effort, it can be seen that California's current natural gas infrastructure, with some additional planned pipeline additions and expansions such as the Ruby Pipeline, is capable of reliably serving both of these purposes. The information garnered in Sections 2 and 3 of this report regarding potential regional bottlenecks in the Los Angeles and San Diego areas can be used to inform future infrastructure development decisions in those areas.

GLOSSARY

bbl	Barrel
Bcf	Billion cubic feet
Bcfd	Billion cubic feet per day
Energy Commission	California Energy Commission
CPUC	California Public Utility Commission
DGLM	Daily Gas Load Model
DSM	Demand-Side Management
EIA	Energy Information Administration
FERC	Federal Energy Regulatory Commission
GDP	Gross Domestic Product
GMM	Gas Market Model
GTN	Gas Transmission Northwest
GW	Gigawatt
GWh	Gigawatt-hours
LDC	Local Distribution Company
LNG	Liquefied Natural Gas
MMbtu	Million British thermal units
MMcf	Million cubic feet
MMcfd	Million cubic feet per day
NOAA	National Oceanic and Atmospheric Administration
NREL	National Renewable Energy Laboratory
NWN	Northwest Natural Gas
NYMEX	New York Mercantile Exchange
PG&E	Pacific Gas and Electric
PV	Photovoltaic
R/C	Residential/Commercial

RACC	Refiner Acquisition Cost of Crude
REX	Rockies Express pipeline
RIAMS	Regional Infrastructure Assessment Modeling System
RPS	Renewables Portfolio Standard
SNGS	Sacramento Natural Gas Storage
SoCal Gas	Southern California Gas
Tcf	Trillion cubic feet
TWh	Terawatt hour
WTI	West Texas Intermediate