Arnold Schwarzenegger
Governor

BARRIERS TO EXPANSION OF NATURAL GAS STORAGE FACILITIES IN CALIFORNIA

PIER FINAL PROJECT REPORT

Prepared For:
California Energy Commission
Public Interest Energy Research Program

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April 2008
CEC-500-2008-036

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Commission Contract No.500-02-004
Commission Work Authorization No. MR-058

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Acknowledgements

This work was completed under a sub-contract to the University of California, Office of the President, California Institute for Energy and Environment (CIEE – http://ciee.ucop.edu). The authors wish to thank Steven Schiller, CIEE's research coordinator, Michael Magaletti and David Michel, the California Energy Commission's contract managers, for their guidance on this project. The authors also wish to thank Briana Kobor of MRW & Associates for her extensive and valuable assistance.

Please cite this report as follows:

Weisenmiller, Robert, Suzie Kito and Laura Norin (MRW & Associates, Inc). *Barriers to Expansion of Natural Gas Storage Facilities in California*. California Energy Commission, PIER Energy Systems Research Program. CEC-500-2008-036

Preface

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

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

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

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

- Buildings End-Use Energy Efficiency
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- Natural Gas Research
- Renewable Energy Technologies
- Transportation

Barriers to Expansion of Natural Gas Storage Facilities in California is the final report for the project Market and Regulatory Options Research for California Natural Gas Storage (contract number 500-02-004, work authorization number MR-058) conducted by MRW & Associates, Inc. The information from this project contributes to PIER's Natural Gas Research Program.

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

Table of Contents

List of Tables

List of Figures

Abstract

This report assesses whether market power threshold tests or other barriers to entry are inhibiting the expansion of gas storage infrastructure in California. Under this assessment, the authors investigated the history of federal and state market power regulation with respect to gas storage projects and find that market power assessments have not inhibited natural gas storage development in California. Researchers identified a number of other potential barriers to storage development, including additional regulatory barriers, market barriers, physical barriers, and incumbent advantages.

Keywords: Natural gas, natural gas storage, market power, California Public Utilities Commission, Federal Energy Regulatory Commission, market power test, Herfindahl-Hirschman Index, market-based rates, cost-based rates, market-based rate Authority, Red Lake, Southern California Gas, Pacific Gas and Electric, Lodi Gas Storage, Wild Goose, Niska Gas Storage, core, non-core, cost-of-service regulation

Executive Summary

Natural gas storage in California serves two primary purposes: 1) it helps utilities meet peak gas demand, and 2) it enables utilities and other natural gas users to purchase extra natural gas when prices are relatively low to avoid purchasing when prices rise. Storage enhances reliability, moderates seasonal price fluctuations, and sets a (soft) cap on natural gas prices.

In Northern California there is an active natural gas storage market supplied by Pacific Gas and Electric (PG&E) and two independent storage providers. In the Southern California/western Arizona market, Southern California Gas (SoCalGas) is the only storage provider. Independent storage providers compete with investor-owned utilities to serve industrial-sized users of natural gas and other “non-core” customers. Investor-owned utilities are the sole service providers for residential and other “core” customers.

A number of indicators suggest that there is demand for additional non-core storage capacity in both the Northern California and the Southern California/western Arizona markets. In addition, the level of profits that SoCalGas has earned on its storage fields in recent years suggests that, depending on the cost of additional storage capacity, the introduction of competition in that market may reduce the cost of storage for consumers.

There have been no proposals for independent storage projects in Southern California, and there has been just one application for a storage project in western Arizona. This proposal failed after the Federal Energy Regulatory Commission (FERC) denied market-based rate authority for the project out of concern that the owner, Red Lake Storage, L.P., would have market power. Red Lake withdrew its application on account of this ruling.

Without market-based-rate authority a company is placed under cost-of-service regulation and is required to have its rates approved in formal rate cases at FERC or at another regulatory body. Cost-of-service regulation is used to protect consumers from monopoly pricing in situations where companies have market power. However, it can be seen by Red Lake and other otherwise-unregulated companies as imposing unnecessary regulatory costs, restricting contract flexibility, and limiting profits.

Red Lake’s withdrawal of its storage application highlighted a limitation of FERC’s market power assessments. In particular, in markets dominated by a large storage provider, such as the western Arizona/Southern California market, any new provider, no matter how small, would be found by FERC’s market power tests to have market power. As demonstrated by the Red Lake case, a finding of market power can be sufficient to deter the development of storage capacity. In response to this case, FERC liberalized its eligibility requirements for market-based rate authority with the hope of encouraging the development of additional storage.

Storage facilities in California are under the regulation of the California Public Utilities Commission (CPUC), not FERC. However, the CPUC also examines market power in assessing eligibility for market-based rate authority. The Red Lake case thus raised the concern that market power tests could be inhibiting the development of natural gas storage in California.

This concern appears to be unsubstantiated, however, since the CPUC's rules were never as restrictive as FERC's rules were. For example, the CPUC granted market-based rates to both California independent natural gas storage providers without requiring a showing of lack of market power. The CPUC recognized the storage projects as in the public interest, and, instead of imposing cost-based rates, the CPUC imposed reporting requirements and restrictions to guard against uncompetitive behaviors. Therefore, market power tests are unlikely to be significant impediments to natural gas storage development in California.

Other regulatory requirements, such as requirements to obtain a certificate of public convenience and necessity and to conduct an environmental review, also do not appear to be the primary barriers to the development of independent storage facilities in Southern California. The same regulatory requirements are imposed on facilities in both Northern and Southern California, but there is an active independent storage market only in Northern California.

Non-regulatory impediments to the development of natural gas storage capacity in California remain. These include financial constraints due to the high start-up costs of storage projects; geophysical constraints on the availability of storage sites; and market impediments, such as incumbent utilities with low embedded costs. Geophysical constraints may be important in Southern California; however, these barriers apply to SoCalGas and to potential market entrants alike. The more important barrier to independent natural gas storage development in Southern California may be incumbent advantage. SoCalGas has existing storage capacity that it could expand. It operates with low embedded costs and collects some of its non-core revenue requirement from core customers. These advantages may be sufficient to deter independent storage providers from entering the Southern California market. Indeed, no independent storage facility has been proposed for Southern California since the early 1990s.

This report investigates barriers to natural gas storage in California, focusing on the impact of market-based rate regulations. As described in more detail at the end of the report, the key conclusions from this investigation are as follows:

- There is demand for additional non-core natural gas storage capacity in California. The CPUC has determined that natural gas storage capacity is adequate to ensure that sufficient natural gas would be available under a variety of adverse scenarios (for example: supply disruption, cold weather). However, the CPUC focuses primarily on whether there would be sufficient natural gas for core customers. At the same time, in recent years, due in part to high and variable gas prices, the demand for natural gas storage has grown.
- Market-based rates are often preferred over regulated cost-based rates.
- The test used by FERC to assess market power in the natural gas storage industry has impeded the development of independent natural gas storage facilities in concentrated markets in the past. However, this test has not constrained storage development in California, since the CPUC, which has jurisdiction over in-state natural gas storage facilities, has granted market-based rate authority to independent storage facilities despite finding a relatively concentrated market.

- FERC’s revised rules are intended to promote the development of additional natural gas storage facilities in the Southwest, but it has not yet been shown whether they are sufficient to encourage new development.
- FERC’s revised rules are not likely to affect the CPUC’s approach to granting market-based rates; however, they may affect the CPUC’s assessment of market power in the Southern California market. In particular, the CPUC recently found the Southern California storage market to be sufficiently competitive and declined to adopt cost-based rates, in part by allowing for consideration of transportation substitutes, consistent with FERC’s revised rules
- There are a variety of barriers to entry, but these have not been sufficient to impede natural gas storage development in the Northern California market.
- There are likely a variety of reasons that additional natural gas storage capacity has not been built in the Southern California market. Relative prices in the Northern and Southern California storage markets may be an issue. In addition, new entrants may be deterred in part because of geology and land-use issues, as well as the existence of an incumbent with low embedded costs and the ability to expand its facilities.

1.0 Introduction: Are Market Power Tests Impeding Natural Gas Storage Development in California?

Natural gas storage providers considering building a facility for non-core customers often apply for market-based rate authority. This authority allows the provider to operate with rates that are established by the market rather than through cost-of-service regulation. If denied market-based rate authority, the provider becomes subject to cost-based rates overseen by the Federal Energy Regulatory Commission (FERC) or a state regulatory body. This restricts the rates that the provider can charge and bounds the provider to regulatory rate proceedings.

In considering applications for market-based rates, FERC historically used only market power tests to determine whether the facility would provide the applicant with market power. If an applicant is shown to have market power, the applicant is denied market-based rate authority. In 2003, FERC denied Red Lake Storage, L.P. (Red Lake) market-based rate authority for its proposed Arizona storage facility, because FERC could not be confident that Red Lake would lack significant market power, even though FERC determined that Red Lake's proposed project was in the public interest (FERC 2003b). Faced only with the option of cost-based rates, Red Lake declined to build the storage facility (FERC 2003a).

This case raised the concern that market power tests could be inhibiting the development of natural gas storage, particularly in the western Arizona/southern California market in which the Red Lake facility would have participated. This market is concentrated due to the dominance of Southern California Gas (SoCalGas), so it is extremely difficult for potential entrants, such as Red Lake, to pass market power tests even if they counterbalance SoCalGas' market power. In response to this concern, FERC revised its procedures and standards for assessing an applicant's eligibility to receive market-based rate authority. Under the new standards, FERC is authorized to provide market-based rate authority to applicants who may have market power if it can be shown that this decision would be in the public interest.

FERC has jurisdiction over natural gas storage projects that are interconnected to the interstate gas pipeline system; however, the California Public Utilities Commission (CPUC) has jurisdiction over gas storage facilities located in California. Both FERC and the CPUC evaluate projects based upon whether there is need for additional capacity and whether the proposed project is in the public interest. While there has been some consistency between the FERC and CPUC approaches to assessing market power issues, there is no requirement for such consistency aside from California's need to compete in the financial markets for investment in storage infrastructure.

The CPUC has not revised its procedures and standards for assessing an applicant's eligibility to receive market-based rate authority in light of FERC's revisions. This raises the question central to this report: Are market power tests conducted by the CPUC to assess eligibility for market-based rate authority inhibiting the development of natural gas storage facilities in southern California?

1.1. Overview of California Regulatory Framework and Storage Facilities

The current CPUC framework for regulating natural gas storage facilities was established in 1993, when the CPUC unbundled utility natural gas storage from gas transportation and allowed independent storage operators to provide service under market-based rates. This unbundling created three types of natural gas storage service: utility-owned core storage, utility-owned non-core ("unbundled") storage, and independently owned non-core storage. Different regulatory concerns relate to each of these services:

- Utility-owned core storage service is fully regulated. The CPUC attempts to ensure that the utility has sufficient capacity to meet its core customer's storage needs and provides the utility with cost-based rate-recovery mechanisms.
- Utility-owned non-core storage service is partially regulated. The CPUC attempts to ensure that ratepayers do not subsidize shareholder investments in non-core storage, sets limits to the amount of capacity that may be used for non-core storage, and sets rate caps for non-core storage. Utilities may expand or build additional storage facilities under this regulatory framework.
- Independently owned non-core storage providers are regulated by the CPUC, but they have been granted authority to charge market-based rates. In the past, providers' interest in developing storage capacity has been contingent on their ability to charge market-based rates.

In addition to the CPUC, California natural gas storage projects must meet the regulatory requirements of the California Department of Conservation's Division of Oil, Gas & Geothermal Resources (DOGGR) and, if State lands are involved, the State Lands Commission. These regulatory agencies and their responsibilities are discussed further in Chapter 5.

Basic information on California natural gas storage is shown in Table 1 and Figure 1 below. Two utilities own natural gas storage capacity in California: PG&E in Northern California and SoCalGas in Southern California. They both offer core services, system balancing services, and a non-core storage program. PG&E owns about half of the 88 Bcf of storage capacity in Northern California, with the remainder owned by two independent storage operators, Niska Gas Storage[1] (owners of Wild Goose) and Lodi Gas Storage.[2] SoCalGas owns all of the 131 Bcf of storage capacity in Southern California. SDG&E does not have its own storage facilities, but is an affiliate of SoCalGas as part of Sempra.[3] There are also

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1. Niska, formerly known as EnCana Gas Storage, is the name of the business purchased by the Carlyle/Riverstone Global Energy and Power Funds.

2. Lodi Gas Storage has submitted an application (A.07-07-025) to transfer its assets to Buckeye Gas Storage.

3. SDG&E currently has a gas storage contract with SoCalGas for 9 Bcf of inventory, 42,000 MMBtu/d of firm injection rights and 297,000 MMBtu/d of firm withdrawal rights for its core customers (DRA 2007, p. 7).

proposals for two new northern California storage facilities, a Sacramento facility to be owned by Sacramento Natural Gas Storage and a Fresno area facility to be jointly owned by Gill Ranch Storage LLC and PG&E.

Table 1: California Storage Facilities[4]

Owner	Facility	Storage (Bcf)	Withdrawal (MMcfd)	Injection (MMcfd)
Northern California				
PG&E[5]	McDonald Island 31.5 Los Medanos 9.3 Pleasant Creek 1	~42	~1,996	~255 (avg.)
Niska Gas Storage	Wild Goose	24[6]	480	450
Lodi Gas Storage	Lodi	17	500	400
Lodi Gas Storage	Kirby Hills Expansion	5	50	50
Northern Total		~88	~3,026	~1,155
Southern California				
SoCalGas	Aliso Canyon Honor Rancho La Goleta Playa del Rey	131	3,175	850

Source: (CPUC 2003b, p. 107; CPUC 2006c; Carlyle Group 2006; LGS 2006a; PG&E 2007c, p. 9; SDG&E and SoCalGas 2005, p.3; SDG&E and SoCalGas 2007a, p.23)

[4] The PG&E and SoCalGas data presented here, which are based on CPUC regulatory filings, differ from data that the utilities reported to the U.S. Energy Information Administration (EIA) in Forms 191-A for 2006. According to EIA Forms 191-A, PG&E storage has working gas capacity of 102 Bcf and a maximum withdrawal capability of 1,720 MMcfd, and SoCalGas storage has working gas capacity of 120 Bcf and a maximum withdrawal capability of 3,760 MMcfd. The 42 Bcf of PG&E storage capacity reported above represents the working inventory and does not include 60 Bcf of non-cycle working gas which is not expected to be cycled on a firm basis. In addition, the SoCalGas withdrawal capacity listed above is the amount that can be delivered at the 25 Bcf level and is the amount that is allocated between core and non-core customers.

5. It is assumed that there is a 1:1 conversion factor to adjust from MDth to MMcf.

6. D.02-07-036 authorized expansion to 29 Bcf for inventory, 700 MMcf/d for withdrawal, and 450 MMcf/d for injection, although current capacity is less than authorized amounts.

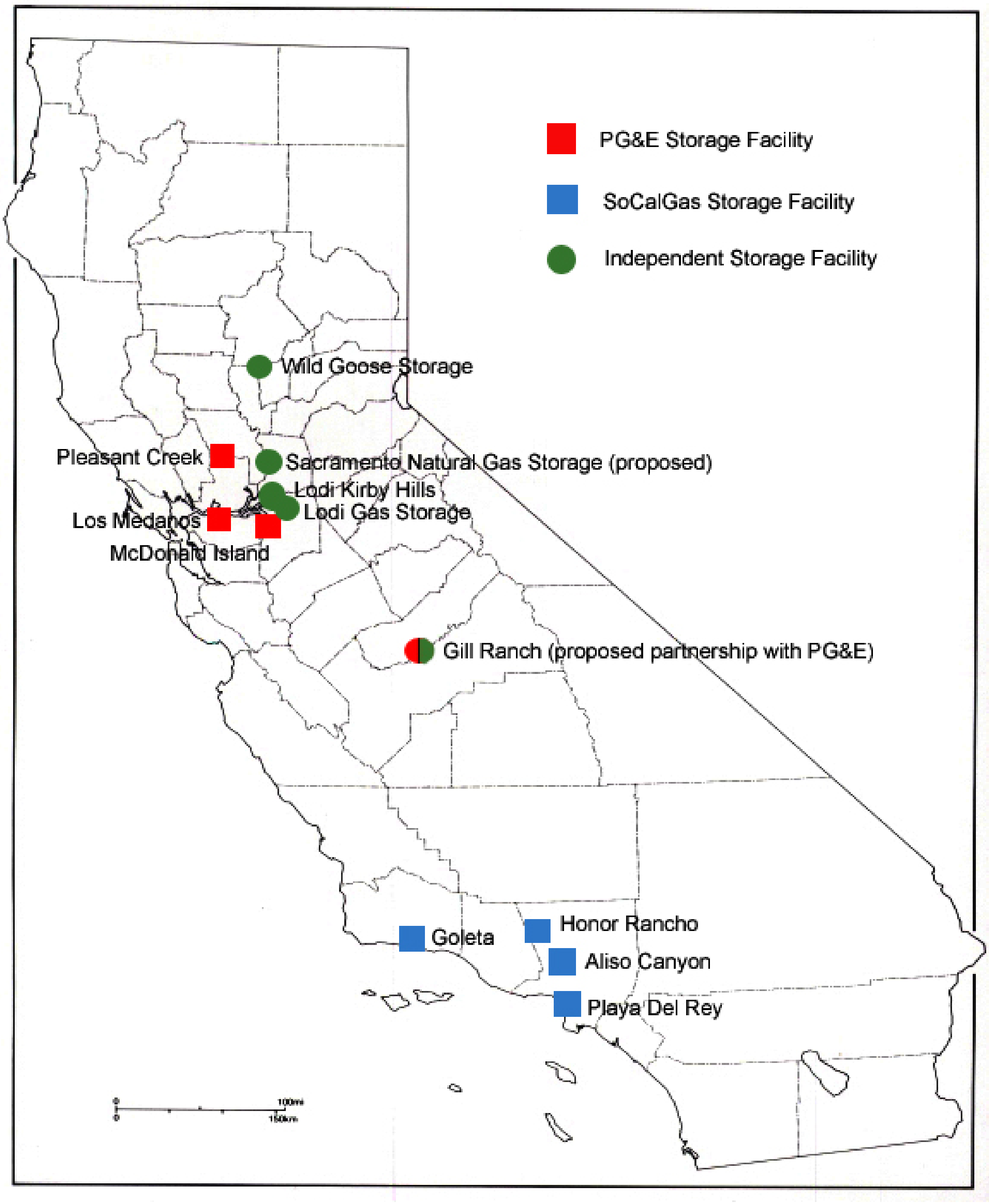


Figure 1: California Natural Gas Storage Facilities

As shown in Table 2 and Figure 2, nearly all of PG&E's storage capacity and more than half of SoCalGas' storage capacity is devoted to core customers. Most of the non-core customers in northern California are served by independent storage operators.

Table 2: Storage Allocation for PG&E and SoCalGas

	Core	Balancing	Non-Core	Total
PG&E				
Inventory (Bcf)	~33	~4	~5	~42
Withdrawal (MMcf/d)	~1,253	~743		~1,996
Avg. Injection (MMcf/d)	~157	~76	~22	~255
SoCalGas				
Inventory (Bcf)	~74	~5	~52	~131
Withdrawal (MMcfd)	1,935	250	990	3,175
Injection (MMcfd)	327	250	273	850

Source: (CPUC 2003b, p. 107; CPUC 2006c; PG&E 2007c, p. 9; SDG&E and SoCalGas 2005, p. 3; SDG&E and SoCalGas 2007a, p. 23)

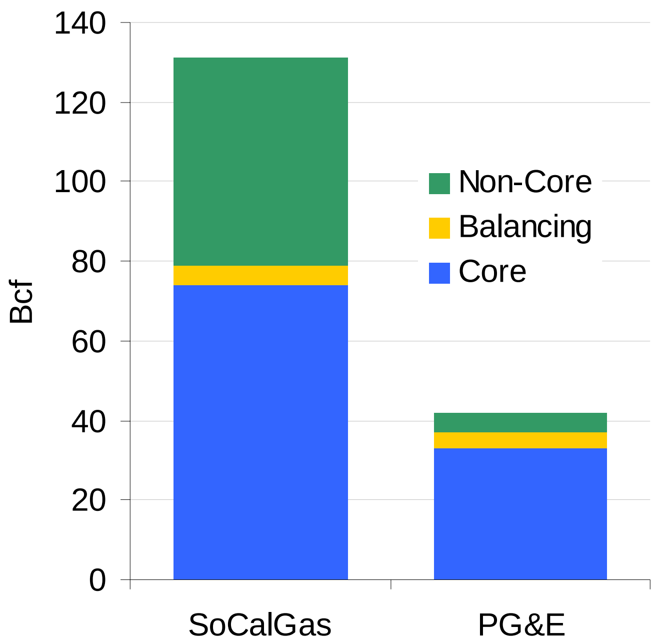
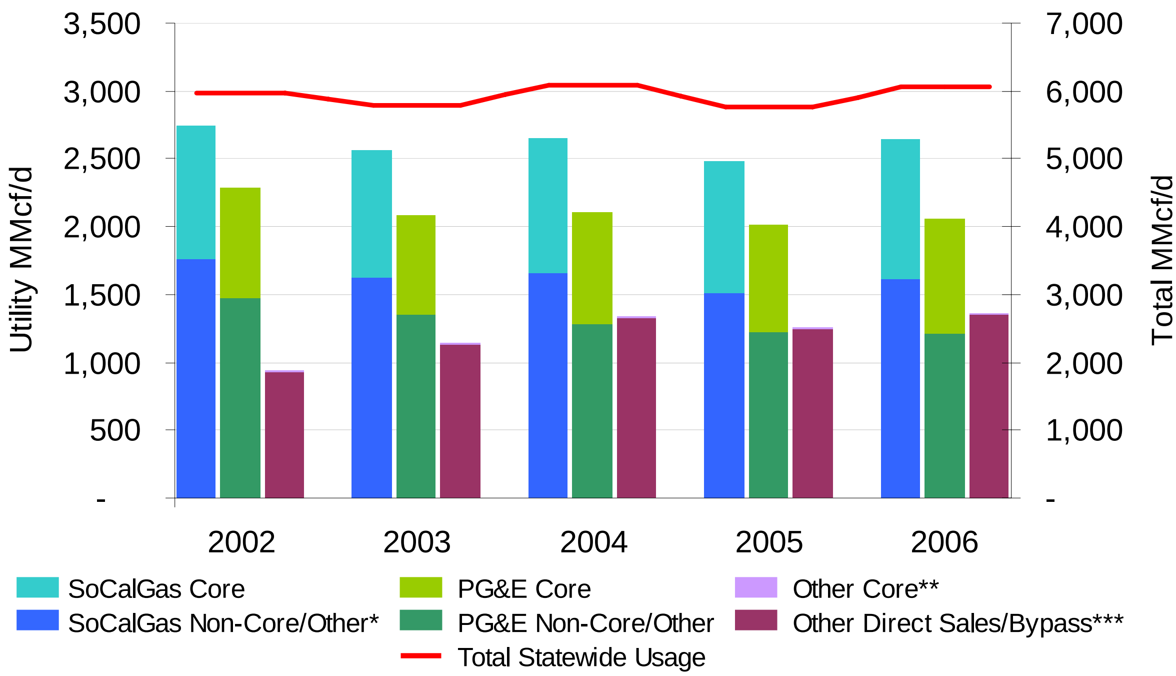


Figure 2: Inventory Allocation for PG&E and SoCalGas

Source: (CPUC 2003b, p. 107; PG&E 2007c, p. 9; SDG&E and SoCalGas 2005, p. 3)

1.2. Overview of Natural Gas Markets in California

Natural gas in California is used primarily to fuel natural-gas fired power plants, to power large industrial equipment, and to fuel commercial and residential space and water heaters. As shown in Figure 3, usage has held steady in recent years and is higher for SoCalGas than for PG&E. This section presents an overview of the role of natural gas storage for utilities and other large natural gas consumers. The roles of storage to manage seasonal fluctuations in gas usage and to manage natural gas price volatility are also discussed.



* Other includes electric generation (EG), enhanced oil recovery (EOR), wholesale and resale
** Northern California and Non-Utility Served Load; Includes Southwest Gas Corp., Avista and Tuscarora data, volume is de minimus
*** Deliveries to end-users by non-CPUC jurisdictional pipelines

Figure 3: Statewide Disposition Summary

Source: (CA Utilities 2007)

1.2.1. *Use of Storage to Manage Seasonal Variations in Natural Gas Usage*

Nearly half of all the natural gas used in California is used to fuel power plants. The amount of natural gas used for this purpose varies seasonally, peaking with overall demand for electricity in the hot summer months, remaining high in the winter months, and decreasing when there is a large amount of hydroelectric power available in the spring and early summer months. The use of natural gas for heating peaks in the winter months, so overall demand for natural gas is generally highest in the coldest months of January, February, and December. Demand is generally lowest in April through June and in October. (See Figure 4.) Because of this seasonal pattern, the utilities (on behalf of their core customers) and other customers tend to inject natural gas into storage facilities during the summer months for withdrawal during the winter peak season. As shown in Figure 5, storage withdrawal tends to peak around December and January with the greatest injection in the spring and fall. During times of summer peak electricity demand (August-September) gas-fired electricity generation draws from the overall supply, reducing injection into storage. This pattern has not changed appreciably as a result of increased reliance on natural gas usage for electric power generation.

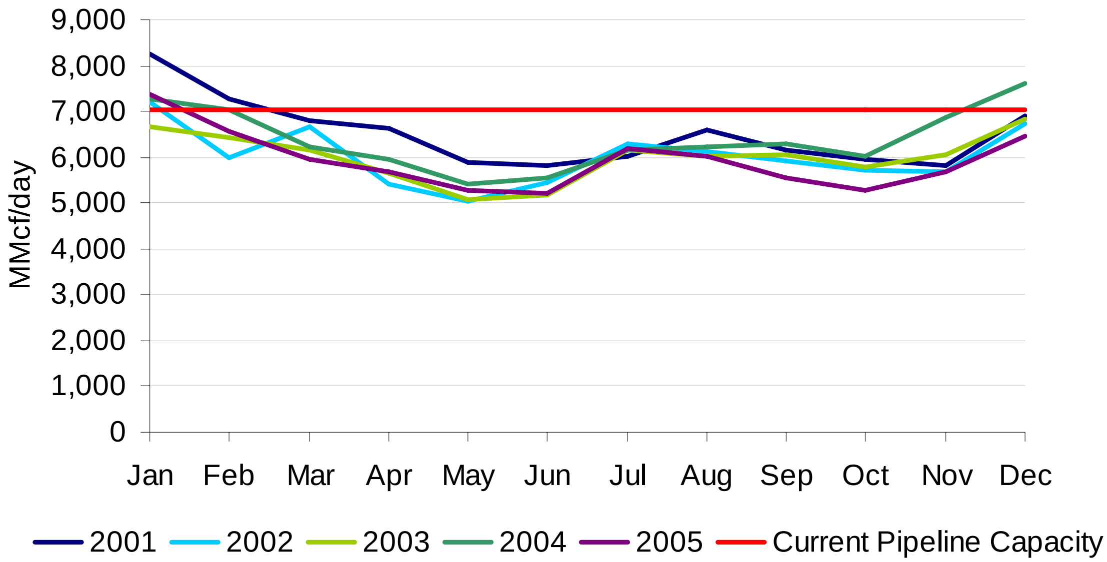


Figure 4: Monthly Natural Gas Usage in California, 2001-2005[7]
Source: (EIA 2007a)

7. Natural Gas Delivered to Consumers (Including Vehicle Fuel). MMcf data converted to MMcf/day.

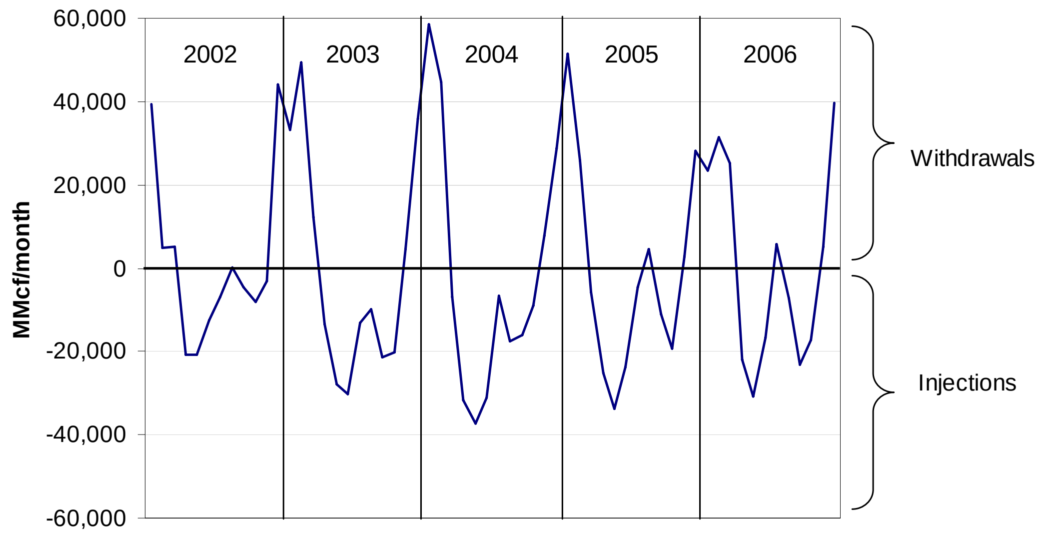


Figure 5: Net California Storage Injection and Withdrawal 2002-2006
Source: (EIA 2007b)

Roughly 13% of natural gas used in California originates in the state. The remaining gas is imported from the southwest U.S. (39%), the Rocky Mountain region (~25%), and Canada (~24%) (Energy Commission 2005). (See Figure 6). Imported gas is delivered on interstate pipelines. These pipelines, along with intrastate pipelines in California, are shown in Figure 7. The capacity of the interstate pipeline systems is shown in Table 3 and as the red line in Figure 4. Note from the graph that in all years except 2003 total interstate pipeline capacity (7,036 MMcf/d) was insufficient to meet natural gas demand during the peak winter months. Storing gas during the summer months for use during the winter is thus an important function of the natural gas storage system.

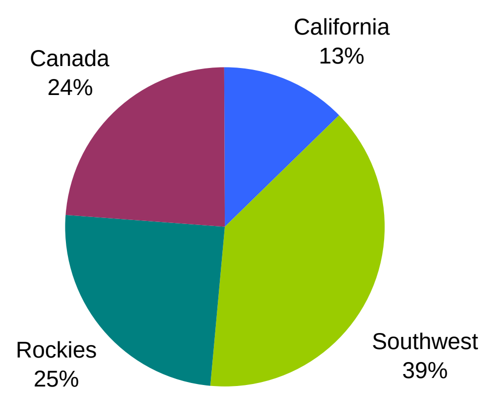


Figure 6: California Natural Gas Supply by Origin

Table 3: Interstate Pipeline Capacity

Pipeline	MMcf/day
SoCalGas	
El Paso at Blythe	1,210
El Paso at Topock	540
North Needles (Transwestern, Questar Southern Trails)	800
Hector Road (Mojave)	50
Wheeler Ridge (PG&E, Kern/Mojave, CA Production)	765
Line 85 (CA Production)	190
North Coastal (CA Production)	120
Kramer Junction (Kern/Mojave)	200
Total Firm Supply Access	*3,875*
PG&E	
Baja Path	1,140
Redwood Path	2,021
Firm Capacity	*3,161*

Source: (CA Utilities 2006, pp. 31, 61)

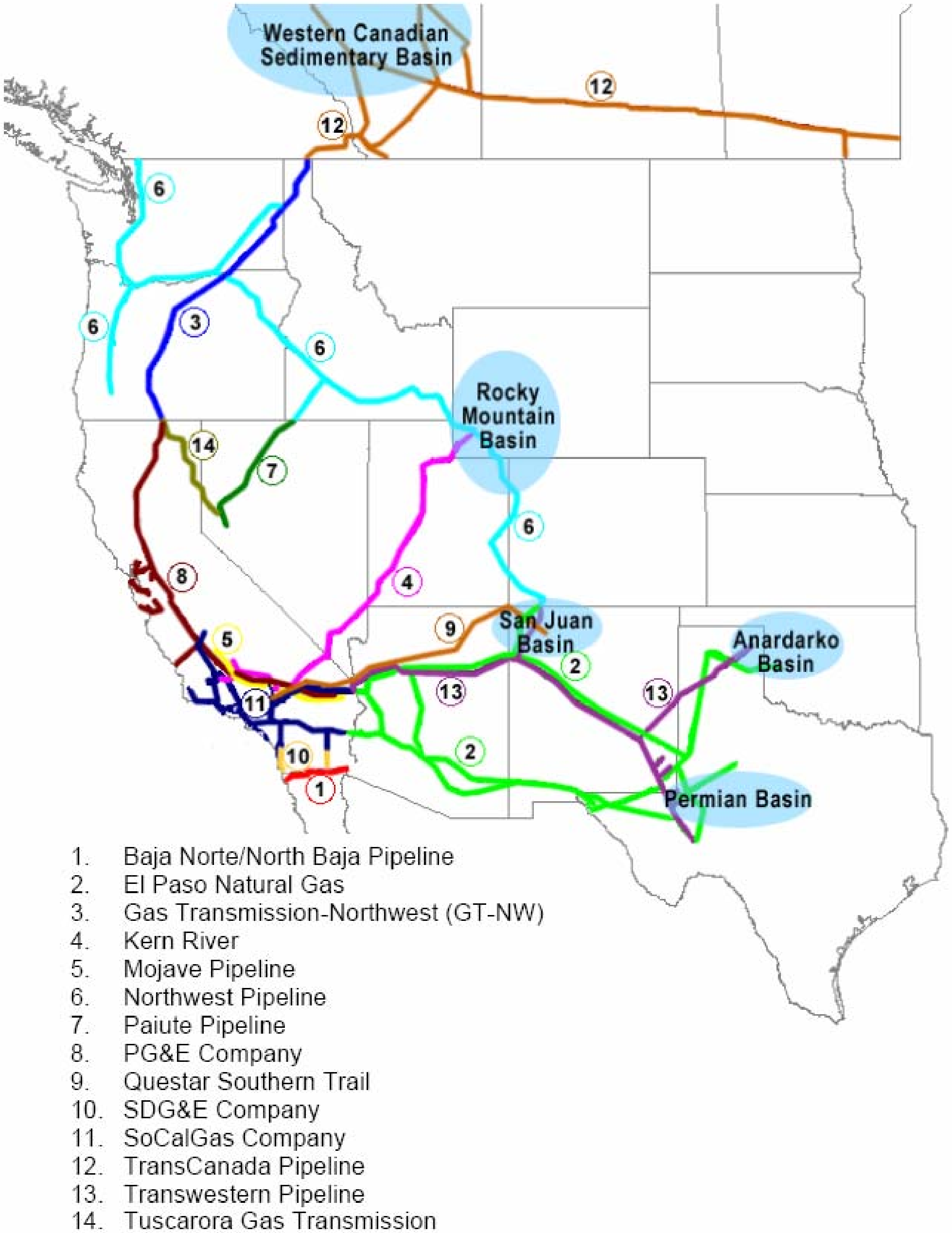


Figure 7: Western North American Gas Pipelines

Source: (CA Utilities 2006, p.15)

1.2.2. *Natural Gas Price Volatility*

Another use of the natural gas storage system is for price hedging to manage normal seasonal fluctuations in natural gas prices and more extreme market changes. Customers can inject natural gas during summers and other low price periods for withdrawal during winters and other higher price periods. The value of storage for this purpose depends upon seasonal price differentials and overall price volatility. Without price variability, there would be no need to attempt to hedge prices. With extreme variability, natural gas storage becomes more valuable.

Figure 8 shows the market prices for natural gas between 2000 and 2007 at Malin and Topock. During the California energy crisis, natural gas prices were higher than seasonally adjusted historic prices and quite volatile. More recently prices have decreased in relative terms, but they remain high compared with historical averages. They also remain vulnerable to short-term spikes and volatility, as was seen in the wake of Hurricane Katrina in late 2005. This vulnerability increases the value of storage, at least in the near term.

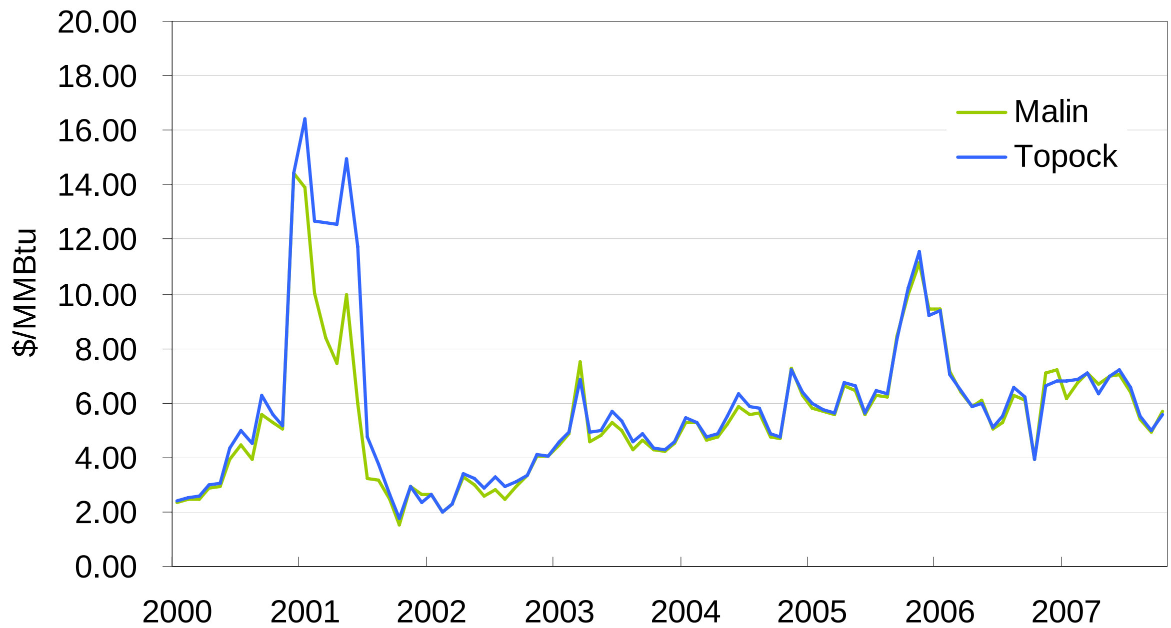


Figure 8: Bidweek Price of Natural Gas, Jan 2000 – Oct 2007[8]

1.3. Would California Benefit from Additional Storage Capacity?

Underlying this report is the assumption that California would benefit from additional storage capacity. This benefit could be in the form of serving unmet need, providing additional services, or lowering prices.

A full market analysis to assess the need for additional storage and the benefits that might ensue to California from additional capacity is beyond the scope of this report. However, in this section we develop a preliminary assessment based on conclusions of other agencies that have investigated the need for storage capacity and based on a number of market indicators. The

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7. Data from Platts Gas Daily, January 2000 to October 2007.

following section examines storage capacity statistics, CPUC and FERC assessments, and several market indicators that help to evaluate the need for natural gas storage in California.

1.3.1. *Natural Gas Storage Capacity in California and the United States*

As shown in Table 4 and Figure 9, most of the natural gas storage facilities in the U.S. are located in the Midwest region (Illinois, Indiana, Michigan, Minnesota, and Ohio) and the Southwest region (Arkansas, Louisiana, New Mexico, Oklahoma, and Texas). The Western region (California, Oregon, Washington, Nevada, Arizona, and Idaho) contains just 7.5% of the working gas storage capacity and 9.2% of the daily deliverability in the Lower 48 states. However, this region has expanded its storage capacity by 56 Bcf since 1998, the most of any region.

Table 4: Comparison of Working Gas Storage Capacity and Deliverability in 1998 and 2005

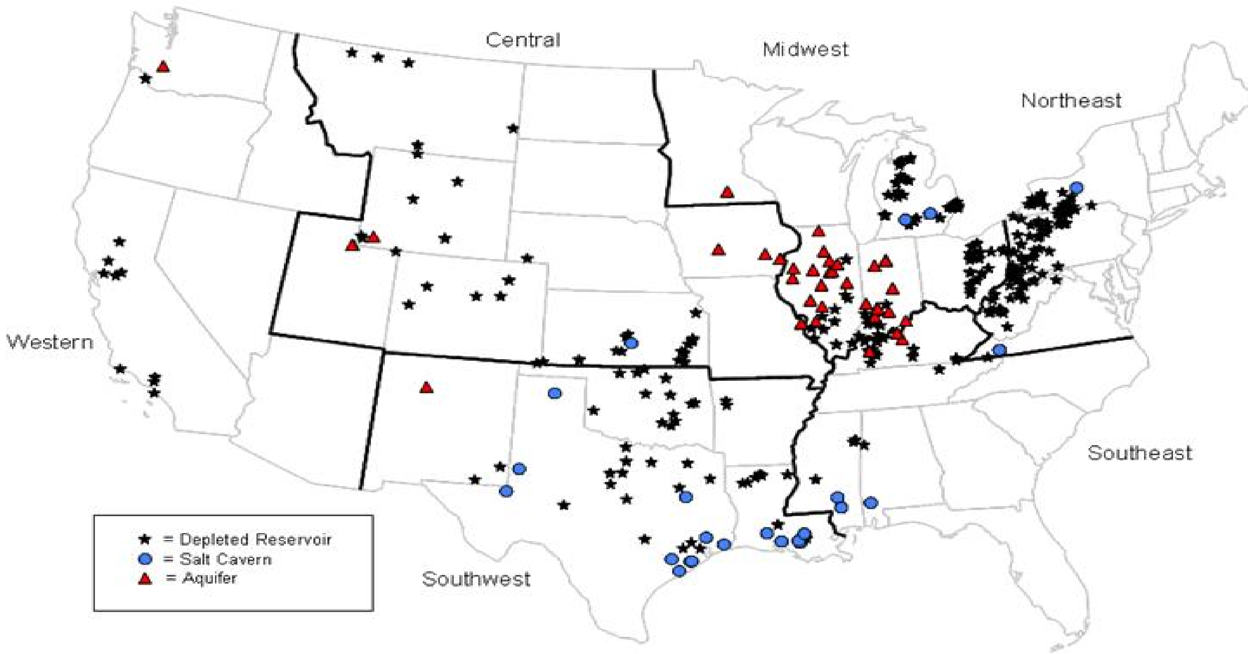
	1998		2005		Growth	
	Working Gas Capacity (Bcf)	Daily Deliverability (MMcf/d)	Working Gas Capacity (Bcf)	Daily Deliverability (MMcf/d)	Working Gas Capacity (%)	Daily Deliverability (%)
Northeast	711	12,539	767	14,751	8%	18%
Southeast	150	4,948	166	6,547	11%	32%
Midwest	1,143	23,431	1,196	26,364	5%	13%
Central	558	6,228	556	6,109	0%	-2%
Southwest	983	20,141	1,024	22,208	4%	10%
Western	245	6,632	301	7,673	23%	16%
United States	3,790	73,919	4,010	83,652	6%	13%

Source: (EIA 2006, p. 3; EIA 2007b)

As shown in Table 5, most of the western capacity is located in California, and most of the western capacity expansion since 1998 has also been in California. This expansion has been driven by the building of independent storage facilities in northern California and the expansion of existing utility-owned storage facilities in southern California. According to the U.S. Energy Information Administration (EIA):

> Since 1998, deliverability in the Western region has increased by 16 percent (1.1 Bcf/d) while working gas capacity has increased by 23 percent (56 Bcf). Contributing to these increases was the installation of two new depleted-reservoir natural gas storage facilities and the expansion of four existing natural gas storage fields (three depleted-reservoirs and one aquifer) during the period. Completion of the two new sites, Wild Goose (1998) and Lodi (2001) fields, in California, and their expansions in 2004 and 2005, respectively, accounted for more than half the increased deliverability in the region.

Conversely, two underground storage sites were abandoned during the period. Southern California Gas Company closed its Montebello and East Whittier storage fields in 2003 causing a temporary drop of 750 MMcf/d in the regional deliverability level for that year (EIA 2006, p. 15).[9]



Source: Energy Information Administration, Office of Oil & Gas, Natural Gas Division Gas, Gas Transportation Information System

Figure 9: U.S. Natural Gas Storage Facilities

9. Note that EIA considers any underground natural gas storage site to be operational regardless of operational activity until it has been officially designated as abandoned by its jurisdictional agency. SoCalGas' Montebello storage facility was taken out of service before 1999, but this was not captured by EIA until 2003.

Table 5: 2005 Working Gas Capacity in the Western U.S.[10]

	1998		2005		Growth	
	Storage Capacity (Bcf)	Daily Deliverability (MMcf/d)	Storage Capacity (Bcf)	Daily Deliverability (MMcf/d)	Storage Capacity (Bcf)	Daily Deliverabi lity (MMcf/d)
California	220	5,840	266	6,330	46	490
Other	25	792	35	1,343	10	551
Western Region, total	245	6,632	301	7,673	56	1,041

Source: (EIA 2006, p. 3; EIA 2007b)

During this same period, no new facilities were built in the rest of the Western region. However, working gas capacity at the Jackson Prairie facility in Washington was expanded by 5.5 Bcf, and working gas capacity at the Mist storage facility in Oregon was expanded from 7.4 Bcf to 14.4 Bcf (EIA 2006, pp. 15-16).[11] In addition, two Arizona projects are currently being considered. According to EIA, these projects are very much needed:

> Although there is a growing need for natural gas storage to accommodate the expanding natural gas pipeline systems in Arizona, only two salt-cavern storage projects are currently being explored. One is the Coolidge site project sponsored by the Chevron and Pacific Texas Pipeline Corporation in conjunction with its proposed 2009 Picacho Pipeline Project, currently before FERC for environmental review. The other is a proposal by El Paso Natural Gas Company to study the practicality of developing a salt-cavern storage facility in Pinal County that would be linked to its southern system. For the near-term, however, it appears that Arizona will remain without any underground natural gas storage facilities (EIA 2006, p. 16).

1.3.2. *CPUC's Infrastructure Adequacy Decision*

The CPUC recently assessed whether there would be adequate natural gas pipeline and storage capacity on a system-wide basis in the event of increased system demand or reduced capacity. This assessment considered only the physical availability of storage and pipeline capacity and did not consider whether there would be economic benefits from increased storage capacity.

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10. There is no standard way to report deliverability. Sometimes average deliverability is reported, while sometimes peak or daily deliverability is reported. In addition, deliverability is sensitive to the amount of gas in storage—when storage is low, there is not enough pressure to enable maximum deliverability. Consequently, data presented by different parties and for different purposes are not always consistent.

11. Northwest Natural also increased deliverability at the Mist storage facility.

Both PG&E and SoCalGas argued that they had sufficient capacity to meet core (and some non-core) demand on an Abnormal Peak Day (APD) and in the event of a supply loss.

PG&E has adopted a 1 in 90 year extreme temperature event for its APD and has estimated that core demand under these conditions would be approximately 3,300 MMcf/d. PG&E would meet this demand with the core's firm capacity, any as-available capacity, and capacity made available through supply diversion and storage withdrawals.

PG&E presented scenarios to the CPUC to demonstrate how it could serve customers with its existing capacity in the event of excess demand or loss of supply. For example, PG&E said that it could meet 300 MMcf/d of additional demand due to a 5-day summer heatwave by using pipeline capacity or reducing storage injections. PG&E also said that it could make up for 600 MMcf/d of lost supply due to a major 30-day pipeline outage by using a combination of supply delivered on the intrastate pipeline and supply in storage, including supply in storage facilities owned by Wild Goose and Lodi. The CPUC concluded, "[assuming] that these hypothetical situations reflect the outward boundaries of likely contingencies (we note that PG&E has not asserted this to be the case), PG&E's contention [that there is adequate storage capacity on its system] appears to be reasonable" (CPUC 2006e, p. 37).[12]

SoCalGas has adopted 1 in 35 year extreme temperature event for its APD and has estimated that core demand under these conditions would be approximately 3,500 MMcf/d. SoCalGas would meet this demand through deliveries from storage (~2,000 MMcf/d) and flowing supplies (~1,500 MMcf/d) (CA Utilities 2006, p. 65).

For the CPUC infrastructure adequacy assessment, SoCalGas calculated reserve margins for natural gas delivery in Northern and Southern California. Two reserve margins were calculated: 1) an annual reserve margin, which compares the amount of capacity that can be delivered from the backbone pipeline system each day to the average daily natural gas demand, and 2) a peak-day reserve margin, which compares the combined daily withdrawal capacity from the backbone pipeline system and from storage facilities ("theoretical peak capacity") with the utilities' peak-day demand. For the PG&E analysis, storage withdrawal capacity from independent storage providers was also included.[13]

As shown in Table 6 below, both utilities are shown to have positive reserve margins. SoCalGas appears to have a larger reserve margin than PG&E does; however, this may be due to PG&E's more extreme demand assumptions.[14] Both systems have constraints that prevent them from

12. It is unclear on what basis PG&E selected these scenarios and whether they represent "the outward boundaries of likely contingencies." PG&E asserted that a pipeline outage of the characterized magnitude is extremely unlikely, but no indication was given of the likeliness of the heat wave or the potential implications of climate change on peak temperatures.

13. The total withdrawal capacity from PG&E's storage is ~2,000 MMcf/d; the total withdrawal capacity from all Northern California storage facilities is currently ~3,000 MMcf/d.

14. PG&E uses a 1 in 90 year extreme temperature event, while SoCalGas uses a 1 in 35 year extreme temperature event.

simultaneously using all firm withdrawal and all backbone capacity, and therefore, reserve margins are somewhat overestimated. True reserve margins are not known. In addition, neither utility plans to fully serve noncore customers (including electric generation) under the peak-day scenario. As PG&E explained in the 2006 California Gas Report:

> Diversion of noncore supply in lieu of expanding firm core supplies has been the basis for infrastructure planning for years…looking towards the future, if gas fired electric generation grows as forecasted, supplemental supplies will eventually be needed if the goal is to serve the core load and most, if not all, noncore load [during APD conditions] (CA Utilities 2006, p. 33).

Furthermore, the CPUC determined that SoCalGas' reserve margin assessment was inadequate, in part because it does not reflect an assessment of the probability of injection and withdrawal by various shippers actually occurring or the deliverability of withdrawn gas over the local transmission system on a peak day: "It is unrealistic to rely on the exercise of all withdrawal rights if customers are not required to inject enough gas or to exercise their withdrawal rights, or if SoCalGas cannot deliver all of the withdrawn gas to the customers. Each customer must factor the likelihood of these occurrences into its assessment of system adequacy" (CPUC 2006e, p. 40).

Table 6: PG&E & SoCalGas Reserve Margins

	SoCalGas MMcfd	PG&E MMcfd
Backbone Capacity	3,875	3,286
2003 Throughput	2,608	2,414
Annual Reserve Margin	49%	36%
Backbone Capacity	3,875	3,286
Firm Withdrawal Capacity	3,175	2,223
Theoretical Peak Capacity	7,050	5,509
Peak-Day Demand 2006/7*	5,578 (3,414 Core 1-in-35-year) (2,164 Noncore)	4,755 (3,255 Core 1-in-90-year) (1,500 Noncore)
Peak-Day Reserve Margin	26%	16%

Source: (SDG&E and SoCalGas 2005, p. 6)

Nonetheless, the CPUC determined that at the current time, there was no reason to conclude that the utility storage systems were inadequate. The CPUC concluded, "[w]e take comfort in the fact that all parties (with the exception of Lodi) support the contention that the current backbone pipeline and storage infrastructure are sufficient. While we note several concerns with the utilities' proposals, we have no reason to believe at this time that the utilities' storage facilities are inadequate" (CPUC 2006e, p. 47).[15] Thus, the CPUC determined that there was adequate physical capacity during extreme conditions. However, as discussed below, the CPUC did not assess whether additional capacity would decrease price volatility or provide other benefits.

1.3.3. *FERC Assessment of Western and Southwestern Markets*

In the Red Lake case in 2003, FERC noted that the development of gas storage facilities has failed to keep pace with the demand for balancing services required by the many new gas-fired generation facilities in the west and the southwest (FERC 2003b, p. 6). In addition, the bid solicitation ("open season") conducted for Red Lake's proposed Arizona facility yielded agreements for over 8 Bcf of capacity, demonstrating demand for additional storage in the western Arizona/southern California market.

1.3.4. *Market Indicators*

The CPUC infrastructure adequacy decision probed the physical need for storage and found that there would be sufficient combined storage and pipeline capacity during extreme conditions. The decision did not address the economic need for storage; that is, whether additional storage facilities would improve the efficiency of the market by increasing competition and offering additional service options to natural gas users. Market activity indicates that current storage fields are heavily utilized and that market participants perceive demand for additional noncore capacity. This indicates that there is likely a physical and economic need for additional storage capacity, at least for noncore customers, and that additional storage could help to moderate the impacts of market price fluctuations.

Utilization of Current Storage Capacity

California storage fields have been heavily utilized in recent years. PG&E does not have sufficient storage capacity even to serve its core customers during peak periods and is relying on 1 Bcf of peak storage capacity from Lodi and PG&E California Gas Transmission (PG&E-CGT) (CPUC 2007d). Lodi announced in the CPUC infrastructure adequacy proceeding that its facilities were being fully utilized. Similarly, as shown in Figure 10, SoCalGas has sold at least 90% of its noncore storage inventory for each of the last four years, completely selling out in two of these years (SCGC 2006, p. 4). Furthermore, the percentage of SoCalGas noncore inventory tied to long-term contracts (i.e., contracts extending from 3 – 15 years) has steadily increased from less than 20% in 2003 to over 40% in 2006. This may indicate that market participants perceive the growing scarcity of storage and feel the need to secure the option with long-term contracts.

15. In its brief in this proceeding, Lodi argued that demand existed for additional natural gas storage capacity. Lodi cited full utilization at its facilities and its planned expansion, Wild Goose's recent expansion, PG&E's application seeking incremental firm core storage capacity, the expected growth in gas-fired electric generation north of Path 15, and the state's planned use of liquefied natural gas, which would increase demand for storage to smooth out LNG deliveries and as a hedge against LNG supply disruptions (LGS 2005, pp.1-2).

Notably, storage capacity is being nearly fully utilized, even though capacity has increased in California in recent years. Since 2001, SoCalGas has expanded its facilities by at least 20.5 Bcf, Wild Goose has expanded its facility by 15 Bcf, and Lodi has constructed a new 5.5 Bcf facility (CPUC 2005b, p. 1; SDG&E and SoCalGas 2005, p. 2).

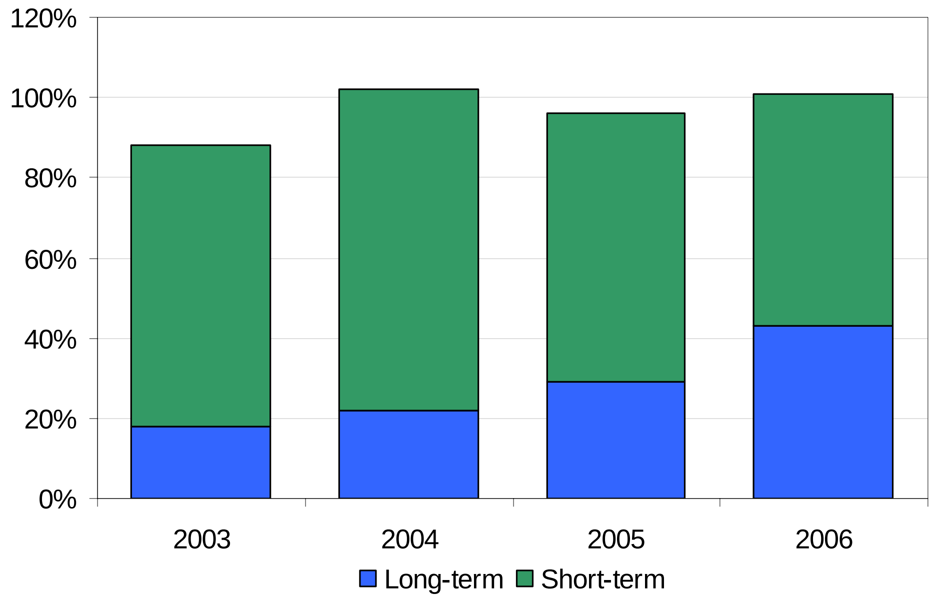

Figure 10: SoCalGas Noncore Storage Program Contracts, Percent of Total Inventory

Source: (SCGC 2006, p. 4)

Proposals for Additional Noncore Storage Capacity

Three projects for additional storage capacity are currently being proposed for northern California: Sacramento Natural Gas Storage is proposing a new 7.5 Bcf facility, Lodi is proposing a 12 Bcf storage expansion project, and PG&E and Northwest Natural are proposing a 20 Bcf facility near Fresno, CA (the Gill Ranch project). Moreover, PG&E is building a new pipeline to its McDonald Island facility, which will increase firm withdrawal capacity for its noncore storage program by 14%, and SoCalGas has proposed to transfer 13 Bcf of core capacity to noncore (PG&E 2007c; SDG&E and SoCalGas 2006a).

The CPUC noted some of this activity in its storage adequacy determination and concluded that "[the] fact that Wild Goose and Lodi are both willing to expand their facilities might suggest that those entities foresee unmet demand, although it also might just suggest that they see an opportunity to win over utility storage customers by offering a superior product or lower prices" (CPUC 2006e, p. 46).

Revenues Earned for Existing Capacity

Another indication of the need for additional capacity can be gleaned in an indirect manner from the revenues received by the utilities for their unbundled storage capacity. SoCalGas' noncore storage revenues have increased from $19 million in 2000 to $72 million in 2006 (SCGC 2007a, p. 8). PG&E does not report the revenues it receives for its unbundled storage program.[16]

1.3.5. *Potential Effect on Storage of Proposed LNG Facilities*

Several liquefied natural gas (LNG) facilities are being proposed or developed in or near California. For example, the Energia Costa Azul LNG facility is currently under construction in Baja California by Sempra Energy LNG, with an expected on-line date of 2008. The facility could bring into Mexico 1,000 MMcf/d of LNG with potential expansion capacity of up to 2,500 MMcf/d.[17] Potential markets include western Mexico, Southern California, and the southwestern U.S.[18]

The influx of additional natural gas into Southern California could have an effect on the natural gas storage market for non-core customers in the region; however the effect could be in either direction. The LNG facilities could decrease the need for storage capacity by increasing flowing gas, or they could increase the need for additional storage facilities by effectively converting Southern California from a gas consuming region into a gas producing region. It is generally desirable to build storage in gas producing regions in order to store the gas that is produced, so that it can be sold at optimal times.

1.4. Conclusion

A complete market analysis would be required to determine the need for additional natural gas storage capacity in California and the impact that additional storage would have on natural gas rates. However, there are a number of indicators that suggest that there is room in the market in both Northern and Southern California for additional storage to meet current demand. For

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16. The Gas Accord sets the maximum rates that PG&E may charge for its noncore storage facilities, and PG&E is at risk for over- or under-recovery. PG&E does not publicly report this information.

17. A consultant report prepared for the California Energy Commission predicted a slower introduction of LNG to the Pacific coast than implied by these figures. The report projected that there would be demand for delivery into the North America Pacific of 830 MMcf/d of LNG in 2010 and 2.59 Bcf/d in 2020 (Energy Commission 2007, p.36).

18. D. 06-12-031 (December 14, 2006) allows gas to flow from SoCalGas onto PG&E's transmission system (i.e., off-system delivery to PG&E). The CPUC declined to allow off-system sales to other pipelines, but noted that "[w]ith the potential for large quantities of LNG to reach California, the opening of new markets is of tremendous importance for these shippers" (CPUC 2006d, p.119). At the same time, the CPUC recognized that the use of SoCalGas' transmission system to deliver gas outside of California would raise "FERC jurisdictional issues pertaining to the Hinshaw exemption of SoCalGas' transmission system" (CPUC 2006d, pp.119-120). (The Hinshaw exemption exempts pipelines from FERC jurisdiction if the pipeline is regulated by the state and all gas is supplied and used within the state.) For these reasons, the CPUC indicated that it would permit SoCalGas and SDG&E to file an application no earlier than May 1, 2008 to address this issue and that this application should "address the impact of the Hinshaw exemption on the proposed service to other pipelines, and how this proposed service may impact the daily operations of the two utilities with respect to all their intrastate customers" (CPUC 2006d, p.120).

example, existing storage capacity has been nearly fully utilized in recent years; existing storage operators are seeking to expand their facilities; PG&E recently purchased 1 Bcf of core storage from independent providers (because it had insufficient storage capacity to meet this demand); and SoCalGas' revenues for non-core storage increased by over $50 million (over 250%) between 2000 and 2006.

In Northern California, there has been significant capacity expansion over the past ten years, and this expansion is continuing. PG&E is expanding the withdrawal capacity of its McDonald Island facility and, with Northwest Natural, has proposed to build a new 20 Bcf facility. In addition, independent storage operators are seeking to expand their facilities and develop a new facility. In Southern California there has also been a significant level of expansion; however this has been accomplished solely via SoCalGas expanding the capacity of existing facilities. No independent storage operators have facilities in Southern California, and there have been no new facility developments in recent years. The one recent attempt to build a facility that would serve Southern California (i.e., the Red Lake facility in Arizona) failed when the owner was not able to obtain market-based rate authority from FERC.

2.0 Market Power Regulation and the Natural Gas Storage Industry

In order to ensure fair competition in the deregulated natural gas storage industry, regulators employ a variety of tests to determine whether a storage facility has market power. Market power is the ability to raise prices above competitive levels for a significant period of time. In the natural gas and electricity industries, regulators have required that companies that wish to charge market-based rates demonstrate that they do not have market power. In the absence of such a showing, regulators often require companies to charge cost-based rates or to mitigate their market power in order to receive market-based rate authority.

According to one assessment by FERC, "Entities with market power can exercise that power in two general areas: (1) the withholding of capacity; and (2) the extraction of monopoly rents. Thus, there are two approaches to protecting consumers against the exercise of market power: (i) conditions that limit the withholding of capacity and (ii) rate protections" (FERC 2005, p. 26). Requiring companies that have market power to charge cost-based rates is one form of rate protection.

In general, companies prefer market-based rates because it allows them substantial pricing flexibility and it does not require them to reveal potentially sensitive financial information. In addition, cost-based rates require regulatory approval and are thus more burdensome to implement, particularly for companies that are otherwise unregulated and inexperienced in regulatory matters. Cost-based rates also restrict profits to a regulated rate of return, which may be lower than the rate of return achievable through market-based rates.

While the goal of market power tests is to prevent a company from being able to abuse the competitive market, there is reason to believe that the tests may have the unintended consequence of impeding needed development of independent natural gas storage facilities. In this chapter we examine market power tests and how they are employed by regulatory bodies in the natural gas storage industry. We also examine the sensitivity of market power tests to the way in which specific input parameters are defined. These definitions determine the context in which market power is assessed and can have a substantial impact on test results.

2.1. Measuring Market Power: The Herfindahl-Hirschman Index

The Department of Justice (DOJ) Horizontal Merger Guidelines are used in a variety of industries, including the natural gas storage industry, to assess market power. The Merger Guidelines are primarily concerned with the effects of horizontal mergers on competition and consumer prices (DOJ 1997). They rely on a market concentration test, the Herfindahl-Hirschman Index (HHI), to assess the market power of merging firms in order to determine whether the proposed merger would be anti-competitive.

To calculate the HHI, the regulatory body defines the relevant product market and geographic market of the merging firms, identifies the firms that participate in the relevant market, and calculates the market shares of the competing firms. The HHI is calculated by summing the squares of the post-merger market shares of each participant. For example, a market with three firms with market shares of 15%, 40%, and 45% would have an HHI of $(15)^2 + (40)^2 + (45)^2 =$ 3,850. In evaluating the market power of natural gas storage owners, the HHI is separately calculated for working gas capacity, maximum daily deliverability, and any other applicable products.

HHI values can range from one to 10,000. A small HHI indicates that customers have sufficiently diverse sources of supply such that no one firm or group of firms should be able to profitably raise the market price. A large HHI indicates significant market concentration such that one firm or group of firms might be able to profitably raise the market price. At one extreme, having 10,000 firms with .01% market shares would result in an HHI of 1, while at the other extreme, an HHI of 10,000 indicates that a single firm serves the entire market (i.e., $(0)^2 + (100)^2 = 10{,}000$). FERC has used an HHI of 1,800 as an indication that closer scrutiny is warranted, because market power is concentrated and the applicant may be able to exercise market power (DOJ 1997). A market with an HHI of 2,000 could include, for example, 5 firms each with a 20% market share. This benchmark arises from the DOJ's Merger Guidelines, which specify the following general principles for evaluating mergers:

<u>Post-Merger HHI Below 1,000</u>: Markets in this region are regarded as unconcentrated. Mergers resulting in unconcentrated markets are unlikely to have adverse competitive effects and ordinarily require no further analysis.

<u>Post-Merger HHI Between 1,000 and 1,800</u>: Markets in this region are regarded as moderately concentrated. Mergers producing an increase in the HHI of less than 100 points in moderately concentrated post-merger markets are unlikely to have adverse competitive consequences and ordinarily require no further analysis. Mergers producing an increase in the HHI of more than 100 points in moderately concentrated post-merger markets potentially raise significant competitive concerns.[19]

<u>Post-Merger HHI Above 1,800</u>: Markets in this region are regarded as highly concentrated. Mergers producing an increase in the HHI of less than 50 points, even in highly concentrated post-merger markets, are unlikely to have adverse competitive consequences and ordinarily require no further analysis. Mergers producing an increase in the HHI of more than 50 points in highly concentrated post-merger markets potentially raise significant competitive concerns. Where the post-merger HHI exceeds 1,800, it is presumed that mergers producing an increase in the HHI of more than 100 points are likely to create or enhance market power or facilitate its exercise. The presumption may be overcome by a showing that other factors make it unlikely that the merger will create or enhance market power or facilitate its exercise, in light of market concentration and market shares (DOJ 1997, Section 1.5.1).

In the context of a proposed merger, the purpose of the HHI test is to determine whether the merger would result in an increase or a decrease in market power, which is defined as the ability to raise prices above competitive levels for a significant period of time. However, the

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19. Sections 2-5 of the DOJ Horizontal Merger Guidelines set forth criteria for determining the competitiveness of markets that raise potentially significant competitive concerns (DOJ 1997).

HHI may not provide much insight into the ability of a firm to exercise market power. The DOJ Merger Guidelines implicitly acknowledge this, as the HHI results are used only to obtain a first approximation of market power, with additional factors considered in all questionable cases. Indeed, DOJ has stated that a high HHI value does not necessarily indicate market power (DOJ 1984).

FERC relies on the HHI criteria in its assessment of market power in the natural gas storage industry; however, FERC does not follow all aspects of the DOJ merger guidelines. In particular, FERC focuses on overall market concentration and the market share of new entrants, rather than on changes in the HHI and market share metrics.

Over the years, there has been some criticism of the HHI test. This criticism has focused on the fact that market concentration is not a measure of market power itself, but rather a measure of the *potential* for market power. Other criticisms focus on the fact that the HHI analysis does not take into consideration supply and demand elasticities (Borenstein and Bushnell 1999).

The development of market power analysis in the electricity industry has resulted in more extensive market power regulation used in the electricity industry. A discussion of these regulations and their relation to natural gas storage can be found in Appendix A.

2.2. Defining the Relevant Markets

An HHI assessment depends only on the market shares of competing firms. However, competing firms must be identified within a defined geographic market and product market. For natural gas storage operators, the relevant geographic market establishes the spatial boundaries within which storage operators compete for business. The product market, in contrast, establishes what product(s) provide competitive alternatives to storage. The choice of geographic and product markets can greatly impact the outcome of an HHI assessment.

2.2.1. *Geographic Market*

A typical market power analysis focuses first on the narrowest possible geographic market. If the degree of market concentration is low in the narrow market, then it will generally also be low in the broader market where the concentration has more capacity over which to be diluted. Finding a low degree of concentration in a narrow market can thereby shorten the necessary analysis, allowing a decision-maker to safely conclude that no market power is present in any of the markets served by the applicant. However, finding a high degree of concentration in a narrow market does not necessarily indicate that there is also a high degree of concentration in a broader market. If it is found that there is not a high concentration in the broader market, the regulator must determine whether the entire region included in the broader market truly operates as one market, or whether only the narrow market should be considered.

This issue arises in the context of the Southern California natural gas storage market. For example, the market for storage capacity has an HHI of 10,000 if only Southern California is considered, because SoCalGas is the only supplier in the market. However, the market for storage capacity in the combined market of Southern California, Sorthern California, and all accessible storage facilities has an HHI of less than 1,000.[20] In this case, broadening the definition of the geographic market shifts the analysis results from highly concentrated (HHI > 1,800) to unconcentrated (HHI < 1,000).

2.2.2. *Product Market*

The product market consists of the specific products or services that provide good alternatives to the applicant's products and services. With regard to natural gas storage, the basic products are inventory, injection, and withdrawal.[21] These products are offered as both firm and interruptible, with components priced individually so that customers may tailor their contractual arrangements to their specific needs.[22] For example, service could be structured a) for firm inventory to hold gas from one period to the next, b) for a small amount of inventory combined with substantial withdrawal capacity to reliably meet peak requirements for a short period, or c) for more balanced inventory, injection, and withdrawal capacities in order to capture a variety of benefits.

At least six distinct services are provided by these products:

- **Commodity Price Arbitrage**. Customers can use storage to buy gas in excess of current requirements when prices are low and then use or sell the gas when prices increase. Price volatility can be profited from seasonally or over much shorter time spans.

  Storage operator services are useful for commodity price arbitrage only if the charge for storage services is less than the expected future differential in gas commodity costs. In the summer of 2000, high gas costs resulted in less gas being injected to storage, as customers perceived either that summer gas costs would drop eventually or that the high summer prices would not be sufficiently less than the available winter gas supplies to make the use of storage services economic.[23] Thus, the use of storage for price arbitrage and customers' value of this service is limited by the customers' price outlook.

  Price arbitrage may limit the market power of natural gas marketers who possess transportation rights on pipelines running near or at capacity.[24] By providing an

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20. For an analysis of the market concentration of the California natural gas storage industry see Appendix C.

21. Inventory refers to storing the gas; injection and withdrawal refer to delivering gas into the storage facility and retrieving it from the storage facility.

22. Firm service guarantees access to storage, injection, and withdrawal capacity up to a contracted amount. Interruptible service is offered on an as-available basis. A party storing gas on an interruptible basis might not be able to withdraw the gas on the preferred date, if all withdrawal capacity on that date has been taken up by firm service customers.

23. "During the 2000 injection season, noncore customers of SoCalGas injected almost no gas into storage…due to the forward price strip, even though SoCalGas' unbundled storage program was fully subscribed" (TURN 2001).

24. "During periods of high demand and tight capacity, prices would ordinarily rise as a result of basic competitive market forces and real scarcity. However, conditions of tight capacity can often create market

alternative to highly or fully utilized pipeline capacity, storage can provide a check to the market power of the gas marketers utilizing such pipelines and provide downward pressure on prices the marketers can charge. The 2000-2001 price increases of southwest supplies reaching California via the El Paso pipeline have been attributed to the market power of marketers during a high demand period for natural gas when California gas customers' had few substitutes (i.e., inelastic demand) (FERC 2000a).

- **Balancing**. Customers can use storage to buffer routine differences between flowing supplies and day-to-day consumption in order to remain within the tolerances of intra- and inter-state pipeline transporters (and thereby avoid the imbalance penalties). Park and lending services are also offered in the broader context of balancing.
- **Alternate Fuel Backup**. At times of natural gas curtailments or supply shortages, customers can use gas in storage instead of using an alternative fuel, such as fuel oil or LNG.
- **Reduce Transport Commitments**. Customers can use storage to meet their peaking requirements in order to avoid purchasing firm transportation for peak day requirements, which would be vastly oversized for much of the year. (If storage covers peak day requirements, customers can purchase firm transportation for only average requirements, saving transportation costs.)
- **Manage Existing Transportation Commitments**. Customers can use storage to situate themselves to sell pipeline access when that access is valuable to third parties. (The customer meets his needs with gas withdrawn from storage when he has sold his pipeline access.) Alternatively, storage can help customers use the pipelines at higher load factors in order to reduce transportation charges.
- **Transportation Cost Arbitrage**. Customers can use storage to enable them to buy transportation when prices are low and sell when prices rise.

To define the product market, good alternative providers of these services must be identified. "Good alternatives" must be readily available (or available soon enough) and must have a price that is low enough and a quality that is high enough to permit customers to substitute the alternative for the applicant's service. For example, while the pipeline system competes directly with natural gas storage facilities for many of these services, it will only be part of the product market if there is available capacity on the system to meet the needs of storage customers, if prices are low enough that storage customers would consider using the pipeline system in place

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power, especially when demand is insensitive to price. When demand is inelastic and approaches capacity, a seller with a relatively small amount of capacity can often begin to influence the market price. It can sell most (if not all) of its output even if it asks for a price higher than what other sellers are asking. The seller may lose some sales by asking a higher price, but these lost sales revenues are more than made up by the higher prices on the output it produces. Thus, while the combination of high demand and tight capacity would ordinarily cause prices to rise due to competitive market forces, they may also create market power that causes prices to rise even higher. From a public policy perspective, the desirable outcome is a competitive price increase, not the higher price increase caused by the exercise of market power" (FERC 2000d, p. 5-17).

of storage, and if service on the pipeline is reliable and can be structured to meet the needs of storage customers.

2.3. "Good Alternatives" and Their Importance for Market Power

There are a variety of services that can substitute for the services provided by gas storage facilities. These alternatives provide users a range of opportunities to meet their peak gas demand or otherwise manage their gas supply takes. The availability of these substitutes means that potential storage customers are not captive: they have a wide range of alternatives from which to choose, and these alternatives serve to set a cap on what storage service providers can charge.

Some of the substitutes for natural gas storage are listed below:

- **Transportation capacity**: FERC has recognized that transportation and storage are interchangeable, as have end-users (Gas Daily 1996; FERC 1992).[25] Transportation and storage both provide deliverability, and absent storage, transportation capacity would generally have to be expanded. Customers can compare the cost-effectiveness and reliability of storage to that of available pipeline transportation.
- **Balancing services:** Balancing services, provided by utilities and by pipelines, allow shippers to balance short-term discrepancies between gas receipts and deliveries without purchasing storage service. Balancing service can be thought of as a form of "reserving" space to handle imbalances in exchange for a fee set lower than the imbalance penalty fee. California utilities also offer pipeline parking and lending services, which operate in a similar fashion, on as-available basis.[26]
- **Alternate fuels:** A customer with alternate fuel capability should not be willing to pay more for gas storage than the difference between the cost of gas and the cost of the alternate fuel (including the cost of factors such as storing the alternate fuel or air quality limitations on using certain fuels).

  Few non-core gas customers in California currently possess alternate fuel capability due largely to environmental constraints associated with burning oil. As the cost of gas rises, however, alternative fuel capabilities may prove an economic alternative to both gas storage and gas.

  Liquefied natural gas (LNG) and liquefied petroleum gas (LPG) are other alternative fuels that are suited to some sites and uses and can serve as direct substitutes for underground gas storage. Several above-ground LNG facilities already help meet peak

25. See also, D.88-11-034, where the CPUC also explored the relationship between storage and transportation service.

26. The gas utilities' balancing services are also a substitute for storage services: both PG&E and SoCalGas offer a monthly balancing service that allows customers to carry as much as ten percent out of balance before incurring a fee. The costs of this balancing service are bundled with gas transportation rates and are provided using a combination of the utilities' storage facilities, along with line pack and draft capability.

demand in the Pacific Northwest. LNG is expensive and, where available, creates a cap on what customers should be willing to pay for storage. A number of companies are considering the feasibility of LNG facilities on the West Coast, and Sempra LNG is currently constructing an LNG terminal in Baja that would deliver 1 Bcf/d and it is expected to be operational in 2008 (Sempra 2007).

- **Gas diversion contracts**: These contractual agreements can be used to purchase gas from another shipper when needed on an emergency basis, such as under operational flow order (OFO) conditions, instead of withdrawing gas from storage. Suppliers serving core customers may find that purchasing gas from a non-core customer who can shut down a plant is a competitive alternative to purchasing storage in order to guard against preparing to serve all customers on a peak-demand, low-probability cold day. While the terms of such contracts are determined via private, individual negotiations, the price should be limited by the value that the customer places on avoiding curtailment and the cost of underground storage. Any non-core customer who is willing to accept being curtailed for a short period in exchange for monetary compensation can execute one of these contracts.
- **Financial products**: The futures market helps place a cap on the price storage operators can charge for storage. Customers engaged in seasonal price arbitrage or trying to minimize seasonal price swing impacts can do so with a futures contract in place of physical storage. Customers can also use a variety of financial products that lock-in or cap natural gas prices.

Table 7 summarizes storage products and the variety of alternatives to these services that can serve as substitutes. Some of these products provide physical access to additional natural gas, whereas others (e.g., financial instruments) provide only price protection. Note that in-state California natural gas production is included as a reliability substitute, since gas customers who can bypass the utilities can use this comparatively reliable supply instead of relying on storage to offset possible utility curtailments.

Ideally, these substitutes would all be incorporated into the HHI analysis as part of the product market. However, the nature of most of these alternatives makes it impossible to translate their services into units describing storage inventory or withdrawal capacity. (For example, what is the market share of financial markets within the natural gas storage industry?) Instead, the regulator generally allows only inclusion of other natural gas storage facilities and, more recently, accessible pipeline capacity, in the HHI analysis. The regulator then relies on the application of good sense and an understanding of the complexities and sophistication of today's gas market to assess the role other alternatives have in a competitive market.

Table 7: Natural Gas Storage Substitutes

Natural Gas Storage Service	Substitutes
Reliability/Deliverability Seasonal/Peak Supply	Storage Providers Transportation Capacity Alternative Fuels, LNG Voluntary Diversion Contracts California In-State Production
Price Arbitrage	Storage Providers Futures Market Spot Market OTC Market
Balancing	Storage Providers LDC Balancing Provisions Pipeline Parking & Lending Imbalance Trading or Aggregation
Managing Pipeline Transportation Costs	Storage Providers Capacity Brokering & Release Spot Sales

Though lacking in a common measure, these alternatives have a significant impact on the market power of storage service providers. By providing alternatives, these services increase the elasticity of demand and create a cap on what a consumer will pay for storage. That is, a consumer should not be willing to pay more for storage than the cost of the available alternatives. The prices of these alternatives are interrelated with storage service prices, and the presence of these alternatives and substitutes may reduce the exercise of market power.[27]

2.4. Other Factors Affecting Market Power

There are a number of additional factors to consider beyond the market share and presence of additional alternatives and substitutes. These factors can preclude participants in the California storage market from exerting market power in the California and western U.S. storage market. For example, as long as there are no substantial barriers to entry, any market power should be mitigated naturally over time by new entrants, who would be attracted to the market by the ability to charge prices in excess of cost. These entrants should drive prices back down to the market-clearing level, where marginal cost equals marginal revenue.

27. The HHI is a measure of supply competition and does not address the elasticity of demand. Substitutes can be thought of as factors that increase the elasticity of demand. In an oligopoly market, both the level of supply competition and the elasticity of demand influence the degree to which a competitor can charge a price above the market-clearing level (i.e., where price equals marginal cost). (Borenstein 1995).

Storage projects are highly capital intensive, but they do not present significant technical barriers: given that a site with appropriate geological characteristics could be found and rights to that site and financing obtained, a storage facility could be built. In a situation with inflated prices due to market power, new entrants should thus eventually drive prices down to a competitive level.

2.5. Conclusion

Market power tests are standard mathematical tools used by regulators to measure the ability of an operator to assert power over the market. In completing a market power analysis considerable variation in results will be obtained by altering the assumptions of the analysis. For example, the choice of geographic market involved in the analysis will, in most cases, significantly impact the results. In addition, a wide or narrow definition of the product market and available substitutes can affect market power conclusions. Even if market power is found to exist temporarily in a market, the true definition of market power is the ability to raise prices for a sustained period of time. In the natural gas market, the ability to raise prices will depend in large part on whether there are alternatives or substitutes for storage, whether customers are price responsive (i.e., it will depend upon the elasticity of demand), and whether there are barriers to entry. If there are no significant barriers, entry into the market may mitigate such price increases in the long-run.

3.0 FERC Regulatory Background

FERC is the regulatory body responsible for overseeing natural gas storage facilities connected to interstate pipelines. On June 19, 2006 FERC liberalized its rules for determining whether a storage project operator should be awarded market-based rate authority. These rule changes were developed out of concern that FERC's prior market power tests had been inhibiting the development of storage capacity in areas where the extra capacity would have been in the public interest. Under the new rules, some applicants who would not have previously been awarded market-based rate authority may now be eligible for this authority. This authority is generally regarded as an important factor in determining whether or not some projects will be economically viable.

This chapter reviews the development of FERC rules and federal law relating to market power assessments for natural gas storage projects. (See timeline in Table 8.) The first section of this chapter discusses the FERC market power rules that were in effect from the 1990s through 2005. The chapter then discusses the pivotal Red Lake case and the subsequent reassessment of FERC's rules following the Energy Policy Act of 2005. The final section of this chapter discusses industry developments under FERC's revised rules. The timeline below outlines the developments to be discussed further in the text.

Table 8: Timeline of Gas Storage Policy Developments

July 1993	FERC approves Transok market-based rates, 64 FERC ¶61,095
July 1994	FERC approves Avoca market-based rates, 68 FERC ¶61,045
July 1995	FERC approves Steuben market-based rates, 72 FERC ¶61,102
January 1996	FERC issues "Statement of Policy and Request for Comments – Alternatives to Traditional Cost-of-Service Ratemaking for Natural Gas Pipelines," 74 FERC ¶61,076
July 1996	FERC approves Manchester market-based rates, 76 FERC ¶61,007
March 2000	FERC approves ONEOK market-base rates 90 FERC ¶ 61,283
June 2000	FERC approves Honeoye market-based rates, 91 FERC ¶ 62,165
August 2002	Red Lake submits FERC application
January 2003	FERC denies Red Lake market-based rates, 102 FERC ¶61,077
March 2003	Red Lake submits rehearing request
June 2003	FERC denies Red Lake rehearing, 103 FERC ¶61,277
August 2003	Southwestern Gas Storage Technical Conference
Sept. 2004	FERC staff issues report, "Current State of Underground Natural Gas Storage"
October 2004	FERC State of the Natural Gas Industry Conference
August 2005	Energy Policy Act of 2005
Dec. 2005	FERC issues Notice of Proposed Rulemaking, Docket RM05-23-000
June 2006	FERC issues final rule, Order No. 678, 115 FERC ¶61,343
Nov. 2006	FERC denies requests for rehearing of Order No. 678 and approves market-based rates for Northwest Natural Gas under revised FERC criteria

3.1. FERC Rules Prior to the Energy Policy Act of 2005

Beginning in the early 1990s, a number of natural gas storage providers applied to FERC for authority to charge market-based rates for storage services. In response, FERC delineated a range of issues that it would review in making a determination of the applicants' potential to wield market power. Only applicants that lacked market power would be granted market-based rate authority. In 1996 FERC formalized these principles in a "Statement of Policy and Request for Comments – Alternatives to Traditional Cost-of-Service Ratemaking for Natural Gas Pipelines" ("Policy Statement") (FERC 1996c).

According to the Policy Statement, FERC would investigate two principal issues in order to determine whether an applicant would have market power: "1) whether the applicant can withhold or restrict services and, as a result, increase price by a significant amount for a significant period of time, and (2) whether the applicant can discriminate unduly in price or terms and conditions" (FERC 1996c, p. 20). To investigate these issues, FERC conducted market concentration and market share assessments. FERC also evaluated ease of entry into the market, firm size, and other competitive factors that might mitigate the ability to exercise market power in regions with high market concentration or by entities with large market shares.

3.1.1. *Market Concentration and Market Share Assessments*

FERC used the HHI analysis to evaluate market concentration, with HHI values of 1,800 and above regarded as indicative of the potential for market power. FERC calculated market share as the ratio of the applicant's storage service capacity to total storage capacity in the defined marketplace. A high market share assessment could indicate the potential for market power even in the case of a low HHI. A low market share assessment could indicate an inability to exercise market power even in the case of a high HHI, since customers would have adequate alternatives. For instance, FERC found that the Richfield Gas Storage System would not have the ability to exert market power due to its small (5%) market share: "Only a very small portion of the working gas in Kansas and possibly even less in the larger group of states would be required to replace all of Richfield's working gas if Richfield attempted to raise [its] price" (FERC 1992, pp. 13-14).

FERC did not establish a market share threshold above which it would consider an applicant to have market power. Indeed, FERC granted approval for market-based rates in the ONEOK natural gas storage case, even though the applicant held relatively high market shares of 13.5% (inventory) and 21.8% (withdrawal) (FERC 2000c). FERC ruled that other measures of competition demonstrated a lack of market power for ONEOK.

Table 9: Selected FERC Approvals of Market-Based Rate Authority for Storage Facilities[28]

Company	Docket No.	Date of Approval	Storage Inventory Capacity		Daily Withdrawal Capability	
			HHI	Market Share	HHI	Market Share
Avoca	CP94-161-000	1994	4,900	3.0%	4,100	9.6%
Steuben Gas Storage Company	CP95-119-000 CP95-119-001	July 28, 1995	4,401	3.5%	3,600	1.66%
Equitable Storage Company	PR96-1-00	April 25, 1996	725	0.52%	517	1.75%
Egan Hub Partners	CP96-199-000 CP96-199-001	October 7, 1996	1,152	2.41%	867	13.58%
Manchester Pipeline Corporation	PR95-15-000	July 1, 1996	1,200	5.5%	1,269	3.35%
Central Oklahoma Oil and Gas Corporation	PR97-8-000	August 29, 1997	1,519	3.04%	1,497	4.51%
ONEOK Gas Storage, LLC	PR99-19-000	March 20, 2000	1,139	13.5%	1,072	21.8%
Honeoye Storage Corporation	CP00-93-000 CP00-94-000 CP00-95-000	June 6, 2000	NA	1.22%	NA	0.60%
Petal Gas Storage, LLC	CP00-59-000 CP00-59-001	Sept. 15, 2000	948	14.37	783	13.75
Transok, LLC	PR00-16-000	October 11, 2000	1,281	7.13%	1,287	6.89%

As shown in Table 9, in some cases FERC also approved market-based rates even when the HHI analysis indicated a concentrated market. For instance, in the Steuben and Avoca cases, the HHIs for working gas capacity and deliverability ranged from 3,600 to 4,900, but FERC concluded that the applicants would not be in a position to control the market because their facilities were small relative to the alternatives (FERC 1994; FERC 1995). In the Honeoye case, despite evidence of a concentrated market, FERC found that as a new market entrant Honeoye would be too small to exert market power (FERC 2000b). In the Transok case, Transok's ability to exert market power was determined to be limited because Transok had to rely on transportation services provided by its competitors in order to market its storage service to customers served by the interstate pipeline system.

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27. The HHI numbers and market share percentages shown here are those presented by FERC in its decisions in each of the cases. These numbers may have differed from the applicants' testimony.

In assessing market concentration and market share, FERC considered only product alternatives that were in existence or under construction at the time of the assessment. Planned facilities and facilities outside of the geographic market that were attached to interconnecting pipelines were considered qualitatively (FERC 1996a, p. 11).

The geographic market that FERC considered varied in scope depending on the particulars of the case. For example, in the Transok case, FERC concluded that the smallest relevant geographic market consisted of the natural gas capacity attached to the Transok storage field through direct interconnections with eight interstate pipelines (FERC 1993). In the Manchester case, FERC concluded that the relevant geographic market included production area storage capacity directly connected to two pipelines with direct interconnects to Manchester's storage facility plus production area storage capacity connected to pipelines that interconnected with these two pipelines, but excluded intrastate storage facilities that would be unavailable for interstate service (FERC 1996b). These determinations were based on an assessment of which facilities would compete with the storage facility under consideration.

3.1.2. *Other Competitive Factors*

In addition to HHI and market share assessments, FERC probed other competitive factors to assess the ability of a seller to exert market power. For instance, FERC considered whether an applicant could sustain a price increase of 10% over a two-year period. If market entry were easy, the applicant would not be able to do so because new competitors would enter the market and drive the price down.[29] FERC also took into consideration the presence of a large and sophisticated customer in the market, since such a customer tends to exert downward pressure on prices and restrict an applicant's ability to exert market power.

3.2. Red Lake

As described above, FERC granted market-based rate authority to several applicants that would appear, based on market concentration or market share assessments, to have the potential to exert market power. However, in an important case in 2003, FERC denied Red Lake Storage, L.P. market-based rate authority even though FERC determined that the proposed project was in the public interest. Faced only with the option of assessing cost-based rates, Red Lake declined to build the storage facility (FERC 2003a).

3.2.1. *The Proposed Project*

Red Lake's proposed project was to be located in Mohave County, Arizona, approximately 30 miles from Kingman, Arizona. It was to have 12.0 Bcf of working gas storage capacity, with a maximum deliverability of approximately 900 MMcf/d and an injection capability of 450 MMcf/d. It was expected to interconnect with the El Paso, Transwestern, and Southern Trails pipelines.

29. In the Transok and Manchester cases, market entry was determined to be easy due to the substantial number of depleted gas fields in the area (FERC 1993; FERC 1996b).

In its application, Red Lake claimed that it should be granted market-based rates because it did not have market power in the relevant geographic market. Red Lake defined the relevant market to include storage facilities in Northern California, Southern California, New Mexico, and Texas. Based upon its market power analysis, Red Lake claimed that it would have a market share of 4.38 percent and an HHI of 3,223 for working gas capacity and a market share of 11.06 percent and an HHI of 3,512 for deliverability.

3.2.2. *FERC Disapproval*

FERC concluded that the product offered by Red Lake, high-deliverability quick-cycling gas storage services, would be beneficial for the southwestern U.S. markets. FERC noted that this region, which incorporates California, Nevada, Arizona, New Mexico, Colorado, and Utah, "has experienced rapid growth in natural gas demand, while development of gas storage facilities has failed to keep pace with the demand for balancing services required by the many new gas fired generation facilities in this region" (FERC 2003b, pp. 6-7). This demand was demonstrated in an open season that resulted in non-binding precedent agreements for over 69% of Red Lake's proposed storage capacity. Moreover, the Red Lake project would provide economic benefits to Mohave County.

However, FERC also concluded that Red Lake's market power analysis was flawed, because it used a geographic market that was too large. FERC noted that Red Lake's facilities were "in the market areas of western Arizona and Southern California, serving the concentrated market for electric generation in the Arizona and Southern California community" (FERC 2003b, p. 10). FERC argued that the New Mexico and Texas storage facilities were in different physical locations and that there was no unsubscribed firm transportation capacity to transport the gas from these regions to western Arizona and Southern California during peak periods. In addition, FERC argued that the Northern California storage facilities were outside of Red Lake's market area, being approximately 600 to 700 miles from Red Lake's Southern California market; that there was no indication that the Northern California storage facilities had unsubscribed firm capacity; and that there was no evidence showing that there was available firm north-to-south gas transportation.

For these reasons, FERC removed the storage facilities located in New Mexico, Texas, and Northern California from its analysis. (FERC also removed the abandoned Montebello storage facility located in Southern California.) FERC then calculated that Red Lake would have a market share of 10.2 percent and an HHI of 8,167 for working gas capacity and a market share of 19.87 percent and an HHI of 6,816 for deliverability. FERC concluded that these "results are out of line with Commission precedent for approving market-based rates for market-area storage facilities. The applicant's market share is too high in a highly concentrated market for the Commission to be confident that the applicant lacks significant market power" (FERC 2003b, p. 13). Moreover, FERC noted that there was no unsubscribed storage capacity available from SoCalGas and that, with "SoCalGas fully subscribed, Red Lake would certainly have market power" (FERC 2003b, p. 15). Accordingly, FERC denied Red Lake's request for market-based rates.

3.2.3. *Request for Rehearing*

On March 3, 2003, Red Lake filed a request for rehearing. Red Lake argued that the market power analysis should have considered storage facilities in Northern California. With this modification, Red Lake claimed that its market share would be 4.4 percent for working gas capacity and 12.3 percent for peak day deliverability and that its HHI would be 3,423 for working gas and 3,225 for peak day deliverability. Red Lake also argued that it would not develop the project unless market-based rates were approved, because service discounts would be required when the market was soft, and with cost-based rates Red Lake would not have the opportunity to recover these losses during peak periods.

FERC reaffirmed its conclusion that it was not appropriate to include the Northern California storage market in the market power analysis. FERC asserted that Red Lake had not shown the availability of transportation service to move the gas from Northern to Southern California. FERC also noted that even including the Northern California market HHIs were above the 1,800 threshold, and closer scrutiny would thus be required. Accordingly, FERC concluded, "Red Lake's request for market-based rates was denied because the market it will operate in will be extremely concentrated and Red Lake will have substantial market power. Red Lake's rehearing request provides no reasonable support for granting rehearing" (FERC 2003a, p. 14). FERC also terminated the proceeding given Red Lake's position that the project would not move forward without market-based rates.

At the end of its decision, FERC noted, "[t]he record here does suggest, however, the propriety of further FERC review of the development of gas storage infrastructure necessary to the optimal operational efficiency of the southwestern natural gas markets" (FERC 2003a, p. 16).

3.3. Reassessment of FERC Market Power Rules

Soon after the Red Lake decision, FERC began to review the status of the natural gas storage markets and the impact of its rules on these markets. In August 2003, FERC held a Southwestern Gas Storage Conference to address issues associated with natural gas storage in this region. In September 2004 FERC issued its staff report on the "Current State of and Issues Concerning Underground Natural Gas Storage" (FERC 2004a). The staff report summarized the background and history of underground storage and discussed possible options for stimulating underground storage development. Of particular relevance are two of the Commission's key findings: 1) storage projects in the Southwest often fail FERC's market-based rates tests, and 2) creative ratemaking approaches may encourage storage development (FERC 2004a, p. 1).

3.3.1. *FERC Staff Report*

FERC noted in its staff report that "[f]ew new projects in the Southwest have been proposed and several have failed or faced significant opposition" (FERC 2004a, p. 26). The report further explained the circumstances regarding these projects:

> The Red Lake storage project failed after being denied market-based rate authority for failing the Commission's market power test. The Desert Crossing storage and transportation project failed due to environmental issues and the contract support that did not materialize. The developers of the Copper Eagle

> storage project failed to secure contractual support and have sold development rights to the project to El Paso Natural Gas Company (El Paso). El Paso has yet to overcome local opposition to the project, secure contractual commitments and file for certificate authorization (FERC 2004a, p. 26).

The staff report cited other circumstances hampering development of storage in the Southwest, including unfavorable geology, competition from pipeline expansions and LNG development, and lack of market signals for storage. In addition, state unbundling efforts limit the incentive for local distribution companies to enter into long-term contracts due to uncertainty over cost recovery.

The staff report proposed a variety of approaches that FERC could use to encourage development of additional storage projects. For example, FERC could modify cost-based rates to include peak and off-peak rates and term differentiated rates, adjust elements of the cost-of-service to reflect higher risks, and/or modify the three-year revenue review. The staff report also proposed that FERC could offer market-based rates to new storage providers in this region:

> [A]llow market-based rates for new independent storage providers, subject to possible mitigation measures, on the grounds that new storage projects add incremental capacity to existing markets, thereby giving customers new choices for services, and with the provision that all market risks lie with the projects owners (i.e., no captive customers). The Commission could determine market-based rates for new independent storage projects to be just and reasonable because customers are better off than they would be if the project was not built, and customers will face additional service options because of the new infrastructure provided by the new storage project (FERC 2004a, p. 30).

Possible mitigation measures discussed in the staff report included requiring capacity to be sold through auctions, requiring periodic reviews of market-based rates, and removing rate caps on capacity release transactions and other short-term and interruptible services.

The staff report also discussed modifying the market power test such that "to the extent a storage provider could demonstrate an inability to secure firm service contracts for the entire capacity of its storage field, for terms exceeding some specified time, such as 1, 2 or 5 years, the Commission could find that it lacked market power, and grant market-based rate authority" (FERC 2004a, p. 31).

3.3.2. *Energy Policy Act of 2005*

On August 8, 2005, the Energy Policy Act of 2005 (EPAct) was signed into law (EPAct 2005). Section 312 added section 4(f) to the Natural Gas Act (NGA). This section allows FERC to grant market-based rates for new storage capacity even if a company is unable to demonstrate that it lacks market power, as long as FERC determines (1) that the market-based rates are in the public interest and necessary to encourage the construction of the storage capacity and (2) that customers are adequately protected. In addition, the law states that "[FERC] shall ensure that reasonable terms and conditions are in place to protect consumers" and that FERC "shall review periodically whether the market-based rate is just, reasonable, and not unduly discriminatory or preferential."

In response to these changes, FERC noted that EPAct Section 312 built upon efforts already underway at FERC to consider policy reforms that would encourage the development of natural gas storage facilities. FERC noted that some of the key findings of its staff report were that natural gas price volatility may indicate the need for additional natural gas storage facilities, that there had been sharp swings in gas prices, and that "[i]n view of the resulting adverse economic impacts, Commission policy should not discourage the development of additional storage capacity through overly narrow definitions of the relevant market" (FERC 2005, p. 7).

FERC also observed that while "current and projected storage development is keeping pace with aggregate national storage demands, underground storage developments in some market areas, such as New England and the Southwest, is not." Moreover, FERC noted that many of the storage facilities "may prove more adaptable than pipelines in supplying gas on an as-needed basis to match the fluctuations in the demand profile of electric generation facilities," that many "wholesale customers are not always willing to enter into long-term storage contracts," and that "[p]ermitting storage operators to earn higher revenues from short-term services during peak demand periods or through other pricing mechanisms may make an investment in the project economically feasible" (FERC 2005, pp. 7, 8, 10).

3.4. New FERC Rules

On June 19, 2006, FERC issued its final rule, Order No. 678, modifying its market power analysis and implementing EPAct Section 312 (FERC 2006e). The Final Rule kept the basic regulations of the Policy Settlement in place but widened the scope of analysis and added important exemptions to the market power assessment. The Final Rule defined the geographic market more broadly by permitting consideration of close substitutes in the product market. Additionally, while the Final Rule maintained the HHI market concentration test and threshold of 1,800, it added an important exemption with the intention of preventing the market power tests from impeding needed development of natural gas storage.

3.4.1. *Product Market Modification*

FERC modified its market power analysis to permit the inclusion of close substitutes to storage in the product market. Substitutes could include available pipeline capacity, local gas production, and LNG terminals.

Under the framework set forth in the Policy Statement, FERC had not considered close substitutes to storage in its assessments of market concentration and market share. Consequently, FERC had often been able to approve market-based rates in production areas, where there is extensive storage infrastructure and low market concentration, and in certain consuming regions where high market concentration is mitigated by factors such as market share and ease of entry. However, as FERC noted, "in areas where there are truly only a limited number of storage service providers, the Commission's traditional analysis will likely result in a storage provider having high HHI values as well as relatively large market shares" (FERC 2006e).

FERC further noted that this result does not show that the applicant would necessarily have market power, because additional storage capacity could compete with interstate pipeline capacity:

> A new entrant proposing to offer its storage service in an area already fully served by existing pipelines would offer customers in that market area new service options, which to some extent would compete with existing service providers. Any new independent storage capacity would be expected to lower the market concentration and increase available alternatives in such a market (FERC 2005, p. 16).

Accordingly, FERC concluded that limiting the market definition to services offered by competing storage suppliers was too narrow and that a more expansive definition should be adopted and should include, when appropriate, available pipeline capacity, local gas production or LNG terminals.

3.4.2. *Market Power Assessment Exemption*

FERC also adopted the authority provided in EPAct to grant market-based rates to applicants who have not demonstrated lack of market power if it can be determined (1) that the market-based rates are in the public interest and necessary to encourage the construction of the storage capacity and (2) that customers are adequately protected. FERC determined that this exception would apply to new facilities developed after August 8, 2005, and to expansions of existing facilities. According to FERC's new rules, the applicant bears the burden of showing that market-based rates are necessary to encourage construction of the facility. If the applicant makes this showing, no traditional market power analysis is required. Also, no additional reporting requirements are required to comply with the periodic review requirement contained in the enabling law.

3.5. Impact of the New Rules

It has not yet been demonstrated whether FERC's new rules will significantly increase the development of natural gas storage facilities in general, or in the Southwest in particular. The first test of the new rules in the Southwest will likely begin when El Paso Natural Gas Company submits an application for its proposed Arizona Natural Gas Storage Project, a 3.5 Bcf underground natural gas storage facility to be located outside of Phoenix.[30] This application is anticipated in late 2007 or early 2008, and El Paso expects that the project would be brought on line in mid-2011 (FERC 2007e).

To the extent that market issues, rather than regulatory issues, have been constraining the development of storage facilities in the Southwest, FERC's new rules may not result in a substantial increase in natural gas storage development in the region. For instance, FERC noted that "despite a perceived need for new storage in the Southwest, there have been proposals for new storage projects that have failed to go forward for reasons unrelated to rate treatment." In

30. El Paso has also proposed the Copper Eagle Storage Project. However, as noted below, this project has been stalled due to security concerns. No expected filing date is currently available.

particular, FERC mentioned the proposed Desert Crossing storage proposal, which has apparently stalled due to shortfalls in contractual commitments and environmental concerns, and the Copper Eagle storage proposal, which has been delayed by safety and security concerns related to the project's planned location near Luke Air Force Base (FERC 2005, pp. 11-12).

3.5.1. *Projects Approved Under FERC's Revised Rules*

Thus far, only Northern Natural Gas has applied for and obtained market-based rates under the new exemption for projects that are in the public interest and that adequately protect consumers.

FERC approved market-based rates for Northern Natural on November 16, 2006. Northern Natural proposed to expand its Redfield storage facility by 10 Bcf with a peak withdrawal rate of 175 MMcf/d. FERC found that additional storage was needed in the area because the proposed expansion was fully subscribed with long-term contracts. In addition, the project entailed significant risks, and existing customers were adequately protected. In particular, FERC found that since all of the estimated capacity was offered in an open season and its capacity was fully subscribed, there was little risk of withholding. FERC also found that customers were adequately protected because Northern Natural would account for all costs and revenues separately to ensure that existing customers would not subsidize the cost of the expansion project (FERC 2006b; FERC 2006d).

Approval of this project was not without controversy. Commissioner Kelly filed a dissent in the case, arguing that the applicant had failed to demonstrate that market-based rates would be in the public interest (i.e., that they were needed to permit expansion) and that customers would be adequately protected. Commissioner Kelly argued that there would be sufficient interest for storage development at cost-based rates and that the new rules were better suited to instances where market-based rates were required for operators to recover their costs, such as where operators face a "soft" market and need to make up for the loss during tight markets (FERC 2006a, p. 2; FERC 2007a). Commissioner Kelly also noted that at the same time that Northern Natural argued that market-based rates were necessary, it also reserved the option to move forward with the project under cost-based rates if it were denied market-based rates. Moreover, Commissioner Kelly argued that Northern Natural faced little risk associated with this facility, because Northern Natural reserved the right to back out of the project, and that customers were not adequately protected from monopoly power. In particular, Commissioner Kelly argued that monopoly power can be exercised not just through withholding capacity or raising prices, but also through requiring customers to sign up for longer terms than they would in a competitive market (FERC 2006a, p. 4; FERC 2007a).

3.5.2. *Other Projects*

While FERC has approved market-based rates for only one facility under its revised rules, FERC continues to approve applications for market-based rates for new storage facilities using its traditional criteria (market concentration and market share). For example, on February 15, 2007, FERC approved market-based rates for a new salt dome natural gas storage facility to be built in Mississippi by Mississippi Hub (FERC 2007d). The facility would have two subsurface caverns, with total working gas capacity of 6 Bcf and deliverability of 1,200 MMcf per day. FERC approved market-based rates, finding that "the proposed projects would not be able to exercise market power due to small size, anticipated share of the market, and numerous competitors" (FERC 2007d, p. 6).

FERC also continues to approve applications for cost-based rates for natural gas storage facilities. For example, on February 5, 2007, FERC issued an order allowing for the expansion of Puget Sound's existing Jackson Prairie Storage Project to increase the withdrawal capability from 850 MMcf per day to 1,150 MMcf per day and for Northwest Pipeline to charge cost-based rates for its allocated share of the incremental capacity. A complete list of FERC-approved projects involving expansions or new capacity since 2000 is shown in Table 28 in Appendix A.

3.6. Conclusion

Federal application of market power tests is not straightforward. Decisions to grant market-based rates are based on the particular market context and the perceived need for the project. In the wake of the Red Lake proposal, FERC modified its rules in order to allow projects that may have market power to be granted market-based rate authority if the project is in the public interest and consumers are adequately protected. This modification responded to the concern that market power assessments could be preventing needed natural gas storage development in some cases, particularly in the Southwest. Since the rules were modified in June 2006 only one facility has been granted market-based rates under the assessment exception, although several facilities have been granted market-based rates through traditional market power analysis. The application for the El Paso facility in Arizona is expected in late 2007 or early 2008 and will provide the first opportunity to assess the impact of the new rules on the Southwest.

4.0 Natural Gas Storage Regulation in California

This chapter reviews the regulatory environment in which natural gas storage projects have been developed and have operated in California. Initially the state's natural gas storage market consisted only of regulated utilities. Then in 1993 the CPUC, which claims jurisdiction over all natural gas storage facilities in the state that offer service to multiple users, issued a decision allowing independent storage development.[31] Since that decision, two northern California independent operators have joined the incumbent utilities in the natural gas storage market and the utilities' operations have been separated into regulated "core" and quasi-regulated "non-core" components. This chapter also summarizes the regulatory structure of the utility-owned natural gas storage facilities, the development and regulation of utility-owned facilities and independent operators, and developments in the CPUC's use of market power assessment. (A timeline summarizing these developments is presented below.) As will be shown, the CPUC granted market-based rates to each independent storage provider, even when the applicant did not demonstrate lack of market power.

31. All current natural gas storage operators in California are regulated by the CPUC.

Table 10: Timeline of California Gas Storage Developments

Date	Action
1980s	CPUC requires natural gas industry to unbundle procurement from transportation services for noncore customers
Late 1992	AB 2744 makes findings regarding gas storage and urges Commission action
Feb. 1993	D.93-02-013, Gas Storage Decision, including SoCalGas and SDG&E Permanent Storage Programs
Feb. 1993	D.93-02-019, Affiliate Transaction Rules (D.97-12-088, D.98-08-035)
May 1994	D.94-05-069, PG&E Permanent Storage Program
Aug.1996	PG&E submits to the CPUC its Gas Accord Settlement Agreement
June 1997	D.97-06-091, CPUC grants Wild Goose CPCN and market-based rate authority with requirement to file cost information
Aug.1997	D.97-08-055, CPUC approves PG&E's Gas Accord Settlement Agreement, which tightened the balancing rules for noncore customers and sets rates through 2002
June 1998	D.98-06-083, upon appeal CPUC revokes requirement for Wild Goose to file cost info
Feb.1999	D.99-02-002, exempted Wild Goose from affiliate transaction rules
April 2000	D.00-04-060, CPUC approves SoCalGas/SDG&E BCAP which, among other provisions, determines the allocation of costs for SoCalGas' non-core storage program
May 2000	D.00-05-048, CPUC grants Lodi CPCN and market-based rate authority
June 2001	D.01-06-081, CPUC grants SoCalGas authority to withdraw working and cushion gas from the Montebello storage facility and sell the abandoned site
June 2001	D.01-06-086, CPUC authorizes SoCalGas to reclassify 14 Bcf of cushion gas to working gas at Aliso Canyon and La Goleta storage fields
July 2002	D.02-07-036, CPUC grants Wild Goose CPCN and market-based rate authority
Aug. 2002	D.02-08-070, CPUC approves Gas Accord II Settlement Agreement, which sets rates through 2003 for gas transmission and through March 2004 for gas storage
Nov. 2002	D.02-11-028, CPUC authorizes SoCalGas to allocate proceeds from the sale of cushion gas at Aliso Canyon and La Goleta
Feb. 2003	D.03-02-071, CPUC approves transfer of 50% interest in Lodi Holdings to WHP Acquisition Company
June 2003	D.03-06-069, CPUC approves indirect change of control (merger of Wild Goose parent Alberta Energy Company with PanCanadian Energy Corp., renamed EnCana Corp.)
Dec. 2003	D.03-12-061, CPUC decision modifying and extending gas accord structure through '04
Dec. 2004	D.04-12-050, CPUC approves Gas Accord II Settlement Agreement through 2007
Nov. 2005	D.05-11-027, CPUC authorizes SoCalGas to reclassify 4 Bcf of cushion gas to working gas and transfer gas in kind to CARE customers
March 2006	D.06-03-012, CPUC grants Lodi Kirby Hill's CPCN and market-based rate authority
July 2006	D.06-07-010, CPUC adopted PG&E's 1-day-in-10 year peak day planning standard for core customer storage and authorized PG&E to acquire additional storage capacity from third-party storage providers to meet this standard
Nov. 2006	D.06-11-019, CPUC approves transfer of control of Wild Goose from EnCana to Niska Gas Storage (80% owned by Carlyle/Riverstone Funds and 20% by SemGroup)

Date	Action
Dec. 2006	D.06-12-010, CPUC authorizes SoCalGas to allocate the 4 Bcf of incremental storage capacity created in D05-11-027 to core customers, on an interim basis, with reconsideration in the next BCAP
Jan. 2007	D.07-01-014, CPUC finds that PG&E did not need a CPCN for construction of Line 57C and could exercise eminent domain authority
March 2007	Resolution G-3398, CPUC approves PG&E contracts with Lodi and PG&E-CGT for additional storage capacity for core customers (1 Bcf) for $3.7 million, with contracts extending through the 2007/08 and 2008/09 winter seasons[32]
April 2007	Sacramento Natural Gas Storage submits an application (A.07-04-013) to the CPUC for approval of a new 7.5 Bcf storage facility
May 2007	Lodi submits an application (A.07-05-009) to the CPUC for 12 Bcf expansion of its facility, with a projected in service date of September 2008
July 2007	Lodi submits an application (A.07-07-025) to transfer its assets to Buckeye Gas Storage[33]
Sept. 2007	D.07-09-045, CPUC approves Gas Accord IV Settlement Agreement
Oct. 2007	D.07-10-001, CPUC modifies affiliate transaction reporting requirements for Wild Goose
Dec. 2007	D.07-12-019, CPUC approves new regulatory regime for SoCalGas and SDG&E transportation and storage.

4.1. Utility-Owned Gas Storage Operations

The utilities' core storage services are fully regulated, with cost-based revenue requirements approved by the CPUC. Revenue recovery for non-core storage services are governed by CPUC-approved settlement agreements that provide rate caps and provisions for revenue sharing between ratepayers and shareholders. The utilities may determine contract terms and rates for non-core service within the constraints of these settlement agreements. The regulatory treatments and current revenue requirements for storage and other gas services are summarized in Table 11 and discussed further in the following sections.

32. According to PG&E, the unit costs of these offers were higher than the cost of PG&E's traditional core storage services but were in line with the market prices for storage peaking services (PG&E 2007a, p.2).

33. The parties submitted a settlement agreement to the CPUC on November 14, 2007, requiring, among other provisions, that Lodi Gas and Buckeye make their records available to the CPUC, that Lodi Gas report semi-annually to the CPUC on gas investments and transactions, and that Lodi Gas not share sensitive market information with entities that control Wild Goose.

Table 11: Regulatory Requirements and Risk Allocation for Utility Natural Gas Services

	SoCalGas	**PG&E**
Core		
Procurement	Regulated through the Gas Cost Incentive Mechanism (GCIM)	Regulated through the Core Procurement Incentive Mechanism (CPIM)
Transmission	~$1.2 billion, with balancing account protection	~$174 million, with balancing account protection
Distribution		~$1 billion, with balancing account protection
Storage	~$79 million, with balancing account protection	~$44 million, with balancing account protection
Non-Core		
Transmission	~$225 million; does not appear to assume throughput risk at this time	~$218 million, with throughput risk
Storage	$21 million, with 50% sharing above and below this level, and approx. $11 million allocated to the Noncore Storage Balancing Account and recovered from all customers	~$7.75 million, with utility at risk for over- or under-collection

Source: (PG&E 2007b; SDG&E and SoCalGas 2006c)

4.1.1. *SoCalGas Regulatory Structure*

SoCalGas provides core and system balancing services on a cost-of-service basis. Its revenues and rates for these services are determined in General Rate Case (GRC) Proceedings and Biennial Cost Allocation Proceedings (BCAP) before the CPUC.[34]

SoCalGas' non-core storage program is governed by a settlement agreement approved in D.00-04-060 (April 20, 2000). Under this agreement, SoCalGas can set fixed and negotiated ("transaction based") rates for its non-core storage services up to a maximum rate cap. Of the total fully scaled marginal cost of unbundled storage, ratepayers and shareholders share equally any revenues above $21 million and any shortfall below this level. In addition, SoCalGas

34. The total core storage costs currently in SoCalGas' rates are $79.1 million (SDG&E and SoCalGas 2006c, p.2).

allocates the balance to the Non-core Storage Balancing Account (NSBA).[35] NSBA revenues are recovered from all customers on an equal-cents-per-therm basis.[36]

SoCalGas currently has four rate schedules for non-core storage, although most transactions take place under G-TBS, Transaction Based Storage Service. Under this schedule, contracts may extend from one month to three years, and reservation charges are capped at $14.271/Dth of inventory capacity reserved.

Proposed New Regulatory Regime

On August 28, 2006, SoCalGas, SDG&E and SCE, submitted to the CPUC an application for approval of a settlement agreement to address issues resulting from the 2000-2001 energy crisis (the Edison Settlement) (SDG&E and SoCalGas 2006a). The settlement agreement resolves disputes that arose between these parties regarding activities during 2000 and 2001 when California experienced substantial increases in natural gas and electricity prices. In particular, it increases the transparency of the natural gas storage market and addresses the relationship between the utilities' core and non-core gas storage programs.

The Edison Settlement follows on the heels of and supplements the Continental Forge Settlement, signed on January 4, 2006, which proposes to resolve class action litigation regarding similar issues.[37] The Continental Forge Settlement implemented a number of structural changes. For example, the settlement requires the integration of the SDG&E and SoCalGas transmission facilities; the implementation of cost-based tariffs; the development of firm, tradable rights for access to utility receipt points and storage; the combination of core procurement operations of SoCalGas and SDG&E under a single department; and the continued separation of utility gas procurement operations from any core commodity procurement activities.

The Edison Settlement builds upon the Continental Forge settlement and addresses a variety of changes to the operation of and services provided by SoCalGas and SDG&E. For example, the Edison settlement would require that SoCalGas treat the gas procurement department similar to other customers, and it would require core nominations to balance with usage, just as non-core usage is required to balance. Major settlement provisions related to storage and comparisons with current provisions are shown in Table 12 below.

35. At the time of the decision this value was $11 million.

36. SoCalGas has indicated that it believes that the 50/50 sharing mechanism should continue based on any new asset and cost allocations that may be established in SoCalGas' upcoming BCAP proceeding, to be filed later this year (SDG&E and SoCalGas 2007a, p.21).

37. "The Continental Forge plaintiffs alleged that Sempra Energy, SoCalGas, and SDG&E conspired to restrict natural gas supplies to California and claimed damages of $23 billion (after applicable trebling)…. At the time of the settlement, the Continental Forge claims were the subject of an ongoing jury trial that began in October 2005" (SDG&E and SoCalGas 2006a, p.2).

Table 12: Settlement Provisions Pertaining to Storage

	Current Provisions	Proposed Provisions
Allocation of capacity to unbundled storage program	46.8 Bcf	51 Bcf
Allocation of capacity to core storage program	Inventory SoCalGas – 74 Bcf SDG&E – 9 Bcf	Inventory SoCalGas and SDG&E – 70 Bcf
Revisions to G-TBS (Transaction Based Storage Service)	Rate Caps Inventory -$14.271/Dth Injection – none Withdrawal - none Term: 1 month to 3 years	Rate Caps[38] Inventory - $1.63/Dth Injection - $60/Dthd Withdrawal - $30/Dthd Term: No more than 3 years without CPUC approval
G-AUC (Auction Storage) G-LTS (Long-Term Storage) G-BSS (Basic Storage)	Open	Closed to new subscription for 5 years
Non-Core Revenue Sharing	50/50 sharing of non-core storage revenues	50/50 sharing of non-core storage revenues, with a shareholder cap of $20 million
Secondary Market for Storage		SoCalGas will facilitate
Release Unbundled Storage Capacity		SoCalGas will release, on an interruptible basis, all unutilized and unbundled storage at a maximum rate equal to 100% of the applicable firm reservation charge

There are a variety of other provisions contained in the settlement agreement. For example, the settlement would require SoCalGas to set monthly storage targets for core gas procurement. The purpose of this provision is to ensure that "market participants [] have a clearer understanding about how the utilities will manage inventory levels for core customers during the storage injection season" (SDG&E and SoCalGas 2006a, p. 9). In addition, the settlement agreement would require SoCalGas and SDG&E to conduct triennial system expansion studies assessing the need for both transmission and storage.

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38. For example, "[t]he maximum price for a package of 1,000,000 dth inventory with 5,000dth/day of firm injection, and 10,000 dth/day of firm withdrawal will be $2,230,000 for any term of up to and including one year, $4,460,000 for any term more than one year but not more than two years, and $6,690,000 for any term more than two years but not more than three years, subject to the year escalation provisions…." (SDG&E and SoCalGas 2006a, Exhibit A)

A number of protests were filed to this settlement. For example, the Southern California Generation Coalition (SCGC) protested the application, in part because it felt that the $20 million cap on rewards was too high and that the rates should be "reduced to cost-based levels" (SCGC 2006, p. 9). To support its case, SCGC cited the increase in revenues associated with SoCalGas' unbundled storage program over the past few years, up to almost $40 million over and above the allocated costs associated with the facilities. Currently, under the revenue-sharing agreement, SoCalGas shareholders are entitled to retain 50% of these profits.[39]

Table 13: Non-core Storage Costs and Revenues, Millions of Dollars[40]

	Revenues	Allocated Costs[41]	Total Profits	Shareholder Profits (50% of Total)
2000	$19	$21	-$2	-$1
2001	$32	$21	$11	$6
2002	$42	$21	$21	$11
2003	$47	$21	$26	$13
2004	$49	$21	$28	$14
2005	$61	$21	$40	$20
2006	$72	$21	$52	$26

Source: (SCGC 2007a, p. 7)

In addition, some interveners proposed that SoCalGas be required to offer cost-based rates for non-core storage service "to avoid providing the core procurement department with an unfair competitive advantage in marketing hub services" (CPUC 2006a, p. 6). To address this issue, the Assigned Commissioner in the proceeding requested that SoCalGas submit additional testimony that included the actual scaled long-run marginal cost for its proposed non-core storage program (CPUC 2006a, p. 6). (As discussed below, the utilities' non-core rates are not supposed to exceed their long-run marginal costs.) SoCalGas provided these data, which are presented in Table 14 below along with the proposed settlement rates, 15-year levelized expansion costs, and the results of the 2006 open season that were presented in the original application.

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39. SCGC challenged claims that the revenues would provide incentives for additional storage facilities or expansions by questioning the availability of additional storage capacity. SCGC argued that "while there may be numerous locations that offer adequate porosity and permeability, those locations often lack sealing characteristics that would make them suitable for commercial gas storage" and noted that "SoCalGas abandoned the Montebello storage field because of gas containment problems" (SCGC 2006, p.8).

40. Ratepayers are responsible for $11 million in contributions to the NSBA (not shown), after which SoCalGas ratepayers and shareholders retain 50% of profits.

41. Allocated costs were determined by D.00-04-060. The balance between total fully scaled marginal costs and the allocated costs is recovered through the NSBA.

Table 14: Proposed Price Caps and Rate References for Non-core Storage Program

	Settlement Cap	15-Year Levelized Expansion Cost	2006 Open Season	Scaled Long-Run Marginal Costs
Inventory	$1.63/dth	$0.60/dth	$1.35/dth	$0.38/Mcf
Injection Capacity	$60/dthd	$39.90/dthd	$39/dthd	$35.40/Mcfd
Withdrawal Capacity	$30/dthd	$20/dthd	$11.60/dthd	$20.33/Mcfd

Source: (SDG&E and SoCalGas 2006b, p. 4; SDG&E and SoCalGas 2007b, p. 1)

SCGC, the City of Long Beach, and DRA submitted testimony in March. SCGC argued that SoCalGas' proposed ceiling rates were too high, that the CPUC should adopt fully scaled long-run marginal cost ceiling rates for on-system end-use customers, and that the SoCalGas shareholder reward should be capped at $5 million (SCGC 2007a). The City of Long Beach argued, among other things, that the CPUC should not allow SoCalGas to change its rates because doing so would double Long Beach's storage reservation costs (Long Beach 2007, p. 25).[42] DRA primarily argued that the proposed allocation of 70 Bcf to the core was insufficient and that the current allocation of 83 Bcf should be retained.

The final decision, D.07-12-019, retained the existing allocation of 83 Bcf for the core,[43] rejected cost-based rates, and adopted the proposed rate caps for transaction based storage services as shown in Table 14. The decision did not reach a conclusion on revenue sharing issues, asserting that the current 50/50 sharing without a cap is too high, but that the proposals for modification were unsubstantiated. The Commission has allowed for reconsideration in SoCalGas' BCAP proceeding (CPUC 2007b).

4.1.2. *PG&E Regulatory Structure*

PG&E's revenues and rates for its transmission and storage functions have been governed by the 1997 Gas Accord, which "established the rules for providing access to PG&E's backbone and local transmission system, and to PG&E's storage system," and by subsequent decisions and settlement agreements modifying and extending the gas accord structure (CPUC 2003b, p. 6). These decisions are outlined in Table 15 below.

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42. There is insufficient public information on market-based prices to assess the validity of this claim. However, it does appear that market-based rates (e.g., 2006 Open Season results) exceed SoCalGas' revenue requirement for its storage program (e.g., Scaled Long-Run Marginal Costs), but are less than SoCalGas' estimates to expand its storage capacity (e.g., 15-Year Levelized Expansion Cost). Thus, while current market-based rates are likely higher than cost-based rates for the utilities, it is unclear how these would compare to cost-based rates for new facilities constructed by the utilities or independent storage operators.

[43] This figure includes the 4 Bcf allocated for CARE customers.

Table 15: Gas Accord Settlement Agreements and Decisions

Date	Name	Description
August 1997	Gas Accord	D.97-08-055. Approved Gas Accord Settlement; rates extended through 2002
August 2002	Gas Accord II	D.02-08-070. Approved Gas Accord II Settlement Agreement. Rates and terms extended through 2003 for gas transmission and through March 2004 for gas storage
December 2003	Commission Decision Modifying and Extending Gas Accord Structure	D.03-12-061. Litigated case; extended gas accord structure through 2004
December 2004	Gas Accord III	D.04-12-050. Approved Gas Accord III Settlement for a three year term, through 2007
September 2007	Gas Accord IV	D.07-09-045. Approved Gas Accord IV Settlement for a three-year term though 2010

According to the CPUC, the main features of the Gas Accord market structure are the unbundled, tradable, firm rights to backbone, transmission, and storage capacity (CPUC 2003b, p. 6). The Gas Accord also established revenue requirements and rates for transmission and storage services. It allowed PG&E to fully recover these costs from core customers but placed PG&E at risk for over- or under-recovery of its revenue requirement for non-core customers. Subsequent Gas Accord settlements have preserved the structure of the original agreement and updated the revenue requirements and rates.

Table 16: PG&E Storage Rates (2007-2010)

Schedule	Rate
Schedule G-SFS – Firm Storage Service Annual Reservation Charge ($/Dth/mo)	 0.1350
Schedule G-NFS – Negotiated Firm Service Injection per day ($/Dth) Inventory ($/Dth) Withdrawal per day ($/Dth)	Maximum Rates 15.6336 1.6205 11.7865
Schedule G-NAS – As Available Storage Service Injection per day ($/Dth) Withdrawal per day ($/Dth)	Maximum Rates 15.6336 11.7865
Market Center Services (Parking and Lending)[44] Maximum Daily Charge ($/Dth/day) Minimum Rate ($ per transaction)	 0.970 57.00

Source: (PG&E 2007b)

44. Lending provides interruptible loans of natural gas to meet demand. The lend is paid back in-kind within a negotiated term, which can run from one day to many months. Parking provides interruptible storage of gas. Gas must be unparked within a negotiated period of time.

PG&E's revenue requirement under Gas Accord III was $444.9 million for 2007 (PG&E 2004, p. 7). Of this amount, $62.3 million is for PG&E's storage facilities, including $44 million for core firm storage, $7.8 million for standard firm service (non-core), and $10.6 million for monthly balancing services. Gas Accord IV, which was approved by the CPUC on September 20, 2007, holds the storage revenue requirement and rates steady through 2010. The 2007-2010 rates for storage service are shown in Table 16 above.

4.2. Regulation of Independent Storage Operators

The natural gas storage market was opened to independent operators in 1993, and the first independent storage facility was authorized in 1997. During this period and in the years since, the CPUC has attempted to find a level of regulation for independent operators that will protect consumers while still encouraging the development of in-state storage capacity. Initially the CPUC had few concerns about market power and readily granted market-based rates to independent operators. Over the years, however, the CPUC's concerns over market concentration and market power have increased, and the CPUC has begun to impose additional regulatory requirements on independent operators to protect against non-competitive behaviors.

The CPUC established the groundwork for market-based rates for independent storage providers in Decision No. 93-02-013, known as the Gas Storage Decision. This decision had its roots in the deregulation of natural gas service, which began in 1986 when the CPUC distinguished between core customers and non-core customers and required the utilities to give non-core customers the option to pursue their own procurement. Deregulation continued in 1990, when the CPUC limited the utilities' involvement in non-core procurement, unbundled interstate pipeline capacity from intrastate transportation options for non-core customers, and effectively allowed the market to determine which interstate pipeline and how much capacity should be built.

At this time, unbundling the storage component was not viewed as nearly as important as unbundling the supply or transportation component. As noted by the CPUC:

> Combined gas supply revenues for SoCalGas, SDG&E, and PG&E are approximately $1,900,000,000 annually. Non-core transportation revenues for the same utilities are approximately $880,000,000 annually. Annual revenues for unbundled storage services will be approximately $30,000,000. This comparison warns us that storage service need not be regulated as finely as gas supply or transportation service, because the monetary risks of unbundling storage supply are smaller (CPUC 1993, p. 8).

However, AB 2744, passed in 1992, found that there were "barriers to investment in new storage facilities, primarily the inability of independent storage providers to compete in an open storage market." The bill urged the CPUC to unbundle storage and "encourage the development of independent storage by establishing interconnection rules and reasonable cost allocation" (CPUC 1993, p. 26). The 1993 Gas Storage Decision began to address these issues.

With the Gas Storage Decision, the CPUC (1) unbundled storage service from transportation; (2) adopted a "let the market decide" policy for construction and expansion of new storage facilities; and (3) removed certain barriers to entry into the market by modifying interconnection and other rules. The CPUC also opened the door to the concept of market-based rates for storage services, ordering the utilities to charge market-based rates for unbundled storage service to non-core customers, as long as these rates did not exceed long-run marginal costs. The issues regarding interconnection rules and reasonable cost allocation for core and non-core utility storage services have been re-litigated in many of the gas restructuring proceedings since that time by the independent storage developers.

Since passage of the Gas Storage Decision, the CPUC has approved market-based rates for all independent storage facilities despite concerns over market concentration and market power. The CPUC's reasoning has been that even if there is a risk of market power, expanding storage capacity can be in the public interest as long appropriate mitigation measures and reporting requirements are in place (CPUC 2002, pp. 17-21). In particular, the CPUC has noted that increasing natural gas storage infrastructure reduces market concentration and that additional storage capacity could help mitigate natural gas price volatility. This reasoning is consistent with the reasoning behind the revisions to FERC's rules, as discussed in the previous chapter.

4.3. California Storage Projects

Over the last decade there has been significant natural gas storage development and expansion in California. The utilities have abandoned some gas storage capacity and procured additional gas storage capacity, and two new storage operators, Wild Goose (now owned by Niska Gas Storage) and Lodi, have developed and expanded storage fields in northern California. No storage facilities have been built in southern California, either by SoCalGas or by an independent storage operator. This section discusses the development of natural gas storage in California and the implications of market power assessments in each case in order to determine whether marker power assessments are inhibiting further expansion in Southern California.

4.3.1. *Utility Storage Capacity Sales and Expansions*

After abandoning the Montebello storage field in 1997 and attempting to sell it in 1998, SoCalGas received permission from the CPUC in D.01-06-081 (June 28, 2001) to withdraw working and cushion gas from the Montebello storage facility and to sell the abandoned site. At the same time, SoCalGas also expanded capacity at its existing natural gas storage fields. According to Steve Watson of SoCalGas,

> In 2001, 14 Bcf of cushion gas was converted to working inventory at the Aliso Canyon and La Goleta storage fields via a $23 million investment in wells that was funded with proceeds from the sales of cushion gas. Another 2.5 Bcf of inventory was gradually added at Honor Rancho through the natural process of storage cycling, which forced liquids out of the reservoir. This additional inventory is allocated to the unbundled storage program (SDG&E and SoCalGas 2005, p. 2).

The CPUC authorized this work in D.01-06-086 (June 28, 2001) and determined the allocation of revenue from the sale of the cushion gas and the allocation of additional storage capacity in

D.02-11-028 (November 7, 2002). The CPUC allocated 40% of the gas to the core and the remaining 60% to SoCalGas and the non-core.

In addition, on November 18, 2005, the CPUC approved D.05-11-027 which authorized SoCalGas "to reclassify the 4 Bcf of cushion gas as working gas, to withdraw the gas, and to transfer the gas in kind to SoCalGas' [low-income] CARE customers at book value" (CPUC 2005a, p. 1). Finally, in D.06-12-010 (December 14, 2006), the CPUC ordered SoCalGas to allocate the additional 4 Bcf of incremental storage capacity to core customers in order to provide low-income customers with additional protections against the high price of gas.

PG&E is in the process of building an additional pipeline, Line 57C, which would connect to its storage facility at McDonald Island. The purpose of the project is to increase reliability if Line 57B fails, but the project also increases incremental withdrawal capacity for PG&E's non-core storage program by 14%.

4.3.2. *Independent Storage Facility Developments and Proposals*

The 1993 Gas Storage Decision set the stage for non-utility providers to enter the natural gas storage market in California. The unbundling of PG&E's gas transmission and storage services from its distribution services in 1997 and the tightening of balancing rules at this time led to increased interest in additional storage capacity for non-core customers.[45]

Proposals to develop independent natural gas storage facilities in California are summarized in Table 17 below. The CPUC approved applications for 46 Bcf of independent storage capacity in Northern California. Two proposals for an additional 44 Bcf of storage capacity in the state were not pursued, and one proposal was denied. Recently, proposals to develop an additional 40 Bcf of storage capacity in Northern California have been announced. Each of these proposals is discussed in the sections that follow.

4.3.3. *Proposals that were Approved*

Four independent storage projects have been approved: the development and the expansion of a facility owned by Wild Goose (now owned by Niska Gas Storage) and the development of two facilities owned by Lodi Gas Storage.

Wild Goose Storage Facility

On August 26, 1996, Wild Goose submitted an application for a certificate of public convenience and necessity (CPCN) and for market-based rate authority to construct and operate the first independently owned natural gas storage facility in California. The proposed facility was to have an inventory capacity of 14 Bcf, a withdrawal capacity of 200 MMcf and an injection

45. Balancing rules were tightened as a result of the PG&E Gas Accord settlement. The balancing rules address the degree to which deliveries can deviate from usage and what conditions or penalties are imposed as a result of imbalances beyond these limits. Gas Accord settlement discussions began in 1995, PG&E submitted the settlement to the CPUC in August 1996, and the CPUC approved the settlement in August 1997 in D.97-08-055.

capacity of 80 MMcf. Gas withdrawn from the facility would be delivered into Line 167 of PG&E's Sacramento Valley Transmission System.[46]

In its application, Wild Goose requested that it be exempt from contract restrictions and reporting requirements applicable to the utilities, which stem from the Gas Storage Decision, and also from requirements to file its rate tariffs with the CPUC. The contract restrictions and reporting requirements, as described by SoCalGas, restrict "long-term contracts to a minimum of 3 years and a maximum of 15 years and [require] SoCalGas to submit its long-term contracts to the Commission for prior approval if such contracts are with off-system customers or if they provide for discounts or load balancing premiums or contain other special features" (CPUC 1997, p. 5).

SoCalGas argued that either it should be exempt from these reporting requirements or the requirements should apply equally to Wild Goose. Wild Goose argued that, unlike SoCalGas, its shareholders would be at risk for any unrecovered revenue due to discounting, that there was no potential for cross-subsidization, and that the CPUC's "rationale for placing restrictions on SoCalGas' storage contracts simply does not apply to Wild Goose because protection of the core ratepayer is not at issue" (CPUC 1997, p. 6). In its June 1997 decision granting Wild Goose a CPCN, the CPUC concurred with Wild Goose's reasoning and concluded that "putting similar restrictions on Wild Goose's contracts is not necessary" (CPUC 1997, p. 9).

46. Line 167 is a PG&E-designated transmission line that connects locally produced gas in the northern Central Valley with PG&E's gas mixer in Yuba City.

Table 17: Storage Facility Proposals

Date Filed	Application Number	Applicant	Inventory Capacity	Withdrawal/ Injection Capacity	Application Status
N/A (proposed in early 1990s)	N/A	McFarland, Kern County	40 Bcf	600 MMcf/d withdrawal	N/A
N/A (proposed in mid- 1990s)	N/A	Eagle Energy/Nahama Natural Gas, Sacramento County	4 Bcf	600 MMcf/d withdrawal	N/A
8/26/1996	A.96-08-058	Wild Goose	14 Bcf	200 MMcf/d withdrawal; 80 MMcf/d injection	Approved in D. 97-06-091 (June 25, 1997), D.98-06-083 (June 18, 1998)
11/5/1998	A.98-11-012	Lodi	12 Bcf[47]	500 MMcf/d withdrawal; 40 MMcf/d injection	Approved in D.00-05-048 (June 18, 2000)
6/18/2001	A.01-06-029	Wild Goose Expansion	Additional 15 Bcf	Additional 500 MMcf/d withdrawal; 370 MMcf/d injection	Approved in D.02-07-036 (July 17, 2002)
7/25/2005	A.05-07-018	Lodi Kirby Hills	5.5 Bcf	100 MMcf/d withdrawal; 50 MMcf/d injection	Approved in D.06-03-012 (March 2, 2006)
12/22/2005	A.05-12-024	King Island Gas Storage, LLC	8 Bcf	150 MMcf/d withdrawal; 150 MMcf/d injection	Dismissed in D.06-12-014 (Dec. 14, 2006)
4/9/2007	A.07-04-013	Sacramento Natural Gas Storage, LLC	7.5 Bcf	200 MDth/d maximum firm deliverability; 100 MDth/d maximum firm injection	Proceeding in process
May 2007	A.07-05-009	Lodi Gas Storage	12 Bcf	200 MMcf/d firm withdrawal; 100 MMcf/d of firm injection	Expected operation date of September 2008
Expected Spring 2008	Not yet filed	PG&E and Northwest Natural	20 Bcf (Northwest Natural: 15 Bcf; PG&E: 5 Bcf)	485 MMcf/d withdrawal; 195 MMcf/d injection	Expected operation date - 2010

45. D.06-03-012 approves a 12 Bcf facility. Lodi currently has a working capacity of 17 Bcf.

The CPUC, however, did not exempt Wild Goose from filing rate tariffs.[48] The CPUC agreed with Wild Goose that it would be appropriate to file tariffs with a range of rates but ordered that "Wild Goose's floor rate should not be below its short-run marginal costs," because this could be predatory, unfair, and perhaps illegal. On the other hand, the CPUC determined that Wild Goose could set its own ceiling rate, "because if a potential or existing gas storage customer finds Wild Goose's rate to be excessive, the customer will have the option of receiving storage service from either PG&E or SoCalGas at their tariff rates" (CPUC 1997, p. 9).

Four CPUC Commissioners signed a dissenting opinion encouraging Wild Goose to file a petition for modification to remove the requirement that Wild Goose submit cost information to ensure that rates do not fall below short-run marginal costs.[49] Wild Goose did so on July 21, 1997. In its decision, the CPUC determined that it was not necessary for Wild Goose to file cost data to justify its rates. The CPUC reasoned,

> In reviewing the instant petition, we did find it highly unlikely that Wild Goose, as a new entrant, could have such a negative impact on the incumbent investor owned utility that it would result in the utility having to exit the gas storage market. Wild Goose is the first, and so far only competitor to enter this market in California. The incumbent utility has 100% of the market share, while Wild Goose starts with a customer base of zero (CPUC 1998a, p. 5).

The CPUC also found that it would be "unnecessary to place a high regulatory burden on a new entrant, given the fact that ratepayers will not bear any portion of the risk for this investment" (CPUC 1998a, p. 5). Accordingly, the CPUC determined that allowing new entrants to file rates without cost justification was reasonable in this instance and consistent with regulation in the telecommunications industry. Moreover, the CPUC concluded that "[a]bsent compelling evidence that the utility has significant market power, this is a reasonable way to regulate public utilities" (CPUC 1998a, p. 6).

Lodi Storage Facility

In 1998, Lodi Gas Storage (LGS) submitted an application to the CPUC for market-based rate authority for a natural gas storage facility providing firm and interruptible gas storage services. The proposed facility was to be located in Northern California, with 12 Bcf of working gas,[50] maximum firm deliverability of 500 MMcf/d and maximum firm injection capability of 400 MMcf/d.

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48. Wild Goose' tariff was filed with the CPUC on December 18, 1998 as Advice Letter No. 1-G pursuant to Resolution No. G-3250. It shows, for instance, short term service rates from $0-$500/Dth and baseload storage inventory demand rates from $0-$36/Dth/month.

49. The four Commissioners chose to dissent from their own opinion so as not to delay the project further by rewriting the decision to remove the cost filing requirement.

48. Lodi currently has a working gas capacity of 17 Bcf.

In its application LGS argued that a traditional CPCN needs assessment was not necessary because of the CPUC's "let the market decide" policy and because the risk of the project would be borne by developers.[51] The CPUC determined that because CPCNs are required by law and because evidence to support a finding of overriding consideration may be needed as part of the California Environmental Quality Act (CEQA) process, "in some instances, a fuller showing of need may be necessary to the extent required by law" (CPUC 2000b, p. 26). In this regard, the CPUC found sufficient evidence of need:

> [B]oth the Commission and the Legislature have found the need for competitive gas storage facilities. LGS and Calpine reiterate and elaborate on the rationale underlying this need. The record has established a need for competitive gas storage services in California, and the benefits of competitive gas storage include (a) increased reliability; (b) increased availability of storage in California; (c) the potential for reduced energy price volatility; and (d) the potential for reduced need for new gas transmission facilities (CPUC 2000b, p. 28).

LGS stated that it did not have market power in the gas storage market because (1) it was a new entrant, (2) it would begin with no market share, and (3) it was not in a position to force any other players out of the market. LGS did not submit a market power study to substantiate these claims. Nevertheless, the CPUC concurred with LGS' analysis, stating in its May 2000 decision that "there is no evidence that LGS currently possesses significant market power in the California gas market." The CPUC granted LGS authority to charge market-based rates, but required LGS to file rate tariffs with the ranges of rates it would charge. LGS was not required to file any cost information to justify its rates.[52]

On February 27, 2003, the CPUC approved the change of ownership for Lodi Gas Storage, in which WHP Acquisition acquired an indirect 50% interest in Lodi concurrent with a reduction of Western Hub's interest from 100% to 50%. At the time, the CPUC noted that "the proposed transaction avoids the likelihood of LGS' near-term default on the construction loan and probable bankruptcy" (CPUC 2003a, p. 15). The CPUC also imposed additional reporting requirements so that it could better monitor the evolving natural gas market. These requirements include: (CPUC 2003a, pp. 15-17)

- Prohibiting LGS from engaging in any storage or hub services transactions with its parents or their affiliates;
- Requiring LGS to report 1) LGS' own purchases of other natural gas facilities, transmission facilities, or substitutes for natural gas, like liquefied natural gas facilities; 2) an increase in storage capacity or in the interstate or intrastate transmission capacity

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49. The "let the market decide" policy was originally adopted in the 1993 Gas Storage Decision D. 93-02-013. See Section 4.2, Regulation of Independent Storage Operators.

52. Lodi's tariff was filed with the CPUC on July 13, 2001 as Advice Letter 1-G. It shows, for instance, interruptible storage service rates from $0-$500/Dth/month and firm storage inventory demand rates from $0-$36/Dth/month.

held by affiliates of its parents or their successors; and 3) merger or acquisition involving affiliates of its parents, or their successors, and another entity that owns gas storage or transmission facilities or facilities that use natural gas as an input, such as electric generation.[53]

- Requiring LGS to report short-term and long-term agreements and, for short-term transactions, quarterly transaction summaries of specific sales.

Wild Goose Expansion

In 2002, the CPUC granted a CPCN for the Wild Goose Expansion Project. The proposed expansion was expected to increase working gas to 29 Bcf, maximum firm deliverability to 700 MMcf/d, and maximum firm injection capability to 450 MMcf/d.[54] Wild Goose proposed to connect the expanded facility to PG&E's Line 400/401. While the CPUC determined that there was sufficient need for the project and allowed Wild Goose to charge market-based rates, it imposed additional requirements because the CPUC could not determine that Wild Goose did not posses market power. In addition, the CPUC also addressed other issues, including interconnection issues and the level of service that would be provided on PG&E's backbone transmission system.

As in previous decisions, the CPUC found sufficient evidence of need for the gas storage facility. The CPUC noted that "gas storage can exert downward pressure on border price increases" and "can serve as a substitute for interstate gas during times of high demand" (CPUC 2002). The CPUC also stated that "[n]o party disputes that the failure of large customers to inject sufficient gas into storage in California is one factor that contributed to the large price increases for natural gas during the winter of 2000/2001" (CPUC 2002, p. 9). In addition, the CPUC noted that Wild Goose had presented evidence of customer interest in the storage facility based on results of open seasons for the existing and expanded capacity. All these factors combined led the CPUC to conclude that Wild Goose had made a sufficient showing of need.

In support of its request for market-based rates, Wild Goose submitted a market-power assessment in which it argued that the appropriate geographic market includes both Northern and Southern California. Wild Goose calculated that HHIs for all of California would be 3,690 for inventory and 4,209 for withdrawal capacity with the expansion. Wild Goose's market share for inventory in northern California and all California markets without the expansion was 19% and 8%, but would increase to 32% and 15% with the expansion. For withdrawal capacity, Wild Goose's market share for Northern California and all of California would expand with the expansion from 9% and 3% to 26% and 10%.

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53. In D.05-12-007 (December 1, 2005), the CPUC approved the change of control for Lodi Gas Storage, in which WHP would sell its remaining 50% ownership to WHP Acquisition Company, owned by ArcLight Energy Partners. The CPUC affirmed that all of the requirements imposed in D.03-02-071 would continue to apply.

54. Wild Goose expanded only to 24 Bcf and maintains an additional 5 Bcf of authorized undeveloped capacity.

The CPUC did not make a determination on whether Northern and Southern California should both be included in the geographic market. Rather, the CPUC concluded that regardless of how the geographic boundaries were drawn, the storage market was highly concentrated and Wild Goose's market shares were relatively high. Based upon the evidence presented, the CPUC concluded that "[w]e are unable to determine, on this record, whether or not Wild Goose can exercise market power. Neither can we determine that the potential for Wild Goose to exercise market power is fully mitigated by its lack of control of the transportation system…." (CPUC 2002, p. 17). As a result, the CPUC concluded that while it should approve market-based rates, the following conditions and requirements should be imposed:

- The relaxed reporting requirements that it had previously adopted should be revoked;
- Wild Goose should be prohibited from engaging in any storage or hub services transactions with its parent or any affiliate company;
- Wild Goose should be required to inform the CPUC promptly of any changes in status (e.g., purchase of additional storage capacity, change of control etc.);[55] and
- Wild Goose should be required to provide to the CPUC short-term service agreements and quarterly transaction summaries.

This decision also determined that Wild Goose should bear the costs associated with the 25-mile natural gas pipeline that would connect the expanded storage facility to PG&E's Line 400/401. The Gas Storage decision found that third-party storage providers should not be responsible for the costs associated with standard interconnections but should pay for any special facilities. In this case, PG&E argued that Wild Goose should bear all of the costs associated with interconnection, because Wild Goose already connects with Line 167 and any additional facilities were thus special facilities. The CPUC agreed with PG&E on this matter and stated that "[w]e agree that the proposed Line 400/401 interconnect will be a second service connection for the Wild Goose facility, and thus, its components constitute special facilities for which Wild Goose should pay" (CPUC 2002, p. 26).

The CPUC also determined that as-available transmission service should be allocated pro rata among customers during times of peak demand. Wild Goose had argued that during peak times "storage customers should have first priority over any as-available transportation over 'new' as-available customers," whereas Lodi took the middle ground and argued "for pro rata allocation of as-available transportation, not just among independent storage customers but also among all customers vying for the same, limited, as available capacity" (CPUC 2002, p. 34). By contrast, PG&E and TURN argued that independent storage customers should be allocated as-available capacity that remains after other as-available transportation customers have been

55. On June 19, 2003, the CPUC issued D. 03-06-069 finding that the holding company merger of Wild Goose's parent, AEC, with PanCanadian Energy Company (thus forming EnCana Corporation), resulted in an indirect change of control over Wild Goose and was subject to CPUC jurisdiction. The CPUC approved the change of control, finding that "it is in the public interest to do so," but levied a $51,500 fine for failing to obtain CPUC permission before the holding company merger. In 2006 a second change of control of Wild Goose Storage from EnCana to Carlyle/Riverstone Funds was approved by the CPUC.

served. The CPUC concluded that "Lodi's evenhanded proposal provides the most competitively neutral approach" and therefore required "a pro rata allocation of as-available Redwood transportation capacity among all potential subscribers, whether they seek to transport flowing supplies of gas or gas previously injected into storage at the Wild Goose or Lodi facilities" (CPUC 2002, p. 35).

Lodi Kirby Hills Facility

In March 2006, the CPUC granted a CPCN to Lodi Gas Storage to construct and operate the new Kirby Hills Natural Gas Storage Facility (Kirby Hills) and granted Lodi market-based rate authority. The proposed facility would have 5.5 Bcf of working capacity, an initial injection and withdrawal capacity of 50 MMcf/d, and a maximum injection and withdrawal capacity of 100 MMcf/d.[56] PG&E initially requested hearings in this case, but PG&E and Lodi settled their dispute, which related to the allocation of interconnection costs, and, as a result, no hearings were required.[57]

In the settlement agreement, Lodi agreed to pay for the interconnection with Line 400, for a temporary interconnection with Line 182, and up to $200,000 for the costs associated with updating PG&E's computer system and modeling programs to reflect the addition of Kirby Hills. In addition, the parties agreed to defer to another proceeding (i.e., R.04-01-025) the issue of whether Lodi could directly interconnect with storage customers.

Although Lodi argued that a traditional needs assessment was not required, it provided relevant information showing need. Lodi indicated that the existing facility was fully subscribed, that the open season for the additional capacity drew indications of demand for 7.3 Bcf of storage capacity, that PG&E had proposed to add incremental firm core storage capacity, and that PG&E had issued a solicitation for 2,200 MW of dispatchable generation capacity, which could add to the demands placed on California's natural gas infrastructure.

Lodi did not file a market power assessment with its application, but the CPUC approved market-based rates for the facility. The CPUC stated that "[b]ecause such authority would be consistent with the pricing authority for LGS's existing facility near Lodi, and also with the policies we have followed since Decision (D.) 93-02-013 to promote competitive gas storage facilities, we will grant the market-based pricing authority that LGS requests". (CPUC 2006b, p. 2)

The CPUC also upheld the conditions that were imposed on Lodi in D.03-02-071 when the CPUC approved the transfer of 50% interest in Lodi's parent, Lodi Holdings, to WHP Acquisition Company (CPUC 2003a). In this decision the CPUC noted that the gas storage market was concentrated and thus, as a condition of the transfer, imposed the same requirements on Lodi that the CPUC had placed on Wild Goose (CPUC 2003a, p. 17). In its March 2006 decision approving the Lodi expansion, the CPUC noted that there was nothing in

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56. Lodi reports that the facility, as constructed, offers 5 Bcf of capacity and 50 MMcf/d of maximum daily injection and withdrawal capacity (LGS 2006a).

57. Duke Energy North America filed in support of Lodi's application.

the record to indicate that the markets were any less concentrated than when these conditions were imposed and determined that these restrictions, including reporting requirements and restrictions on affiliate transactions, would remain in place (CPUC 2006b, p. 30).

4.3.4. *Proposed Projects Not Ultimately Developed*

Three proposed storage projects were ultimately not developed. It does not appear that market-based rate authority was a factor in any of these decisions.

In its 1993 Natural Gas Storage Decision, the CPUC discussed the proposed McFarland natural gas storage facility. In making its decision to adopt a "let the market decide" policy the CPUC noted that "potential storage inventory available from independent providers—most notably McFarland—is relatively large and is accessible to the intrastate pipelines of both SoCalGas and PG&E. Compare McFarland's potential inventory of about 40 billion cubic feet (bcf) of working storage—purchased from SoCalGas and PG&E—against about 115 bcf for SoCalGas and about 100 bcf for PG&E" (CPUC 1993, p. 10). However, this storage facility was not developed, due in part to lack of demand at the time the project was being proposed (Tobin 2007). Another project, the Eagle Energy/Nahama Natural Gas's Putah Sink project, was on hold in 1997. This facility, too, was not developed (EIA 1997).

More recently, the King Island Gas Storage, LLC storage project was abandoned. On January 23, 2006, the CPUC Energy Division sent a letter stating that the application, which had been submitted the prior month, failed to comply with CEQA. King Island did not provide supplemental material to address the CPUC's concerns, and the CPUC dismissed the application in D.06-12-014 (December 14, 2006).

4.3.5. *Proposals for New Natural Gas Storage Facilities*

Three applications for new natural gas storage projects in northern California have been submitted to the CPUC; no new projects have been proposed for southern California.

In April 2007 Sacramento Natural Gas Storage, LLC, submitted an application (A.07-04-013) to the CPUC for a proposed natural gas storage facility to be located mostly within the City of Sacramento. The proposed facility would have 7.5 Bcf of inventory capacity, 200 MMcf/d of firm withdrawal capacity, and 100 MMcf/d of firm injection capacity. In its application, Sacramento Natural Gas Storage requested that the CPUC issue a CPCN, market-based rates, and a mitigated negative declaration pursuant to CEQA.[58] PG&E and Sacramento Natural Gas are currently involved in bilateral negotiations regarding a number of issues, including cost allocation of interconnection and other costs, operating and balancing agreements, and bypass issues.

In May 2007 Lodi submitted an application (A.07-05-009) to the CPUC to add an additional 12 Bcf of working gas storage capacity to its current facility and to provide an additional 100

58. A mitigated negative declaration is issued when there are potentially significant effects on the environment, but where revisions in the project plans would avoid the effects or mitigate the effects on the environment and there is no substantial evidence that, with the revisions, the project would have a significant effect on the environment.

MMcf/d of injection and 200 MMcf/d of withdrawal. The CPUC has not yet set a schedule for this application, though Lodi has given an expected in service date of September 2008 (LGS 2006b).

In September 2007 PG&E and Northwest Natural announced their intention to build a 20 Bcf storage facility at Gill Ranch near Fresno, CA. Of the 20 Bcf capacity, Northwest Natural will control and market 15 Bcf. PG&E's 5 Bcf share will be market separately. The parties are expected to conduct an open season in the fall of 2007 and submit an application to the CPUC in the spring of 2008, with an expected in-service date of 2010 (Platts 2007, p.5).

4.3.6. *Market Power Analysis of California Projects*

Despite approval of market-based rates for all projects in California, a full market power analysis was only completed for the Wild Goose projects. As described above, in each of the other cases the operator was either found to not have potential for market power, or to be able to mitigate potential market power through regulatory restrictions. Table 18 below includes the results of HHI and market share calculation carried out for each approved and proposed project (not including transportation capacity and other substitutes.[59] The analyses were based on a geographic market including both Northern and Southern California and relying on market characteristics at the time the decision to grant market-based rates was issued.[60] The HHI and market shares from the Red Lake case are included for comparison.

As shown in Table 18, the CPUC has consistently approved market-based rates for facilities with HHIs well above the 1,800 threshold. In the case of the original Wild Goose facility, market-based rates were approved without restriction despite HHIs of approximately 5,000 for both inventory and withdrawal. The historical analysis shows that market power tests have not impeded development of independent natural gas storage in California. Market analysis for the proposed Sacramento Natural Gas Storage facility, Lodi expansion, and Gill Ranch facility shows HHIs for inventory and withdrawal of between 3,300 and 3,800. If the CPUC continues its historic trend, it appears likely that market-based rates will be granted to these proposed facilities.

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59. The values for the Wild Goose Expansion and Red Lake are from the original analyses completed as part of their applications. All other values are based on market characteristics at the time of decision. In the case of Sacramento Natural Gas Storage, the proposed Lodi expansion, and Gill Ranch, values are based on the current market.

60. For example, the original Wild Goose and Lodi applications were decided prior to SoCalGas's expansion. This difference in SoCalGas's capacity is included in the analysis.

Table 18: California Project Market Power Comparison

Project	Inventory HHI	Inventory Market Share	Withdrawal HHI	Withdrawal Market Share	Restrictions Imposed?
Red Lake	3,223	4.4%	3,512	11.1%	Denied
Wild Goose	5,025	8.7%	4,910	3.8%	No
Lodi	4,401	6.9%	4,177	8.6%	Yes
Wild Goose Expansion	3,690	32%	4,209	15%	Yes
Lodi Kirby Hills	4,155	8.5%	3,805	8.9%	Yes
Sacramento (proposed)	3,759	3.5%	3,579	3.1%	(n/a)
Lodi (proposed expansion)	3,733	15.3%	3,634	11.8%	(n/a)
Gill Ranch (proposed)	3,477	6.53%	3,309	7.13%	(n/a)

4.4. Market Power and Southern California

As discussed above, in response to the proposed Edison Settlement some interveners requested that SoCalGas be required to charge cost-based rates, arguing that the utility has a monopoly on storage in the region. SoCalGas objected to this request, arguing that it does not have market power in the region and that cost-based rates would inhibit further development of natural gas storage in Southern California, either by an independent storage provider or by SoCalGas itself (SDG&E and SoCalGas 2007a; SDG&E and SoCalGas 2007c). To support its argument that it did not have market power, SoCalGas provided a market analysis examining market concentration and market share in the California market consistent with FERC's revised criteria, which allow applicants to include close substitutes in the product market. (See the HHI analysis in Table 19, which includes both storage facilities and pipelines.)

In particular, SoCalGas argued that "[c]ontrary to the assertions of interveners, there is a competitive market for storage. That competition comes from flowing supply, secondary markets, other storage fields, and core storage" (SDG&E and SoCalGas 2007a, p. 10). SoCalGas calculated an HHI of 1,400 including storage, pipeline capacity, and local production in both Northern and Southern California. SoCalGas argued that it was appropriate to include Northern California storage "since all of these supplies can be delivered into Southern California through Wheeler Ridge" (SDG&E and SoCalGas 2007a, p. 11). SoCalGas' analysis is shown in the table below.[61]

61. SoCalGas owns both the core and non-core storage facilities, as well as the in-state natural gas transmission and distribution facilities. However, operational control of the storage assets is separate and customers have access to SoCalGas' natural gas transmission system on a non-discriminatory basis. Nonetheless, if these facilities are combined for purposes of the HHI calculation, the HHI value would increase.

SoCalGas also argued that cost-based rates would make it less likely that new storage will be built: "[c]learly, there is no incentive for a storage competitor to try to invest fully at risk capital to attempt to enter the Southern California market and compete against these [long-run marginal cost] price caps" (SDG&E and SoCalGas 2007a, p. 7).

Table 19: SoCalGas HHI Analysis in A.06-08-026

Conservative Market Share / HHI Analysis for Supplies Competing w/ Unbundled Storage

Storage and Storage-Substitutes	Capacity* MMcfd	Market Share, %	Square of Mkt Share	
SoCalGas Noncore Storage	1,240	**8.3**	69.3	
SoCalGas Core Storage	1,935	13.0	168.7	
Southern CA Production	230	1.5	2.4	
El Paso (North & South Systems)	3,710	24.9	620.2	
Transwestern	1,210	8.1	66.0	
Kern River	1,830	12.3	150.9	
Southern Trails	80	0.5	0.3	
GTN-TransCanada	2,190	14.7	216.1	
PG&E Storage	1,345	9.0	81.5	
Wild Goose Storage	480	3.2	10.4	
Lodi / Kirby Hills Storage	550	3.7	13.6	
Northern CA Production	98	0.7	0.4	
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Total	**14,898**	**100**	**1,400**	**<-- HHI**

* For storage facilities withdrawal capacities are used.

Source: (SDG&E and SoCalGas 2007a, p. 11)

In addition, SoCalGas argued that a cost-based proposal would diminish the likelihood that SoCalGas would build additional storage. SoCalGas argued that it "cannot expand its storage unless it has customers willing to sign long-term contracts at the high price levels that will pay for such expansions" and that these customers would not sign such contracts if there was the possibility that they could obtain "limited existing storage at artificially low prices on a year to year basis" (SDG&E and SoCalGas 2007a, p. 9).

In its responsive testimony, SCGC argued that flowing supplies are not good substitutes for storage, and, even if they were, the appropriate geographic market includes only Southern California and the take-away capacity on pipelines. Based upon this and other adjustments, SCGC calculates a revised HHI of 1,904 (SCGC 2007b, p. 13).

In surrebuttal testimony SoCalGas argued that the geographic market considered by SCGC is inappropriate and that SCGC did not account for all sources of supply. By including new sources of supply that are expected to be soon available in Southern California (i.e., TGN at Otay Mesa and North Baja near Blythe), SoCalGas calculated an HHI of 1,334 using SCGC's geographic market (SDG&E and SoCalGas 2007c, pp. 8-9).

The final decision, D.07-12-019, did not adopt cost-based rates, noting that "SoCalGas and SDG&E operate in an integrated gas procurement market that covers most of the western U.S. and Canada, within which producers and marketers compete in supplying Southern California and other regions in this geographic area" (CPUC 2007b, p.20).

4.5. Conclusion

The CPUC has approached market power regulation on a case by case basis. In the reviewed cases in which lack of market power cannot be established the CPUC has not treated the market power tests as an impediment for development. Rather, the CPUC has recognized the public need for the project and has granted market-based rates conceding some restrictions.

Nonetheless, other impediments to the development of natural gas storage capacity in California remain. These impediments have not been sufficient to thwart the development of a robust natural gas storage market in Northern California; however, they have forestalled all independent natural gas storage development in Southern California. Impediments may include market barriers, such as the market power of incumbent utilities with low embedded costs, and other regulatory barriers, such as requirements for filing an application for a CPCN and completing a California Environmental Quality Act (CEQA) review. These and other impediments to the development of additional storage capacity in California are discussed in Chapter 5.

5.0 Barriers to Independent Storage

While the CPUC has granted market-based rates for a number of independent storage facilities in northern California, no new natural gas storage facilities have been proposed or built in Southern California. Initially this was likely due to the fact that prices were insufficient to sustain additional capacity, but more recently, as prices have risen, this may be due to barriers to entry.

There are many barriers to entry in any business, and particularly so for a capital-intensive business in a mixed regulated/free-market environment. In this section we present an overview of a number of regulatory, market, and physical barriers to entry in the natural gas storage market. We also identify which of these barriers differentially impact Southern California and might therefore be contributing to the lack of independent storage in that region. A market analysis to determine the relative importance of each of these and other barriers could be of assistance to the state in its efforts to encourage additional independent natural gas storage facility development in California.

5.1. Regulatory Barriers

In some cases, certificates of need can restrict entry; likewise, other environmental or zoning restrictions or permitting requirements can restrict entry. While the threshold for certificates of need for natural gas storage in California is not high, environmental regulations, land use issues, and permitting requirements pertain to natural gas storage facilities and may inhibit entry and development. In addition, regulatory ratemaking treatment for incumbent utilities determines the prices against which independent storage operators must compete and also the ability of the incumbents to lower their prices below market value.

5.1.1. *Regulatory Requirements*

California natural gas storage projects must meet the regulatory requirements of the California Department of Conservation's Division of Oil, Gas & Geothermal Resources (DOGGR). (The informal rule is that the CPUC jurisdiction begins at the wellhead; however, DOGGR also regulates equipment and facilities.) If state-owned lands are involved, projects must also meet the requirements of the State Lands Commission. The primary responsibilities of these agencies are shown in Table 20, and reporting requirements to these agencies are shown in Table 21.

CPCN and CEQA requirements do not always apply to facility expansions. For example, PG&E was not required to obtain a CPCN for the construction of Line 57C to the McDonald Island storage facility, which increased the maximum withdrawal capacity from the facility by 101 MDth/d. The CPUC ruled that a CPCN is not required under Section 1001 of the PUC Code "for an extension within any city or county within which it has theretofore lawfully commenced operations… or for an extension within or to territory already served by it, necessary in the ordinary course of business." The CPUC reasoned that "[w]hile the construction of a parallel pipeline may not actually extend further into the recognized service area, the situation is analogous to a utility replacing a deteriorated portion of an existing pipeline, a situation where a CPCN is not required" (CPUC 2007a, p. 6). The CPUC similarly determined that a CEQA review was not required for the natural gas storage expansion projects in southern California under a categorical exemption for existing facilities because they involved only negligible expansion of use and involved only minor alterations (CPUC 2001, p. 28).

The ability of an incumbent to expand a facility without obtaining a CPCN or undergoing a CEQA review reduces the expansion costs and additions to the incumbent's revenue requirements. On the other hand, a new entrant would be faced with the cost and delays of these regulatory proceedings. These costs, however, do not appear to be prohibitive although the proceeding can be expected to last roughly a year or two. In addition, any litigation connected to the CPCN or CEQA review could add significant costs and delays. Avoiding these costs and risks thus provides incumbents an advantage over new entrants.

In addition, even when the utilities are required to undergo CEQA reviews, the cost to utilities is likely less because the utilities already have in place the legal and regulatory infrastructure to handle these proceedings. For example, the utilities already have relationships with the commissioners and the administrative law judges, they have substantial experience with CPUC proceedings, and they have in-house legal and regulatory staff to address these issues. These proceedings thus likely serve as lower barriers for the utilities than they do for newcomers to the state, smaller organizations, or organizations that have little regulatory experience.

Table 20: Regulatory Agencies Overseeing Development and Operation of Natural Gas Storage Facilities

Agencies	Responsibilities
California Public Utilities Commission	Regulates utilities and their rates; issues certificate of public convenience and necessity (CPCN); lead agency under CEQA for certain storage projects[62]
Department of Conservation's Division of Oil, Gas & Geothermal Resources	Oversees the drilling, operation, maintenance, and plugging and abandonment of oil, natural gas, and geothermal wells; maintains information on oil and gas production and injection
State Lands Commission	Has exclusive jurisdiction over all oil and gas development on state-owned properties and is responsible for sovereign lands (i.e., land underlying navigable and tidal waterways), among other responsibilities

62. The CPUC is the lead agency for purposes of the CEQA analysis for gas storage facilities and major gas transmission lines (CPUC 2007e). The State Lands Commission was the lead agency for PG&E's Line 57C project for an additional pipeline to its McDonald Island storage facility.

Table 21: Reporting Requirements for California Storage Operators

	PG&E	SoCalGas	Independents
CPUC Requirements			
Cost Basis for Rates	Required (Absent findings that the market is workably or effectively competitive, "rates for firm noncore storage service must not exceed long-run marginal costs (LRMC), scaled to meet revenue requirements, plus premiums necessary to compensate utilities for the risk of underrecovery of the costs of new or expanded facilities or for load balancing requirements") (CPUC 1993, Appendix B, Section 5.2).		Not required ("We will not require that Wild Goose provide costs data to the Commission in order to have its tariffs approved") (CPUC 1998b).
Tariffs	Standard Firm, Negotiated Firm, and As-Available Storage	Basic, Auction, Long-Term, and Transaction Based Storage Service	Wild Goose: Baseload[63] and Short Term Storage Service Lodi: Firm[64] and Interruptible Storage Service
Contract Terms	Utilities are required to submit long-term contracts to the CPUC.[65] It is unclear whether short-term transactions are reported.		Required to submit to the CPUC copies of all service agreements and quarterly summaries of all short-term transactions
Affiliate Actions	Governed by affiliate transaction rules		Must report investments in natural gas production, transmission, storage facilities; increases in storage on transmission capacity held by affiliates; and mergers involving affiliates that own gas facilities or use gas (electric generation)
DOGGR Requirements			
Data	Monthly production, injection and oil and gas disposition information, as well as basic well data and tests, logs, and surveys[66]		

63. Wild Goose presented very large ranges for its services, including $0 - $36/Dth/month for its Inventory Demand Rate, $0-$300/Dth/day/month for its Injection Demand Rate, $0-$200/Dth/day/month for its Withdrawal Demand Rate, $0-$100/Dth for its Injection and Withdrawal Commodity Rates (Wild Goose 1998).

64. Lodi presented ranges nearly identical to those filed by Wild Goose.

65. SoCalGas' long-term contracts are reported via advice letters.

66. Monthly production and injection information available from http://www.consrv.ca.gov/DOG/prod_injection_db/index.htm. Annual data available from http://www.consrv.ca.gov/DOG/pubs_stats/annual_reports/annual_reports.htm.

5.1.2. *Eminent Domain*

A public utility is authorized to obtain land via eminent domain in order to meet its obligation to serve. For example, according to Section 615 of the PUC Code, "A pipeline corporation may condemn any property necessary for the construction and maintenance of its pipeline." A public utility that also offers competitive service is not allowed to use eminent domain for competitive purposes, unless the CPUC finds that this would serve the public interest (CPUC 2007c). This authority would apply to independent storage operators to the extent that the CPUC makes a public interest finding.

In D. 07-01-014 (January 11, 2007), the CPUC issued an opinion finding that PG&E could exercise its eminent domain authority in the construction of Line 57C. The CPUC explained that restrictions on eminent domain in competitive markets do "not apply to the condemnation of any property that is necessary solely for an electrical company or gas company to meet its commission-ordered obligation to service," that a "necessary component of this obligation to serve is continued reliability of facilities used to serve core customers," and that the purpose of the redundant pipeline is "to avoid a *catastrophic* failure of existing Pipeline 57B" (CPUC 2007a, p. 9). Nonetheless, the CPUC recognized that the pipeline would also enable PG&E to withdraw larger volumes of gas from McDonald Island, which then could be sold to non-core customers on the competitive market (CPUC 2007a, p. 1). Accordingly, the CPUC ordered that the next PG&E rate case consider the reasonableness of the project, the ratesetting for components found to be reasonable, and whether operational criteria should be imposed to ensure reliability. The CPUC approved this project with no additional operational criteria in D.07-09-045.

The ability of an incumbent utility to use eminent domain in projects that at least partially assist core customers is an advantage that is not shared by independent storage operators.

5.1.3. *Ratemaking Treatment of Incumbent Utilities*

In order to attract customers away from SoCalGas (or the other substitute services), new entrants would have to offer more attractive rates or terms of service. The maximum storage rates set by the CPUC for SoCalGas storage services (shown in Table 22) therefore may cap the rates that new entrants can charge.[67] If a rate cap is set too low, new market entrants may have trouble competing against the utilities' rates. This does not appear to be a barrier in California. In Northern California, the incumbent utility does not have excess storage, so newcomers may not be competing against incumbent rates. In Southern California, newcomers would be competing against SoCalGas' maximum rates, which are much higher than PG&E's and, at least according to some customers, are too high (SCGC 2007a).

The utilities' revenue requirements set the lower bounds on the revenue that they aim to recover and thus on the prices that they would charge. If a utility has a low revenue requirement, it could potentially undercut the rates of a competitor. The low revenue

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67. Most of the utilities' storage contracts are based on negotiated rates, which are bounded by the CPUC-imposed rate caps shown in Table 22. The utilities also offer firm service contracts.

requirements for SoCalGas' non-core storage program ($0.45/Mcf) may therefore act as a deterrent for potential competitors evaluating whether to enter the market. SoCalGas' revenue requirement is less than 30 percent of PG&E's revenue requirement ($1.55/Mcf) for the same product and just 60 percent of SoCalGas' embedded cost ($0.75/Mcf).

Table 22: PG&E and SoCalGas Maximum Rates for Negotiated Storage Service, 2007

PG&E	SoCalGas
Inventory - $1.62/Dth Injection - $15.63/Dth/day Withdrawal - $11.79/Dth/day	Current: Inventory - $14.271/Dth Proposed: Inventory - $1.63/Dth Injection - $60/Dth/day Withdrawal - $30/Dth/day

SoCalGas is able to charge less than its embedded cost, because it can allocate stranded costs to the utility's Non-core Storage Balancing Account (NSBA), which is recovered from all customers, both core and non-core. In the 2000 BCAP for SoCalGas and SDG&E, ORA charged that the NSBA provided the utilities with an advantage of potential competitors, who do not have balancing accounts to protect them from marketplace risk, and that this account should be eliminated (CPUC 2000a, p. 76). In response, the CPUC reduced the risk to ratepayers from 100% of stranded costs to 50%, with the remainder of the risk shifted to shareholders (CPUC 2000a, p. 141). (In return, shareholders receive 50% of the profits above a certain level.) In recent years, SoCalGas has not had a need to lower its rates below embedded costs, because market prices have been robust. However, should a new entrant offer storage in Southern California, SoCalGas could theoretically lower its rates below costs, drive out the entrant with uncompetitive rates, and share its stranded costs with ratepayers.

Incidentally, SoCalGas has pointed to this risk- and profit-sharing structure as an impediment to its own storage expansions. According to the utility, "it would be difficult to economically expand unbundled storage if SoCalGas is required to bear 100% of the expansion cost, but only receives half of the revenues resulting from that expansion" (SDG&E and SoCalGas 2005, p. 13).

5.2. Incumbent Advantages

As already seen in the discussion of CEQA requirements, incumbents have some regulatory advantages over newcomers due to their incumbent status. They also have cost advantages, as discussed in this section. Notably, these advantages apply both to the IOUs and to the now-incumbent independent storage facilities in Northern California. However, the advantages tend to be most significant for SoCalGas, due to its dominant market share and the large capacity of its non-core facilities.[68]

68. As shown in Figure 2, PG&E owns just a small amount of non-core storage capacity.

5.2.1. *Incumbent Cost Advantage*

It is more difficult to enter a market if a new entrant would face significant cost disadvantages compared to the incumbents. According to the DOJ, "this situation can occur for a variety of reasons, but tends to be most important when entrants would be unlikely to achieve economies of scale (i.e., reductions in average cost from operating at a higher rate of output) and scope (i.e., reductions in costs from producing several products together) already achieved by incumbents" (DOJ 2006). This is likely the case in both the Northern and Southern California markets, especially since the incumbents developed their storage facilities when prices for cushion gas were much lower than they are today. It may be more important in Southern California, because of the large amount of non-core storage capacity owned by SoCalGas.

5.2.2. *Incumbent Expansion Capacity*

Independent storage providers in California compete with incumbent utilities that have existing and expandable storage assets. If it is less expensive for an incumbent to expand than for a newcomer to build capacity, it could be difficult to enter a market, such as the southern California natural gas storage market, where the incumbent is known to have the ability to expand.

Recent SoCalGas storage facility expansion projects have not only been inexpensive, they have been funded in part by the sale of cushion gas and have resulted in additional profits to shareholders and ratepayers. For example, by installing new injection wells SoCalGas was able to expand the working capacity of its Aliso and LaGoleta storage facilities by 14 Bcf. This expansion freed up 14 Bcf of cushion gas. Since natural gas prices are substantially higher than they were when the facilities were built and the cushion gas was injected, SoCalGas was able to sell the cushion gas at profit. In fact, the $23 million facility expansion was funded entirely through the sale of this cushion gas (SDG&E and SoCalGas 2005, p. 2). Similarly, in 2005 SoCalGas expanded its working capacity by 4 Bcf at an estimated cost of $14 - $19 million and recovered roughly $50 million worth of natural gas that had been originally purchased for $1.5 million. (In this case, the profits were allocated to CARE customers.)

The opportunities for such economical working capacity expansions are limited, and according to SoCalGas future capacity expansions will be more expensive. (SoCalGas' estimates of its future expansion costs are shown in Table 23 below.) However, SoCalGas has an additional low-cost opportunity for expanding its non-core capacity—the utility can shift some capacity from core to non-core customers. In fact, the Edison Settlement proposes to shift 13 Bcf of SoCalGas and SDG&E storage capacity to noncore customers (DRA 2007, p. 12). Parties in favor of this reallocation argue that the remaining 70 Bcf for SoCalGas and SDG&E core is sufficient to meet core needs. This proposal was not adopted (CPUC 2007b).

Table 23: SoCalGas' Estimated Cost of Storage Expansions

	Bcf or MMcfd	Capital $MM*	Level Reservation Charge over 15 years**
Inventory	5	$20	$0.60/mcf
Withdrawal @ 25 Bcf	152	$20	$20/mcfd
Injection	150	$40	$39.90/mcfd
* Preliminary estimates (+/- 25% accuracy). **15% levelization factor from Cost-of-Service Model, multiplied by capital costs and divided by capacity addition. Charges exclude variable O&M and injection fuel costs.[69]			

Source: (SDG&E and SoCalGas 2005, p. 15)

5.2.3. *Incumbent Contracting Advantage*

New entrants into a market will be at a competitive disadvantage if the incumbent has secured long-term contracts with existing customers. As shown in Figure 10, SoCalGas has secured long-term contracts for over 40% of its inventory. This can be a significant barrier to new entrants, because long-term contracts are among the tools that entrants have to mitigate other risks of entry, such as the risk that their entry into the market will deflate prices and increase their capital risks. For example, Kleit and Coate argue that in some circumstances "sunk costs may not be a major impediment to entry when a group of customers can commit to an entry enhancing strategy," including signing long-term contracts (Kleit and Coate 1993). This is of particular relevance in the natural gas storage industry, where many firms conduct open seasons and sign long-term contracts before building additional storage facilities.

5.3. Market Barriers

New entrants into the California natural gas storage market may face several barriers related to the structure of the market, in particular the large capital costs and the incumbent advantages.

5.3.1. *High Sunk Costs and Minimum Viable Scale*

It is difficult to enter a market if the sunk costs of entry are high. Sunk costs include the cost of facilities, regulatory approvals, permitting, marketing, and other costs that could not be recovered upon exiting the market.[70] Since many sunk costs are fixed costs (i.e., independent of

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69. According to SCE, "The Cost-of-Service model calculates the utility's revenue requirements associated with (1) depreciation of the capital investment over 15-years, (2) authorized returns of 8.68% on the remaining capital investment, and (3) taxes associated with the authorized return. The present value of the stream of levelized payments is identical to the present value of a stream of traditional annual revenue requirement."

70. The capital costs of natural gas storage facilities are, indeed, significant. SoCalGas reported in 2005 that the long-run marginal costs of a 5 Bcf facility expansion would be $20 million, with an additional $60 million required to increase injection and withdrawal capacity by 150 MMcf/d each. The cost of a new facility can be expected to be higher than the cost of a facility expansion (SDG&E and SoCalGas 2005, pp. 9, 15).

the size of the project), projects with high sunk costs are often more financially viable if they are larger. However, if the minimum viable scale for a new project is too large, the entry of the new project into the market will depress prices. As described by Kleit and Coate:

> While a prospective entrant may observe prices that would make entry profitable, those prices are, from the point of view of the entrant, merely a mirage. As soon as a new firm enters the market, the collusive agreement dissolves and prices will be driven below the pre-entry competitive level. Thus, the entrant will not capture the profits from supra-competitive prices, instead the entrant will lose money on its sunk costs, even though it has a cost structure identical to its entrenched competitors (Kleit and Coate 1993).

This can present a significant barrier to entry in some industries. It may be an issue in the California natural gas storage market in some cases if the size of a profitable natural gas storage facility is larger than the market can absorb. For instance, there may be particular abandoned storage fields that would be unprofitable to develop, because they have sufficient capacity that their entry into the market would depress market prices.

In Northern California, it appears that the market was able to absorb the storage capacity introduced by Wild Goose and Lodi. However, PG&E does not have much excess storage capacity for non-core customers. Consequently, new capacity initially served customers who otherwise would not have had access to storage capacity. It did not compete against pre-existing storage facilities as much as non-storage options. In contrast, new capacity in Southern California would compete against SoCalGas' non-core storage services and, if large enough, could depress market prices.

5.3.2. *Access to Essential Facilities*

As recognized by the U.S. DOJ, "gaining access to physical facilities built and owned by third parties can pose a significant entry obstacle" (DOJ 2006). In the case of natural gas storage, this issue could include access to land, which has other competing uses, as well as access to natural gas distribution systems owned by incumbent utilities.

For example, new entrants in California must rely on PG&E and SoCalGas' pipelines and other competitors' pipelines for transportation services in order to market their storage services to customers. In the Transok case, Transok's ability to exert market power was determined to be limited because Transok had to rely on transportation services provided by its competitors in order to market its storage service to customers served by the interstate pipeline system.

5.4. Physical Barriers: Geology and Land Use Issues

There are three types of underground natural gas storage facilities: depleted reservoirs, aquifers, and salt caverns. All of the facilities in California are depleted reservoirs. Depleted reservoirs are usually "the cheapest and easiest to develop, operate and maintain" (NGSA 2004). In addition, the geological characteristics of the sites are known, and existing equipment and infrastructure can be used to develop the facilities.

There are numerous abandoned oil and gas reservoirs in California, and there appears to be no shortage of potential sites for underground storage facilities. Indeed, in Northern California a number of independent natural gas storage facilities have already been built and additional facilities have recently been proposed.

There is also an abundance of abandoned oil and gas facilities in Southern California; however, some claim that they are not physically or economically suited to development. For example, the SCGC questioned the availability of additional suitable storage capacity, arguing that "while there may be numerous locations that offer adequate porosity and permeability, those locations often lack sealing characteristics that would make them suitable for commercial gas storage." In support of this claim, SCGC noted that SoCalGas abandoned the Montebello storage field because of gas containment problems (SCGC 2006, p. 8). Other officials in the field believe that it is not geology or lack of interest on the part of natural gas storage developers that is inhibiting development, but land use -- land owners can extract more value by selling to real-estate developers than by developing gas storage facilities (Fields 2007). While this may in part explain why additional storage facilities have not been developed in load serving areas, it does not fully explain why proposed facilities in less densely populated locations in southern California were not developed (e.g., the McFarland facility proposed in the 1990s).

5.5. Conclusion

As shown in Table 24, there are a number of potential barriers to the development of natural gas storage facilities. Rate regulation and other regulatory requirements do not appear to be the major barriers to the development of independent storage facilities in Southern California. The same regulatory requirements are imposed on facilities in Northern and Southern California, but there is an active independent storage market only in Northern California. Furthermore, the CPUC has rejected just one independent storage application and has provided market-based rates to each operating independent facility.

Other barriers such as geology and preferred alternative land-use options, may in some cases be important; however, these barriers apply to SoCalGas and to potential market entrants alike. The more important barrier to independent natural gas storage development in Southern California may be incumbent advantage. SoCalGas has existing storage capacity that it could expand, likely for less than it would cost to build a new storage facility. It operates with low embedded costs and collects some of its non-core revenue requirement from core customers. These advantages as well as potential price differences between Northern and Southern California are likely sufficient to deter independent storage providers from entering the Southern California market, at least in the near term. Indeed, no independent storage facility has been proposed for Southern California since the early 1990s.

Table 24: Potential Barriers to Natural Gas Storage Development

Regulatory Barriers	Regulatory Requirements	Costly proceedings; may be cheaper for incumbent than entrant, especially in the case of an expansion.
	Eminent Domain	Utilities able to exercise eminent domain, even when only part of the project is for core customers.
	Ratemaking Treatment of Incumbent Utilities	Price cap set by CPUC effectively a cap for potential entrants into a competitive market.
Incumbent Advantages	Incumbent Cost Advantage	Difficult for entrants to achieve the economies of scale possible for incumbents.
	Incumbent Expansion Capacity	Cheaper for incumbent to expand current facility than to build new facility.
	Incumbent Contracting Advantage	Incumbents may have long-term contracts with customers.
Market Barriers	High Sunk Costs and Minimum Viable Scale	Large capital, regulatory, permitting and marketing costs may make only large projects viable. This may decrease prices and inhibit cost recovery potential of new entrants.
	Access to Essential Facilities	Entrants would require land and access to distribution owned by incumbent utilities.
Physical Barriers	Geology and Land Use Issues	Storage facilities require specific geology and land conditions. Economically viable sites may have already been developed.

6.0 Conclusion

Expanding in-state natural gas storage infrastructure would improve California's natural gas market by providing market participants greater ability to mitigate price volatility through arbitrage. More stable natural gas prices would benefit both gas and electricity ratepayers and provide greater cost predictability for businesses. In this report we examined whether the current approach to assessing market power for natural gas storage facilities is inhibiting optimal development of storage facilities in California, particularly in Southern California. We conclude as follows:

- **There is demand for additional natural gas storage capacity in California.** The CPUC has determined that natural gas storage capacity is adequate to ensure that sufficient natural gas would be available under a variety of adverse scenarios (e.g., supply disruption, cold weather). However, the CPUC focuses primarily on whether there would be sufficient natural gas for core customers. At the same time, in recent years, due in part to high and variable gas prices, the demand for natural gas storage has grown. As a result, independent storage operators have added additional capacity in northern California, and SoCalGas has expanded existing fields in Southern California. Moreover, new natural gas storage projects and expansions have recently been proposed in Northern California, but no new projects are currently planned for Southern California.
- **Market-based rates are often preferred over regulated cost-based rates.** The purpose of market power tests is to determine whether an industry participant can exert market power and thus increase prices over and above "competitive" levels for a sustained period of time. In general, regulators in the energy industry have granted authority for market-based rates in the absence of a finding of market power. Companies often prefer market-based rates to cost-based rates with regulated rates of return, because market-based rates provide substantial pricing flexibility, are less burdensome to implement, and may lead to higher rates of return.
- **The HHI test is used by FERC to assess market power in the natural gas storage industry.** In the past, this test has impeded the development of independent natural gas storage facilities in concentrated markets. However, this test has not constrained storage development in California, since the CPUC, which has jurisdiction over in-state natural gas storage facilities, has granted market-based rate authority to independent storage facilities despite finding a relatively concentrated market.
- **FERC's revised rules are intended to promote the development of additional natural gas storage facilities in the Southwest, but it has not yet been shown whether they are sufficient to encourage new development.** Despite liberalizing its rules for granting market-based rates in June 2006, no new storage facilities have been proposed for the southwest, although El Paso Natural Gas may submit an application for a new storage facility later this year. Given that FERC's revised rules have not led to new applications for storage facilities in this region, it is likely that there are others barriers inhibiting the development of additional storage capacity in this region.
- **FERC's revised rules are not likely to affect the CPUC's approach to granting market-based rates.** Since the CPUC's 1993 Natural Gas Storage Decision, the CPUC has adopted a "let-the-market-decide" policy for the construction and expansion of new storage facilities. The CPUC has not required the submission of market power analyses

in order to obtain market-based rates and has granted market-based rate authority to independent storage operators despite finding that the California market is concentrated. The CPUC has approved market-based rates for two independent storage operators in northern California and, based on these precedents, it appears likely that the CPUC would grant market-based rates for new entrants in the Southern California market. Consequently, it does not seem that market power tests present a barrier to the further development of storage facilities in California.

- **FERC's revised rules, however, may affect the CPUC's assessment of market power in the southern California market.** Some customers have argued that SoCalGas has market power and should charge cost-based rates even to the non-core market. In part by using FERC's revised criteria allowing inclusion of substitutes in a market power test, SoCalGas argues that it does not have market power and that cost-based rates would diminish the incentives for SoCalGas or other new entrants to build additional natural gas storage capacity in the Southern California market. In this case, the CPUC found the market to be competitive in part by allowing for consideration of transportation substitutes, consistent with FERC's revised rules.
- **There are a variety of barriers to entry, but these have not been sufficient to impede natural gas storage development in the northern California market.** Natural gas storage operators face numerous barriers to entry, including high sunk costs and numerous regulatory requirements (e.g., CPCN, CEQA), but these have not been sufficient to impede development in the Northern California market, presumably because prices are high enough to justify expansion and new entry.
- **There are likely a variety of reasons that additional natural gas storage capacity has not been built in the southern California market.** Initially, no new natural gas storage facilities were built in Southern California due to the fact that there was ample capacity and prices were low. More recently, SoCalGas has added some additional capacity, but SoCalGas argues that it has not expanded its facilities further because, based on open season results, it is unable to obtain long-term contracts at prices sufficient to cover its capacity expansion costs. New entrants may be deterred in part because of these pricing issues, geology and land-use issues, as well as the existence of an incumbent with low embedded costs and the ability to expand its facilities.

Appendix A: Market Power Regulation in the Electricity Industry

Market power tests in the electricity industry have been revisited several times over the past decade. A "hub and spoke" test was used during the 1990s. This was replaced by a "supply margin analysis" in 2001 and by two market screens and a "delivered power test" in 2004. This appendix outlines these historical developments and compares these market power tests to market power tests employed in natural gas storage regulation.

Hub and Spoke Method

In the 1990s FERC employed a four-part test to determine whether applicants could exercise market power for electric energy sales and whether they should be granted market-based rates: a market share analysis, a transmission market power analysis, an analysis of whether the applicant can erect barriers to entry, and an analysis of whether there is potential for affiliate abuse and reciprocal dealing (FERC 2004b, para. 8, 9).

To evaluate market share, the applicant would calculate his market share both within his control area market ("hub") and separately for each of the control area markets to which his capacity directly interconnected (first-tier markets or "spokes"). This is referred to as a hub-and-spoke analysis. The analysis would be conducted with respect to total installed capacity and uncommitted capacity (installed capacity less retail load obligations of the utility) (Roach 2002, pp. 53-54). If the applicant would be found to have a market share of less than 20% to 30%, FERC would generally grant the applicant the right to sell at unregulated prices in the wholesale market (Roach 2002, p. 52).

Many parties criticized the hub-and-spoke method, arguing that it did not take into consideration transmission constraints, that it failed to account for the fact that some capacity might be uneconomic, and that the basis for the 20% to 30% market share threshold was unclear (Roach 2002, p. 54). Others argued that the method was too simplistic. For example, FERC Commissioner Massey, in a 2001 case in which he was dissenting, stated that "the 20% market share threshold is too simplistic. Surely our painful experience in the California market has demonstrated that suppliers can successfully exercise market power and drive up prices with market shares far below 20%" (FERC 2001a).[71]

Even before the California energy crisis, Borenstein and Bushnell argued "that concentration measures can be misleading indicators of the potential for market power" in the electricity industry, in part because they fail to account for supply and demand elasticities (Borenstein and Bushnell 1999, pp. 286, 319). Borenstein and Bushnell also argued, "[a]s a screening tool, the Cournot analysis presents several advantages over concentration measures. In particular, it can explicitly test for whether an individual firm can profit from a unilateral reduction in output" (Borenstein and Bushnell 1999, p. 320). Using a Cournot[72] simulation to assess the then newly deregulated California electricity market, Borenstein and Bushnell found, "under the historical

71. Also see (Roach 2002).

72. According to Borenstein and Bushnell, "at the Cournot equilibrium, each firm is producing its profit maximizing quantity given the quantities that are being produced by all other Cournot participants in the market" (Borenstein and Bushnell 1999, p. 304).

industry structure, there is the potential for market power in the high demand hours of several months of the year" (Borenstein and Bushnell 1999, p. 320).

In November 2001, in the course of reviewing triennial market power updates of a variety of generators, FERC determined that it should adopt a new, interim market power screen, the supply margin assessment (SMA). In support of this move, FERC noted that "because of significant structural changes and corporate realignments that have occurred and continue to occur in the electricity industry, our hub-and-spoke analysis no longer adequately protects customers against generation market power" (FERC 2001b, p. 7). FERC concluded, that "[t]he hub-and-spoke analysis worked reasonably well for almost a decade when the markets were essentially vertical monopolies trading on the margin and retail loads were only partially exposed to the market. Since that time markets have changed and expanded" (FERC 2001b, p. 7). The SMA, which is explained in the following section, was to be adopted on an interim basis until FERC conducted a rulemaking into appropriate market power tests.

Supply Margin Assessment

According to FERC, the SMA improves upon the hub-and-spoke analysis in two ways. First, the SMA considers transmission constraints. Second, the SMA assesses whether the applicant is pivotal to the market; that is, whether at least some of the applicant's capacity must be used to meet the market's peak demand.

FERC explained the advantages of the SMA:

> When an applicant is pivotal, it is in a position to demand a high price above competitive levels and be assured of selling at least some of its capacity. An applicant will be pivotal if its capacity exceeds the market's surplus capacity above peak demand –that is, the market's supply margin. Thus, an applicant will fail the SMA screen if the amount of capacity exceeds the market's supply margin. By contrast, under the hub-and-spoke method, an applicant would pass the screen if its market share were less than 20 percent, even if its capacity were pivotal. The SMA's supply margin threshold is a better screen for market power because, unlike the 20 percent market share screen, it is sensitive to the relative scarcity of electricity supply available from suppliers other than the applicant in the applicable market. Effectively, the supply margin threshold identifies whether the applicant is a must-run supplier needed to meet peak load in a control area. Thus, the supply margin is sensitive to the potential for the applicant to successfully withhold supplies in the market in order to raise prices (FERC 2001b, p. 8).

In implementing this test, FERC compared the applicant's generation capacity in a control area market (and that owned or controlled by affiliates) to the supply margin (i.e., the difference between available supply and peak demand), where available supply included all uncommitted generation that could reach the market once transmission constraints are taken into account.[73] If the applicant's generation capacity exceeded the supply margin (for example: the difference between available supply and peak demand), the applicant would be required to offer

73. All sales, including bilateral sales, into an ISO or RTO with FERC-approved market monitoring and mitigation would be exempt from the SMA.

uncommitted capacity for spot market sales using a split-the-savings formula.[74] In December 2001, FERC delayed implementation of the mitigation measures (i.e., mandatory sales under the split-the-savings formula) for spot energy sales.

Numerous parties criticized the SMA on theoretical and practical grounds. Arguments against the SMA include the following:

- The SMA could mistake a market shortage for market power, and price signals should not be blocked during market shortages
- The SMA looks only at a single moment in time, whereas market power is the ability to raise prices for a *sustained* period of time
- The SMA would discourage building at existing sites, as this would increase the capacity held by one owner (Roach 2002, pp. 60-61).

Other criticisms related to how the SMA was applied. For example, a number of parties objected to the focus on an applicant's total installed generation. These parties argued that "such an approach assumes that all of the applicant's capacity is available to the wholesale market and, accordingly, overstates the amount of an applicant's capacity, which in turn overstates the applicant's market power potential" (FERC 2004b, para. 42). Further developing this point, some parties contended that "utilities with a regulatory obligation to serve retail customers in their service territories at fixed or regulated rates and with long-term contractual obligations cannot withhold substantial amounts of generation and, therefore, cannot drive up prices" (FERC 2004b, para. 43). Many parties also argued that FERC should only adopt market power tests as indicative screens rather than definitive tests.

The SMA remained in use for just two and a half years.

Uncommitted Market Share, Pivotal Supplier, and Delivered Price Test

On April 14, 2004 FERC issued an order modifying the then-existing generation market power analysis and its policy governing market power mitigation on an interim basis (FERC 2004b). In this decision, FERC replaced the SMA and adopted two "indicative screens" for assessing generation market power. The two indicative screens are the pivotal supplier and the market share analysis. If an applicant passed these two screens, there would be a rebuttable presumption that the applicant did not possess market power in generation, although interveners could present contrary evidence. Likewise, if an applicant failed either screen, this would create a rebuttable presumption that market power exists, although the applicant could rebut the presumption of market power with a delivered price test, and would also have the option of filing a mitigation proposal or adopting default cost-based rates, as explained in more detail below.

In May 2006 FERC issued a notice of proposed rulemaking (NOPR) to codify and revise its current standards for market-based rates, and in June 2007 FERC issued its final rules. The new rules more specifically define the market under consideration and address concerns that spikes in electricity prices in the West and elsewhere may have resulted from unchecked market concentration and market power. They retain, but modify in some respects, the two indicative

74. Under the split-the-savings formula, a "seller's incremental cost (the out of pocket cost of producing an additional MW) is compared with a buyer's decremental cost (the cost of not producing the last MW). The average of the incremental and decremental costs is the split savings rate" (FERC 2001b).

screens: the market share and pivotal supplier tests. For both of these screens, FERC defined the default geographic market as the generator's balancing authority area (i.e., the control area) and directly interconnected areas for traditional (non-RTO/ISO) markets, and as the entire RTO/ISO markets for those areas with RTO/ISO's with sufficient market structure and a single energy market. However, where FERC has found there to be sub-markets within an RTO/ISO, the sub-market is to be used as the default geographic market.

The first screen is the market share screen. This screen measures for each of the four seasons "whether a seller has a dominant position in the market-based on the number of megawatts of uncommitted capacity owned or controlled by the seller as compared to the uncommitted capacity of the entire relevant market," including uncommitted supplies that can be imported (limited by simultaneous transmission import capability) (FERC 2007c, para. 34, 37). The market share analysis adopts an initial threshold of 20 percent, meaning that a supplier with more than 20 percent market share in the relevant market for any seasons will have a rebuttable presumption of market power.[75]

The second screen is the pivotal supplier screen. According to FERC,

> [The pivotal supplier screen] evaluates the potential of a seller to exercise market power based on uncommitted capacity at the time of the balancing authority area's annual peak demand. This screen focuses on the seller's ability to exercise market power unilaterally. It examines whether market demand can be met absent the seller during peak times. A seller is pivotal if demand cannot be met without some contribution of supply by the seller or its affiliates (FERC 2007c, para. 35).

If the applicant's uncommitted capacity during the peak is equal to or greater than the net uncommitted supply, then the applicant will have rebuttable presumption of market power. The reasoning behind this test is that "[i]n markets with very little demand elasticity, a pivotal supplier could extract monopoly rents during peak periods because customers have few, if any alternatives" (FERC 2004b, para. 72). The pivotal supplier screen focuses on uncommitted capacity, whereas the SMA focused on installed capacity.

If an applicant fails either of these indicative screens, the applicant can conduct a delivered price test (DPT) analysis or implement mitigation measures (e.g., cost-based rates). Under a DPT analysis, an applicant determines the economic capacity for each season and load condition and then conducts the market share, pivotal suppliers and market concentration analyses.[76] Initially, FERC indicated that a "showing of an HHI less than 2,500 in the relevant market for all season/load conditions for applicants that have shown that they are not pivotal and do not posses more than a 20 percent market share in any of the season/load conditions would constitute a showing of a lack of market power, absent compelling evidence from

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73. "The 20 percent threshold is consistent with section 4.134 of the U.S. Department of Justice 1984 Merger Guidelines issued June 14, 1984, reprinted in Trade Reg. Rep. P13,103 (CCH 1988): 'The Department [of Justice] is likely to challenge any merger satisfying the other conditions in which the acquired firm has a market share of 20 percent or more" (FERC 2006c).

76. Economic capacity is capacity that can be delivered (i.e., there is sufficient transmission capacity) and is price competitive (i.e., no greater than 5% above current market price).

interveners" (FERC 2004b, para. 72). In its 2006 NOPR, however, FERC clarified that "[t]he DPT does not function like the initial screens in that the failure of either the economic capacity or available economic capacity analyses does not result in an automatic failure as a whole" (FERC 2006c, para. 28). And in its final rules, FERC indicated that,

> Sellers that fail either screen will be rebuttably presumed to have market power. However, such sellers will have full opportunity to present evidence (through the submission of a Delivered Price Test (DPT) analysis) demonstrating that, despite screen failure, they do not have market power, and the Commission will continue to weigh both available economic capacity and economic capacity when analyzing market shares and Hirschman-Herfindahl Indices (HHIs) (FERC 2007c, para. 8).

Critics claim that market share analyses can fail to detect market power, although for different reasons. For example, Borenstein et al. "found that firms with only 7-8% market share could exert significant market power during peak periods – rather than the 20% standard set by FERC" (Borenstein 1999). On the other hand, others note that "a firm could have a large market share and the market could appear concentrated, not because the firm has market power but because it has low costs or sells superior products" and that because of this problem "antitrust today does not rely heavily on profitability measures in making inferences about market power" (Baker and Bresnahan 1993, pp. 4-5).

Other Market Power Tests

A number of other market power tests were proposed for the electricity industry but ultimately rejected by FERC. For example, some parties proposed that FERC use a contestable load analysis. Using this screen, "if the amount of non-applicant supply is at least twice the contestable load, advocates of the contestable load analysis believe that is sufficient to make a finding that the market is competitive" (FERC 2007c, para. 49). FERC rejected this test, arguing in part that the contestable load analysis was a variant of the pivotal supplier screen and that it fails to consider the relative price of competing supplies (i.e., if non-applicant supply is competitively priced and, thus, in the market) (FERC 2007c, para. 66-67).

The State Attorneys General and others suggested that FERC adopt behavioral modeling, such as game theory, rather than structural analysis. FERC concluded that while game theory has been used in experiments and theoretical studies, it was not a practical approach given the data gathering and analysis burden and the volume of analyses FERC performs (FERC 2007cpara. 121, 124).

Comparison and Critique of the Market Power Tests

All of the market power tests currently employed in the energy industry take the same broad approach, in that they define the relevant geographic markets and product markets and establish threshold or screening criteria. However, how these product and geographic markets are defined and what threshold criteria are employed differ. Appendix B contains a reference table summarizing the market power tests.

In the case of natural gas storage, FERC defines the product market to include all storage capacity and available substitutes, including pipeline capacity, local production, or LNG. On the other hand, in the electricity industry FERC defines the product much more narrowly to include uncommitted peak capacity and uncommitted capacity during the four seasons. It is clear that FERC is much more concerned in the electricity industry with the exercise of market power during peak periods.

The geographic market is not explicitly defined in the natural gas context, but rather defined by the location of the competing natural gas storage facilities and available substitutes. In the electricity industry, however, the geographic market is specifically identified as the balancing authority area or RTO/ISO, if applicable, and extends to other areas to the extent that there is uncommitted capacity available considering transmission constraints.

The threshold tests in the two industries also differ. While FERC examines market share in both industries, in the electricity industry FERC looks specifically at market share during discrete time periods (four seasons) and limits consideration to uncommitted capacity. In the natural gas storage industry, FERC examines total storage capacity, even storage capacity committed to the core or committed under long-term contracts. In addition, FERC uses a 20 percent threshold level for its market share screen in the electricity industry, while there is no specific threshold in the natural gas storage industry. Finally, while FERC looks at market concentration and HHI measures for the natural gas storage industry, FERC assess whether the applicant for market-based rates is a pivotal supplier in the electricity industry.

In both industries, if applicants fail these market power tests, applicants can still obtain cost-based rates or propose other remedies.

Critiques of most of these tests focus on the fact that they attempt to measure market power indirectly by looking at market concentration and not specifically a company's ability to raise prices above competitive levels. In the electricity industry, critics have charged that the screens have failed to accurately measure the ability of firms to exercise market power and thus have allowed companies to exercise market power and extract monopoly profits. On the other hand, critics of FERC's final rule charge that the rules are unduly burdensome and will unfairly prevent some applicants from obtaining market-based rate authority.

Overall, in the electricity industry, the revised rules regarding market-based rates have resulted in changes in the industry. According to FERC, "[i]n the three years since the April 14 Order, the Commission has revoked the market-based rate authority of two sellers, thirteen sellers relinquished their market-based rate authority, and six companies satisfied the Commission's concerns for the grant of market-based rate authority at the DPT phase" (FERC 2007c, para. 91).

On the other hand, it appears that the market power tests in the natural gas storage industry have not proven overly restrictive. According to the Natural Gas Supply Association, "Since 1996, FERC had 40 requests from storage operators for market-based rates and approved all but one" (NGSA 2006). It should be noted, however, (as shown in Table 25) that some natural gas storage applicants have not requested market-based rates and have opted to obtain cost-based rates for natural gas storage facilities.

Table 25: FERC-Approved Natural Gas Storage Projects Since 2000 For Expansions or New Capacity

Market-Based Rates			Cost-Based Rates		
Bluewater Gas Storage	MI	10/27/2006	ANR Pipeline Company	MI	8/9/2004
Bobcat Gas Storage	LA	7/20/2006	ANR Pipeline Company	MI	11/22/2006
Bobcat Gas Storage	LA	4/19/2007	ANR Pipeline Company	MI	5/31/2007
Caledonia Energy Partners	MS	4/19/2005	CenterPoint Energy Gas Transmission	OK	7/25/2005
Central New York Oil & Gas	NY	2/21/2001	Dominion Transmission, Inc.	NY, PA, WV	9/11/2003
Central New York Oil & Gas	NY	9/22/2006	Dominion Transmission, Inc.	PA, VA, WV	6/16/2005
Copiah County Storage Co.	MS	6/13/2002	Dominion Transmission, Inc.	PA	9/14/2007
Egan Hub Partners, LP	LA	4/2/2003	Gulf South Pipeline Company, LP	MS	3/24/2005
Egan Hub Storage, LLC	LA	6/14/2001	Hardy Gas Storage, LLC	WV	11/1/2005
Freebird Gas Storage, LLC	AL	4/15/2005	Kinder Morgan Interstate Gas Transmission, LLC	CO, NE	9/11/2003
Gulf South Pipeline Company	LA	11/21/2002	Natural Gas Pipeline Co. of America	OK	3/25/2005
Liberty Gas Storage, LLC	LA	12/8/2005	Natural Gas Pipeline Co. of America	TX	1/23/2006
Mississippi Hub, LLC	MS	2/15/2007	Natural Gas Pipeline Company of America	TX	12/24/2002
Petal Gas Storage Company	MS	3/15/2000	Northern Natural Gas Company	KS	3/24/2006
Petal Gas Storage Company	MS	2/28/2003	Northern Natural Gas Company	IA	7/1/2007
Petal Gas Storage Company	MS	3/28/2007	Texas Eastern Transmission, LP	MD	2/22/2006
Pine Prairie Energy Center	LA	11/23/2004	Texas Gas Transmission	KY	2/11/2005
Seneca Lake Storage, Inc.	NY	2/14/2002	Saltville Gas Storage Company	VA	6/14/2004
SG Resources Mississippi	MS	10/10/2002			
Starks Gas Storage	LA	7/21/2005			
Tres Palacios Gas Storage	TX	9/20/2007			
Unocal Windy Hill Gas Storage, LLC	CO	5/19/2006			
Wycoff Gas Storage	NY	10/6/2003			

Source: (FERC 2007b)

Appendix B: Comparison of Market Power Tests

Gas Industry				
Market Power Rule	**Product Market**	**Geographic Market**	**Threshold Test**	**Other Considerations**
1996 Alternative Rate Policy Statement, 74 FERC ¶61,076 (1996)	-Competing storage capacity	-Defined narrowly -Must be un-subscribed firm transportation capacity to transport gas from competing storage facilities	-Market concentration (HHI) for working gas capacity and maximum daily deliverability -HHI above 1,800 warrants closer scrutiny	-Market share -Ease of entry
2006 Final Rules – Order 678, 115 FERC ¶61,343 (2006)	-Competing storage capacity -*Close substitutes including available pipeline capacity, local gas production or LNG terminals*	-Defined more broadly given the consideration of close substitutes	-Market concentration (HHI) for working gas capacity and maximum daily deliverability -HHI above 1,800 warrants closer scrutiny -*Market-based rates allowed if in the public interest and consumers adequately protected, even if lack of market power not demonstrated*	-Market share -Ease of entry

Electric Industry				
Market Power Rule	**Product Market**	**Geographic Market**	**Threshold Test**	**Other Considerations**
Hub and Spoke Method,	-Installed and uncommitted generation	-Generator's control area and directly interconnected control areas (regardless of transmission constraints)	-Benchmark at 20 percent or more in each of the relevant markets	-Transmission market power -Barriers to entry -Reciprocal dealing
Supply Margin Analysis, 97 FERC ¶ 61,219 (2001)	-Peak capacity	-Generator's control area and directly interconnected control areas *considering transmission constraints*	-Whether the supplier is pivotal, i.e., whether at least some of the applicant's capacity must be used to meet the market's peak demand	-Affiliates' capacity included in calculation -Mitigation measures include mandatory spot market sales with split-the-savings pricing formula
Uncommitted Pivotal Supplier, 107 FERC ¶61,018 (2004) & 115 FERC ¶61,210 (2006)	-Uncommitted peak capacity	-Generator's control area and directly interconnected control areas *considering transmission constraints*	-If the applicant's uncommitted capacity is equal to or greater than the net uncommitted supply, then the applicant will have rebuttable presumption of market power	-If screening test failed, can implement mitigation or conduct delivered price test
Uncommitted Market Share, 107 FERC ¶61,018 (2004) & 115 FERC ¶61,210 (2006)	-MW of uncommitted capacity during four seasons	-Generator's control area and directly interconnected control areas *considering transmission constraints*	-Supplier who has more than 20 percent market share in the relevant market for any season will have rebuttable presumption of market	-If screening test failed, can implement mitigation or conduct delivered price test
Delivered Price Test, 107 FERC ¶61,018 (2004) & 115 FERC ¶61,210 (2006)	-Economic capacity for each season and load condition	-No clear boundaries, capacity considered economic if it can be delivered and it is price competitive	-Using economic capacity, provide pivotal supplier, market share (20% threshold) and market concentration analyses (2,500 HHI threshold)	

Appendix C: Market Power Analysis for California

This appendix presents several market power analyses for the California storage facilities. There are two major components to a market power analysis: an HHI market concentration test and a calculation of market share. Consideration of substitute products is generally not included in these analyses; however, substitute products can have a significant role in limiting market power, and their impacts can be separately considered. To illustrate the impact of substitute products, we present market power test results that consider both natural gas storage facilities and pipeline capacity.

Market Concentration Analysis

The two definitions required to conduct an HHI market concentration analysis are the product market and the geographic market. For natural gas storage facilities, two product markets are considered: inventory and withdrawal capacity. The selection of geographic market is not straightforward and can have a large impact on the analysis results.

Geographic Market

This analysis examines four definitions of the California natural gas storage geographic markets and the impacts of these definitions on the HHI results. The markets are shown in Figure 11. Storage facilities are marked for identification according to their geographic area.

Market Area A1 includes only Northern California. This geographic market includes the existing storage facilities of PG&E and the Wild Goose and Lodi projects. PG&E holds 42 Bcf of inventory capacity, with withdrawal capacity of 1,996 MMcf per day. PG&E uses 33 Bcf of its storage for core customers but has offered as much as 5 Bcf to noncore customers at tariffed rates, with some storage also used to provide balancing service. Wild Goose and Lodi have a combined 46 Bcf of inventory capacity and 1,030 MMcf/d of withdrawal capacity.

Market Area A2 includes only Southern California, which presently contains only the storage facilities of SoCalGas. SoCalGas' Aliso Canyon, Honor Rancho, Goleta, and Playa del Rey fields offer a combined 131 Bcf of working inventory space and 3,175 MMcf per day of peak day deliverability.

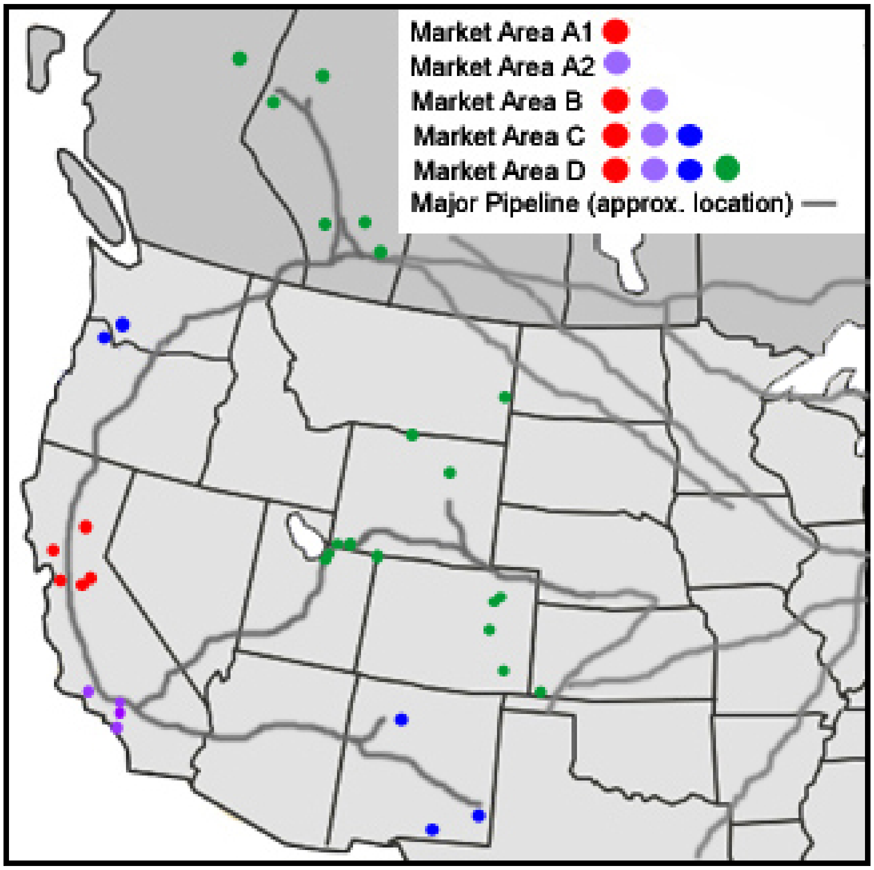

Figure 11: California Natural Gas Storage Geographic Markets[77]

Market Area B includes both Southern and Northern California and has 219 Bcf of inventory capacity and 6,201 MMcf/d of deliverability. Within Market Area B, the significant market presence of PG&E and SoCalGas creates a concentrated market and, to some degree, may limit the market power of independent storage providers. These utilities have a wide customer base, a long-established history, and name recognition. In comparison, new storage operators may not have these advantages.

Market Area C includes storage facilities that are connected to an interstate pipeline that can move gas directly (or almost directly) to California. This includes El Paso Natural Gas' Washington Ranch field and ENSTOR's Grama Ridge. These facilities connect directly to El Paso's mainline. Also included within Market Area C is PNM's Las Milpas field. This field is not directly available to users in California, but it serves to reduce the demand for storage that can reach California. In the north, Market Area C includes Jackson Prairie and Mist.

Market Area D reaches further to include storage facilities in Wyoming, Montana, Colorado, Utah, Alberta, and British Columbia that deliver gas into pipelines that interconnect with the primary pipelines serving California. This includes projects such as Questar's Clay Basin, which can support transportation on the Kern River Pipeline (as well as users in the Pacific Northwest), in addition to a variety of different production area storage projects in western Canada. Consistent with FERC's analysis in Richfield (which included indirectly

75. Map only includes the natural gas storage facilities included in the analysis.

accessible production area facilities), these facilities are not necessarily connected to pipelines that can reach California directly, but they are accessible indirectly through pipelines that can reach California (FERC 1992). As such, they could present alternatives to California storage services.

Defining the geographic market broadly to include Market Areas C and D reflects the fact that storage facilities located at a far distance (particularly upstream) from California could be reasonable substitutes for some consumers. In the Transok case, which was discussed in Chapter 3, FERC defined the geographic market to include all directly interconnected storage (FERC 1993). While the inclusion of Market Areas C and D does not meet this definition in the strictest sense, potential users within this market area can economically access alternatives and can be expected to compare these alternatives to in-state options. It is thus reasonable to consider these alternate storage opportunities within the geographic area used to analyze market power.

Table 26 summarizes the total quantity of inventory and withdrawal that are available to consumers in each of the four geographic markets.

Table 26: Total Storage Inventory and Deliverability Currently Available in the Four Relevant Geographic Market Areas

Market Area	Market Description	Inventory (Bcf)	Withdrawal (MMcf/d)
A1	Northern California	88	3,026
A2	Southern California	131	3,175
B	All California	219	6,201
C	Connected to California	309	7,922
D	Accessible to California	879	15,009

Market Concentration

HHIs were calculated for the four different (increasingly broad) geographic market areas and two different storage products: working gas capacity (or inventory) and withdrawal deliverability. The results are presented in Table 27 below.

Table 27: HHI Analysis Summary for Inventory and Withdrawal

	Inventory	Withdrawal
A1. Northern California	3,647	4,933
A2. Southern California	10,000	10,000
B. All California	4,167	3,796
C. Connected to California	2,400	2,492
D. Accessible to California – Facilities Separate	893	983
D. Accessible to California – Facilities Combined by Company Ownership	1,245	1,398
All California – With Transportation Substitutes	na	1,294

It is clear from Table 27 that the market for storage in California (i.e., Market Areas A and B) is concentrated due to the large storage facilities owned by SoCalGas in southern California and, to a lesser extent, by PG&E, Lodi, and Wild Goose in Northern California. The size of these facilities lead to a concentrated market even in Market Area C, which includes interconnected facilities in New Mexico and the Pacific Northwest.

Expanding to Market Area D, the HHIs drop to a level which FERC would consider not concentrated, for example, below the threshold of 1,800. This broader market area includes several large projects that offset the impact the California storage providers have on the market, and therefore reduce the HHI for inventory to 893 and for withdrawal to 984. In this region, however, many of the storage facilities are under common ownership (e.g., El Paso owns Washington Ranch as well as Young, Flank, Latigo, Fort Morgan and Boehm, and Niska owns AECO Hub as well as Wild Goose, etc.) . However, even combining these facilities under common ownership results in HHIs below FERC's threshold level of concern.

As discussed in the body of this report, an HHI analysis assesses only market concentration, not market power. In addition, it does not capture the breadth of services made possible by storage or the alternatives that can substitute for storage. To more completely assess potential market power, we examine market shares and the impacts of alternatives.

Market Share

Most experts agree that low market share will prevent the exercise of market power, particularly for markets shown in an HHI analysis to be highly concentrated. Market share matters because "the smaller the percentage of total supply that a firm controls, the more severely it must restrict its own output in order to produce a given price increase, and the less likely it is that an output restriction will be profitable" (DOJ 1997, Section 2.0).

As shown in Table 28, SoCalGas has 100% market share in Southern California, and PG&E has a market shares of 48% and 66% of the Northern California inventory and withdrawal markets. The independent storage operators have much smaller market shares. The market shares of each entity declines when California is considered one geographic market. In this instance, for example, PG&E holds 19% of the inventory capacity, and 32% of the withdrawal capability. Market shares fall further when considered in the context of the larger geographic markets.

Table 28: Market Share Analysis for Storage Facilities Located in California

	Capacity		Southern or Northern CA Market Share		Entire CA Market Share	
	Inventory (Bcf)	Withdrawal (MMcf/d)	Inventory (Bcf)	Withdrawal (MMcf/d)	Inventory (Bcf)	Withdrawal (MMcf/d)
SoCalGas	131	3,175	100%	100%	60%	51%
PG&E	42	1,996	48%	66%	19%	32%
Lodi	22	550	25%	18%	10%	9%
Wild Goose	24	480	27%	16%	11%	8%
Northern CA	88	3,026	100%	100%	40%	49%
CA Total	219	6,201			100%	100%

Table 29 through Table 34 present the market shares and HHIs for each provider's inventory and deliverability in the four defined geographic markets. These tables clarify the dominance of the PG&E and SoCalGas storage facilities and demonstrate the low market shares of Wild Goose and Lodi, particularly in the context of the broader markets. In fact, the market shares of Wild Goose and Lodi are close to the range of market shares held by applicants for whom FERC has approved market-based rates. These low market shares may preclude the independent facilities from being able to raise prices and thereby exercise market power, even in the northern California market.

Table 29: Geographic Market Area A

	Inventory	Market %	HHI		Withdrawal	Market %	HHI
PG&E	42	48	2,278	PG&E	1,996	66	4,351
Lodi	22	25	625	Lodi	550	18	330
Wild Goose	24	27	744	Wild Goose	480	16	252
Total	88	100	3,647	Total	3,026	100	4,933
SoCalGas	131	100	10,000	SoCalGas	3,175	100	10,000

Table 30: Geographic Market Area B

	Inventory	Market %	HHI		Withdrawal	Market %	HHI
PG&E	42	19	368	PG&E	1,996	32	1,036
Lodi	22	10	101	Lodi	550	9	79
Wild Goose	24	11	120	Wild Goose	480	8	60
SoCalGas	131	60	3,578	SoCalGas	3,175	51	2,622
Total	219	100	4,167	Total	6,201	100	3,796

Table 31: Geographic Market Area C

	Inventory	Market %	HHI		Withdrawal	Market %	HHI
PG&E	42	14	185	PG&E	1996	25	635
Lodi	22	7	51	Lodi	550	7	48
Wild Goose	24	8	60	WGS	480	6	37
SoCalGas	131	42	1,796	SoCalGas	3175	40	1,606
WashRanch	48	15	237	WashRanch	250	3	10
Grama Ridge	6	2	4	Grama Ridge	125	2	2
Las Milpas	2	0	0	Las Milpas	3	0	0
Mist	14	5	21	Mist	493	6	39
Jackson Prairie	21	7	46	Jackson Prairie	850	11	115
Total	309	100	2,400		7,922	100	2,492

Table 32: Geographic Market Area D – Facilities Separate[78]

	Inventory	Market %	HHI		Withdrawal	Market %	HHI
PG&E	42	5	23	PG&E	1996	13	177
Lodi	22	3	6	Lodi	550	4	13
Wild Goose	24	3	7	Wild Goose	480	3	10
SoCalGas	131	15	222	SoCalGas	3175	21	447
WashRanch	48	5	29	WashRanch	250	2	3
Grama Ridge	6	1	0	Grama Ridge	125	1	1
Las Milpas	2	0	0	Las Milpas	3	0	0
Mist	14	2	3	Mist	493	3	11
Jackson Prairie	21	2	6	Jackson Pr	850	6	32
Boehm	5	1	0	Boehm	124	1	1
Flank	7	1	1	Flank	164	1	1
Fort Morgan	9	1	1	Fort Morgan	450	3	9
Latigo	8	1	1	Latigo	139	1	1
Young	6	1	0	Young	250	1	3
Leroy	1	0	0	Leroy	75	0	0
Clay Basin	51	6	34	Clay Basin	765	5	26
Chalk Creek	0.3	0	0	Chalk Creek	35	0	0
Coalville	0.7	0	0	Coalville	65	0	0
Clear Creek	4	0	0	Clear Creek	50	0	0
Billy Creek	0.5	0	0	Billy Creek	5	0	0
Elk Basin	28	3	10	Elk Basin	135	1	1
Baker	164	19	348	Baker	115	1	1
Aitken Creek	48	5	30	Aitken Creek	400	3	7
Suffield	85	10	94	Suffield	1800	12	144
Countess	40	5	21	Countess	1250	8	69
Hythe	10	1	2	Hythe	200	1	2
Dunvegan	12	1	1	Dunvegan	35	0	0
Carbon	40	5	21	Carbon	550	4	13
East Crossfield	50	6	32	East Crossfield	480	4	10
Total	879	100	893		15,009	100	983

76. The sums of the market share percentages and HHI figures may not match the totals due to rounding.

Table 33: Geographic Market Area D – Facilities Combined by Company Ownership[79]

Owner	Field	Inventory	Market %	HHI	Withdrawal	Market %	HHI
ATCO	Carbon	40	5	21	550	4	13
BP Canada	Crossfield	50	6	32	480	3	10
Chevron	Aitken	48	5	30	400	3	7
	Dunvegan	12	1	2	35	0	0
El Paso	WashRanch	48	9	88	250	9	84
El Paso	Young	6			250		
El Paso	Flank	7			164		
El Paso	Latigo	8			139		
El Paso	Fort Morgan	9			450		
El Paso	Boehm	5			124		
Encana	Hythe	10	1	1	200	1	2
ENSTOR	Grama Ridge	6	1	0	125	1	1
GNM	Las Mipas	2	0	0	3	0	0
Lodi	Lodi	22	3	6	550	4	13
Niska	Wild Goose	24	17	287	480	24	553
Niska	Suffield	85			1,800		
Niska	Countess	40			1,250		
Northwest Natural Gas	Mist	14	2	3	493	3	11
PG&E	PG&E	42	5	23	1,996	13	177
Puget Sound Energy	Jackson Prairie	21	2	6	850	6	32
Questar	Leroy	1	6	42	75	7	44
Questar	Clay Basin	51			765		
Questar	Chalk Creek	0.3			35		
Questar	Coalville	0.7			65		
Questar	Clear Creek	4			50		
SoCalGas	SoCalGas	131	15	222	3,175	21	447
Williston Basin	Billy Creek	0.5	22	482	5	2	3
Williston Basin	Elk Basin	28			135		
Williston Basin	Baker	164			115		
Total		879	100	1,245	15,009		1,398

77. The sums of the market share percentages and HHI figures may not match the totals due to rounding.

Effect of Storage Alternatives

The HHIs and market shares associated with California's combined storage and flowing supply market can be estimated. For this analysis, the maximum withdrawal rates along with the individual receipt point capacities for interstate and California supplies (See Table 34.)

A key assumption in comparing the capacities of flowing and storage supplies is the available withdrawal rate. Unlike the relatively stable capacity of pipelines, available withdrawal rates vary with the accumulated inventory of the storage fields. The withdrawal rate from a given field reaches its maximum when the field is fully filled. This available withdrawal rate declines as the field is drawn down and the pressure within the storage field declines. The average withdrawal capability will depend upon the rate at which the storage field is drawn down and refilled. In addition, the withdrawal rate availability will be limited by the need to inject supplies into the field. The portion of the time needed to refill will depend upon the injection capacity.

The use of the maximum available withdrawal rate is clearly an overstatement of the withdrawal rate availability since it does not account for the availability limitations associated with necessary injections. Injections may be necessary over half of the days of the year to maintain desired inventory levels. The maximum withdrawal rate may, however, show the available withdrawal rate capacity for peak demand days, when market concentration is of most concern. For this reason, maximum withdrawal rate will be used for this combined storage and flowing supply analysis.

Table 34 shows the HHI and market share values for the combined flowing supply and storage capacities for Market Areas A and B, respectively. In Market Area A, the HHI values are 2,656 for Southern California and 2,485 for Northern California. The HHIs for the combined California market are 1,294 with no other facility expansion and would be less if proposed pipeline and storage expansions were included. Clearly, the California market for flowing supplies and storage is a less concentrated market, although the HHIs for Southern and Northern California remain somewhat higher than FERC's 1,800 HHI threshold value for markets concentration.

Table 34: Market Power Analysis for Combined Storage and Flowing Supply

	Inventory (MMcf/d)	Separate Markets		California Market	
		Market Share	HHI	Market Share	HHI
SoCalGas	3,175	45%	2,028	24%	564
SoCalGas System Interstate Receipt Point Capacity					
Mojave (Hector Road)	50	1%	1	0%	0
El Paso (Blythe)	1,210	17%	295	9%	82
El Paso (Topock)	540	8%	59	4%	16
Transwestern (Topock)	800	11%	129	6%	36
Kern-Mojave (Wheeler Ridge)	765	11%	118	6%	33
Kern-Mojave (Kramer Junction)	200	3%	8	1%	2
California Source Gas	310	4%	19	2%	5
Southern CA	7,050	100%	2,656	53%	739
PG&E	1,996	32%	998	15%	223
Lodi	550	9%	76	4%	17
Wild Goose	480	8%	58	4%	13
PG&E System Interstate Receipt Point Capacity					
US Southwest	1,140	18%	326	9%	73
Canadian Gas	2,021	32%	1,024	15%	229
California Source Gas	130	2%	4	1%	1
Northern CA	6,271	100%	2,485	47%	555
CA Total	13,321			100%	1,294

Glossary

Arbitrage –The practice of using natural gas storage to buy gas in excess of current requirements when prices are low and then using or selling the gas when prices increase.

Backbone Capacity – Refers to the capacity of the PG&E and SoCalGas operated natural gas pipeline.

Balancing Services – Service provided by utilities and pipelines that allows shippers to balance small, short-term discrepancies between gas receipts and deliveries in lieu of purchasing storage service.

Bcf – Billion cubic feet. One cubic foot is roughly equal to one decatherm (dth).

Core/Non-Core Storage – Core storage is utility-owned natural gas storage capacity designated to serve the utility's core or bundled customers. Non-core storage is utility storage capacity in excess of the core requirements and independent operator capacity available on the market.

Cost Based Rates – Rate structure calculated by assessing a facility's cost of supply and adding a regulated allowable rate of return (profit); generally assessed through the process of rate case proceedings.

Cushion Gas – Volume of gas in a storage facility that provides the necessary pressure for withdrawal of working gas. Cushion gas is generally not available for commercial withdrawal.

Ease of Entry – Relative presence or absence of barriers in place that would affect the ability of a new firm to go into the business, or enter the market. For example: regulatory compliance, incumbent advantage, technological development.

Elasticity of Demand – The degree to which demand for a product will change with a change in price. Higher elasticity signifies that demand will change drastically with a small change in price and low elasticity, or inelasticity, signifies that demand will change little with a large change in price.

Firm Withdrawal – Removal of gas from storage facilities under contract to serve core customers.

Geographic Market – The spatial boundaries within which storage operators compete for business.

HHI - Herfindahl-Hirschman Index; a market concentration test calculated by summing the squares of the market share of each party in a given market. A large HHI indicates a concentrated market.

Injection – The deposit of natural gas into a storage facility.

Interruptible Service – Storage service provided on an as-available basis, once core customer requirements have been met.

Inventory – The quantity of natural gas stored in a facility, usually measured in Bcf (billion cubic feet). Sometimes inventory is differentiated between working gas and cushion gas (see definitions).

Load Factor – The ratio of a consumer's actual consumption to the consumption that would have occurred had consumption been fully sustained at the maximum (peak) level.

Market-based Rates – Rates determined by the seller of natural gas storage services, the rate will levels of supply and demand.

Market Concentration – Characteristics of market share among sellers in a market. A market with high concentration will have few sellers, each with a large portion of the market share. A market with low concentration will have many sellers, each with a small portion of the market share.

Market Power – The ability to raise prices in a market above competitive levels for a significant period of time.

Market Power Test – Mathematical tool for assessing the degree of market power present in a given market.

Market Share – The proportion of supply under the control of a seller, i.e. the ratio of one operator's working gas inventory to the total supply of storage products on the market.

MMcfd – Million cubic feet per day

Open Season – Time period in which bids are accepted from a given solicitation.

Park and Lending Services - Interruptible service offered to utility customers providing them the ability to park (inject) or lend (withdraw) gas into or out of the pipeline at a specific location for a specific period of time.

Product Market – The set of products that provide competitive alternatives to the product in question. Pipeline capacity and LNG are examples of products included in the product market for natural gas storage.

Substitute Product – One product is considered a substitute product for another if the two goods can be consumed or used in place of each other. Pipeline capacity is one example of a substitute product for natural gas storage.

Withdrawal – The removal of gas from a natural gas storage facility. Withdrawal allows for the transport and use of the stored natural gas.

Working Gas – The volume of gas in a storage facility that is available for commercial withdrawal.

Acronyms and Abbreviations

BCAP	Biennial Cost Allocation Proceedings
Bcf	Billion cubic feet
CARE	California Alternate Rates for Energy
CEQA	California Environmental Quality Act
CPCN	Certificate of Public Convenience and Necessity
CPUC	California Public Utilities Commission
DOGGR	California Department of Conservation, Division of Oil, Gas & Geothermal Resources
DOJ	U.S. Department of Justice
DPT	Delivered Price Test
Dth	Decatherm
EIA	U.S. Energy Information Administration
EPAct	Energy and Policy Act of 2005
FERC	Federal Energy Regulatory Commission
GRC	General Rate Case
HHI	Herfindahl-Hirschman Index
IOU	Investor Owned Utility
ISO	Independent System Operator
LDC	Local Distribution Company
LGS	Lodi Gas Storage, LLC
LNG	Liquefied Natural Gas
Lodi	Lodi Gas Storage, LLC
LPG	Liquefied Petroleum Gas
MMcf	Million cubic feet
NOPR	Notice of Proposed Rulemaking
NSBA	Noncore Storage Balancing Account
OFO	Operational Flow Order
ORA	Office of Ratepayer Advocates (now called Division of Ratepayer Advocates)
OTC	Over the Counter

PG&E	Pacific Gas & Electric Company
PUC	Public Utilities Commission
RTO	Regional Transmission Organization
SCE	Southern California Edison
SCGC	Southern California Generation Coalition
SMA	Supply Margin Assessment
SoCalGas	Southern California Gas Company

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