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*Implications and Policy
Options of California's
Reliance on Natural Gas*

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Preface

This report provides an assessment of the benefits, risks, and implications of the increased use of natural gas to meet California's growing energy needs. It explores several aspects of the issue, including a range of gas demand scenarios, current and anticipated future gas production in California and other regions, interstate and intrastate pipeline capacity, and storage capacity. It closes by reviewing policy alternatives to address the issues identified in the analysis. The report should be of interest to state and regional energy officials, energy utilities and other interested parties. The Energy Foundation and RAND Science and Technology provided the support for this research. The Energy Foundation and RAND will continue to provide analysis on planning issues with respect to energy and the environment.

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Contents

Preface	v
Figures	vii
Tables	ix
Summary	xi
Acknowledgments	xv
Acronyms	xvii
1. INTRODUCTION	1
California's Reliance on Gas for Electricity Generation	1
Approach	4
2. NATURAL GAS DEMAND PROJECTIONS AND PROFILES	6
Projected Natural Gas Demand in California, 2002 to 2010	6
Seasonal Natural Gas Load	9
3. CALIFORNIA'S NATURAL GAS SUPPLY	13
Import Dependence	13
Resources Available to California	15
Upstream Natural Gas Demand	17
4. PIPELINE CAPACITY	19
Natural Gas Storage and Pipeline Relationships	22
A System Constrained	24
5. NATURAL GAS PUBLIC POLICY CHOICES FOR CALIFORNIA	28
Infrastructure Improvement	29
Options for Natural Gas Demand Reduction or Management	31
The Electricity Generating Sector	31
The Residential, Commercial, and Industrial Sectors	34
6. CONCLUSIONS	36
References	39

Figures

S.1.	Future System Capacity Compared with Estimated Demand	xii
1.1.	California In-State Generating Capacity	1
1.2.	Cumulative Net Gas-Fired Capacity Additions	2
1.3.	Projected Natural Gas Consumption for Electricity Generation in California	4
2.1.	Gas Demand in California	7
2.2.	Potential Range of California Gas Demand	7
2.3.	Share of Total U.S. Gas Demand by Application	9
2.4.	Average Western Storage Injections and Withdrawals, 1997–2001	11
2.5.	Projected Change In California’s Seasonal Natural Gas Demand Pattern	11
3.1.	Map of Western Pipelines and Gas Resource Basins Serving California	14
3.2.	Total Production and California’s Share by Major External Supply	15
3.3.	Natural Gas Resources in Major External Basins	16
3.4.	Estimated Total Production and California Share by Major External Supply Basin in 2010	17
4.1.	Southern California Border Natural Gas Prices	19
4.2.	Interstate Transmission Capacity to California	21
4.3.	Existing California Interstate and Receipt Capacity in 2000	21
4.4.	Future California Interstate and Receipt Pipeline Capacity in 2010	22
4.5.	Net Withdrawals and Injections from Storage in California	24
4.6.	Estimated Growth in Monthly Deliveries to California Gas Consumers Through 2010	25
4.7.	Future System Capacity Compared with Estimated Demand	26
6.1.	Impact of Different Scenarios on Gas Demand	36

Tables

1.1.	Plans for New Generating Capacity in the WSCC	3
3.1.	Supplies of Natural Gas to California (Bcf)	14
4.1.	Natural Gas Storage Capacity in the West	23
6.1.	Summary of Scenarios and Possible Impact	37

Summary

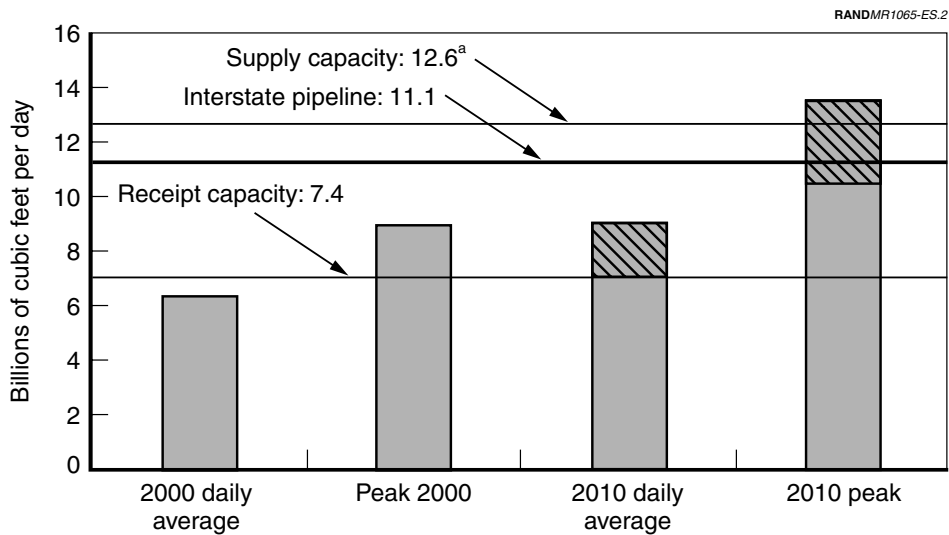
California's current energy plans call for increased reliance on natural gas to meet its growing electricity demand. The California energy crisis of 2000 and 2001 has spurred strong growth in new electric generating capacity—most of it fired by natural gas. As a result, consumption of natural gas for electricity generation could double between 2000 and 2010. The increased demand for natural gas will place a burden on an already constrained pipeline system that serves California and other western states. This report describes likely problems and potential options for addressing and preventing problems in natural gas management in California due to this trend. While the analysis takes a California-centric view, California's dominance as an energy consumer in the West highlights the regional scope of the problem.

In the analysis, we address the following natural gas demand, supply, and transportation issues:

1. We project a range for future California natural gas demand providing upper and lower estimates. California gas demand could increase by between 18 and 50 percent by 2010.
2. California is a natural gas producer, but the share of demand met by local production will remain small. California's reliance on imports may grow sharply over the next decade.
3. Even though it appears that sufficient resources exist to meet demand growth in California and the West, California will have to compete with neighboring states for natural gas supplies. There is considerable evidence that the current pipeline infrastructure is operating very close to capacity and that plans for interstate pipeline expansion may lag behind expected demand growth. Expansion plans for interstate pipeline capacity will, at best, only marginally meet requirements given anticipated demand growth throughout the West.
4. The shift toward gas-fired electricity generation is having an effect upon gas delivery infrastructure in the state. It appears that current publicly available plans for expansion of receipt and storage capacity by 2010 are inadequate to meet the level of gas demand growth projected for California.

5. A growing summer peak in natural gas consumption for electricity generation is making it increasingly difficult to manage storage. This trend is reducing the ability of the system to manage demand fluctuations.
6. In summary, there is a good chance that the existing and currently anticipated infrastructure will be inadequate to meet rising demands (Figure S.1) and that system capacity may fall 3–6 billion cubic feet per day (Bcf/d) short. This creates a risk to California of volatile and rising gas prices and recurring supply problems.

California has both supply-side and demand-side options to reduce the risk of gas price increases and volatility as well as gas supply problems. On the supply side, the state needs to address the infrastructure shortfalls that are evident in the gas supply system before they result in severe market consequences. This means increasing receipt capacity by building new pipelines, increasing the capacity of existing pipelines, and studying the viability of increasing storage capability. To do the latter, the state can provide incentives for utilities to create slack capacity and can also expedite the permitting process to allow additional capacity to be constructed, thereby meeting the growing needs of California consumers and protecting the environment before potential shortfalls and price spikes occur. The lead time required to develop pipeline and storage infrastructure makes the



^aCalifornia production + interstate pipeline capacity to California border + storage withdrawal capacity.
 NOTE: Cross-hatched portion of bar represents uncertainty in the forecast.

Figure S.1—Future System Capacity Compared with Estimated Demand

issue a pressing one for legislators. The regional nature of the problem also requires regional cooperation and planning for management of natural gas transportation and storage needs.

Increasing supply capability is not the only option for reducing the risk of increasing gas demand. There are a number of options for reducing the growth in demand for natural gas. Gas demand can be addressed directly in the residential, commercial, and industrial sectors through the adoption of tougher building codes and appliance standards. In the past, California has had notable success in improving energy efficiency and moderating growth in electricity demand but has been less aggressive in pursuing natural gas efficiency programs directly. The potential exists to improve the efficiency of natural gas use and to slow natural gas demand growth in the residential and commercial sectors despite continued economic and population growth.

California may also seek to moderate natural gas demand growth by using measures directly aimed at electricity generation. This could be done by retrofitting older gas-fired power stations with modern and efficient equipment, replacing antiquated gas-fired power stations, and diversifying the portfolio of electricity generation by including other generation options. In particular, this report includes estimates of the impact of using renewable resources and combined heat and power (CHP) distributed generation to reduce the growth in natural gas demand.

The state needs to view individual energy supply and demand options in the context of a portfolio, and should look at each of these options as having a role to play as a consequence of their particular profile of costs, benefits, timing, and risks. While deriving an optimal mix of these options is beyond the scope of the project, the report develops some scenarios and estimates the impact on new receipt capacity required under different energy portfolio options. Under a scenario with increased renewables, combined heat and power and more aggressive energy efficiency, the required receipt capacity could be reduced to 1–3 Bcf/day by 2010. To hedge against future potential problems, the state should engage in a regional planning process and implement an energy portfolio designed to address the issues outlined here.

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Acronyms

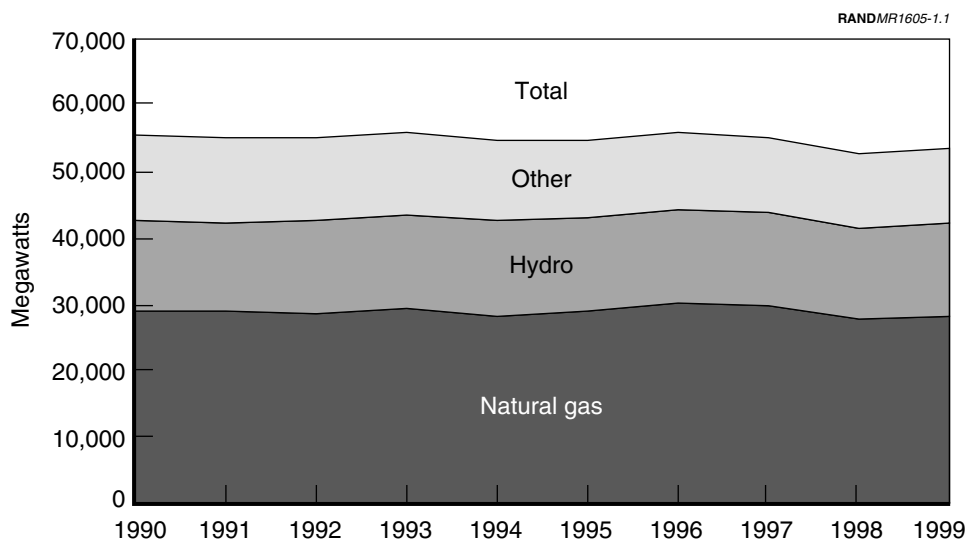
AEO	Annual Energy Outlook
Bcf	Billion cubic feet
Bcf/d	Billion cubic feet per day
Btu	British thermal unit
CHP	Combined heat and power
CEC	California Energy Commission
DOE	U.S. Department of Energy
EIA	U.S. Department of Energy, Energy Information Administration
GRI	Gas Research Institute
GTN	Gas Transmission Network
GW	Gigawatt
mcf	Thousand cubic feet
MMcf	Million cubic feet
MMcf/d	Million cubic feet per day
MMcf/month	Million cubic feet per month
MW	Megawatt
RPS	Renewable portfolio standard
SDG&E	San Diego Gas and Electric
SJB	San Juan Basin
Tcf	Trillion cubic feet
WSCC	Western Systems Coordinating Council

1. Introduction

California's Reliance on Gas for Electricity Generation

Beginning in the summer of 2000 and continuing through 2001, California suffered from a variety of energy problems. Wholesale electricity prices rose to unprecedented levels in the latter part of 2000. By December 2000, wholesale prices exceeded \$376 per megawatt hour, 11 times the price one year earlier. High wholesale prices resulted in a steep rise in retail electricity prices. The related problems produced shortages, rolling blackouts, increased electric bills for consumers, and the bankruptcy of one of the state's utilities.

The crisis forced the California electric system to operate with thin electric generation and transmission margins. The situation also highlighted a structural problem with California's electricity generating portfolio. California's in-state generating portfolio depends primarily on two sources—natural gas and hydropower—as shown in Figure 1.1. With the exception of 1999–2000, natural

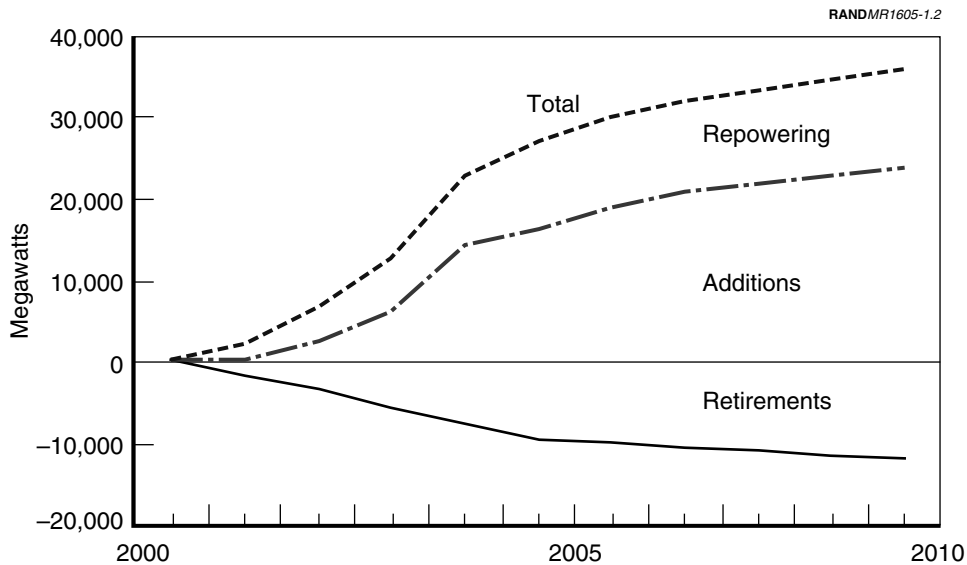


SOURCE: DOE/EIA Inventory of Electric Utility Power Plants in the United States, 1994-1999, Inventory of Nonutility Electric Power Plants in the United States, 1999-2000 and RAND estimates.

Figure 1.1—California In-State Generating Capacity

gas and hydroelectricity have generally worked well together in California and the West to provide a flexible system that can respond rapidly and efficiently to load fluctuations. In addition, California has used natural gas storage to meet peak demand requirements and to add greater flexibility to the gas delivery system. However, specific characteristics of hydroelectricity and natural gas were contributing factors to California's electricity crisis. For example, the bottoming of a coincident national boom-bust cycle in the natural gas exploration and production industry led to short-term gas supply constraints across the nation and higher natural gas prices—just when gas generation was needed to make up for the shortfalls in hydroelectric generation due to the drought in the Pacific Northwest. The increased demand for natural gas in the summer of 2000, combined with natural gas market factors, contributed to a large spike in natural gas prices and had an impact on gas storage reserves, causing concern about potential supply constraints during the winter months and contributing to the price increases.

Given current market trends, the diversity of the California generating portfolio is not expected to improve in the near term. In the coming decade, aggressive construction and proposals for new gas-fired generating capacity imply an even greater reliance on natural gas generating capacity. As shown in Figure 1.2, total gas-fired electric generating capacity is expected to grow by 35,000 megawatts (MW) over the next ten years, almost a 50 percent increase from 2000. Since



SOURCE: Based on revised GRI projection for utility and merchant capacity.

Figure 1.2—Cumulative Net Gas-Fired Capacity Additions

hydroelectricity and natural gas have been the primary components of electricity generation in California for several decades, the situation is manageable if there is adequate natural gas supplies and infrastructure planning. As this report will show, however, it is possible that the lack of infrastructure planning may lead to supply and price problems in the future.

California is not alone in its dramatic increase in gas-fired electricity generating capacity. Natural gas is viewed as the fuel of choice throughout the Western Systems Coordinating Council (WSCC). Table 1.1 summarizes current plans for new generating capacity in the WSCC.¹ Of the 91 gigawatts (GW) of proposed capacity, 83 GW will be produced by natural gas-fired power stations. Natural gas is the fuel of choice because of its low capital cost, relative ease of permitting and siting, relatively short lead times for construction, and a perception of low risk. In the past, California would have expected to receive a portion of the electricity generated at facilities throughout the region. Today, much of the new capacity is being developed to meet local demand in the rapidly growing western states. The region-wide increase in natural gas consumption for electricity generation will increase the burden on a constrained interstate natural gas pipeline infrastructure in the West. As we note later in this report, California is at particular risk because of its location at the terminus of the pipeline infrastructure.

New power stations in California would dramatically increase natural gas consumption throughout the state. New plants would operate at higher

Table 1.1
Plans for New Generating Capacity in the WSCC²

	Non-California	California	Total
Under construction	14,700	9,900	24,600
Approved	10,000	1,800	11,800
Under review	22,800	9,300	32,100
Application process	2,200	2,000	4,200
Announced	18,100	100	18,200
Total	67,800	23,100	90,900

¹Note that the siting, application, review, approval and construction process for power stations is complicated and risky. The estimates provided in Table 1.1 are only an indication of planned expansion and are best viewed as indicators of future growth rather than actual projections.

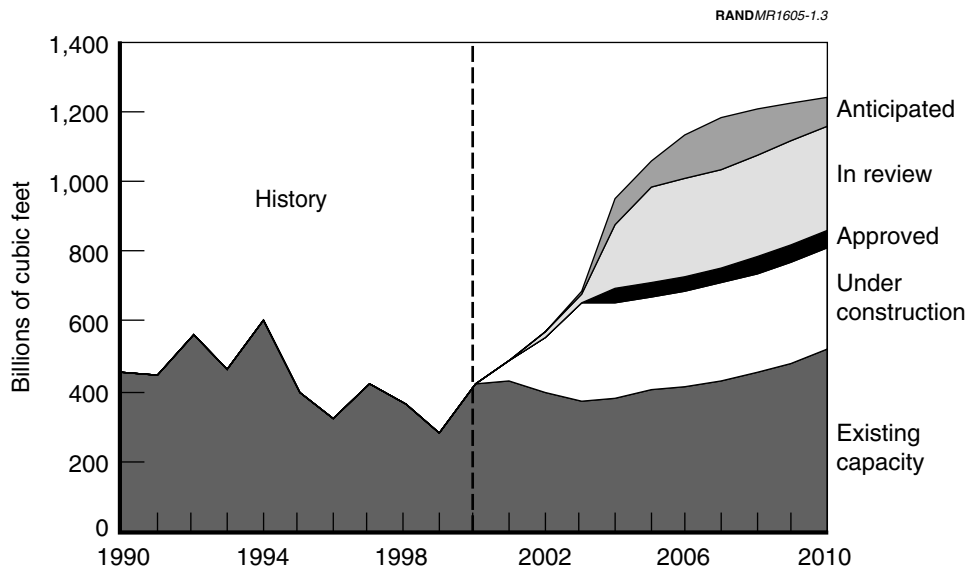
²This table does not include canceled or delayed plants. As of April 2002, in California 680 MW have been canceled and 8,022 MW have been delayed. This represents about one-fourth of the potential demand growth. The reinstatement of these plants depends primarily on the pace of state and national economic recovery and the return to financial health of independent power producers.

utilization rates than the previous generation of gas-fired plants that were intended mostly for use in meeting peak electric demand requirements. Figure 1.3 illustrates this point. If all of the planned capacity were installed, consumption of natural gas for electricity generation could increase by up to 800 billion cubic feet annually over the next few years. Gas demand growth for electricity generation is projected to outpace gas demand growth in the residential, commercial, and industrial sectors. However, the strong demand growth for electricity generation could stress the transmission and distribution infrastructure, which would have an adverse impact on all sectors.

Will increased reliance on natural gas result in years of energy supply instability and price volatility? Choe (2001) studied the trend toward increased adoption of natural gas as an electricity-generating fuel of choice in Washington State and has raised concern about this issue.

Approach

To address the above questions for California, we look closely at issues of natural gas demand, production, transmission, and storage. Using projections from the Energy Information Administration (EIA) and the Gas Research Institute (GRI, now Gas Technology Institute), along with California Energy Commission (CEC) power station planning documents, we construct a range of demand projections



SOURCE: Based on revised GRI projection for utility and merchant capacity.

Figure 1.3—Projected Natural Gas Consumption for Electricity Generation in California

that can be used for risk analysis. Additionally we examine the implications of the change in the seasonal demand profile for natural gas. The report next examines the adequacy of interstate pipeline and intrastate receipt pipeline³ and storage capacity. This includes a review of both existing and anticipated capacity based on known expansion plans. Last, we look at the implications for California and potential policy options.

This section of the report introduces and reviews the issues. Section 2 summarizes gas demand in California, develops the projected demand range for use in the analyses, and discusses changes in the seasonal load pattern in recent years. Section 3 examines the adequacy of gas supply and discusses the potential implications for California gas supply of the growing upstream demand for natural gas. Section 4 addresses pipeline infrastructure issues. In particular, it examines the adequacy of interstate and intrastate pipeline capacity and storage capacity. Section 5 discusses the implications and policy options available to California to maintain a more balanced energy system and avoid gas supply shortages and price instability. Section 6 presents our conclusions.

The key questions addressed in the report include the following:

- Can the natural gas supply system serving California handle the increased demand implied by the surge in gas-fired electric generating capacity?
- What are the specific shortcomings and how can they be addressed over the next decade?
- What are the policy alternatives to address the problems created by the increasing reliance on natural gas to meet growing demand for electric power generation?

³The report focuses on intrastate receipt capacity at the California border and not on the entire intrastate system. California is expected to import a majority of the natural gas it consumes; if the receipt capacity is inadequate, it acts as a bottleneck.

2. Natural Gas Demand Projections and Profiles

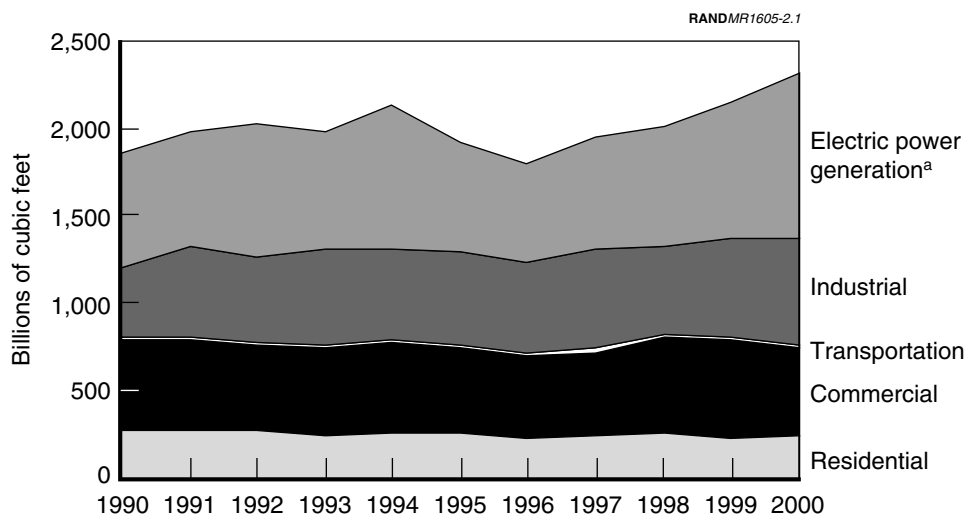
First, we develop a range of natural gas growth estimates for California. A plausible range for growth, not a precise projection, is needed to investigate the adequacy of the gas supply and transportation infrastructure and identify potential policy problems and solutions. Much of the projected natural gas demand growth is for electricity generation, which has a different seasonal load profile from those of the residential, commercial, and industrial sectors. The difference in seasonal load has significant implications for the natural gas delivery infrastructure.

Projected Natural Gas Demand in California, 2002 to 2010

From 1990 to 1999, natural gas demand in California grew more rapidly (2.2 percent per year) than the national average (1.9 percent per year). Increased demand for natural gas for electric power generation (both utility and non-utility sources) was one of the primary causes. Figure 2.1 illustrates that from 1996 to 2000, annual natural gas demand for electricity generation grew from approximately 570 billion cubic feet to almost 950 billion cubic feet. This strong growth was at least partially driven by weather-related factors, including warm summers and the ongoing drought in the Pacific Northwest that reduced hydroelectric capacity. Demand for power generation is expected to be the source of much of the gas demand growth in California over the next decade because of the construction of an unprecedented amount of new central station gas-fired generating capacity.

Two projections were used to estimate the range of gas demand growth. The 2001 Edition of the GRI Baseline Projection (GRI Baseline) was used to establish the upper range of the gas demand; and the 2001 EIA Annual Energy Outlook (AEO) (EIA 2001c), which assumes that California continues to meet much of its electricity demand with imports, was used to establish the lower range of the gas demand. The CEC's projection of gas demand (CEC 2001a) falls within this range. The projected range is presented in Figure 2.2.

Both the GRI Baseline and AEO projections are based on highly detailed econometric and engineering models and on project demand by sector (e.g.,



^aIncludes gas consumed by utilities, merchant and cogenerators in the commercial and industrial sectors.

SOURCE: DOE/EIA. *Historical Natural Gas Annual, 1930 Through 2000* and RAND estimates for industrial and commercial cogeneration and merchant plant consumption.

Figure 2.1—Gas Demand in California

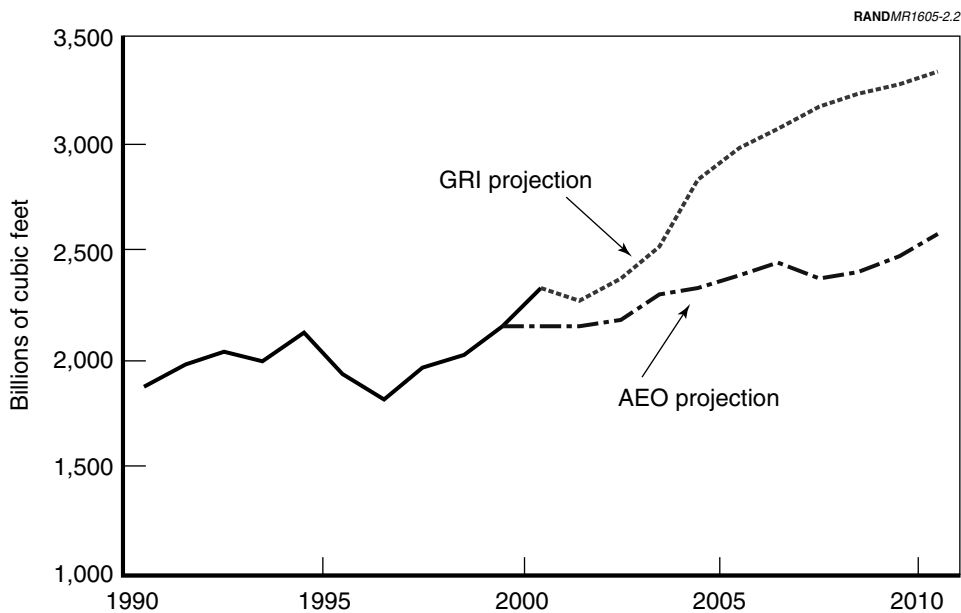


Figure 2.2—Potential Range of California Gas Demand

residential, commercial, industrial, electric generation, and transportation), energy application, and region (generally census regions with some sub-census regional detail). Both also include extensive detail on energy supplies and price by fuel type.¹ They are used regularly as references by other organizations. Not surprisingly, given the complexity of the problem and the opportunity for interpretation, the GRI Baseline and AEO projections differ by more than 700 billion cubic feet (Bcf) per year by 2010.

Although the projections were released last year, each analysis dates from 1999 and 2000. The GRI Baseline projection was released in March 2001, and its analysis was performed between November 1999 and August 2000. The AEO projection was released in December 2000 and is the result of analysis performed over the year prior to its release. However, events in the California market proceeded so rapidly in response to the electric crisis during the latter half of 2000 that neither the GRI Baseline nor the AEO projections anticipated an increase in electric generating capacity construction. While some of the plants proposed at the height of the crisis have been canceled or postponed in recent months, the remaining new gas-fired capacity will lead to increases in gas consumption over the next five years.

We adjusted the GRI Baseline natural gas demand projection to better reflect a number of factors relevant to this study. First, GRI's geographic breakdown is presented by census region. RAND apportioned the Pacific 2 (California and Hawaii) regional projection of gas demand by sector to each state based on recent historical shares. The effect of this adjustment is small since little natural gas is consumed in Hawaii. Second, RAND updated the GRI projection to reflect the surge in new electric generating capacity expected in the short term. Data to support this adjustment include stated plans for new capacity, existing capacity retirements, and utilization rates. The data used to make these adjustments were taken from the CEC, EIA, GRI, and other sources. Projected growth in new natural gas-fired capacity after 2005 was reduced as part of this adjustment. We felt that the surge in near-term capacity construction appeared to be saturating the market and would likely limit new construction in the later years. The adjustments were necessary to satisfy our focus on the next decade, and the new natural gas-fired electricity generating facilities will have a significant impact on the pattern and magnitude of gas demand and the relevant policy implications over that time period.

¹Projections from the CEC were not used because we were not able to verify completeness and consistency.

Though the results of the AEO projection are also presented by census region, the relevant AEO region (Pacific) is much larger than the comparable region used in the GRI Baseline. The AEO Pacific region includes California, Hawaii, Oregon, Washington, and Alaska. RAND also apportioned natural gas demand for the AEO Pacific region to each state based on recent historical shares. The California gas demand projection was not adjusted to reflect the near-term surge in new gas-fired generating capacity.

Figure 2.2 presents the adjusted GRI Baseline and AEO projections for natural gas demand in California. The upper line represents the GRI projection and shows natural gas demand in California growing from 2,320 Bcf in 2000 to 3,320 Bcf by 2010. The lower line represents the AEO projection and shows demand growing from 2,145 Bcf in 1999 to 2,570 Bcf in 2010. The following analysis assumes that demand lies within the range established by these two projections.

Seasonal Natural Gas Load

Figure 2.3 shows an estimate of total U.S. gas demand broken out by end-use application in 2000. The dominant application of natural gas in the residential and commercial sectors is space heating. Space heating accounted for an estimated 66 percent of residential and 57 percent of commercial sector gas consumption in 2000. Roughly 25 percent of U.S. natural gas demand in 2000 was used for space heating. Further, the entire space-heating demand for natural gas

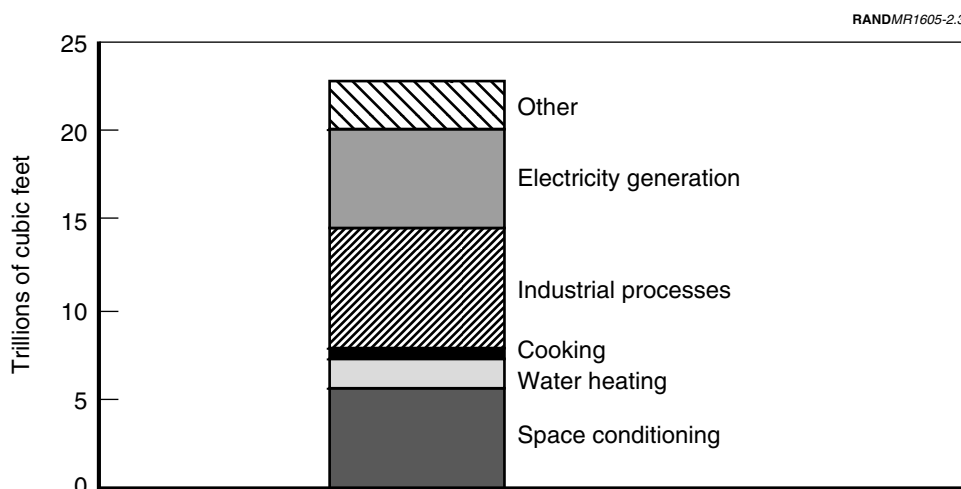


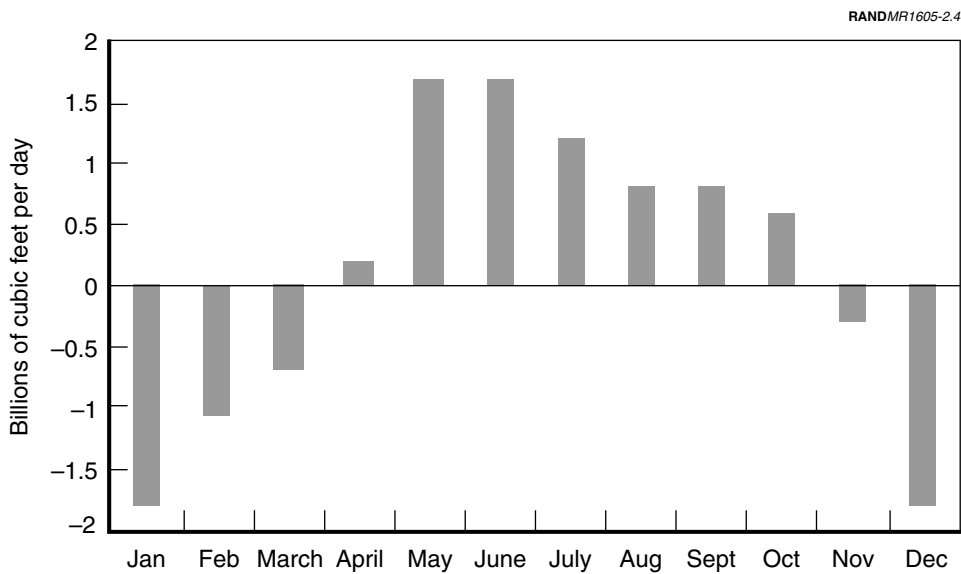
Figure 2.3—Share of Total U.S. Gas Demand by Application

is concentrated in only three or four winter months. Historically, this large share of total gas demand has resulted in a monthly demand curve that peaks in the winter and bottoms in the summer. The seasonal loads have been relatively predictable and this information has been used to plan system expansion and storage utilization (Choe 2001).

The primary driver of natural gas demand growth in both the GRI and AEO projections is electricity generation, which has historically had a different seasonal load profile than the space-heating load in the residential and commercial sectors. The projected disproportionate growth in gas consumption for electric power generation will modify the aggregate seasonal load profile over time. This change in seasonal load profile has significant implications for the natural gas transportation infrastructure (e.g., intrastate and interstate transmission and storage) and for managing gas demand and supply.

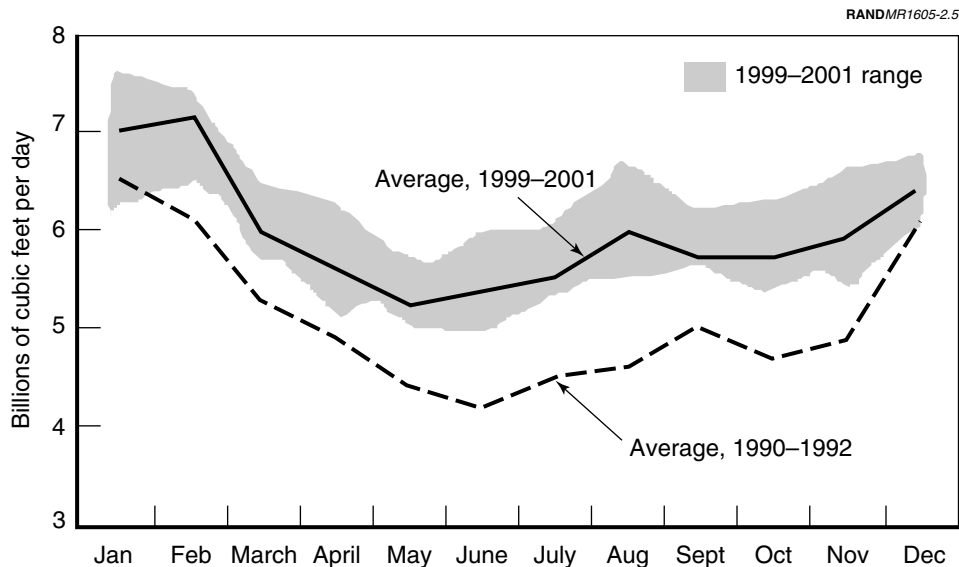
A predictable monthly load curve is essential for the successful planning and utilization of the gas transmission, storage and distribution network. For example, California uses injections and withdrawals to balance the seasonal demand swings in the state and to manage production from some of California's gas fields. The standard procedure is to inject natural gas into storage facilities during the late spring, summer, and early fall and withdraw the gas during the winter months. Figure 2.4 shows the monthly pattern of natural gas injections and withdrawals in western U.S. natural gas storage facilities between 1997 and 2001. All but a small fraction of the western storage capacity is in California.

The increased use of natural gas for electricity generation has gradually changed the monthly pattern of natural gas load in California, and the rapid growth in gas consumption in the coming years may accelerate this shift. Figure 2.5 compares the average monthly demand curve for California over two periods: 1990–1992 and 1999–2001. These curves show the traditional winter peak but also illustrate the development of a summer peak due to the increased use of natural gas for electricity generation to meet space-cooling loads. Electricity demand peaks in the summer months (June–September) primarily due to air-conditioning loads and is generally about 20–25 percent higher in the summer than in the winter months (November to February). The 1999–2001 range, shown by the shaded area, also indicates that the summer peak in a given year can be substantially higher than the average. The growth in this summertime peak will make it more difficult to manage storage and seasonal gas load since injections to storage will need to occur in a shorter period of time.



SOURCE: American Gas Association, "American Gas Storage Survey."

Figure 2.4—Average Western Storage Injections and Withdrawals, 1997–2001



SOURCE: DOE/EIA, www.eia.doe.gov/cmeu/states/_states_ng.html.

Figure 2.5—Projected Change In California's Seasonal Natural Gas Demand Pattern²

²Includes deliveries to gas consumers but excludes transportation, lease and plant, and pipelines.

This shift in seasonal load due to the increased demand for power generation may impact the following:

- the effectiveness of storage facilities to act as a buffer against natural gas availability perturbations
- the ability of storage to offset the impact of the increased utilization of the interstate pipeline system to meet upstream demand growth
- the capability for California to deal with increased regional competition for natural gas supplies.

As the summertime peak grows through increased power production, it becomes more difficult for California to buffer gas flows with storage, and the gas supply system has less flexibility to deal with unexpected fluctuations in demand. The shift also creates the possibility of short-term natural gas delivery problems similar to those experienced during 2000 and 2001. To properly address these concerns and those raised by the growth in natural gas demand, we must analyze the natural gas supply, transport, and storage capabilities in California. .

3. California's Natural Gas Supply

Import Dependence

California is dependent on imports of natural gas, from Canada and the Rocky Mountains. California gas production meets only 15 percent of demand. In the coming decade, domestic California natural gas production is not expected to keep up with growth in demand, so its share will decline accordingly. The increase in natural gas imports will occur at a time when the Pacific Northwest and Mountain regions are also growing and looking toward natural gas as a primary source for meeting energy demand growth. Adequate natural gas resources appear to exist in regions accessible to California to meet demand growth. Therefore, questions about supply adequacy principally involve issues of sufficient investment to turn those resources into deliverable gas and the ability of the pipeline (intrastate and interstate) and storage infrastructure to deliver that gas to customers.

Table 3.1 summarizes the sources of California's natural gas supplies between 1995 and 2000. On average, California imported 1,750 billion cubic feet of natural gas per year or 85 percent of its total demand. The primary sources of these imports were supplies from the Rocky Mountain states and Canada. During the late 1990s, imports from the Rocky Mountain states and Canada met 50 percent and 35 percent of California's consumption, respectively. These areas are expected to continue to be the primary source of California's supply over the next decade.

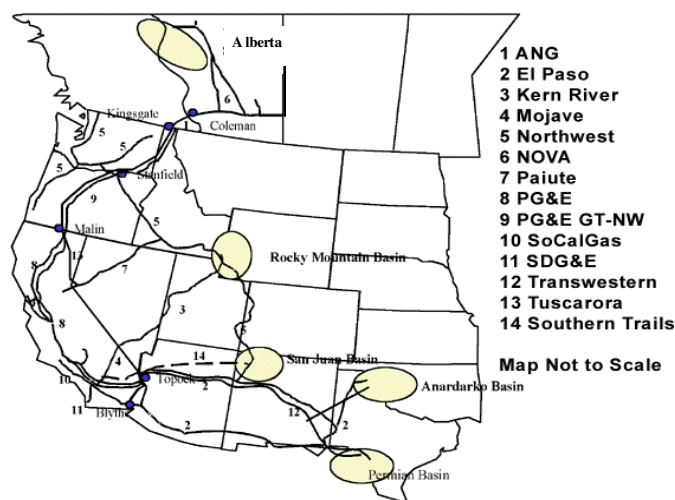
As depicted in Figure 3.1, California relies upon four basins in the Western United States and Canada for its natural gas. The San Juan basin, which straddles the border between northern New Mexico and southern Colorado, is the largest supplier of natural gas to the state (see Figure 3.2). Canadian production (Alberta/BC) dwarfs that of most U.S. basins; this area is the primary supplier of natural gas to the Pacific Northwest (Choe 2001) and the Midwest. California consumes 11 percent of this basin's production. California and the Pacific Northwest compete for access to the Rocky Mountain production. Historically, California also consumed gas from the Permian basin in Texas. Though the state

has ceased to rely upon this source, it may be a future option to diversify sources of natural gas.¹

Table 3.1
Supplies of Natural Gas to California (Bcf)

	1995	1996	1997	1998	1999	2000
California-produced	268	274	274	305	372	366
Continental U.S.–Produced	949	819	898	1084	1174	1250
Canadian-produced	742	729	773	736	621	640
Withdrawal from storage	27	51	16	(41)	8	48
Total supply	1986	1873	1961	2083	2175	2303
Total demand	1925	1807	1947	2015	2146	2322
Unaccounted for ^a	61	66	14	68	29	(19)

^aMeasurement error due to pressure and temperature differentials as well as loss due to system leakage.

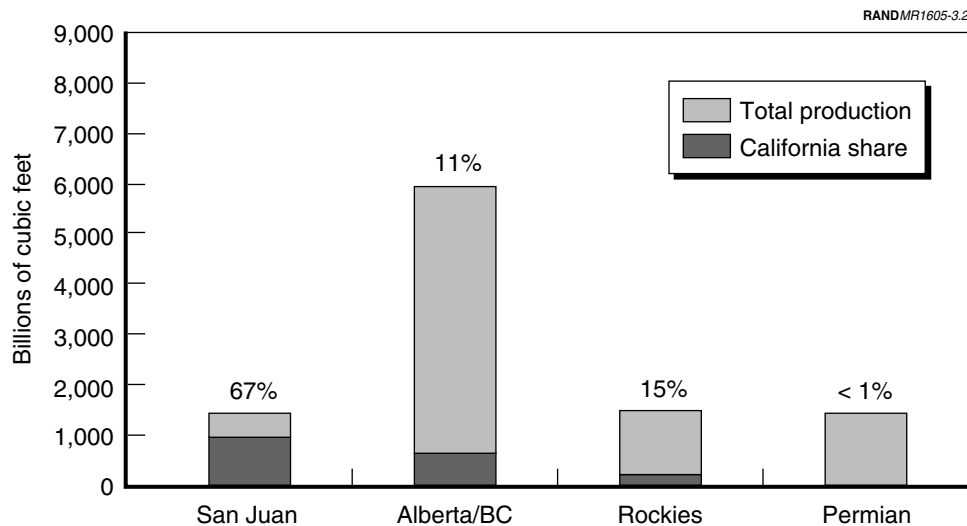


Source: California Energy Commission. <http://www.energy.ca.gov/>

naturalgas/western_state_pipelines.html

Figure 3.1—Map of Western Pipelines and Gas Resource Basins Serving California

¹ We will not discuss the geological surveys and estimates of total natural gas resources in North America. All estimates indicate that the natural gas resources are sufficient to meet demand for at least several decades (see, for instance, the *GRI Baseline Projection Data Book*, 2001 edition.) The existence of such abundant supply makes the planning problem one of leasing, exploration, field development, production, transmission, and distribution.



NOTE: Percentages represent California's share.

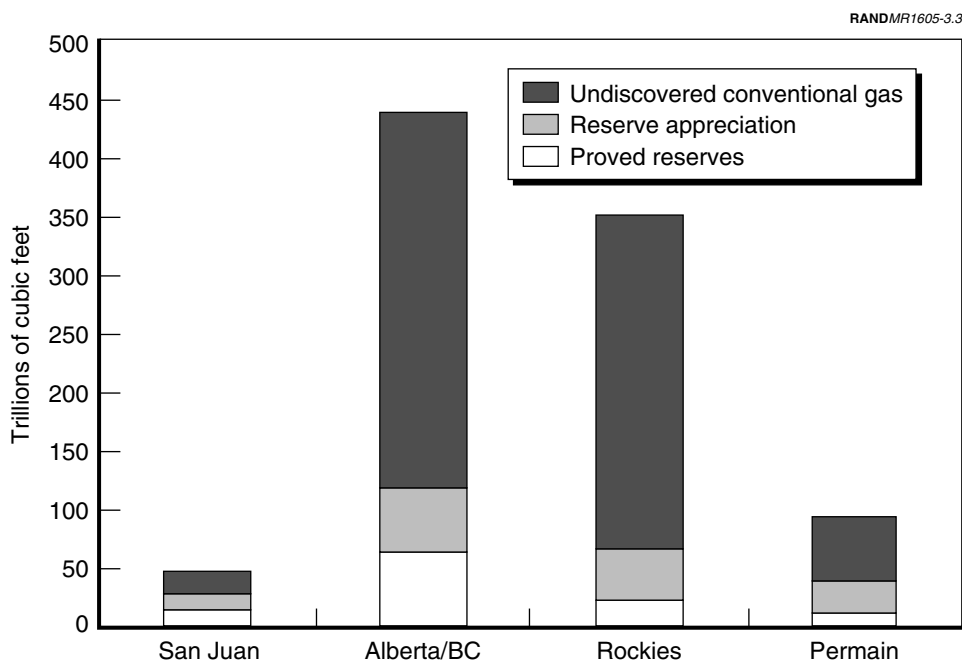
SOURCE: DOE/EIA. Natural Gas Annual 2000.

Figure 3.2—Total Production and California's Share by Major External Supply Basin in 1999

Current natural gas production in California is approximately 350 Bcf per year. Production as a percentage of total demand is expected to decline gradually, so reliance on imports will increase as demand grows. Projections indicate that in-state California production can be expected to satisfy approximately 10 percent of demand by 2010, versus a 15 percent share in 2000.

Resources Available to California

The resource basins that currently serve California will continue to be the primary source of supply over the next decade. Based on resource estimates taken from the 2001 GRI Baseline Projection, the San Juan, Alberta/British Columbia, Rocky Mountain and Permian basins have natural gas resources that range in size from 50 to 450 trillion cubic feet (Tcf) (Figure 3.3). Given current production rates, this implies basin lives from 30 to 75 years. While there is uncertainty about any resource estimates and their availability for development, the resource should be adequate to meet supply needs for at least the next ten years. However, it is also important to note that the San Juan basin, upon which southern California relies for much of its current supply of natural gas, has the smallest resource. Over the long term, California may have to replace imports from the San Juan Basin if production begins to decline.



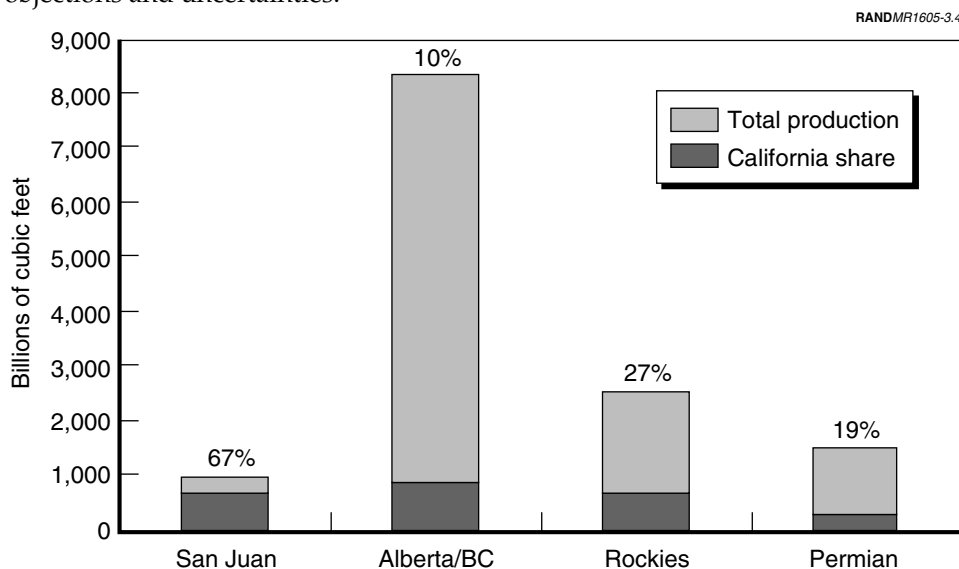
SOURCE: Based on GRI resource estimates. Dated December 31, 1998.

Figure 3.3—Natural Gas Resources in Major External Basins

Given current projections of production from California's major external natural gas supply basins, California can expect a similar mix of natural gas suppliers. Figure 3.4 shows projected total production and California's fraction based on the GRI demand scenario described in Section 2. In this scenario, the same four supply basins meet California's demand increase with the shares from each basin roughly proportional to today's shares.

Liquefied natural gas (LNG) is another potential source of natural gas supply for California. LNG is transported in ships and reheated to a gaseous state at port for transport and delivery through the pipeline infrastructure. The price of imported LNG depends on a number of factors, including the cost of initial production, transport and processing. There is continuing interest in LNG, although there are safety concerns. Currently, there are four LNG terminals in the U.S., but none exist on the West Coast. There is a proposal to build an LNG facility in Baja, Mexico as well as at other locations on the West Coast. Most of these proposed facilities are intended to serve the California market. To date, none of the proposals has progressed very far and all are subject to an assortment of

objections and uncertainties.



NOTE: Percentages represent California's share.

Figure 3.4—Estimated Total Production and California Share by Major External Supply Basin in 2010

Upstream Natural Gas Demand

The prior discussion highlights two aspects of California's natural gas supply situation: (1) Sufficient resources appear to exist to meet supply requirements and (2) California's reliance on out-of-state natural gas resources will increase significantly over time. This subsection discusses the consequences of increasing gas demand outside of California.

Because of its population, climate, size, and economy, California is currently the dominant energy consumer in the West. California consumes over 55 percent of all natural gas in the western states. However, other areas in the West are expected to sharply increase their gas demand in the near term. For example, the Pacific Northwest is expected to increase its reliance on natural gas as a fuel for electricity generation due to limits on hydroelectric resources. Under-construction and approved generation facilities are predicted to result in a 33 percent increase in natural gas demand by 2010 in Washington (from 600 to 800 billion cubic feet annually). Proposed power stations would add an additional 400 billion cubic feet of demand annually (Choe 2001). The result will be a dramatic increase in regional demand for natural gas, which may limit the amount of natural gas available to California from Canada and the Rockies.

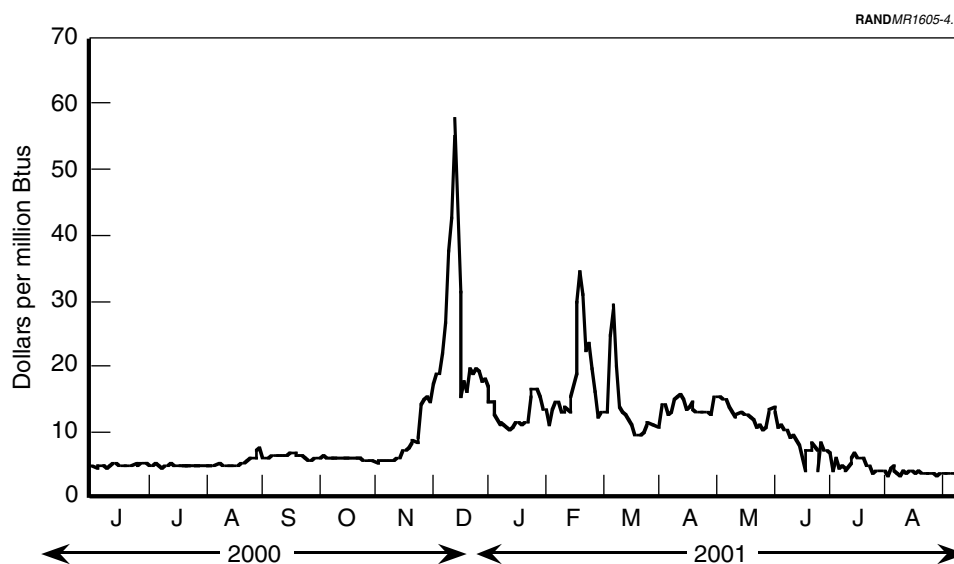
Additionally, other states that lie along the pipelines connecting the supply basins to California continue to expand their use of natural gas. On its way to California, natural gas must travel through Washington, Oregon, Idaho, Montana, Utah, Nevada, New Mexico, and Arizona. Projections from GRI, EIA, and others appear to indicate that natural gas resources are adequate to meet the needs of these states and California, but—as we discuss in the following section—the pipeline infrastructure that carries this gas is severely limited. Therefore, any long-term gas supply contracts for upstream delivery reduce the amount of natural gas that can reach California. For example, 32,553 MW of electricity generation capacity is proposed for construction in the Southwest in the coming decade. The majority of the proposed capacity will use natural gas (CEC 2001). Not all of these plans are expected to come to fruition, but the gas diverted to these generating units will limit the gas available to California.²

² The CEC also notes that there is a trade-off between in-state and out-of-state natural gas consumption for electricity generation: “Natural gas power plants in surrounding states that sell electricity into California theoretically displace natural gas-fired power plants in California. Therefore, the increase in upstream power plant demand may reduce the need for increase pipeline capacity to meet a lower natural gas demand for electric generation within California” (CEC 2001).

4. Pipeline Capacity

Although the electricity crisis in late 2000 and early 2001 received the most media attention in California, problems with natural gas were just as pronounced. In summer 2000, electricity imports from the Pacific Northwest were constrained. “For the first time in a decade, California’s older, inefficient gas-fired generating plants were called upon to operate on a continuous basis. The legal, institutional, physical and fiscal infrastructures all reached their limits simultaneously” (Choe 2001). Throughout the fall, higher-than-average use of gas for electricity generation caused by a number of factors limited the injection of gas into storage in preparation for the winter peak gas demand period.

The result was price volatility and shortfalls in natural gas availability. On a monthly average basis, gas prices rose by a factor of five at the southern California border. The resulting spike in daily gas prices was even greater. Figure 4.1 illustrates the spike in natural gas prices that occurred at the California border in 2000 and 2001.



SOURCE: Enerfax, <http://www.enerfax.com> (2002).

Figure 4.1—Southern California Border Natural Gas Prices

The CEC expects that total consumption of natural gas will reach approximately 2,750 billion cubic feet by 2010 (CEC 2001a), which falls in the range set by the GRI and EIA estimates discussed in Section 2. The CEC, GRI, and EIA all agree that sufficient natural gas resources exist to meet California's 2010 demand needs (CEC 2001a; GRI 2001; EIA 2001a). The problem by 2010 is more likely to be the transmission infrastructure. Constraints within this system have a high probability of causing delivery shortfalls and price volatility as demand grows.

This section examines the adequacy of interstate natural gas pipeline capacity and California receipt capacity with respect to projected California demand growth over the next decade and the supply sources discussed earlier. We do not examine the entire intrastate pipeline system in detail but instead focus on the receipt or border capacity, which has the potential of being a key bottleneck. Our analysis indicates that interstate and receipt pipeline capacity is and will remain very tight. "Slack capacity"—the natural gas equivalent of an electric generator's reserve margin—is limited, and increases in capacity are uncertain. This lack of capacity casts doubt on the ability of the transmission system to serve California's demand. There is a high risk that the receipt and interstate pipeline capacity will fall short of future demand requirements.

Figure 4.2 is a map of the major natural gas pipelines serving the southwestern United States (EIA 2000b). The PG&E Gas Transmission Network (GTN) pipeline serves Northern California. The Kern River pipeline serves electric generation and industrial customers in Eastern California. The Transwestern Pipeline at Needles and the El Paso pipelines at Ehrenberg and Topock serve Southern California. San Diego Gas and Electric (SDG&E) operates a pipeline that serves a natural gas generating facility in Rosarito, Mexico. California natural gas customers are served by four geographically distant supply areas—the San Juan basin and basins in Texas, the Rocky Mountains, and Alberta/British Columbia in Canada—and by six major pipelines that enter California at two primary points, one in northern California and one in southern California.

The delivery capacity of the interstate pipeline system and the receipt capacity of the intrastate pipeline system do not appear to match. Figure 4.3 illustrates the delivery and receipt capacity of the major pipelines. At each interface location, California's receipt capacity is less than the interstate pipeline capacity. The result is that although the major interstate pipelines are capable of delivering 7.3 Bcf/d to California, the infrastructure is only capable of accepting 6.7 Bcf/d (CEC 2001). In and of itself, this is not a significant issue. However, Figure 4.4 shows that when proposed expansions of the interstate pipeline system to California are included, delivery capacity will reach 11.1 Bcf/d by 2010, but publicly available

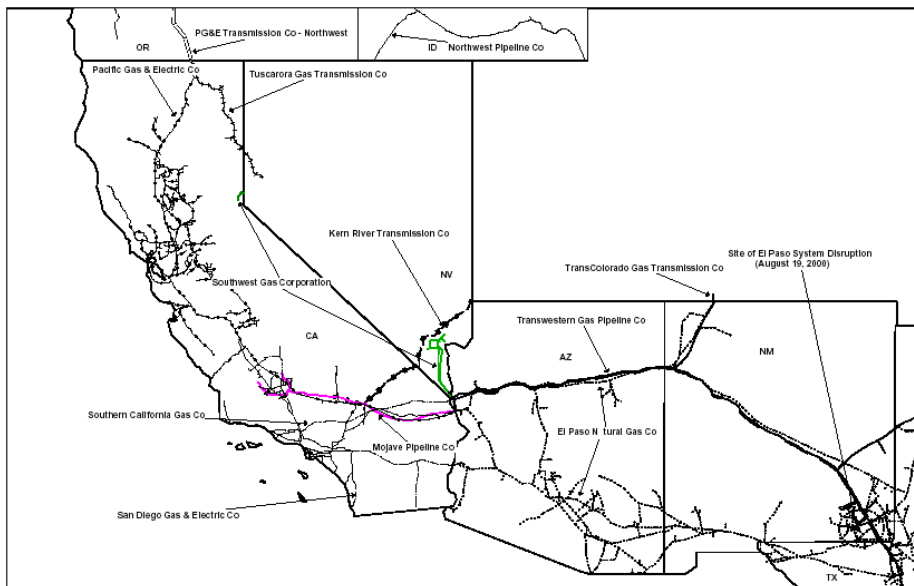
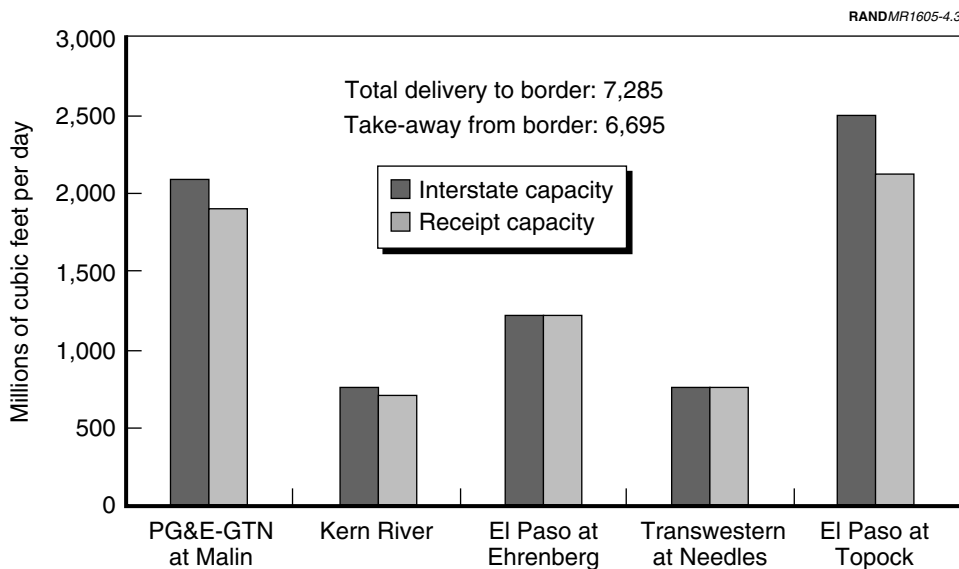
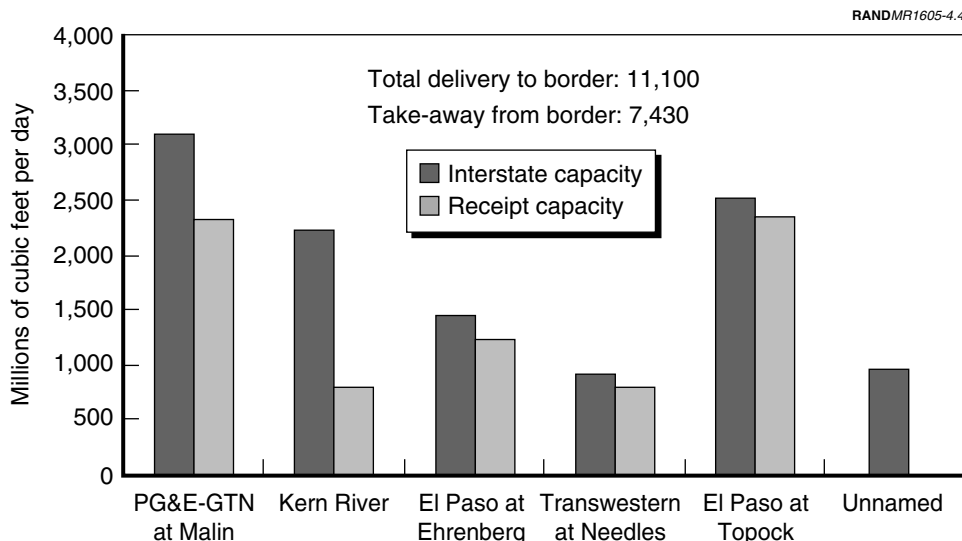


Figure 4.2—Interstate Transmission Capacity to California



SOURCE: DOE/EIA, "Electricity Shortage in California: Issues for Petroleum and Natural Gas Supply," www.eia.doe.gov/emeu/steo/pub/special/california/june01article/canatgas.html and California Energy Commission, "Natural Gas Infrastructure Issues," October 2001

Figure 4.3—Existing California Interstate and Receipt Capacity in 2000



SOURCE: DOE/EIA, "Electricity Shortage in California: Issues for Petroleum and Natural Gas Supply," www.eia.doe.gov/emeu/steo/pub/special/california/june01article/canatgas.html and California Energy Commission, "Natural Gas Infrastructure Issues," October 2001.

Figure 4.4—Future California Interstate and Receipt Pipeline Capacity in 2010

expansion plans will boost receipt capacity to only 7.4 Bcf/d. The shortfall in receipt capacity may result in significant problems for California as it attempts to meet growth in natural gas demand.

Natural Gas Storage and Pipeline Relationships

Pipeline delivery capacity is typically less than peak-day natural gas demand. The pipeline system and natural gas storage facilities work together to meet peak demand. The release of gas from the storage facilities increases the amount of gas delivered to customers beyond that available to the state from pipelines; during periods of relatively low load, operators refill storage facilities. Critical to the successful operation of the system is excess pipeline capacity under normal operating conditions. If the pipelines are operating at full capacity, it is impossible to inject or remove gas from storage. California dominates storage in the western United States. Table 4.1 summarizes working natural gas storage capacity in several western states.

The constraints on the pipeline system have an impact on storage system operation. In recent years, California's natural gas storage facilities have supplied

Table 4.1
Natural Gas Storage Capacity in the West

	Total Capacity ^a (Bcf)	Working Gas Capacity ^b (Bcf)	Deliverability ^c (Bcf/day)
Washington	37.3	18.2	1.5
Oregon	21.1	11.7	0.3
California	475.7	228.3	6.7
New Mexico	96.6	20.0	0.4

^aBased on DOE/EIA data: http://www.eia.doe.gov/pub/oil_gas/natural_gas/data_publications/natural_gas_annual/current/pdf/table_014.pdf.

^bMaximum reported amount of working gas in storage since 1990 based on DOE/EIA data: http://www.eia.doe.gov/oil_gas/natural_gas/info_glance/storage.html.

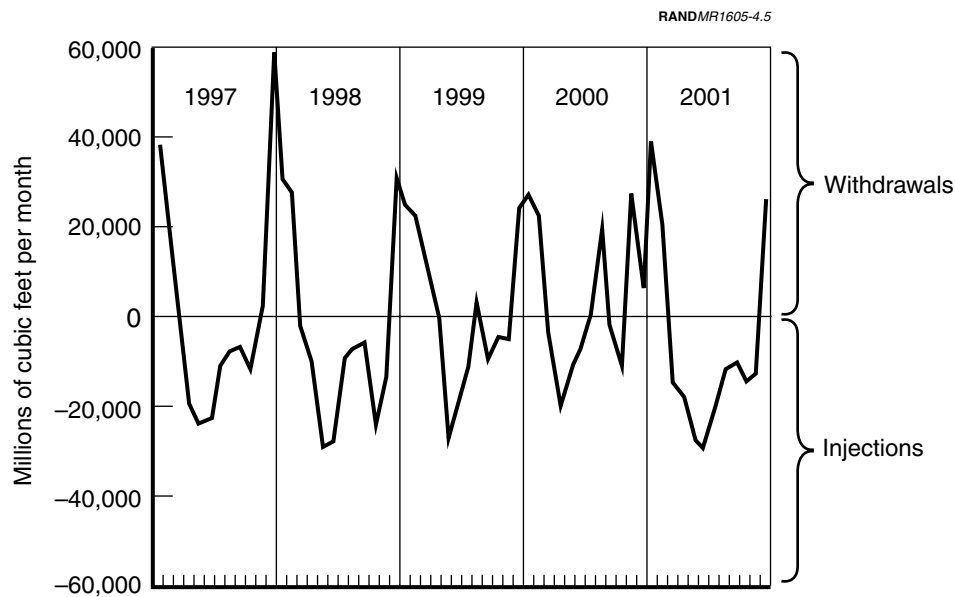
^cDeliverability of natural gas from storage facilities was estimated through extrapolation using 1996 deliverability data and 2000 storage capacity (as reported in the *Natural Gas Monthly*, EIA 2002).

SOURCE: EIA 2002a.

gas to electricity producers to help to meet the increased summer load. (Recall Figure 2.4, which illustrated the typical pattern of natural gas injections in the spring and summer and withdrawals in the winter.) During the period of price and supply problems, there were a number of complicating factors in the storage of natural gas. Gas customers are divided into two classes by the CEC—core customers (residential and small commercial who buy gas directly from the gas utilities) and non-core customers (large industrial concerns, including power plants that buy directly from wholesalers). The gas utilities are responsible for storing gas for the core customers. Non-core customers, including power plants, are responsible for their own storage. They rent space from the utilities but do not necessarily fill it. That is one reason that storage was low after summer 2000. In 2001, the state government arranged a compromise that helped get storage filled for the summer and winter of 2001. Over the long term, however, this issue that needs to be addressed.

System capacity is currently adequate to handle core storage/peaking needs, but it is uncertain whether there will be adequate storage and incentives to meet the needs of the non-core customers. The uncertainty lies in the amount and degree to which non-core electric generators will contract for and fill storage. Their decision to fill or not to fill is primarily an economic one and can be affected by the price of storage (which is set by storage operators), gas price expectations, and the potential exercise of market power by interstate pipelines.

Figure 4.5 shows monthly net injections and withdrawal for a number of recent years. Summer 2001 was comparatively mild; the weather and the weak economy contributed to typical net natural gas injections during the summer months. In general, it is believed that as electric generation demand for natural gas grows,



SOURCE: DOE/EIA, <http://tonto.eia.doe.gov/oog/ftparea/wogirs/xls/ngm13vmall.xls>.

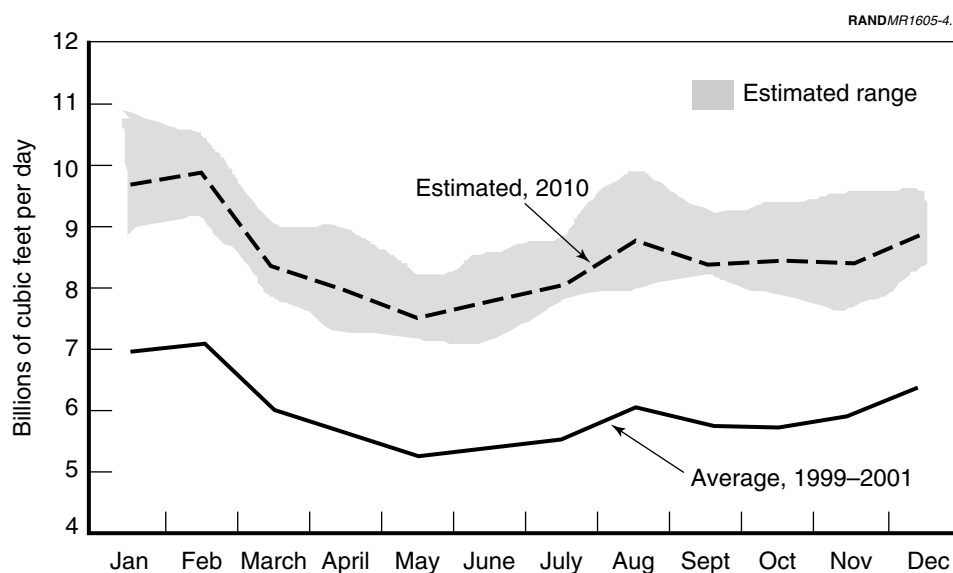
Figure 4.5—Net Withdrawals and Injections from Storage in California

storage facilities will help meet summer peak generation requirements more often. Figure 4.6 compares average monthly gas demand between 1999 and 2001 with projected monthly demand in 2010. It shows a potential increase in demand during the summer months due to increased demand for electric generation. The shaded area indicates a range of potential demand based on typical fluctuations from year-to-year. Based on this range, the peak summer demand could rival the winter peak in years with warm weather. This level of summer demand will limit the storage operator's ability to help meet wintertime peak demand, and natural gas storage will become increasingly important. Questions for policy makers include the following:

- How can we ensure that the electric generators will contract for storage capacity and inject sufficient quantities of gas into storage to meet requirements?
- How can we ensure that adequate storage facilities will be developed as overall gas demand grows?

A System Constrained

The projected growth in natural gas demand will only increase the stress upon the delivery and storage infrastructure. Based on the GRI Baseline and AEO



NOTE: Excludes consumption of natural gas by vehicles, lease and plant, and pipelines.
 SOURCE: DOE/EIA, www.eia.doe.gov/cmeu/states/_states_ng.html and RAND estimates based on GRI data for 2010.

Figure 4.6—Estimated Growth in Monthly Deliveries to California Gas Consumers Through 2010

projections, growth in California natural gas demand between 2000 and 2010 will range between 18 and 50 percent. With relatively constant in-state California natural gas production, the increased demand will need to be met with increased imports of natural gas, which will require pipeline and storage capacity expansion.

Figure 4.7 compares current and projected daily demand (both average and peak loads) to the future aggregate supply system capacity (the amount of gas that could be delivered to California consumers equals domestic California production plus interstate pipeline capacity plus storage capacity), interstate pipeline capacity, and intrastate receipt capacity. Under our demand scenarios, the total supply capacity would appear to be able to meet the average daily load but not peak load in 2010. However, future intrastate receipt capacity will be unable to meet either the average daily or peak load requirements in 2010 in either scenario. There is a 1.7 billion cubic/day (Bcf/d) deficit when compared with the GRI average daily load in 2010, and between a 3.1 (AEO) and 6.1 (GRI) Bcf/d deficit when compared with the peak-day load in 2010. The shortage of intrastate receipt capacity is clearly the weak link in the system.

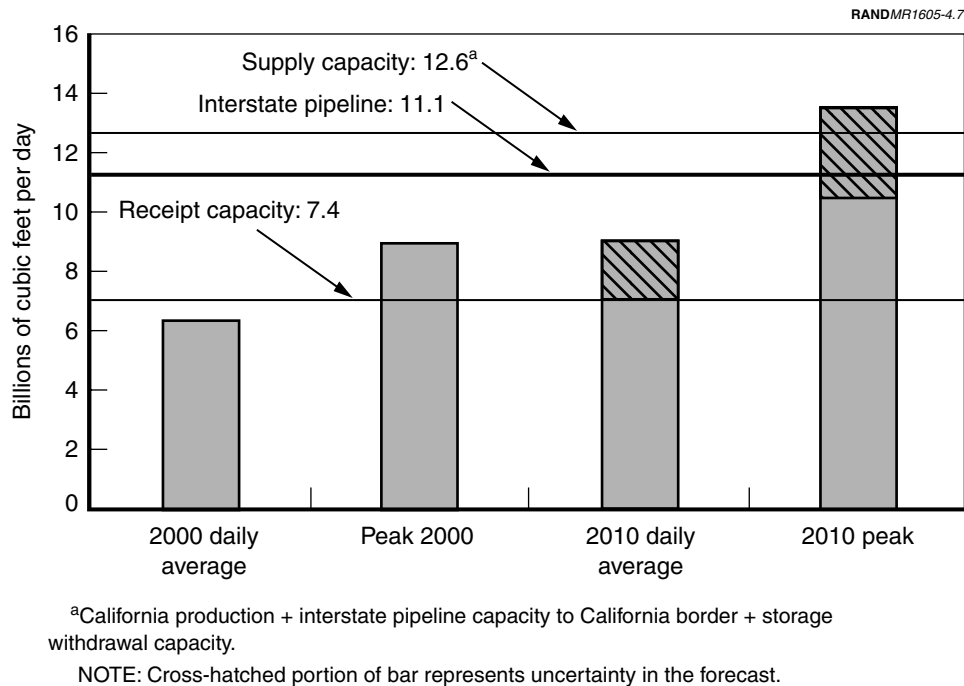


Figure 4.7—Future System Capacity Compared with Estimated Demand

It is also important to recognize that these comparisons are being made based on the rated capacity of each element in the system. California's location at the terminus of the pipeline system makes it vulnerable to increases in upstream demand for natural gas (between the gas fields and California).

Existing pipeline and storage capacity is likely to be inadequate to meet the projected growth in the demand. Interstate pipeline, California production, and storage capacity is probably adequate to meet the projected level of growth. However, the intrastate receipt capacity is inadequate. The increase in demand will strain the natural gas transport and storage system as the difference between transmission capacity and demand continues to shrink. Consequently, the natural gas transmission system will have less flexibility to absorb disturbances and meet sudden spikes in load. This will create conditions that are precursors of price volatility and gas supply constraints.

While our analysis cannot predict regional price volatility—in part because the models deal with yearly averages and because of the embedded assumptions

regarding infrastructure development¹—it does show that tight infrastructure conditions could lead to natural gas price volatility and supply problems.

¹For example, the EIA projection assumes that more than 3.5 Bcf/d of additional pipeline capacity will be built to provide gas to the California by 2010.

5. Natural Gas Public Policy Choices for California

The previous sections discussed the impact of California's increased reliance on natural gas for electricity generation. The main points are summarized here:

- Natural gas consumption will increase by between 18 and 50 percent by 2010, mostly due to new in-state electricity generation.
- The adequacy of the U.S. natural gas resource base does not appear to be an issue in the near to mid term. Sufficient resources exist to meet California's natural gas demand growth assuming adequate investments are made in exploration and production.
- Existing interstate pipeline and storage capacity is constrained, and additional investment will be required if future demand requirements are to be met. Interstate pipeline capacity may become more critical because California will increasingly rely on natural gas imports.
- Existing intrastate receipt capacity may not be adequate to meet the projected growth in demand. It is the bottleneck in the natural gas infrastructure.
- The growing share of gas consumed for electricity generation may make it more difficult to manage the storage system because of summer withdrawals needed to meet electricity generation requirements.

These points imply that California's natural gas customers may face the risk of supply shortfalls and price volatility similar to those experienced in 2000 and 2001, owing to increasing reliance on natural gas for power. In addition, increasing and fluctuating natural gas prices are passed through to electric rates. This section describes options for California to mitigate the risks associated with increased reliance on natural gas to meet its energy needs. Other than inaction, California's policy choices to address the implications of increased reliance on natural gas fall into two broad categories: supply-side infrastructure expansion and demand reduction or management. In practice, however, both options will probably need to be adopted in varying degrees to ensure adequate energy supplies and to avoid price and supply volatility.

Infrastructure Improvement

It is clear from the analysis that current plans for the expansion of intrastate pipeline receipt capacity will be inadequate to meet the level of gas demand growth projected for California. Figure 4.7 illustrated the significant potential shortfall. The current pipeline system has little slack capacity due in part to economic considerations and regulations that promote the high utilization of pipelines. It is in the interest of California's gas consumers that slack capacity be maintained to avoid price volatility. The gas utilities have little economic or regulatory incentive to maintain adequate slack receipt capacity, and California may need to create the correct environment for utilities to maintain a level of capacity that reduces the risk of price and supply volatility. The California Public Utility Commission (CPUC), in conjunction with the CEC, should evaluate the appropriate level of capacity needed and should study options for creating incentives to meet these goals.

In general, there are three ways to increase the intrastate receipt capacity of the system: build new pipelines, increase the capability of existing pipelines, and increase storage. The first reaction to this problem is usually to build new pipeline capacity. For California, this would mean building 3–6 Bcf/d of receipt capacity. The problem is the lead time for building this new capacity. Pipelines can easily take ten years to construct. There is often a long permitting process that includes a number of different state and local agencies with the CPUC as the lead agency. There are also constraints and uncertainties in the planning and building of pipeline infrastructure. Construction costs are affected by location, terrain, and the constraints imposed by the multiple jurisdictions through which the pipeline passes. Pipelines also have environmental impacts, which include the potential of opening previously undisturbed lands to development, potential for restricting animal movements, and the possible risks from leaks. Many of these problems can be mitigated, but the required measures increase the time, cost of construction, and cost of maintenance.

Another option is to increase the capacity of existing infrastructure, which can be done through a number of different techniques including increasing compression. Last year, Southern California Gas identified 13 options to enhance receipt capacity by a total of 300 MMcf/d, with costs ranging from \$2 million to \$35 million. All of these improvements could be made within two years. The choice to do them would depend on review by the CPUC. There are fewer hurdles to cross in permitting these upgrades than in constructing new pipelines, but there is a limit to how much the flow through existing capacity can be increased.

Finally, it is possible to increase storage capability, although it faces similar siting and permitting constraints. In addition, the effective amount of storage capacity is limited by the amount of gas that can be injected in periods of low demand and the capability to withdraw from storage. More study needs to be done to assess the capability for injecting into and withdrawing from storage and to investigate potential sites for increasing natural gas storage.

Since it is likely that new pipeline capacity will be needed at some time in the future, California should consider legislation similar to that enacted for power plant construction, which allows for expedited reviews of pipeline construction or expansion projects and includes specific deadlines for each stage of the process. Permitting, right-of-way, review, and approval processes could be expedited to allow additional capacity to be constructed to meet the growing needs of California consumers, while still considering the impact on the environment and society. If this is to be part of the solution, legislators will have to act soon given the lead time involved with adding pipeline and storage infrastructure.

Further, expansion plans for interstate pipeline and storage capacity will only marginally meet requirements given anticipated California demand growth. The El Paso pipeline explosion in 2000 and the resulting loss of pipeline capacity illustrated the sensitivity of the interstate pipeline system to disturbances. Because California is at the terminus of the pipeline system, it is at particular risk for similar disruptions in the future. A comprehensive plan to ensure that adequate interstate pipeline capacity exists to meet demand growth would help stabilize natural gas availability and price volatility. The need to address natural gas pipeline capacity is a regional problem. Pipeline disruptions and regional growth affect the entire western United States. Natural gas price spikes in the winter of 2000 propagated to Colorado and the Pacific Northwest. California is the dominant energy consumer in the region, but it is incapable of managing regional gas production, transportation and storage alone. Regional cooperation, planning and possibly oversight, perhaps through a regional entity may be necessary to address the problems outlined in the previous sections. This entity could oversee interstate pipeline and regional storage capacity and have the ability to provide incentives, finance, or require the construction of new pipeline and storage capacity as needed to serve the requirements of the entire region. One model for such an organization could be the Regional Transmission Organizations being developed in the electricity industry. The result would be shared risk among current pipeline operators and an improved competitive environment.

Options for Natural Gas Demand Reduction or Management

If rising natural gas demand and constraints on the pipeline system are the primary causes of gas price volatility, one option that would have a long-term payoff would be to reduce the gas demand growth in any of the consuming sectors: residential, commercial, and industrial, or to reduce gas use for electricity generation. Another option, not discussed here, would be to reduce growth in electricity demand. This would indirectly reduce gas consumption because natural gas is the marginal fuel used to meet growth in electricity generation.

The Electricity Generating Sector

Projected growth in natural gas demand is driven by demand for electricity generation. Since much of the anticipated growth will result from new gas-fired capacity that is yet to be installed, policies that address the growth of electricity generation directly may be a viable option for the state. Options in this area fall into three broad categories: reductions in natural gas consumption at existing power stations through the targeted replacement or retrofit of existing capacity, diversification of generation energy supplies, and reductions in electricity demand growth.

A program aimed at replacement and retrofit activity could encourage the installation of the most efficient equipment at existing power stations. Such a policy could reduce total and peak natural gas demand. A reduction in peak gas demand levels, in particular, would help to reduce upward pressure on gas prices and moderate price volatility.

Better diversification of energy supplies for generation, especially with proposed new generating capacity, could create increased generation flexibility. California's in-state electric generation portfolio is largely based on two major fuel sources: hydroelectricity and natural gas. Diversification of this portfolio could take several forms. The option of locating coal-fired power stations out of state and importing the electricity is an example of diversification that has been used in the past. However, because this option requires long-distance transmission, the result would be to shift the risk of shortages from natural gas to electricity, which also travels in a conduit operating near capacity (CEC 2001b).

A number of other diversification options are not welcomed by various interests in the state. These include a shift toward oil, coal, or nuclear energy. For example, fossil-fueled facilities were once designed to burn either natural gas or fuel oil, the latter of which could be stored on site. These older dual-fuel plants are being

retired in favor of single-fuel plants—primarily for environmental reasons. Local and regional air quality concerns exclude coal-fired power generation from consideration. Nuclear power has unknown financial viability and has received little public support in recent decades. Fuel cells may provide options for distributed electricity production, but not in the near term because of high costs, and most would be gas-fueled. Current technology for distributed generation,¹ which includes small natural gas turbines (microturbines), are less efficient than central-station advanced combined-cycle power plants if used strictly to provide electricity, and will not help to reduce stress on the natural gas system.

There are two sets of options that can help diversify the electric power system and slow the growth of natural gas demand: renewable technologies and combined heat and power (CHP) in distributed generation applications. Renewable generation, such as wind, solar, geothermal, or biomass, currently produces approximately 9 percent of California's electricity and can reduce natural gas demand growth at the margin. CHP, which utilizes the waste heat from the electricity generation process for heating and cooling applications, can be effective in alleviating some natural gas demand.

There are proposed bills in the legislature to implement a renewable portfolio standard (RPS) for California that would require that 20 percent of total generation in 2010 be met by non-hydroelectric renewables. Effective use of renewable resources for electricity generation poses some difficult problems. While biomass and geothermal generators are generally dispatchable to meet changes in electrical load, intermittent renewable resources, such as wind and solar, cannot substitute one-for-one for other sources and may require backup generation capacity to keep the probability of load loss to within acceptable margins. However, renewables offer opportunities to help reduce the strain during summer and winter peak times. With advances in technology and better resource information, renewables can contribute to a utility's peak capacity.

If 20 percent of electricity generated were provided by non-hydroelectric, renewable technologies and replaced natural gas generation, natural gas demand could be reduced by between 220 and 285 Bcf per year by 2010, depending on assumptions about what future capacity might be displaced.² To put this number in context, with delivered natural gas prices of \$3 per million Btu this reduction would imply a \$700–\$900 million per year reduction in gas purchases for

¹ In this context, distributed generation includes electricity generated on or adjacent to the place of its demand.

² The estimate is based on a 20 percent reduction of total generation (measured in kWh) and a proportional reduction of natural gas generation. Uncertainty is due to assumptions regarding the efficiency of displaced capacity.

electricity generation. However, this may or may not represent a cost-savings to customers because the renewable capacity will tend to require greater capital expenditures that could offset fuel savings completely or in part. If the primary goal is to reduce gas demand to alleviate the need for gas supply infrastructure expansion, the use of more renewables for electricity generation could help. This would also help reduce upward pressure on gas prices and might reduce the potential for price volatility and supply shortages. A recently released report from the EIA on a national RPS (EIA 2002c) shows that future gas prices can be moderated by an RPS. The forecasted 2010 wellhead reference gas price forecast is \$2.85. The forecasted price with a 10 percent RPS is \$2.72; with a 20 percent RPS, it is \$2.67. The report notes that with a national 10 percent RPS the reduction in gas price just about offsets the increased costs of renewables and that the RPS can reduce the volatility in both price and supply that threatens gas markets.

CHP also has the potential to reduce the growth of natural gas demand by substituting some natural gas used in heating and cooling applications with waste heat from electricity generation. On average for the United States, if an application needs both electricity and heat, the overall efficiency of providing electricity and steam separately is about 45 percent, whereas the potential for combined heat and power is as high as 85 percent.³ For example, an industrial facility requiring 185 Btus of energy to supply electricity and steam requirements may only need 100 Btus of energy to supply the same requirements if the steam is generated using waste heat from the electricity generation process. However, in the case of large, central station power plants, using the waste heat is difficult because there are few nearby steam applications.

For small-scale applications, using microturbines in commercial buildings provides opportunities to use the waste heat from the turbines to heat the building in the winter, to heat its water, and in some cases to cool the building in the summer, thereby reducing the amount of natural gas that may be required for those applications.⁴ For example, current heat rates for a microturbine application for a commercial office building are about 13,000 Btu/kWh (compared to about 7,000 Btu/kWh for a combined-cycle natural gas plant). The net heat rate if the system is used for combined heat and power is about 7,700 Btu/kWh. Therefore, one can provide electricity, heat, and hot water for about the same amount of natural gas as used for electricity alone, saving an average

³ See calculations done by USDOE at http://www.eren.doe.gov/der/combined_heat_power.html.

⁴ Ibid. The primary benefit would be in heating applications because they use more natural gas than do cooling applications. Savings calculations are reported in a number of places, including the American Council for and Energy Efficient Economy, <http://aceee.org/pubs/ie983.htm>.

100,000-square-foot office building about 300 million Btus of energy per year.⁵ In the commercial sector alone, California has the potential for up to 7,000 MW of combined heat and power.⁶ If 2,000 MW of generation is converted to distributed CHP, it could potentially reduce natural gas demand by about 20 Bcf per year. More study is needed to determine the cost-effectiveness and potential of these applications.

The Residential, Commercial, and Industrial Sectors

California has been a leader in building energy efficiency for 25 years. Title 24, California's building code, is among the strictest in the nation, and it has helped to moderate growth in California residential and commercial energy consumption for over two decades (Bernstein et al. 2000). Programs to reduce gas and gas-fired power demand include building codes, funding for energy-efficiency projects, distribution of compact fluorescent light bulbs, appliance rebate and exchange programs, and commercial and industrial subsidies. The more aggressive implementation of these types of policies could be used to help reduce energy consumption. For example, measures taken during the summer of 2001—a combination of public information and direct and indirect subsidies—helped to reduce electricity demand. Statewide estimates indicate that California's electricity demand was reduced by 6.7 percent on average and by 10 percent during peak hours (CEC 2002), with most of the reduction occurring before the major increases in retail prices.

Similar programs could be developed for natural gas. They would target major household natural gas end uses, including water heating and space heating. Water heating consumes more than one-third of all delivered residential natural gas. Water heater efficiency is measured by an energy factor (EF) that measures the fraction of heat energy input that is converted to hot water. The EF of the current stock of residential water heaters in CA ranges from a low of 0.54 to a high of 0.6. Over 20 percent of the current stock has an EF of less than 0.56 and over 40 percent has an EF between 0.56 and 0.58.⁷ If one-third of the existing

⁵ Calculations based on numbers presented in *The Market and Technical Potential for Combined Heat and Power in the Commercial/ Institutional Sector*, Prepared for U.S. Department of Energy, Prepared by ONSITE SYCOM Energy Corporation.

⁶ Op. cit.

⁷ Calculations were derived from a number of sources including *1996 Measure Cost Study Final Report*, California Energy Commission, P300-97-002, December 1996; *Statewide Residential Lighting and Appliance Saturation Study: Final Report*, June 2, 2000, prepared by RLW Analytics, Inc. for San Diego Gas and Electric; *1998 Baseline Energy Outlook*, California Energy Commission, August 1998; *EIA Historical Natural Gas Annual 1930 through 1999*, Energy Information Administration, October 2000, Washington, DC; <http://www.socalgas.com/residential/savemoney/efacts/waterheat.html>; http://www.pge.com/003_save_energy/003a_res/index.shtml.

inefficient stock could be upgraded with the most efficient water heater today, annual demand for water heating could be reduced by 10 percent. In addition, it is possible to further reduce hot water demand through the use of low-flow showerheads and EnergyStar dishwashers and washing machines. Not only do these measures reduce energy used for hot water, they also have the added benefit of reducing water use.

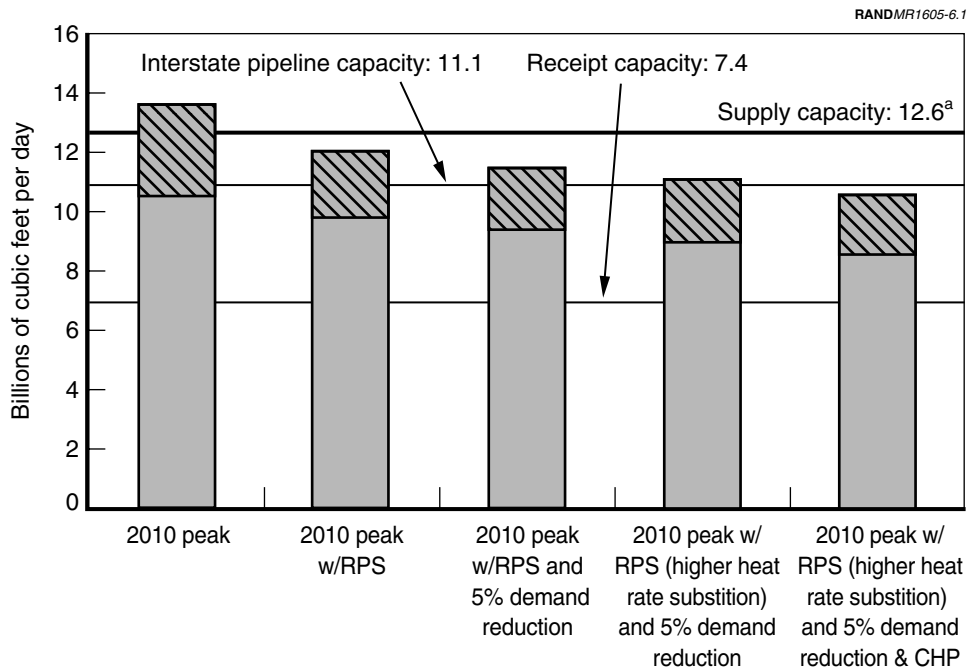
Space heating consumes more than 40 percent of natural gas in the residential sector in California. The average fuel use efficiency (AFUE) of furnaces ranges from 0.60 to 0.98. In California, 40 percent of the existing stock has an AFUE of less than 0.78 and 4 percent of the stock is above 0.90. Replacing the least efficient models with the most efficient ones could reduce household natural gas demand for heating by almost 20 percent.

Clearly there needs to be further analysis of the cost, benefits, and timing of improving the efficiency of the natural gas appliance stock. By themselves, these measures will not “solve” the capacity problem—the solution will require a combination of measures. But the success of the measures taken during the summer of 2001 showed that with targeted government actions, efficiency gains of 5 percent or more can be achieved. Energy efficiency measures could be an important element in addressing the energy needs of California.

6. Conclusions

One may view California’s options for managing energy supply and demand as a portfolio in which the costs, benefits and risks are balanced. An energy management portfolio mitigates risks through a well-balanced strategy of improved planning, infrastructure investment, the adoption of a greater diversity of energy supply sources, and the use of programs to moderate demand growth. The “optimal” portfolio would be one that maximizes the risk-adjusted returns or minimizes the risk-adjusted costs.

Each component of the portfolio comes with its inherent risks and returns. Wind and photovoltaics have no future fuel risks, but have some capital and operation risks. Efficiency has no fuel risks, but has implementation risks. Natural gas has out-year price and supply risks, but may have lower costs. Although finding an optimal mix is beyond the scope of this analysis, we can illustrate some scenarios that might be achievable. Figure 6.1 shows 2010 peak gas consumption under a



^aCalifornia production + interstate pipeline capacity to California border + storage withdrawal capacity.

NOTE: Cross-hatched portion of bar represents uncertainty in the forecast.

Figure 6.1—Impact of Different Scenarios on Gas Demand

Table 6.1
Summary of Scenarios and Possible Impact

Assumptions	Renewables	Efficiency	CHP	Additional Intrastate Receipt Capacity Needed
2010 reference				3.1–6.1 Bcf/day
2010 reference	20% of electricity generated by renewables, with renewables displacing new natural gas units at 6,650 Btu/kWh heat rate			2.4–4.6 Bcf/day
2010 reference	20% of electricity generated by renewables, with renewables displacing new units at 6,650 Btu/kWh heat rate	Reduction in demand growth of 5%		1.9–4 Bcf/day
2010 reference	20% of electricity generation by renewables, with renewables displacing less efficient units at average stock heat rate plus 20%, 8,550 Btu/kWh	Reduction in demand growth of 5%		1.5–3.6 Bcf/day
2010 reference	20% of electricity generation by renewables, with renewables displacing less efficient units at average stock heat rate plus 20%, 8,550 Btu/kWh	Reduction in demand growth of 5%	2000 MW	1.0–3.1 Bcf/day

variety of scenarios and also shows the infrastructure needed to meet those scenarios. The scenarios are summarized in Table 6.1.

The simplified portfolio analysis presented above shows the potential effectiveness of such policy tools as a renewable electricity-generating portfolio standard. If California were to adopt a 20 percent RPS, achieve a 5 percent efficiency improvement, and install 2,000 MW of CHP, the state could reduce

potential infrastructure expansion needs to between 1.0 and 3.1 Bcf/day. The type of infrastructure investment needed to meet the capacity needs of the lower demand might require smaller, less capital-intensive projects and may be simpler to implement.

Timing is a critical component in the deployment of any portfolio. Some infrastructure improvements, such as increasing pipeline compression, can be done quickly; others, such as new pipelines, can take ten years. Efficiency programs can achieve quick results—especially if they include direct equipment replacement programs rather than waiting for equipment to be replaced at the usual turnover rates. CHP distributed generation and many renewable technologies can be deployed in two to three years. In the long term, for California to successfully hedge against future price and supply volatility, it should engage in a regional planning process to address the region's energy problems. More immediately, however, California needs to look at its energy portfolio and begin to implement a portfolio designed to address some of the scenarios derived and presented in this report.

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