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Chapter 2

Does California Need Underground Gas Storage to Provide for Energy Reliability through 2020?

ABSTRACT

This chapter addresses whether or not California needs underground gas storage to provide reliability for the near-term, i.e. through 2020. The chapter describes the natural gas transmission and distribution systems that serve California, the current and evolving role of underground gas storage in preserving reliable natural gas and electricity service in California and possible alternatives to underground gas storage that would preserve that reliability. A copy of the scope of work is contained in Appendix B.

1.0 The California Gas System

California's pipeline capacity and underground gas storage facilities give California consumers diverse options for supply and operational flexibility that most states do not have and have successfully served California's natural gas demand requirements except for a handful of instances.¹ Approximately 85% of the gas used in California comes from out-of-

1. The State routinely assesses the adequacy of the pipeline and storage capability relative to demand. For example, the two large gas utilities, Southern California Gas Company (SoCalGas) and Pacific Gas and Electric Company (PG&E), presented a joint assessment to the CPUC in support of accessing new gas supply in 1961 (see CPUC Decision No. 6226). Every two years these utilities continue to present an updated assessment in the California Gas Report (CGR). The California Energy Commission (CEC) conducts assessments and outlooks for natural gas, often in conjunction with its Integrated Energy Policy Report (IEPR), augmented sometimes by the Research and Development Division. The CPUC has also presented various assessments. See, for example, MRW & Associates, "Natural Gas Storage in California," 2007 http://www.energy.ca.gov/research/notices/2007-11-15_workshop/presentations/MRW+associates_NG_Storage_in_CA.pdf (Accessed March 2017). See Also ICF, "The Value of Natural Gas Storage and the Impact of Renewable Generation on California's Natural Gas Infrastructure." CEC Energy Research and Development Division Final Project Report, CEC 500-2013-131, 2009 (Accessed March 2017). And Myers, Khosrowjahi and Hendry "California Natural Gas Infrastructure Outlook," CPUC Energy Division Staff Report November 2001, found at http://docs.cpuc.ca.gov/published/report/natural_gas_report.htm#P679_36190 (Accessed May 2017).

state sources.² Interstate pipelines serving California include Gas Transmission Northwest, El Paso, TransWestern, Kern River, Ruby, Southern Trails, Paiute and Tuscarora pipelines. Figure 1 displays the supply basins and connecting high pressure transmission pipelines that deliver natural gas to California, or that otherwise have an impact on California markets. These supply basins include the Western Canadian Sedimentary Basin in Alberta, the “Rockies” basins centered in southwestern Wyoming, the San Juan basin of northwestern New Mexico, the Permian basin of west Texas and, in years past, even the Texas/Oklahoma Panhandle’s Anadarko basin. Some of these basins are more than 1,000 miles away from California’s key population centers. The pipelines between the producing areas and California also serve markets outside of California. Virtually all the gas that comes into California stays in California, where it is either consumed immediately or put into storage to consume later.

SoCalGas and PG&E serve most, but not all, of the State’s gas consumers. SoCalGas and PG&E own and operate approximately 9,830 miles of high pressure transmission lines inside the State that interconnect with the interstate pipeline delivery points at the southeastern and northern borders of the State. PG&E and SoCalGas deliver gas from the transmission lines to end-use customers through their distribution systems (see Figure 3).^{3, 4}

2. Production occurs in both northern and southern California. The wells in southern California tend to produce primarily oil, with a small amount of hydrocarbon output in the form of natural gas; wells in northern California, in contrast, tend to produce only natural gas.

3. The 9,830 miles is compiled from the 2015 and 2016 Form 10-K reports filed with the Securities and Exchange Commission by Sempra (parent company of SoCalGas and SDG&E) and PG&E, respectively. SoCalGas and PG&E were the largest two natural gas utilities in the U.S., in terms of number of customers. SoCalGas delivered more gas to customers than any other gas utility, while PG&E ranked second (see American Gas Association, Statistics Database 2015 Ranking of Companies, at <https://www.aga.org/sites/default/files/1002totcust.pdf>).

4. Most end-use customers receive gas at the distribution level (which consists of smaller-diameter pipes that operate at pressures of less than 60 psig). Some large customers, however, receive gas from larger pipelines at pressures that qualify as transmission level (i.e., they are larger-diameter pipe that operate at higher pressures). See, for example, Pacific Gas and Electric 2017 Gas Rate Finder, Volume 45-G, No. 4. April 2017. Online: <https://www.pge.com/tariffs/GRF0417.pdf> (Accessed July 2017).

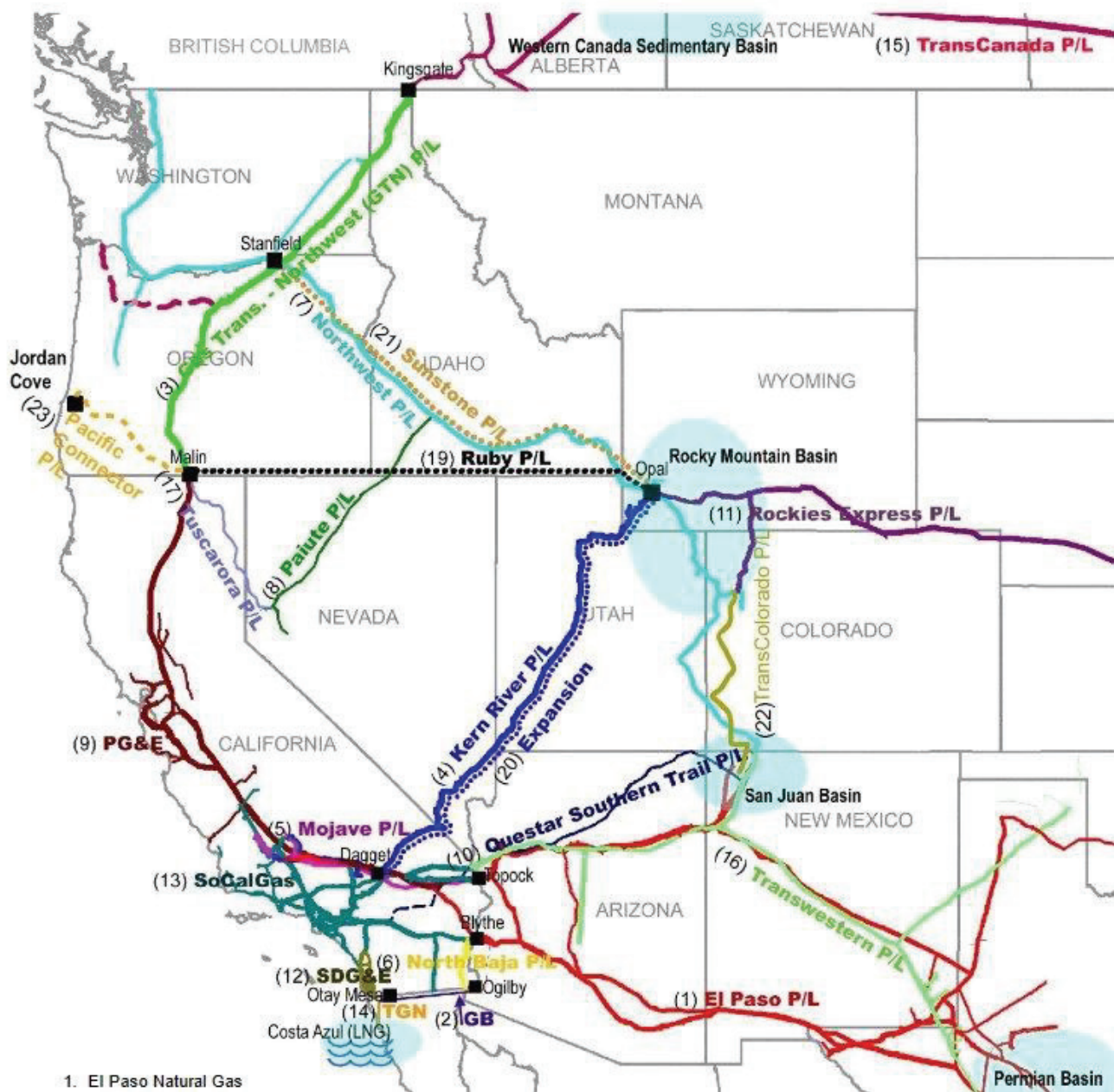


Figure 1. Western Gas Pipelines and Supply Basins Serving California

Source: California Gas Report

Pipelines that come in from the receipt points at the state lines do not all connect to each other within the State.⁵ However, customers can buy gas from any supply area connected by the interstate pipelines to the intrastate system whether or not they have a direct connection to that supply.⁶

The 12 depleted gas or oil fields used to store gas underground are an essential element of the intrastate pipeline and distribution gas delivery systems in meeting peak seasonal natural gas demand in California. With a capacity of 375 bcf, six companies operate these fields pursuant to the Public Utilities Code of the State of California under certificates granted by the California Public Utilities Commission (CPUC). PG&E and SoCalGas each own and operate four facilities comprising approximately 60% of the total storage capacity.

No other state has such a diversity of supply access and storage capability. Through this system, California has the flexibility to augment pipeline gas with stored gas. Local gas distributors in states without storage have to pay for firm interstate pipeline capacity that is used only in peak months or restrict deliveries of natural gas to non-core customers in winter demand months.⁷ And many pipelines are not connected to underground gas storage.⁸ Figure 6 shows the locations of some 400 facilities nationwide that can store over 4,700 Bcf of gas across the country. Additional large gas storage facilities are also located in Ontario and Alberta, Canada.

5. Other aspects of the pipeline system constrain the flow such as the physical capacity of the pipes, flow direction conflicts, constraint points, and lack of interconnection between the pipelines. The direction of physical flow is generally from the state line towards the load centers. Gas from Canada and the Rockies arrives at Malin, Oregon and flows south. Gas from the Rockies can also flow southwesterly from Wyoming towards Las Vegas and enter California there, crossing the Mojave Desert and terminating at Bakersfield. Gas from the San Juan Basin flows in at Topock, Arizona (Needles, CA), from which one pipeline continues on to Los Angeles (LA) and another moves towards Barstow, then Bakersfield and turns north. From there it crosses over to the Highway 101 corridor and terminates at Milpitas. Gas from the Permian Basin flows in at Ehrenberg, Arizona and continues across the desert to Moreno Valley and on into the southern portion of the LA Basin.

6. Customers can buy gas through an “exchange displacement” process which allows a customer located in Redding to buy gas from Texas or a customer in southern California to buy Canadian gas supply. For example, PG&E physically delivers gas from Canada that was purchased by customers of SoCalGas or SDG&E to its customers in northern California. PG&E replaces that gas by delivering to SoCalGas an equivalent amount of gas from the Southwest. PG&E’s displacement capability is limited to the quantity of gas that can be transferred through the Kern River Station.

7. For a long time, Indiana had restrictions on new non-core customers using gas in winter months. Massachusetts is another example. Pipeline tariffs there used to offer a seasonal firm service: firm in summer and interruptible in winter. See also Tussing and Teepee (1995), p. 122.

8. See Aspen’s 2010 “Implications of Greater Reliance on Natural Gas for Electricity Generation,” p. 62, for a list (that may need updating) of pipelines not connected to underground gas storage.

U.S. underground natural gas storage facilities by type (July 2015)

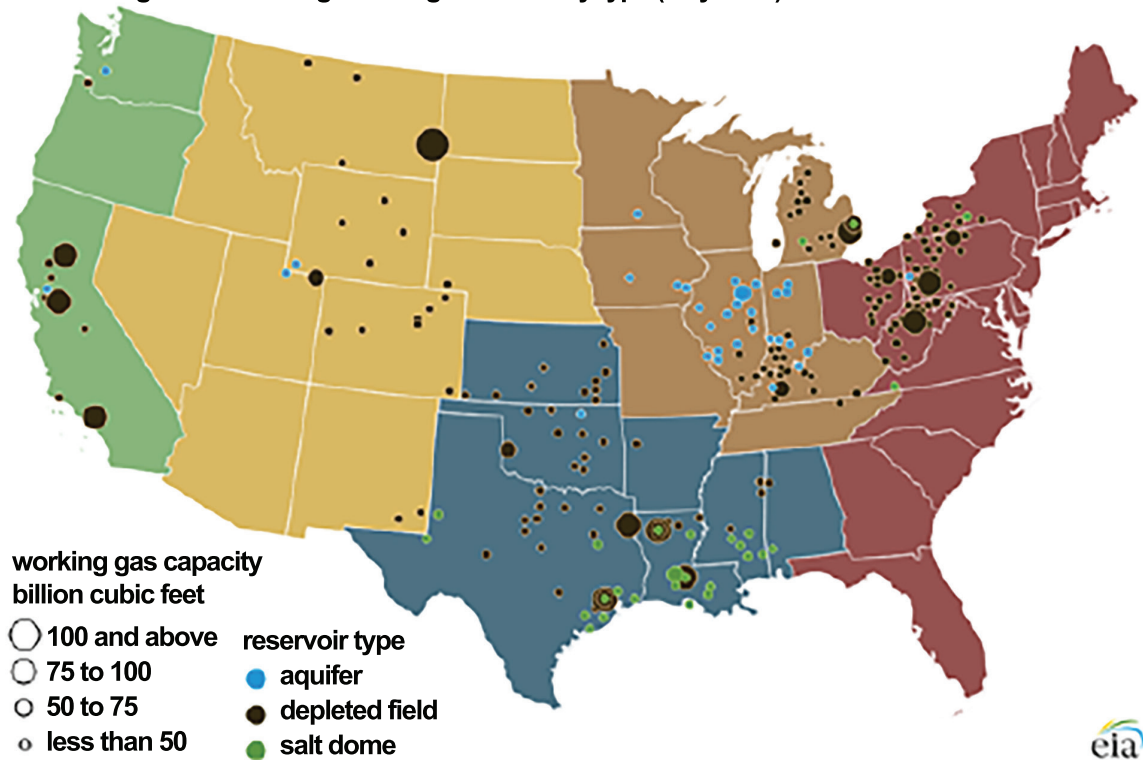


Figure 2. U.S. Underground Gas Storage Facilities

Source: Energy Information Administration

Figure 3 displays the general location of the various in-state underground gas storage facilities relative to the gas transmission system in California. SoCalGas owns all the storage in southern California. PG&E owns some of the storage they use in northern California, but “independently operated” gas storage also plays a role.⁹ The Legislature explicitly encouraged independent gas storage to help create open and competitive markets for storage services. In this respect, gas utilities do not control any aspect of independent gas operations. The Legislature also encouraged unbundling, or separation of storage costs from the rates charged by public utilities for services such as gas transportation or supply sales.¹⁰

9. Several types of companies own natural gas storage facilities, including utilities, pipeline operators, and dedicated storage owners. Some storage facilities are owned by utilities who use them to meet their customers’ needs. The majority of storage facilities in the U.S. are owned and operated by pipeline and independent service providers who lease their use to large end-use customers or third-party shippers.

10. AB 2744 (Costa) Chaptered 1992.

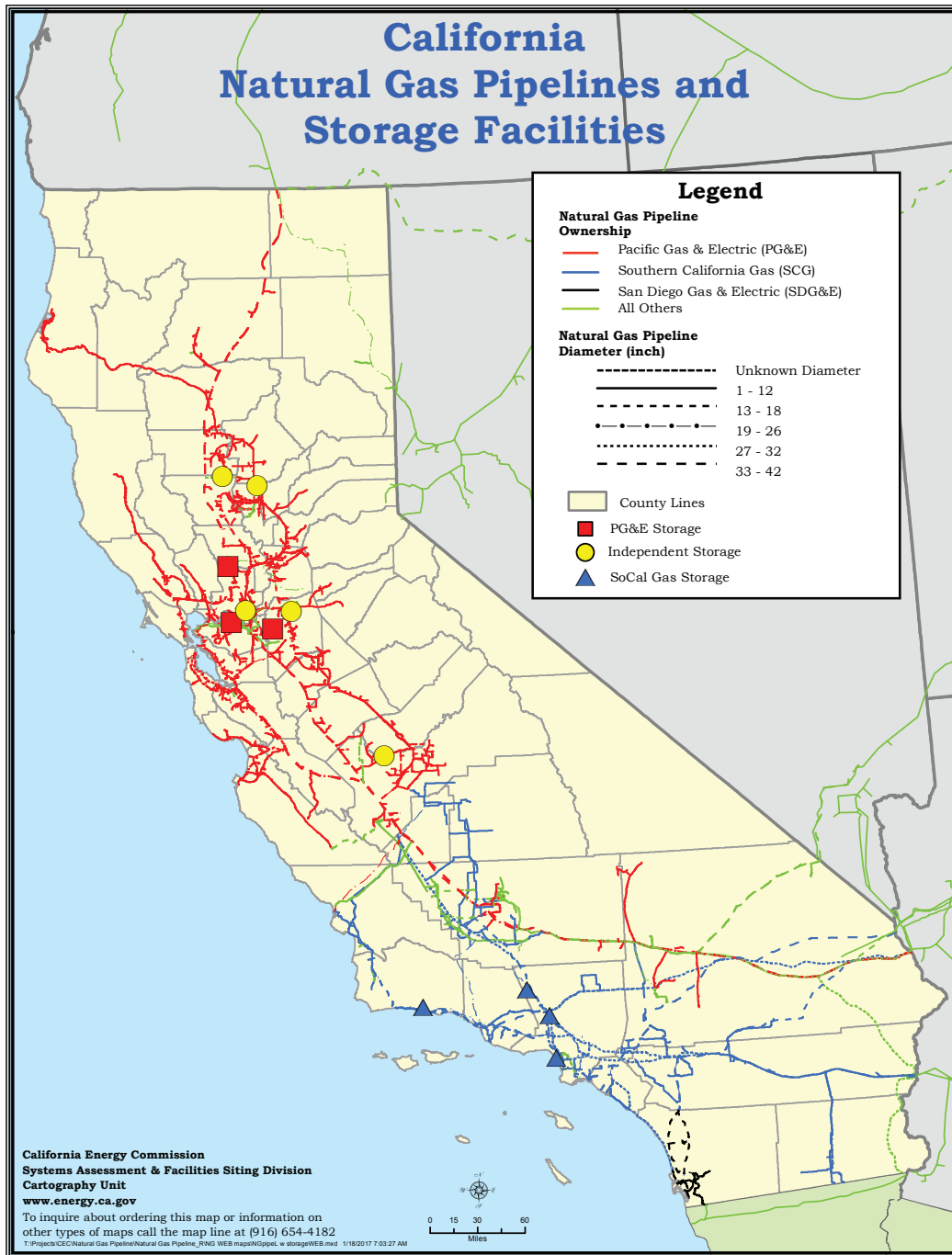


Figure 3. General Layout of California High Pressure Pipeline and Storage Facilities
Source: California Energy Commission

1.0.1 Customer Types

The regulatory framework for the transportation, storage, distribution and sale of natural gas in California separates gas supply service from transportation service and splits customers into core and non-core customers.¹¹ Residential and small commercial customers are deemed “core” customers. The utility provides core customers with gas supplies, transmission, storage, distribution, metering, and billing all “bundled” into one package. The CPUC does not allow the utilities to add any mark-up or profit to the commodity cost of the gas supply. Instead, utilities earn an allowed rate of return, approved by the CPUC, on the physical assets they own, such as pipelines, distribution lines, compressor stations, and storage facilities.¹²

The remaining customers are deemed “non-core.” As defined by the CPUC, non-core customers are those that annually consume a threshold quantity of 250,000 therms of gas annually, which equates to about 25 MMcf (CPUC Decision Nos. 86-12-010 and 90-09-089). Under rules adopted in 1986 and revised in 1990, the CPUC does not permit the gas utilities it regulates to procure gas supply and re-sell it to non-core customers (CPUC Decision Nos. 86-12-010 and 90-09-089). Instead, non-core customers must buy their own gas. The utilities provide non-core customers with transportation service, meaning that the utility simply delivers to the customer the amount of gas that the customer purchased elsewhere.¹³

11. This basic breakdown was adopted by the CPUC in D. 86-12-010 and implemented May 1, 1988. The CPUC regulates rates and the terms of service provided by PG&E, SoCalGas, SDG&E, and Southwest Gas Company. Several municipalities operate gas utilities, including the cities of Long Beach, Palo Alto, and Coalinga. These gas utilities receive transmission service from PG&E and SoCalGas, respectively, depending on their location. SDG&E has a very short summary of the initial implementation and key developments at <http://www.sdge.com/customer-choice/natural-gas/history-gas-choice-and-definitions>.

12. Bills to core customers, nonetheless, typically break out and show the commodity cost of gas supply (that the utility procures on behalf of core customers) separately from the cost of delivery.

13. The CPUC requires transportation service to non-core customers be provided on a non-discriminatory basis. This means that any customer willing to pay the CPUC-approved rate and abide by the applicable tariffs for service must be provided service under those stated terms and conditions. Those terms and conditions also specify rules for prioritizing service when capacity or supply become constrained. More specifically, it means that the utility is not allowed to block market access or discriminate in providing information among market participants. The utility staff that procure gas supply on behalf of core customers (often referred to as the “core procurement group”) are considered to be market participants and thus are sequestered from the transportation operations staff. An information firewall must be maintained between those employees who perform functions related to the distribution business and those employees who are involved with the sale of gas.

Both core and non-core customers have equal access to gas transmission capacity. However, the California gas utilities curtail non-core customers first in the event of a gas supply or a gas capacity shortage for several reasons. First, only core customers are entitled to firm uninterrupted service¹⁴ because of the high cost and safety issues involved in restoring service after a curtailment. The recovery process requires a house to house, block by block effort to purge individual distribution lines and services of any air and water that might have invaded the gas lines during an outage and to relight pilot lights and restart gas appliances. Recovery can take several days depending on the number of customers. Second, the gas delivery system was sized to serve only core customers on a very cold day. Finally, because fewer system costs are allocated to non-core customers, they pay a lower rate for gas transportation service than the rates charged to core customers. The CPUC adopted this framework at a time when non-core customers could burn alternate fuels when natural gas was not available.¹⁵ Now regulatory requirements governing air emissions mean that most large non-core gas customers cannot easily switch to an alternate fuel leaving fewer options to maintain operations. So, while non-core customers are, by definition, interruptible, California essentially provides firm service to all customers.

1.0.2 Gas Flows To and From the Receipt Points

If full, the interstate pipelines that connect to PG&E and SoCalGas can bring 10,360 MMcf to the state line each day.¹⁶ With a few exceptions, these interstate pipelines terminate at the state line where they interconnect with one or both of California's two large local distributors, PG&E and SoCalGas.¹⁷ Most load is served by local distribution companies, but not all; and most decisions about capacity in California are made by the CPUC, but not all.¹⁸

14. "Firm" means never interrupted.

15. This framework goes back to the Natural Gas Policy Act of 1978 that required states to develop end-use priority rules after the gas service curtailments in Midwestern states such as Indiana, Illinois and Ohio during the very cold winter of 1976-77.

16. The industry commonly describes the capacity of a pipeline in terms of what it can deliver in a 24-hour period and describes this as MMcf per day or MMcfd.

17. Gas Transmission Northwest terminates at Malin, Oregon and PG&E takes over. TransWestern Pipeline terminates at Topock, Arizona/Needles, CA and interconnects with PG&E and with SoCalGas there. El Paso Natural Gas' northern mainline terminates at Topock and interconnects there with PG&E and SoCalGas. El Paso's southern mainline terminates at Topock and feeds into SoCalGas (and the North Baja pipeline that can feed Mexico). PG&E and SoCalGas add odorant to the gas at the receipt points where they take the gas from the interstate pipelines.

18. Some customers of Southwest Gas (which has small amounts of non-contiguous service area along the edges of the State and elsewhere) are served via connection from other interstate pipelines, such as those in the Lake Tahoe area served from Nevada via Paiute Pipeline.

^{19, 20, 21} The interstate pipelines serving California are shown in Figure 3.

19. Gas entering the PG&E or SoCalGas systems becomes subject to the regulatory jurisdiction of the CPUC (which has adopted PHMSA DOT 192 as its standard for safety, risk, and pipeline integrity regulation). The CPUC regulates not in addition to, but in lieu of, the Federal Energy Regulatory Commission (FERC). FERC, nonetheless has ways of influencing California. California participates in the rate cases of the interstate pipelines upstream of California. FERC also approves the tariff of the CAISO, which includes treatment of certain aspects of gas cost recovery in electricity markets. The principal of open access, non-discriminatory transportation service that applies under FERC pipeline regulation is similar to that adopted in California.

20. This occurs as the result of a 1954 amendment to 1938's federal Natural Gas Act called the "Hinshaw Amendment." Absent the Hinshaw amendment, one would expect the high-pressure transmission portion of the PG&E and SoCalGas systems to be regulated by FERC as interstate pipelines that would drop off gas to local distribution companies regulated by the CPUC. The Hinshaw Amendment was enacted by Congress after the U.S. Supreme Court ruled that out-of-state gas carried by an intrastate pipeline affiliate of a gas distribution company in Ohio (East Ohio Gas) that delivered all of that gas to the local distribution company (LDC), which then re-delivered it only to the LDC's retail customers, was operating in interstate commerce, and thus subject to regulation under the Natural Gas Act by the Federal Power Commission. With the Ohio situation being analogous to the situation of PG&E and SoCalGas bringing gas from the State line to their retail end-use customers, SoCalGas (then known as Pacific Lighting) turned to southern California House member Carl Hinshaw for legislative relief. The amendment he sponsored exempts a pipeline receiving gas in interstate commerce from FERC regulation if the state regulates the pipeline's rates, services, and facilities and if the gas received is consumed entirely within the receiving state. California's PG&E and SoCalGas meet this two-pronged test of the Hinshaw amendment, namely, the gas that comes in is consumed in California and the rates, services, and facilities are regulated by the CPUC. In federal regulatory proceedings, PG&E and SoCalGas are sometimes referred to as "Hinshaw pipelines." FERC interprets the Hinshaw exemption from federal regulation to be an option exercised at the request of a facility applicant, and not a requirement a state can impose. For example, the Mojave Pipeline and Kern River Gas Transmission (or "Kern River" pipeline) which crosses from Nevada into California and continues on to its terminus around Bakersfield did not seek permission to construct and operate in California from the CPUC. Instead, it sought certification only from FERC and proposed to operate the entire pipeline as a federally regulated pipeline, with that federal status continuing to the pipeline's terminus well into California. Such permission is sought via application for a certificate of public convenience and necessity (CPCN) or simply "certificate." Kern River's certificate was granted by FERC at: CP89-2047-000 et al. (Jan. 24, 1990); Mojave's at 47 FERC ¶ 61,200 (1989).") The CPUC, PG&E, and SoCalGas opposed FERC's granting of Certificate of Public Convenience and Necessity (CPCN) to Mojave and Kern River. While SoCalGas settled with the pipelines, the CPUC and PG&E did not. FERC approved the settlement and granted the CPCNs, leading the California parties to challenge the CPCNs in federal court. The court ruled in favor of FERC and the Kern River. Another example of a FERC-jurisdictional pipeline operating in California is Tuscarora, which interconnects with Gas Transmission Northwest at Malin and crosses the northeastern high desert of California, serving customers in towns such as Susanville, on its way to Reno.

21. Mojave pipeline was a joint venture between El Paso Natural Gas and TransWestern Pipeline to bring southwest gas across the State line and directly serve the enhanced oil recovery (EOR) fields in Kern County. Kern River was a competing project to bring Rockies production to Kern County. Chevron USA, which was both an EOR producer in Kern County and a gas producer in the Rockies, eventually signed on as a shipper with Kern River. Kern River, Mojave and SoCalGas agreed, in a settlement approved by FERC, that both Kern River and Mojave would build from their respective starting points (in different supply basins) to a point near Barstow. At that point, the two pipelines would merge and continue on to the Bakersfield area. The agreement gave SoCalGas an option to purchase the California portion of Kern and Mojave 20 years after startup, which would have been 2013. EPNG bought out Enron's share of Mojave in 1993.

Table 1. Interstate Pipelines Serving California.

Pipeline	Firm Capacity (MMcfd)	Year First Online*
Gas Transmission Northwest	2,090	1961 ¹
El Paso Natural Gas Company	3,770	1948
TransWestern Pipeline Company	1,185	1960
Kern River Gas Transmission	1,735	1992 ²
Ruby Pipeline	1,500	2011
Southern Trails	80	2003 ³
SubTotal Connected to PG&E and SoCalGas*	10,360	
Additional Pipelines Serving Outlying Areas		
Paiute Pipeline Company	41	1988 ⁴
Tuscarora Gas Transmission Company	230	1995
GRAND TOTAL⁵	10,631	

- 1 Originally known as Pacific Gas Transmission; constructed and owned by PG&E. PGT was sold to TransCanada Pipelines Limited in 2004. See http://www.csrreport.transcanada.com/docs/Investor_Centre/aif_2005_TCPL_eng.pdf (Accessed March 2017).
- 2 Kern River Gas Transmission was originally a partnership between the Williams Companies and Tenneco. It was sold to Berkshire Hathaway in 2002.
- 3 Southern Trails was purchased by Questar from ARCO in 1998. Then known as ARCO's Line 90, it was constructed in 1957 as an oil pipeline and ran from the Four Corners area to Long Beach. Questar intended to convert it to natural gas service for its entire length, hoping to pick up load that sought alternatives to SoCalGas. SoCalGas and others argued the "bypass" of its facilities would be uneconomic, leading the CPUC to approve SoCalGas tariffs that effectively penalized customers who took service from Southern Trails if they also maintained a connection to SoCalGas. Effectively killing the intended market, Questar ultimately converted only 488 miles. Southern Trails interconnects with SoCalGas at North Needles and terminates at Essex, California with an interconnection to PG&E. Questar's website states its intention to sell the remaining mileage by the end of 2017. See <https://rbenenergy.com/taxonomy/term/1626/feed>; <https://www.gpo.gov/fdsys/pkg/FR-1999-03-22/html/99-6839.htm>; <http://www.prnewswire.com/news-releases/questar-pipeline-completes-purchase-renames-line-90-pipeline-77523932.html> and <https://www.sec.gov/Archives/edgar/data/764044/000091205702012527/0000912057-02-012527.txt> (pp. 5-6) for more on this pipeline over the years.
- 4 Paiute crosses from Nevada to serve the Lake Tahoe area; it does not connect to PG&E or to SoCalGas.
- 5 The grand total shown includes capacity that enters or crosses California (Paiute and Tuscarora) but serves load such as that in Reno, it is therefore generally excluded from the remainder of this analysis.

Source: Compiled from various sources by Aspen Environmental Group

History of SoCalGas, CPUC Decision No. 62260, FERC Calendar Files

* The first year online is very close to date of original construction; additional facilities may have been added later.

Although the interstate pipelines can deliver 10.3 Bcf per day to the state, PG&E and SoCalGas do not have the capacity to receive and transport that much gas to their load centers. Table 2 shows the amount these utilities can receive, known as "receipt point capacity" or "take-away capacity."

As of 2017, PG&E can take a total of slightly over 3 Bcf per day through a system of high pressure transmission lines connecting to receipt points at Malin, Kern River Station, and Topock. In theory, SoCalGas can take 3.875 Bcf per day, but various factors reduce this amount. For example, SoCalGas has voluntarily reduced the operating pressure on its Line 2000 that runs from Ehrenberg through Moreno Valley into the southern part of the LA Basin until it completes hydrostatic testing of the pipeline.²² This lower operating pressure reduces Line 2000's effective transportation capacity by 200 MMcfd, as captured in Table 2. Also, although SoCalGas has the pipeline capacity to take a total of 310 MMcfd from California natural gas producers located along the coast or in the San Joaquin Valley, production from those sources has declined, and recently only about 60 MMcfd has been delivered for sale to utility customers. Utility forecasts and producers do not cite any expectation for recovery and consequently, this analysis discounts the capacity down to the expected supply. In calculating the rate that gas can be delivered in California, we use the take-away capacity unless the available supply at any receipt point is consistently and significantly less than that capacity.^{23, 24, 25}

22. Required under the post-San Bruno remediation measures. SoCalGas' Envoy system lists the end date for the voluntary maximum operating pressure as "TBD."

23. The CEC's 2015 Natural Gas Outlook projected that California natural gas production would continue to decline. The 2016 California Gas Report used 122 MMcfd, stating it was the average supply delivered to it from California sources in 2015 (2016 CGR, p. 79). The Joint Agency technical assessments use 60 MMcfd. An analysis of scheduled quantities reported on SoCalGas' Envoy web site supports use of the 60 MMcfd.

24. SoCalGas also has work on its Line 3000 at Topock that further reduces its take-away capacity by about 250 MMcfd. This situation should be short-term and is not therefore reflected in the adjusted estimate of 3.425 MMcfd in take-away capacity.

25. Additionally, Kern River delivers gas directly to end-users, many of which are located in Kern County in addition to making deliveries to PG&E's Line 300 and to SoCalGas' Line 225 at Wheeler Ridge (or at Kramer Junction, into the main line coming in from Topock) (Kern River Gas Transmission Company, 2015). Reflecting typical deliveries to PG&E and to SoCalGas, the net remaining capacity delivering gas directly to end users should be close to 835 MMcfd. The exact value for what Kern River delivers to California may decline over time as upstream markets use more of Kern River's capacity; data in their 2017 customer meeting presentation shows that is already happening. The customer meeting presentation can be found at: <http://services.kernrivergas.com/portal/DesktopModules/KernRiver/Documents/ViewDocument.aspx?DocumentID=271> (Accessed April 2017).

Table 2. Take-Away Capacity at Gas Utility Receipt Points.

Gas Utility Receipt Point	Maximum	Adjusted*
	(Bcfd)⁶	(Bcfd)
SoCalGas ⁷		
California Line 85 Zone	0.16	0.060
California Coastal Zone	0.15	0
Wheeler Ridge Zone	0.77	0.77
Southern Zone	1.2	1.0
Northern Zone	1.6	1.6
SoCalGas Subtotal	3.9	3.4
PG&E		
Redwood Path (Line 400/401)	2.0	1.9
Baja Path (Line 300)	1.0	1.0
CA Production	0.039	0.039
PG&E Subtotal	3.1	2.9
Direct Delivery ⁸		
Kern River/Mojave	1.2	1.2
TOTAL	8.1	7.5

7 Maximums reported for SoCalGas found in the 2016 California Gas Report, p. 82.

8 This should include the very small amount delivered via connection from Paiute Pipeline into Lake Tahoe.

Source: Compilation by Aspen Environmental Group

2016 California Gas Report, Wood, Natural Gas Infrastructure, 2009

** The adjusted figures are a better representation of the firm delivery capability than the maximums.*

All told, the take-away capacity of PG&E and SoCalGas, taking into account direct deliveries by Kern River within the state, is 7.5 Bcfd making the working capacity of the state's storage fields critical in meeting gas peak requirements of 11.8 Bcfd (see Conclusion 2.3). Any significant increase in take-away capacity would require building new pipelines in California.

This combination of multiple pipelines into the State coming from diverse supply basins²⁶ combined with the seasonal and hub services allowed by underground gas storage located near the load centers, make California different from any other natural gas market or system in the U.S. For example, California stands in stark contrast to the U.S. northeast which has historically relied on gas produced and transported from the Gulf Coast. The two pipelines that bring Canadian gas (Iroquois and Maritimes & Northeast) to the northeast are not connected to storage.²⁷ The closest analog to California's gas system might be Union Gas in Ontario, Canada, with its vast storage facilities near Windsor, but even Union Gas does not have the diversity of supply sources and pipeline options as California. Safety notwithstanding, California's access to underground gas storage near its load centers makes it the envy of the nation's natural gas market.

The Working Capacity of a Storage Field

The "working capacity" of a storage facility or inventory shown in Table 3 reflects the quantity that can be injected and withdrawn from the field.²⁸ California has 375 Bcf of working capacity to hold natural gas underground using 12 individual facilities. Working capacity calculations exclude what is known as "cushion gas" which is simply natural gas that is held in the field (not produced) and serves to maintain pressure in the reservoir to drive working gas out. Section 1.1 in Chapter 1 contains detailed information about each storage facility and its key characteristics.

26. Basins supplying California include Alberta's Western Canadian Sedimentary Basin, the Four Corners Area's San Juan basin, west Texas' Permian basin, the Rockies, and in years past even the Texas/Oklahoma Panhandle's Anadarko basin.

27. It takes three days for stored gas to go from far western New York or Pennsylvania to the northeast.

28. Under normal conditions operators do not withdraw cushion gas because the pressure decline associated with withdrawal can allow water to invade what was previously gas-filled pore space and consequently decrease gas storage capacity. Furthermore, the long residence time of cushion gas in the reservoir allows it to mix and entrain residual hydrocarbon components. Operators may have to process these components out of the gas in order to reach the pipeline quality required by utility tariffs. Both conditions can take time to correct in order to restore the reservoir to full working capacity.

Table 3. Underground Gas Storage Working Inventory Capacity.

	Working Capacity (Bcf)	Maximum Withdrawal Capacity⁹ (Bcfd)
U.S.	4700	
California	370	
Utility-Owned & Controlled	240	5.9
PG&E	100	2.2
SoCalGas	140	3.7
Independently Owned	130	2.7

⁹ Maximum withdrawal capability is achievable at full field inventory. As inventory declines, so does deliverability. Decline is not linear but depends on field configuration, including number of wells. These values do not reflect the impact of DOGGR's new rules that allow withdrawal only through the inner tubing instead of tubing plus well casing. The value of the utility-owned facilities also includes 1.8 Bcf for Aliso Canyon.

Source: EIA, U.S. Field Level Storage Data CEC 2003 Natural Gas Market Assessment

1.0.3 General Natural Gas Demand Levels

The natural gas market in California represents about 8% of the nation's total, or on average close to 6 billion cubic feet (Bcf) per day. Only Texas consumes more natural gas than California. Energy Information Administration data indicates California's annual share of the nation's natural gas market has ranged as high as 10% over the last 20 years (EIA 2017 U.S. Total Natural Gas Consumption). In terms of per capita gas use, California's gas consumption ranks about 23rd (StateMaster.com, 2001).

Figure 5 shows the annual demand for the U.S. and California. The use of natural gas across the U.S. has increased in recent years mostly due to low natural gas prices and new or proposed environmental regulations causing electricity generators to move away from coal. Some of the demand increase did come from industrial demand for gas, with a small increase in residential and commercial demand. In contrast, California's use of gas has remained level partly because the State did not have much coal-fired electricity to begin with.

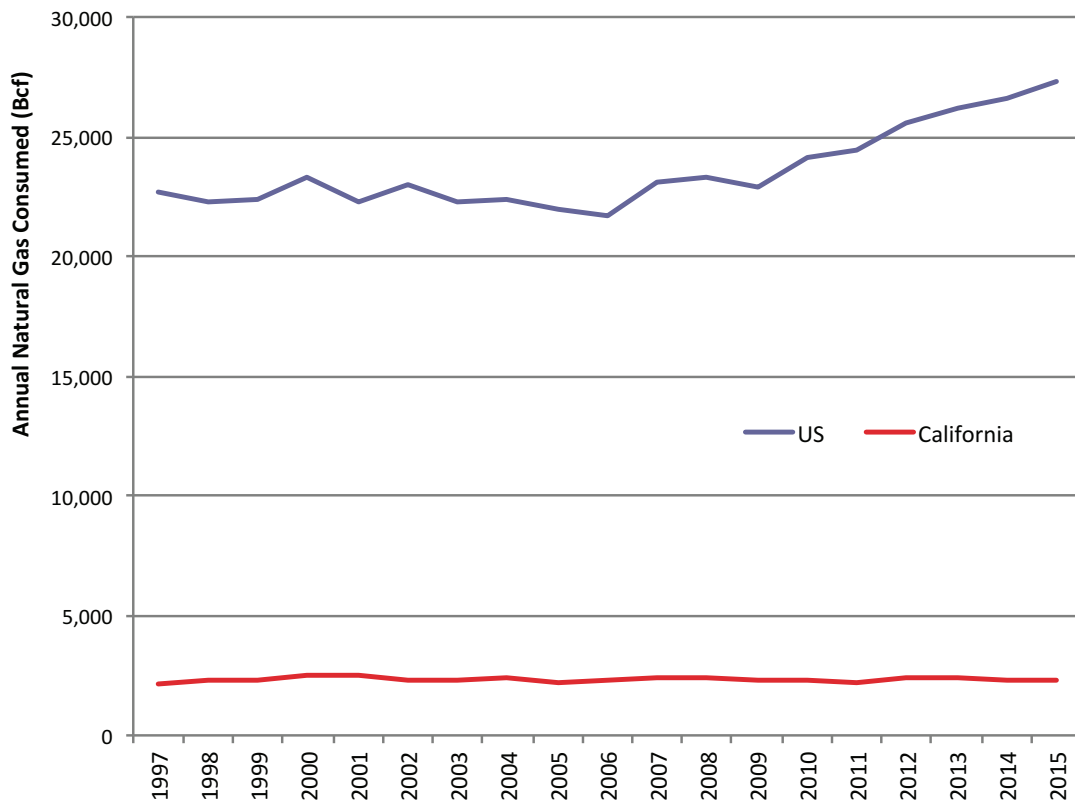


Figure 5. U.S. and California Annual Natural Gas Demand

Source: U.S. Energy Information Administration, Natural Gas Annual

Historical data illustrates how California's natural gas demand varies by month. As shown in Figure 6, California's demand for gas peaks in winter with higher use of natural gas for space heating in those cooler months. In some years, demand peaks in December and in other years it peaks in January. In most years, an intermediate, lower peak occurs in summer. This intermediate summer peak reflects use of gas by electric generators. The late summer fall-off in hydro-electric generation and higher temperatures resulting in a demand for air conditioning cause the summer peak. The drought conditions from 2010 to 2014 exacerbated the summer peaks, whereas somewhat milder summers and an increase in renewable generation in 2015 and 2016 resulted in smaller summer peaks. Weather explains most of the year-to-year variation, due both to changes in heating-degree days in winter and cooling-degree days in summer.

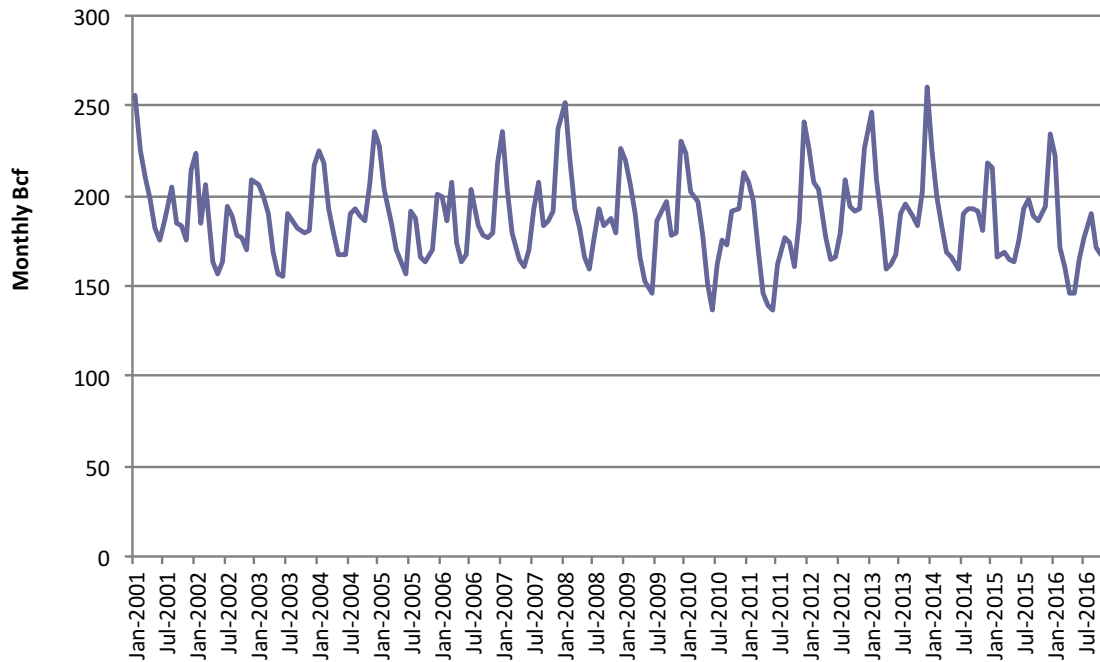


Figure 6. California Natural Gas Demand by Month: 2001–2016

Source: U.S. Energy Information Administration, Natural Gas Monthly

Figure 7 breaks monthly demand out, stacking it by customer class. Industrial and commercial class demands vary by month but are relatively flat in comparison to residential and electric generation (EG) demand. Figure 8 breaks this down further to focus on just core and EG total monthly demand. Individual days would show even more extreme peaks. The figure makes it easier to see the winter peak in core customer demand and the summer peak in EG. Note the low electric generation in spring 2011 caused by late spring precipitation, which increased the amount of hydropower available and forestalled use of natural gas until the hydro run-off had been used.

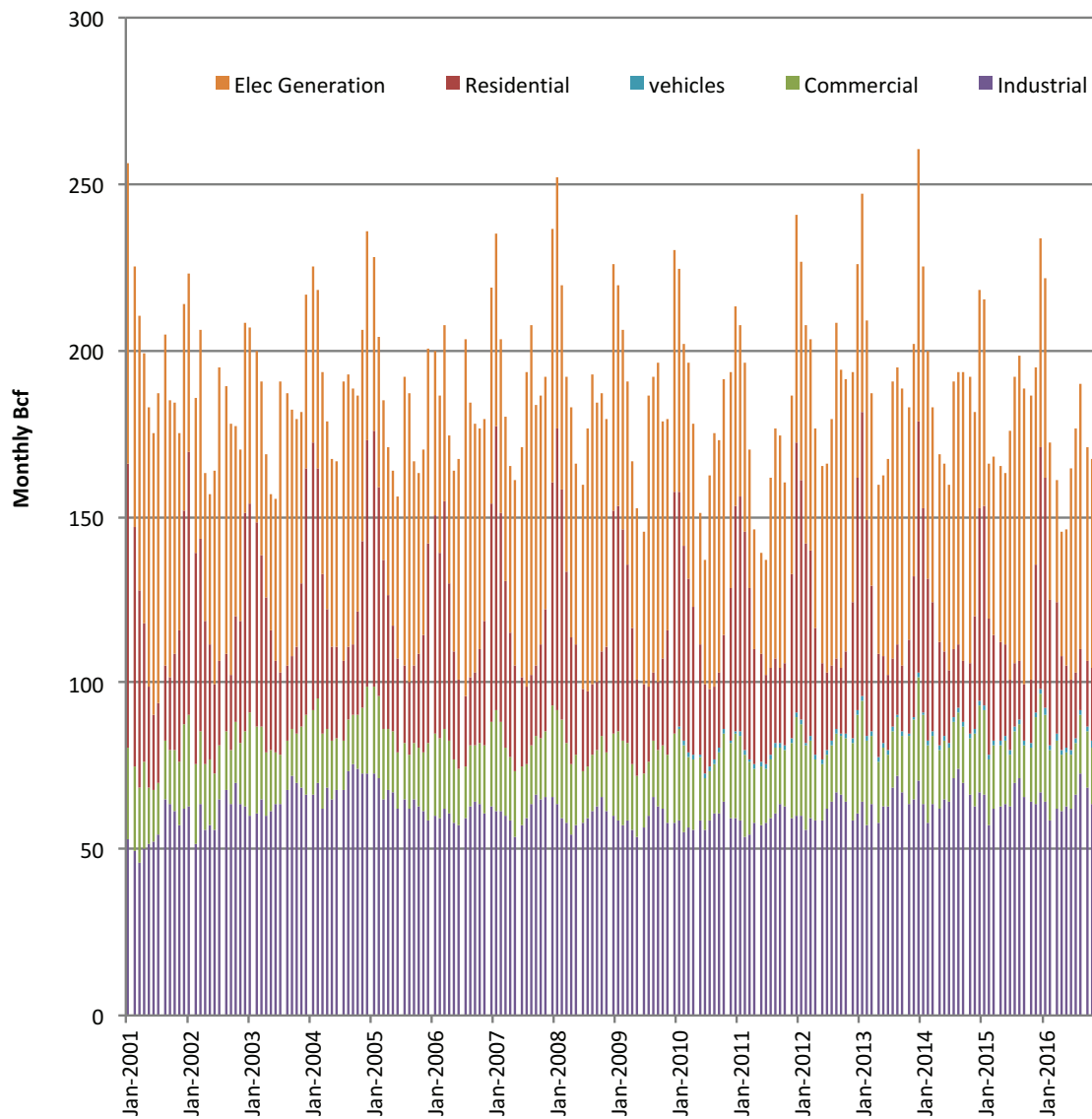


Figure 7. California Monthly Average Natural Gas Demand by Class
Source: U.S. Energy Information Administration, Natural Gas Monthly

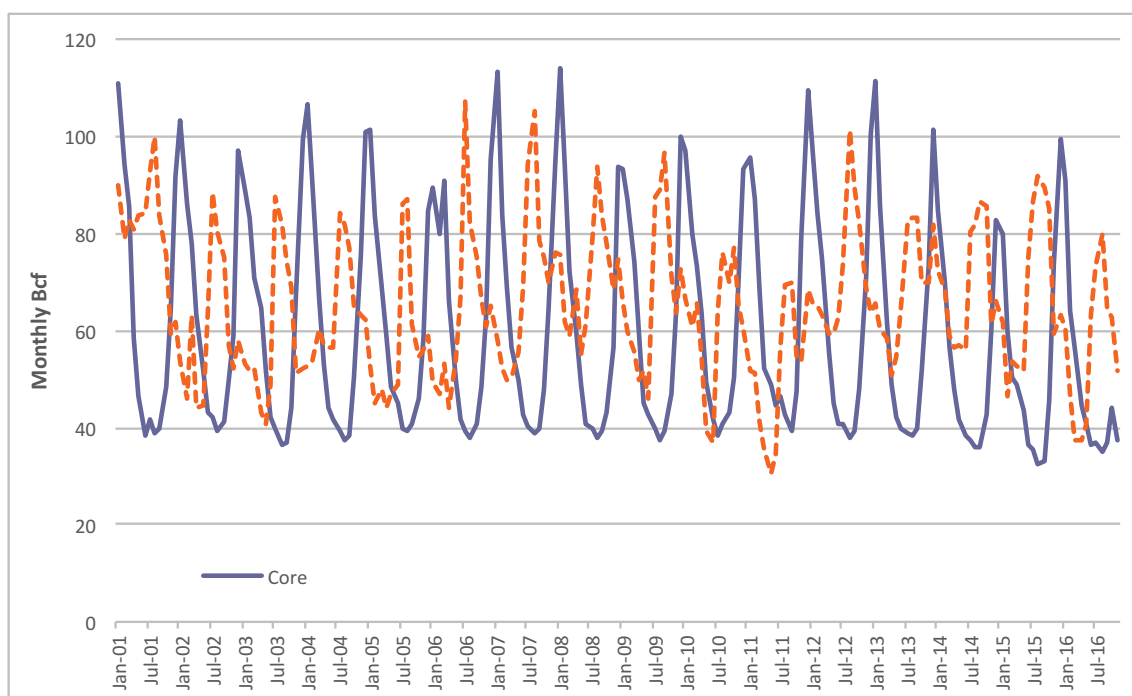


Figure 8. Core and EG Demand by Month

Source: Aspen Analysis of EIA Monthly Demand Data

1.0.3.1 Expectations for Future Gas Demand

The utilities predict that statewide total natural gas demand will decrease significantly in the next 15 years. Table 4 provides the latest publicly-available forecasts prepared by the utilities. These project average daily demand in both average (normal) and cold, dry-hydro years to decline by more than 0.7 Bcf per day by 2020. That would be an 11.5% decline from 2016's forecasted demand for an average temperature year. The decline by 2030 is double that (1.4 Bcf per day), representing a 23% drop relative to 2016. The utilities attribute the forecasted decline to "aggressive energy efficiency," meaning more efficient power plants and policies are anticipated to acquire and prefer zero- or low-carbon generation alternatives.

Table 4. Gas Utility Demand Forecasts.

	2016	2020	2025	2030	Projected Decline from 2016 to 2030
Condition	(Bcf/d)				
Average Temperature and Normal Hydro	6.1	5.4	5.0	4.7	-1.4
Cold Year and Dry Hydro	6,774	5,978	5,853	5,363	-1,411

Source: 2016 California Gas Report

These demand forecasts may not capture all the factors that will affect overall gas demand. At a 2017 IEPR workshop, CEC Chair Weisenmiller noted that the retirements of California's San Onofre and Diablo Canyon nuclear units will cause an increase in forecasted gas demand (CEC, 2017a). The nuclear units are expected to be replaced by a mixture of resources with 50% or more to include energy efficiency and demand response, energy storage and renewables- in the case of San Onofre.²⁹ In a workshop one day prior to the 2017 IEPR workshop, CPUC staff cited 9,380 MW of gas-fired generating capacity expected to retire by 2022 (Kito, 2017). This figure excludes another 2,839 MW of gas generation owned by Los Angeles Department of Water and Power (LADWP) that must also retire due to the State Water Resources Control Board's (SWRCB) rule to eliminate once-through cooling (Los Angeles Department of Water, 2016). Retiring units are older, with higher heat rates than newer generation, meaning that they consume more natural gas in each hour they operate relative to newer units. Staff further cited the growth of Community Choice Aggregations (CCA), which promise consumers cheaper and greener renewable sources. This shift, ostensibly, would further reduce use of gas-fired generation and may not be captured by production cost dispatch projections that are used to project the gas-fired generation burn.

Utilities are finding that some gas-fired power plants are being dispatched (i.e., operate) too seldom to accrue sufficient operating revenue to be profitable.³⁰ Some generators have threatened to pull their equipment and move it out of California, a seemingly extreme and unlikely response, but it demonstrates the frustration among independent generators and suggests a confirmation of the reduction in natural gas demand for electric generation as California increasingly shifts to renewables. This change is also unlikely to be captured in the demand forecasts and is another indicator overall future California gas demand will decline.

Finding: While forecasts suggest falling total gas demand out through 2030, none of the forecasts break out how much gas might be necessary to firm intermittent renewable generation and the timing of that need, factors which can affect the need for gas storage.

29. See "Preliminary Reliability Plan for LA Basin and San Diego," August 2013. See also "Joint Proposal for the Orderly Replacement of Diablo Canyon Power Plant with Energy Efficiency and Renewables" (CPUC et al., 2013).

30. One example of this is Calpine's Sutter power plant. See <http://www.powermag.com/calpine-to-take-uneconomic-ccgt-plant-offline-in-calif/> (Accessed May 2017).

1.1 What is the role of gas storage in California today?

Storage serves both physical balancing and financial roles in California today. The roles are listed in Table 5 and described in further detail below.

Table 5. Functions of Underground Gas Storage in California.

Function	Short Description
Physical balancing of supply and demand functions	
Monthly Winter Demand	Storage provides supply when monthly winter needs exceed the available pipeline capacity.
Flat Production	Storage sustains flat aggregate natural gas production.
Winter Peak Day Demand	Storage provides supply when winter peak day demands exceed pipeline capacity.
Intraday Balancing	Storage provides intraday balancing to support hourly changes in demand that the receipt point pipelines cannot accommodate. This service is essential in allowing the flexible use of gas-fired electricity generators to back up renewable generation.
Stockpile	Storage provides an in-state stockpile of supply in case of upstream pipeline outage or other emergency such as wildfires.
Financial functions	
Seasonal Price Arbitrage	Storage allows savings through seasonal price arbitrage (winter prices are usually, but not always higher than summer prices).
Liquidity/Short-term Arbitrage	Grants marketers a place to hold supply and take advantage of short-term prices for liquidity and short-term arbitrage.

Source: Aspen Environmental Group

1. Monthly Winter Demand

The first function of storage in meeting seasonal demand is easy to visualize. Once gas wells are completed and begin production, they produce at an ever-declining rate. New wells must be drilled to offset that decline. Consequently, natural gas production tends to be relatively flat over a year and flat over a day. Against this flat production, demand varies by season. In its simplest form, the difference between production and demand is injected into storage in the summer months and withdrawn from storage in the winter months. Using storage in this manner positively affects pipeline utilization rates by using pipeline capacity more efficiently and cost-effectively. Figure 9 illustrates this generic use of storage.

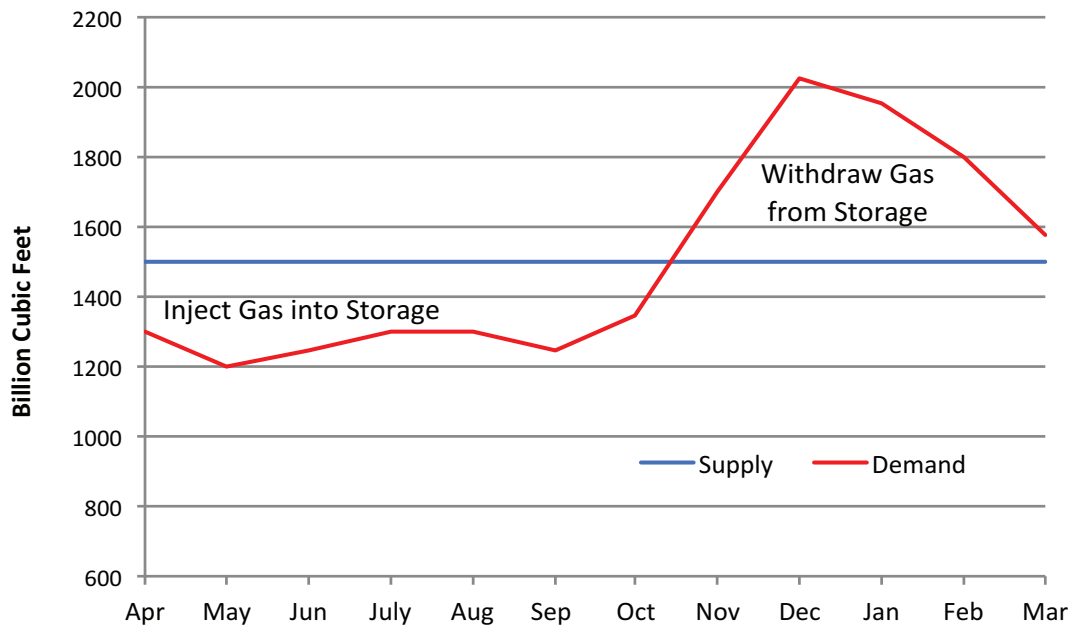


Figure 9. Stylized Illustration: Using Storage to Manage Variable Demand Against Flat Supply³¹

Source: Aspen Environmental Group

This stylized illustration depicts in conceptual terms the way California uses gas from underground storage to meet the portion of winter demand for which we chose not to build pipeline capacity.

A 1959 CPUC decision marks the conscious choice to use underground gas storage and approves PG&E's acquisition and conversion of the gas field at McDonald Island from natural gas production to underground gas storage:

To make such long-distance transmission projects economically feasible, it is necessary that the transmission pipeline be operated at as high a load factor as possible, resulting in a fairly constant flow of gas in large quantity at all times during the year. On the other hand, the gas requirements for applicant's system are subject to large seasonal, weekly and daily fluctuations. After engineering and economic studies, applicant has concluded that the most feasible way of attempting to equate these opposing requirements of supply and usage is to store gas in underground depleted or partially depleted gas fields during periods of low demand and to withdraw gas therefrom during system peak demands and other periods of large usage (CPUC Decision No. 58706 1959).

31. Values selected for purposes of illustration; actual supply, demand and daily injection and withdrawal rates vary from these stylized monthly averages.

Building storage costs less than building pipeline capacity to meet peak demand because the incremental pipeline capacity to meet peak demand would only be used on a peak day. This would have resulted in paying for capacity that is only used once in a while.

In-state storage provides better economics than new pipeline capacity.

Figure 10 compares average daily demand for each month to California's total 7.5 Bcfd pipeline take-away capacity as determined in Table 2. This total pipeline take-away capacity would be the maximum daily demand that can be served without access to some sort of supplemental gas supply.

Finding: Nearly every winter has a month with average daily demand that exceeds, or nearly exceeds, pipeline take-away capacity.³²

Conclusion 2.1: Without gas storage, California would be unable to consistently meet the winter demand for gas.

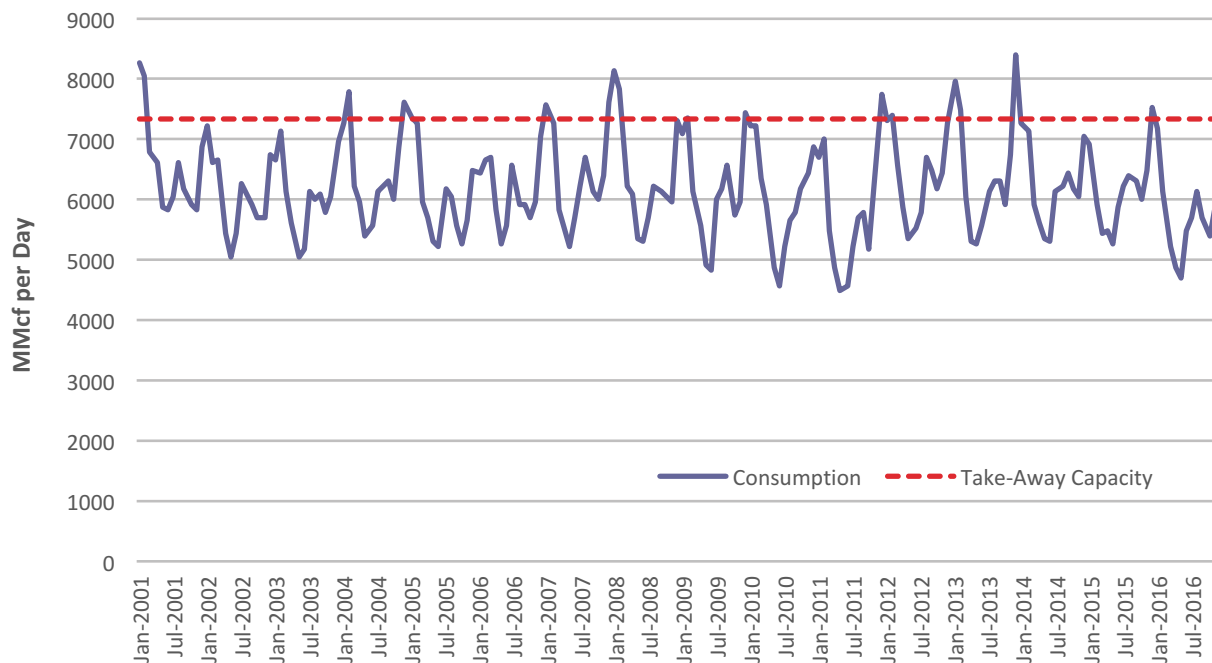


Figure 10. Average Daily Gas Consumption by Month Vs. Take-Away Capacity

Source: Aspen Environmental Group

32. Gas operators like to maintain a margin, or headroom, between what their system can do versus maximum demand. This accommodates unplanned outages as well as under-forecasts of maximum demand.

2. Sustaining flat aggregate wellhead production

Gas production rates also limit the rate of gas imports to California. Gas producers who serve California do not have to modify production patterns to follow load and would object to such a requirement.

Conclusion 2.2: If California had no gas storage, the burden of allowing relatively constant gas production to match to seasonally varying demand would shift to production and storage located more than 1,000 miles upstream from California.

No study has been found that contemplates such a scenario.

3. Winter Peak Day Demand

Gas storage bridges the gap between average daily consumption in winter months and the swing up to peak day demand, sometimes called a “needle peak.” A 2001 report by the California Assembly’s Subcommittee on Natural Gas Costs and Availability found, “[t]he natural gas pipeline system is not able to supply enough natural gas to meet peak system requirements. Therefore, stored natural gas must be withdrawn to supplement the pipeline supplies to avoid service interruption” (Canciamilla, 2001). At that time, historical winter peak demand was 5,300 MMcfd relative to SoCalGas’ pipeline deliverability of 3,500 MMcfd.

The utilities in the California Gas Report (CGR), describe their highest winter and summer sendouts for each of the last five years.³³ These are shown in Table 6. The highest recorded total demand in the recent five-year period is 11,157 MMcfd. This occurred on December 9, 2013. The second-highest was 9,423 MMcfd, occurring on December 19, 2012. Meeting these levels of demand without using underground gas storage (and all else equal) would require building 4,000 MMcfd of new pipeline capacity and associated compressor stations and equipment.

Data presented in the CGR demonstrates times that California’s intrastate pipeline take-away capacity is inadequate to meet summer peak day needs. The highest summer day sendout recorded by the utilities (including deliveries to customers directly served by Kern River) in the last five years was 7,801 MMcf per day. This occurred on August 13, 2012. 2015’s September 10 was not far behind, at 7,795 MMcf per day. California’s 7,511 MMcfd total pipeline take-away capacity is insufficient to serve that level of demand.

33. Daily data can also be pulled from PG&E and SoCalGas’ public web sites, long known as “bulletin boards” in the industry, which exist for the purpose of providing gas market participants with information to increase market transparency. No known source collects daily utility demand data independent of the gas utilities. This makes sense, as the utilities are the only entity that can measure system sendout and therefore would be the ultimate source of such data.

Good planning requires forecasting peaks, not just using recent recorded peaks. California's utilities plan to a forecast because they cannot know exactly what weather conditions will occur in any given year. If the utilities plan only to meet recent peaks, they run the risk that more extreme conditions will occur and we will not have adequate capacity to serve demand under those more extreme conditions. Looking only at the recent past ignores this critical statistical information. The CGR contains the gas utilities' forecasts of demand by year to 2022 and then every five years out to 2035. For 2020, PG&E and SoCalGas together show 9,068 MMcfd for a winter peak day sendout which is more than can be served with the intrastate take-away capacity of 7,500 MMcfd (7.5 Bcfd). For summer in 2020 they forecast 5,265 MMcfd peak day sendout. Adding in the load served directly by Kern River results in a summer peak forecast of 6,446 MMcfd which appears servable with current intrastate take-away capacity.

For winter, we show two figures: they differ with respect to the relative level of severity assumed to drive core customer loads. SoCalGas' peak day reflects core customer load resulting from a 1-in-35 year cold experience, meaning that the forecast reflects the highest number of heating degree days expected to occur once every 35 years.³⁴ This 1-in-35 year occurrence is the design standard to which SoCalGas' local transmission and distribution system is built, to which the CPUC has assented on numerous occasions. Both of the winter forecasts in Table 6 use the 1-in-35 condition to calculate core load for SoCalGas.

For PG&E, Table 6 shows the two different forecasts used for planning and cost allocation: a 1-in-10 (for both core and non-core) and the 1-in-90 that captures higher core load. The difference between the two demand conditions for PG&E's core load is about 7 degrees Fahrenheit in the system composite temperature (calculated at six weather sites) which increases core demand by approximately 570 MMcfd. For non-core customers, the load forecast is always calculated using the less extreme 1-in-10 weather condition.

Because the size of the intrastate pipelines limits California's ability to import gas, 4,334 MMcfd of peak daily demand cannot be met (Table 6). Recall Table 1 showing that interstate pipeline capacity to California of 10.6 Bcfd and Table 2's derivation of an adjusted take-away capacity equal to 7.5 Bcfd. Even if the interstates were full to the California state line (and the odds of that happening on a peak day are probably low), California has no way to get that gas from the state line to the state's gas consumers. Interstate pipeline capacity cannot meet the more extreme winter peak that includes the 1-in-90 demand criterion for PG&E.

34. A heating degree day is the difference in degrees Fahrenheit between the actual temperature experienced and a benchmark temperature of 65 degrees.

Table 6. State-wide Peak Day Demand Deficit Relative to Intrastate Pipeline Take-Away Capacity.

Date	Pipeline Capacity	Demand =	Deficit
	(Bcfd)		
Recorded			
August 13, 2012	7.5	7.8	-0.3
September 10, 2015	7.5	7.8	-0.3
December 9, 2013	7.5	11.1 ¹⁰	-3.6
December 19, 2012	7.5	9.4	-1.9
Forecast			
Cold Temperature Dry Hydro Year (Average Day)	7.5	6.0	surplus
Total Winter Peak Day 2020: • PG&E 1-in-10 for core and non-core • SoCalGas 1-in-10 for non-core and 1-in-35 for core • Direct serve load	7.5	10.2	-2.7
Total Winter Peak Day 2020: • PG&E 1-in-90 core and 1-in-10 for non-core • SoCalGas 1-in-35 for core and 1-in-10 for non-core • Direct serve load	7.5	11.8	-4.3
Summer 1-in-10 Peak Day 2020 + Direct Serve	7.5	6.4	surplus

10 Of this, 4,836 MMcfd occurred on the PG&E system (see Pipe Ranger archives for date) and 5,011 MMcfd on SoCalGas (see Envoy archives for date). This leaves 1,310 MMcfd of direct-served load to reach the 11,157 statewide total shown.

Source: Aspen Environmental Group. Sendout taken from 2016 California Gas Report.³⁵

Table 7 breaks the forecasted deficit out between PG&E and SoCalGas. PG&E appears to have a larger deficit in winter than SoCalGas when looking at its more extreme 1-in-90 peak day. By 2020, both distributors appear to have surpluses available to meet summer 1-in-10 peak day demand.

35. Demand on the reported dates from 2016 CGR, p. 53: "Statewide Recorded Highest Sendout." Peak day demands for SoCalGas are 1-in-35-year occurrence from p. 93. The 1-in-10 for PG&E comes from p. 53 and the 1-in-90 comes from p. 52. The Direct Serve load of 1,181 MMcfd comes from p. 21's "Statewide Annual Cold Temperature/Dry Hydro Requirements" table. The direct serve load is largely for EOR cogen so logically it should not vary with temperature.

Table 7. Forecast Peak Day Capacity Deficit Breakdown: PG&E versus SoCalGas
(does not include the direct serve component included in Table 6).

	PG&E			SoCalGas			Total Utility
	Pipeline Capacity	Demand	Deficit	Pipeline Capacity	Demand	Deficit	Total Deficit
	(Bcfd)						
Winter Peak Day 2020 <ul style="list-style-type: none"> PG&E 1-in-10 for core and non-core SoCalGas 1-in-10 for non-core and 1-in-35 for core 	2.9	4.1	-1.2	3.4	5.0	-1.5	-2.7
Winter Peak Day 2020 <ul style="list-style-type: none"> PG&E 1-in-90 core and 1-in-10 for non-core SoCalGas 1-in-35 for core and 1-in-10 for non-core 	2.9	5.7	-2.8	3.4	5.0	-1.5	-4.3
Summer 1-in-10 Peak Day 2020	2.9	2.2	0.7	3.4	3.0 ¹¹	0.4	-1.1

11 SoCalGas' forecasted 1-in-10 summer peak demand for 2017 is higher, at 3,300 MMcfd, which results in a deficit of 115 MMcfd that must be made up with gas from storage. This is separate from the use of storage to meet the intraday balancing needs of electric generators.

Source: Aspen Environmental Group. Demand taken from 2016 California Gas Report.

** The SoCalGas forecast in this case is 1-in-10 for non-core and 1-in-35 for core; PG&E is 1-in-90 for core and 1-in-10 for non-core.

Finding: California does not have enough intrastate pipeline take-away capacity to meet forecasted peak winter demand. California's intrastate pipeline capacity (7.5 Bcfd) is insufficient to meet the forecasted 11.8 Bcfd peak load corresponding to a very cold winter day.

Conclusion 2.3: California does not have enough intrastate pipeline take-away capacity to meet forecasted peak winter demand. Currently, winter peak load of 11.8 Bcfd can only be met reliably if storage can deliver 4.3 Bcfd.

Finding: The California utilities, together, have enough storage delivery capacity to meet winter peak day demand based on historic regulatory and operational requirements with about 0.5 Bcfd surplus that can be utilized in case of gas system outages.³⁶

36. This reliability estimate does not include independent storage of 2.7 Bcfd because independent storage has no obligation to serve.

This simple comparison of capacity versus demand is useful for understanding why storage is important to reliability. However much more analysis is required for detailed utility system planning. That planning must be done with hydraulic models that capture constraints that may exist within a gas system and can assess the transient dynamic changes in demand versus supply during the gas day. Hydraulic modeling takes into account the flow rates of gas given the pressure distribution in the pipeline network and frictional resistance. These factors control whether enough gas can be supplied at a specific location. In other words, the balances shown delimit the best-case outcome at the assumptions shown and a hydraulic analysis may well find impacts that could be worse.³⁷ Even when the analysis shows an aggregate surplus of pipeline capacity versus peak day demand it does not necessarily mean storage is not needed. It may still be needed in certain hours of that day.³⁸

4. Daily and hourly balancing

Daily and hourly balancing is a critical short-term function of gas storage. Both PG&E and SoCalGas allow their customers a tolerance on the requirement to match scheduled deliveries with scheduled usage. That tolerance is 10% of total usage in a month, and the customer has until the end of the following month to settle their imbalance account with the utility. In the case of under delivery of gas supply, once line pack³⁹ is depleted (a decision made at the sole discretion of gas operators) the utility uses gas from storage to remedy

37. Unlike the electricity system where stakeholders can sign non-disclosure agreements to obtain the dataset and run system flow models, the gas utilities have as yet never provided their datasets to third parties and have repeatedly insisted that their systems are too complicated for anyone else to model. Results of a 2014 system expansion study for SoCalGas and SDG&E can be found at <https://beea.socalgas.com/regulatory/documents/2014-gas-system-expansion-study.pdf> and a 2011 storage capacity study at <https://socalgas.com/regulatory/documents/StorageExpansionStudy2011.pdf>. Both accessed July 2017. Both studies were prepared pursuant to CPUC Decision No. 07-12-019 and were reviewed by global engineering consultancy GL Nobel Denton, which is also the vendor of the hydraulic modeling platform used by both PG&E and SoCalGas and well-known in the industry.

38. The reliability assessment presented at the May 22, 2017 Energy Commission's Joint Agency workshop on Aliso Canyon reliability shows the importance of hydraulic analysis. SoCalGas' summer high sendout day forecast for 2017 in the CGR is 3,301 MMcfd, implying a surplus in summer 2017 of 124 MMcfd. The hydraulic analysis shows SoCalGas must withdraw gas from storage to meet summer peak day demand. That hydraulic analysis, reviewed by outside experts including Los Alamos National Laboratory (LANL), demonstrated that in some hours, the needed withdrawal would reach close to the full hourly withdrawal capability of the three non-Aliso gas storage fields. This summer use of gas storage by SoCalGas has been known to gas suppliers and key stakeholders for years (see Figure 15 showing the monthly withdrawal pattern). All of the presentations from that workshop are available at http://www.energy.ca.gov/2017_energy_policy/documents/2017-05-22_workshop/2017-05-22_presentations.php (Accessed October 2017).

39. Line pack is gas that is maintained in a transmission pipeline or distribution main to keep it pressurized enough that customers can take gas out of it without pressures dropping so low that gas stops flowing. Line pack will be discussed further in the subsection discussing potential alternatives to underground gas storage.

the mismatch between receipts of gas into its system with demand from customers. This is particularly important for SoCalGas because when imbalances outstrip supply enough that system operating pressures fall below acceptable levels, they must either pull from storage or curtail load. These gas imbalance provisions remain among the most liberal in the industry.⁴⁰

This balancing issue can be seen in the summer 2016 Aliso Canyon Risk Assessment Technical Report for hydraulic simulation of September 9, 2015 (shown below as Figures 11 and 12).⁴¹ This simulation demonstrates what would happen without gas from storage. In the simulation, SoCalGas saw load growth all day, starting at the hourly equivalent of 2,800 MMcfd and increasing over the afternoon to 4,500 MMcfd, while supplies coming in (i.e., receipts of gas) stood fixed at 3,500 MMcfd. By 11am, demand in the simulation outstrips supply by enough to cause pressures to begin to fall. They fall continuously on the northern system from about 10am until 10pm. Pressures within the LA Basin at Los Alamitos and El Segundo (with power plant and refinery load located nearby) are in decline virtually at the start of the gas day, at 400 psig at 6am and drop continuously until 7pm, roughly an hour after load begins to fall at 6pm. The analysis did not indicate what explicit minimum operating pressures would require curtailments absent gas from storage, but stated that the decline from 400 psig down to 325 psig caused by the supply-demand imbalance would likely have resulted in load curtailments absent the ability to pull gas from all four SoCalGas storage fields.⁴²

Finding: Average daily scheduling of gas delivery generally works because the gas company covers the hourly mismatch between flat deliveries and variable usage. Electric generation load causes the change in gas load shown in Figure 11 in hours 12 through 7. Since electric generators have to schedule the same quantity of gas delivery each hour, the incremental supply often comes from storage.

40. Baltimore Gas and Electric (BGE) recently updated its balancing provisions using customer smart meter data. It had been allowing suppliers until the following summer to make up differences, which would be more liberal than California's. BGE has much lower gas demand than California and owns some storage. See McShane, "Leveraging Gas Smart Meter Technology to Improve Energy Choice" June 2017.

41. Hydraulic modeling allows simulation of physical pipeline operations. It calculates operating pressures over the course of a gas day and identifies conditions where low or high-pressure limits, among other parameters, are violated. Hydraulic modeling is routinely used to assess system capability to serve new load and the impact of adding new facilities.

42. While the demand analyzed came from September 9, 2015, the supply available assumed limited pipeline flowing supply of only 1,878 MMcfd, with the rest of the gas supply coming from storage. Pulling that 1,589 MMcfd from SoCal's other three fields (Honor Rancho, La Goleta, and Playa del Rey) essentially used them at their maximum withdrawal capacities. Operating records posted on Envoy show that supply on September 9 consisted of 2,495,000 Dth and a storage withdrawal of 1,126,000 Dth (using the units displayed in Envoy). Customers were out of balance that day by 347,000 Dth. The point here is merely to demonstrate the need for gas from storage to balance the system within the gas day.

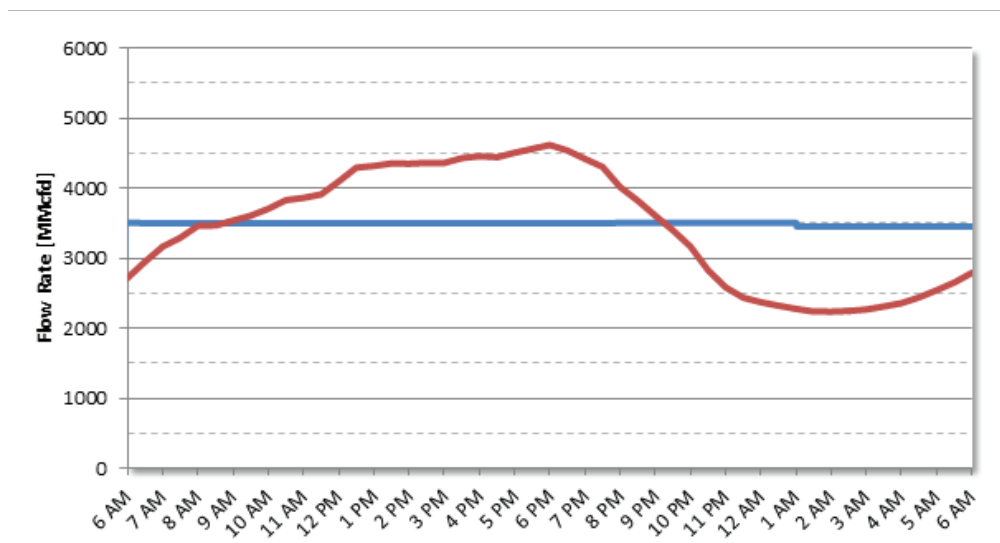


Figure 11. Supply Receipts and Load by Hour for SoCalGas September 9, 2015
Source: Aliso Canyon 2016 Summer Technical Assessment

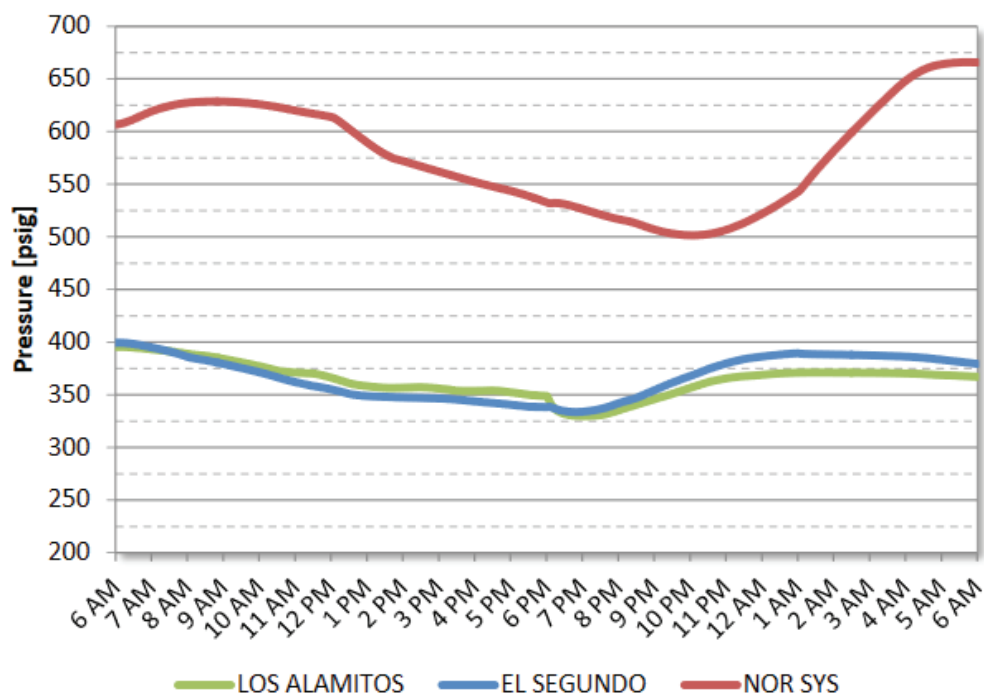


Figure 12. Hourly Operating Pressures on SoCalGas September 9, 2015
Source: Aliso Canyon 2016 Summer Technical Assessment

PG&E and SoCalGas reserve some of their storage capability explicitly for balancing. PG&E reserves 75 MMcfd of injection and withdrawal, and up to 4 Bcf of inventory capacity to balance its system (PG&E Pipe Ranger, 2017). SoCalGas reserves 8.0 Bcf of storage inventory capacity, 200 MMcfd of storage injection capacity, and 525 MMcfd of storage withdrawal capacity to balance its system.⁴³

Conclusion 2.4: Gas storage provides crucial hourly balancing for the gas system in all seasons. Without gas storage, California would be unable to accommodate the electricity generation ramping that now occurs nearly every day and that may increase as more renewables are added to the grid.

Pipelines and utilities without storage have to impose much more onerous, restrictive conditions on customer imbalances. Kern River is an example of a pipeline that serves load in California, yet today has no storage located along its route. It has such tight balancing provisions that in 2001, when California's Department of Water Resources (DWR) was buying gas to supply a power project served by Kern River (in place of bankrupt PG&E and near-bankrupt Southern California Edison), the supplier required DWR to take the same quantity of gas every day, even on weekends when the project was not likely to operate. DWR had to find a buyer for the gas on weekends on grounds that there was no place on the Kern River system to put the gas. A sale on a weekend when demand is typically lower than on a weekday required selling the gas for less than the purchase price, i.e., at a loss, thereby increasing costs to California consumers. (Differences between weekend and weekday market prices vary depending on market conditions. In that timeframe, those differences might have been as much as 20% of the daily price.) In general, these tight balancing provisions are evidenced in frequent warnings to shippers that the system is close to its over-packed or over-drawn limits, and admonishments to keep their deliveries matched with their usage or pay penalties. Any flexibility that a pipeline offers is limited by its line pack or access to storage, and, except in California, tariffs that offer more flexible provisions command premium prices.

Electric generators face obstacles to paying premium prices for flexible services or to buying storage service in general. Storage is priced on a reservation charge basis plus a per unit cost to inject and withdraw. The cents per MMBtu added to the cost of natural gas cannot be

43. Approved in CPUC Decision No. 16-06-039, which adopted these values in a settlement in SoCalGas' Triennial Cost Allocation Proceeding (CPUC, 2014c). The balancing provision can be found at pages A-3 and A-4 of the settlement, which was filed via motion to the CPUC on August 31, 2015 and is available at <http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M154/K297/154297787.PDF> (Accessed April 2017). Interestingly, the TCAP settlement further provides that once the Aliso Canyon Turbine Replacement Project goes into service, the balancing function will be allocated an additional 145 MMcfd of storage injection capacity, for a total of 345 MMcfd, and some associated changes to the conditions required to call a High Pressure operational flow order (OFO) will occur. The change to the quantity reserved once the new compressors go into service and associated OFO rule change further demonstrate how closely storage and the balancing rules are intertwined.

recovered by generators bidding into competitively dispatched markets. The independent merchant generators also prefer to purchase daily spot market gas whose price is likely to be aligned more closely with that of other bidders into electricity markets, and which helps set the market-clearing price in electricity market dispatch auctions. They see no increase in revenue from incurring the extra cost for holding storage. In California, it is easier to let the gas utility balance the system. These generators also have no obligation to operate if they do not have fuel. In contrast, gas-fired generators owned by vertically-integrated utilities (all located outside California since the divestiture required by AB 1890) tend more frequently to buy storage or flexible services because their regulator will allow them to pass that cost on in rates.

5. Stockpile

Storage protects California with a reserve, or stockpile, should one of the interstate pipelines fail or should weather to our east cause a reduction in gas supply available through the pipelines. This amplifies the problem of winter peak demand because unusually cold weather in the production basins can lead to wellhead and gathering line freeze-offs, shutting down production and consequently limiting gas supply available to California from the interstate pipelines. These same unusually cold events concurrently create much higher gas demand in states to our east, which further reduce gas available to California from the interstate pipelines. FERC and NERC staff, in their 2011 cold weather event report, documented seven cold weather events that resulted in curtailing more than 100,000 gas customers in Texas, New Mexico, Arizona, and San Diego.⁴⁴ They cite a 1989 event severe enough that PG&E notified CPUC commissioners it was preparing to curtail non-core customers.⁴⁵ In the 2011 event, temperatures in the Dallas area (likely somewhat warmer than in the heart of the Permian and San Juan basins that help supply California) dropped to -10 F. Farmington, NM in the heart of the San Juan basin, saw highs of 13 and 19 degrees, respectively, on February 3 and 4, and had four consecutive nights between 6 and -6 degrees (New Mexico State University Agricultural Science Center Farmington, 2011). The electric utility in El Paso, Texas reported 60 hours with temperatures below 18 degrees and lows near zero (El Paso Electric Company, 2011). The Permian basin reportedly lost 30% of its production and the San Juan basin lost between 50 and 70%. Forty percent of processing capacity across five supply basins including East Texas and the Gulf Coast was lost (Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1- 5, 2011). In the end, PG&E's stored gas was sufficient to address both the increase in load in its service area and the drop in supply flowing in from the El Paso system. Even with gas from

44. See "Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011," pp. 169 to 189. P. 3 of the "Legislative and Regulatory Responses by States" appendix documents that some of the 30,000 customers in New Mexico were without natural gas service for a week. The report also documents cold weather events affecting supplies in 1983, 1989, 2003, 2006, 2008, and 2010.

45. Opinion provided by technical expert..

storage, the drop in interstate deliveries to California was enough that SoCalGas curtailed service to 59 non-core (including electric generation) customers. San Diego Gas and Electric (SDG&E), which is served solely via SoCalGas' southern main line and is not connected to in-state gas storage, had to curtail all non-core load except for two generators that CAISO said were needed for grid reliability (Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1- 5, 2011).

Finding: Underground gas storage protects California from outages caused by extreme events, notably extreme cold weather that can drastically reduce out-of-state supplies.

Conclusion 2.5: Gas storage could increasingly be called on to provide gas and electric reliability during emergencies caused by extreme weather and wildfires in and beyond California. Both extreme weather and wildfire conditions are expected to increase with climate change. These emergencies can threaten supply when demand simultaneously increases.

6. Seasonal Price Arbitrage

Storage can serve a price function. To the extent that gas can be injected when gas market prices are low and withdrawn when prices are high, storage becomes a physical hedge against those higher prices (for price arbitrage). "Slow-turn" storage, i.e. that which can cycle once per year, is good for this type of summer versus winter price arbitrage. The turn rate is a function of how fast a field can be refilled and is determined by the magnitude of injection capability relative to the inventory.⁴⁶ As will be shown later, summer prices are not always lower than winter prices, so in some years the arbitrage result is negative. Fast-turn storage that allows several cycles per year is useful for shorter-term arbitrage. Natural gas marketers and producers tend to prefer short-term, opportunistic arbitrage in which they either store excess gas hoping for a higher-priced day on which to sell it, or use it to manage unforeseen changes in their production and sales portfolios.

Before the advent of competitive supply markets, utility storage did not serve price arbitrage. During this time, California's gas utilities invested in underground gas storage and natural gas was purchased by a utility from a pipeline under long-term contracts at a fixed annual price with fixed escalators. As such, seasonal price savings did not exist and price was not part of the justification for storage. Since then, we have seen periods of relatively stable prices, in which case, storage used for price arbitrage would have very little effect on natural gas prices to California consumers.

The natural gas spot market emerged after the 1970's gas shortage became the 1980's gas glut. FERC opened natural gas markets to commodity competition, allowing prices to be set

46. Until companies independent of the utilities began to invest in and offer storage services, most storage was single turn and took all summer long to refill a field before winter.

in the open market. This replaced long-term contracts that had linked natural gas prices to oil prices and escalated at fixed rates and contained provisions that required a utility to pay for the gas whether it took it or not. In so doing, FERC also directed that pipelines could no longer sell natural gas and required they provide transportation service on a non-discriminatory, open access basis (see FERC Order Nos. 380, 436, 500, and 636). As a result, the price for gas supply (often called the ‘commodity price’) began to be set on a monthly basis. One feature of this competitive market is that higher winter demand often results in winter prices being higher than summer prices. To the extent that a utility can buy extra gas at low summer prices and store it for winter, it can reduce its winter month gas purchases and thereby reduce costs to its supply customers.

Figure 13 displays so-called “citygate” prices for California as reported by EIA back to January 1989.⁴⁷ The data shows various price spikes, including several severe ones; some of which occurred during winter months. (The 2001 price spike is associated with the power crisis and a pipeline outage; the 2006 spike is due to hurricanes Katrina and Rita; and the 2008 spike is the commodity price run-up prior to the financial crisis.) All else equal, being able to pull lower-priced gas from storage in those months would have had the effect of reducing costs to Californians. Table 8 compares average summer and winter prices for the last five years. In 2012, 2013, and 2016, summer prices were lower than in the following winter and storage provided a hedge against higher winter prices. However, 2014 and 2015 show the opposite; winter prices fell and the achieved result from the storage hedge was negative. Assuming 82 Bcf of storage for core customers, the average net result for the five-year period would be a gain for those consumers of approximately \$5 million.

47. Nominally, a citygate is the meter station where gas from an interstate pipeline is transferred to a local distribution company. On the PG&E system, the citygate is instead a series of virtual locations where gas transfers from its backbone transmission system into its local transmission and distribution system. A similar but not completely analogous concept applies on the SoCalGas system. One should interpret the prices shown as a proxy rather than as a literal price one can observe in the market.

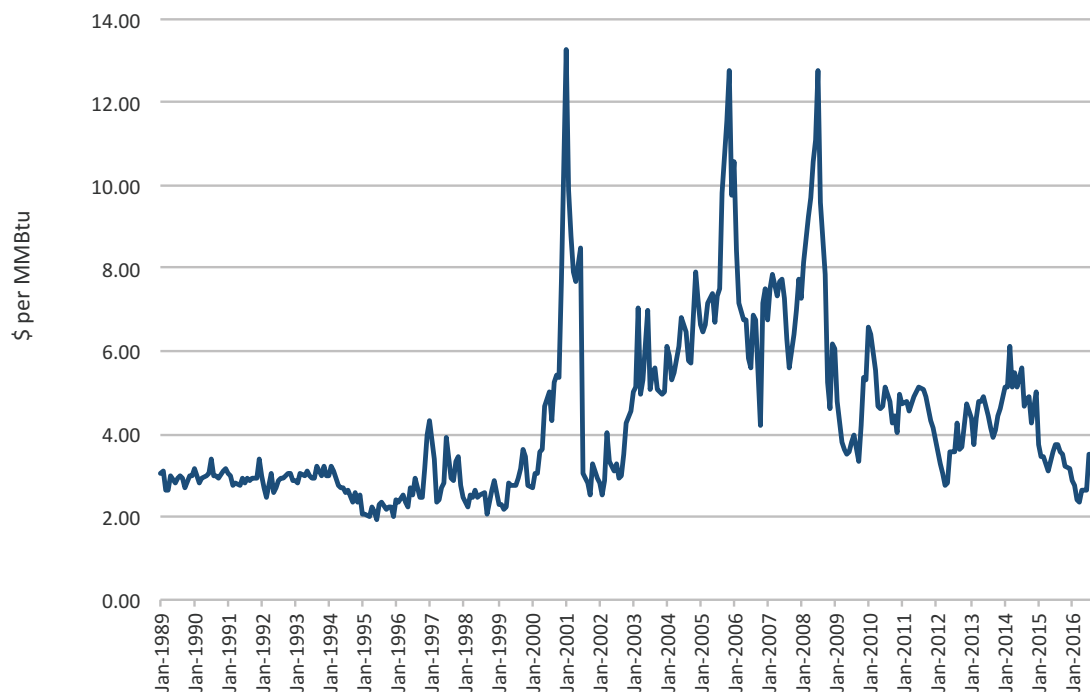


Figure 13: California “Citygate” Natural Gas Price by Month

Source: U.S. Energy Information Administration, Natural Gas Monthly

Table 8: Theoretical Physical Storage Price Hedge Results 2012 - 2017.

	Avg Price	W-S Diff	Storage Reserved For Core Customers		Theoretical Seasonal
	\$ per MMBtu	\$ per MMBtu	Bcf	MMBtu	Savings to Core Customers \$ (nominal)
Summer 2012	3.48				
Winter 2012 - 13	4.29	0.81	82	86,100,000	\$70,000,000
Summer 2013	4.43				
Winter 2013 - 14	5.10	0.66	82	86,100,000	\$58,000,000
Summer 2014	5.11				
Winter 2014 - 15	3.98	-1.13	82	86,100,000	-\$96,000,000
Summer 2015	3.50				
Winter 2015 - 16	2.89	-0.61	82	86,100,000	-\$53,000,000
Summer 2016	3.14				
Winter 2016 - 17	3.69	0.55	82	86,100,000	\$47,000,000
Total Seasonal Savings Since 2012					\$25,000,000
Average Seasonal Savings Since 2012					\$5,000,000

Source: Aspen Environmental Group

Practitioners know that forecasting monthly natural gas prices is exceedingly difficult. Many focus instead on watching the strip of monthly prices traded on the New York Mercantile Exchange (NYMEX). These prices represent the price traders are willing to pay today for gas delivered in future months. Twelve calendar months of futures prices is known as the “12-month strip,” and almost always displays the market’s default expectation that winter prices will be higher than summer prices. The 12-month strip for April 13, 2017 appears in Figure 14 and displays an underlying expectation that next winter’s prices will be perhaps twenty-five or thirty cents per MMBtu higher than those for summer 2018.⁴⁸

Gas storage levels can also affect gas prices. EIA, since about 1998 (and the American Gas Association before that), collects data from storage facility owners on how much gas was injected or withdrawn during the prior week and releases this data every Thursday.⁴⁹ Sometimes, when forward prices display little seasonal variation, the trade press will report that storage injections are low for a given week and say the reason is because prices are not providing a reason to inject. However, such logic ignores the fact that storage is needed to match the physical seasonal difference between natural gas production and demand. Many utilities – not just in California – need stored gas to meet winter demand, regardless of winter versus summer price signals.

Conclusion 2.6: Seasonal price arbitrage can be considered a second-order benefit of utility-owned gas storage. In theory, the utilities could purchase financial contracts to achieve this price benefit. As long as California needs storage to meet winter reliability needs, however, it is prudent to also capture price benefits when they are available. This allows California to avoid the transaction costs that would be associated with using financial contracts to hedge winter prices.

48. The futures prices change every day based on news about supply and demand. It is entirely possible that the curve in July or September will look very different than this relatively flat curve of traded prices in mid-April.

49. Nationwide, the market often hangs in wait for the weekly report release and prices will noticeably change when reported activity deviates from normal weather, leading to larger- or smaller-than normal storage activity.

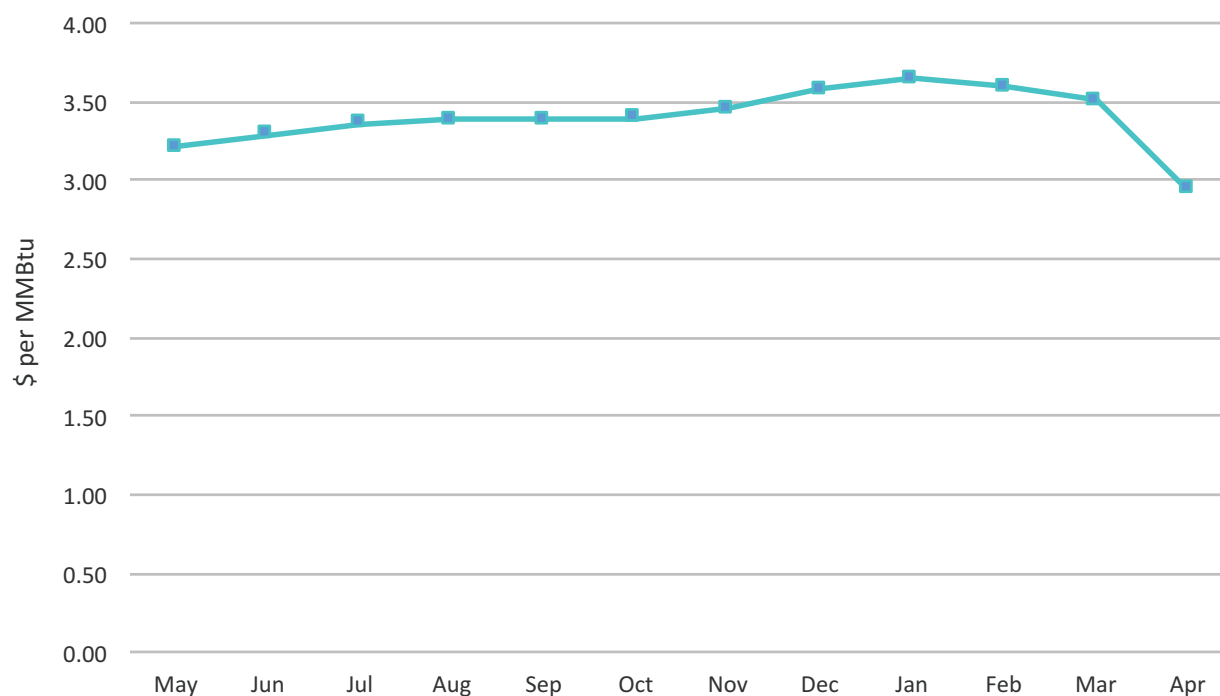


Figure 14. 12-month Futures Strip of Natural Gas Prices on April 13, 2017

Source: Aspen Environmental Group; prices via http://quotes.ino.com/exchanges/contracts.html?r=NYMEX_NG

7. Market Liquidity

Finding: Natural gas storage in California also enhances market liquidity. It allows marketers a place to store gas for short periods of time (in contrast to the utilities storing gas primarily for winter). This extra degree of freedom helps to manage dis-synchronies between sales contract starts and stops; the timing of new production coming on line; or maintenance periods at a production, gathering or pipeline facility.

Conclusion 2.7: Storage allows access to gas supply in local markets rather than having to wait for it to be transported. In short, storage provides more options to dispose of or to access supply.

Underground gas storage helps the State meet the winter demand for gas and provides a vehicle for intraday balancing of supply and demand, which has become of critical value as intermittent renewable electricity generation has become more important. Storage also creates a way to stockpile supplies inside the State should interstate pipelines fail or should weather to the east of the State cause interruptions in either natural gas production or higher demand. Storage allows physical price arbitrage by storing gas when prices are low to use later when prices are high. Storage also gives buyers and sellers an extra “sink” or “source” to make the market more fluid.

Conclusion 2.8: The overarching reason for the utilities' underground gas storage is to meet the winter demand for gas. If storage capacity is sufficient to help meet winter demand, it is then able to perform all the other named functions, including intraday balancing, compensating for production which is not aligned with demand, creating an in-state stockpile for emergencies, and allowing arbitrage and market liquidity.

Recommendation 2.1: In evaluating alternatives that would reduce dependence on underground gas storage and shift norms about controlling interruptibility, the State should obtain a detailed analysis of the gas system to ensure that the balancing roles gas storage plays on all timescales can be effectively managed by other means. This analysis should include hydraulic modeling of the gas system. The State should also take into account the role these facilities have had in addressing emergency situations, including extreme weather and wildfires.

1.1.1 How is Storage Designed to Operate in Different Utility Regions?

Subtle differences exist between storage on the PG&E system and the SoCalGas system. Both systems tend to inject gas most of the “summer” season (April 1 to October 31), and withdraw during “winter” (November 1 to March 31). Both use storage to remedy customer imbalances. Both own facilities located close to their largest load centers. Both sell inventory, injection, and withdrawal capacity to non-core customers and marketers via some form of auction that prices those services at market-based rates. The key difference between PG&E and SoCalGas is that, until the 2015 Aliso Canyon incident forced the nearly complete shut-down of the field, SoCalGas had enough capacity that it could lease access for 36% of its overall storage capability to third parties. Aliso Canyon is so large, with geological differences between the East Field and the West Field, that SoCalGas could inject into one part of the field and withdraw from another or even switch from net injection to withdrawal within the same gas day (See Figure 1.1-2 in Chapter 1). This allowed them to give customers enormous flexibility, and enhanced their ability to serve both users of traditional storage services as well as market storage services.⁵⁰

PG&E only offers a relatively small percentage of its storage capacity for sale to the non-core market. Market storage services are offered by independent gas storage companies. All of this independent storage is located in northern California and is connected to the PG&E system. The independent fields are designed to cycle (i.e., inject and withdraw) their full inventory as many as five to six times per year whereas the utility fields realistically can cycle only once per year. The independent operators can do this because they have a much higher ratio of injection capacity to inventory. Injection requires compression, and injecting more gas quickly requires more compression than injecting over the whole summer season. The independent storage is designed to affect arbitrage on a much shorter-term basis than the seasonal utility storage and these storage providers price their service knowing this, with

50. Figure 1.1-2 in Chapter 1 shows SoCalGas withdrawing from some wells while injecting into others.

an eye towards capturing the option value of the service. Independent storage facilities have eschewed any obligation to help provide winter reliability, arguably believing their approach yields higher profits than a business model based on traditional utility cost of service regulation.

The configuration of the two utility systems also gives rise to differences in how they respectively operate storage. SoCalGas appears to be much more dependent on storage to balance its system. This is partly because the SoCalGas system has less available line pack than PG&E by design. All of PG&E's fields are connected to the Bay Area transmission loop or its higher pressure "backbone transmission" system. The independent storage is also connected to backbone transmission and some of the independent storage can also feed into what is known as "local transmission." It is of note that more of the power generators in the north are connected to the higher pressure backbone transmission system; whereas southern California has a larger concentration of power projects inside the Los Angeles basin instead of along the higher pressure mainlines on the way in to the basin. This leads SoCalGas to operate its storage more as a daily shock absorber which PG&E does not have to do.

SoCalGas also tends to experience higher electric generation loads in the mid-to-late summer than PG&E. SoCalGas commonly injects gas in April, May, and June, then backs off injections (or even withdraws) in July through early September, resuming injection in late September and continuing injection well past the November 1 gas industry start of winter. Figure 15 illustrates the injection and withdrawal profile for SoCalGas based on a compilation of daily reported inventory on SoCalGas' Envoy™ public data site for a 15-year period. Negative values represent injections and positive values are withdrawals. The average profile reflects the average of inferred inventory levels for each calendar month and is the best representation of the profile SoCalGas has typically achieved. In other words, in the data period's average May (i.e., the average of all 16 Mays), SoCalGas is injecting about 500 MMcfd. SoCalGas then typically reduces injections (to more like 150 MMcfd) as demand rises in the later summer, then increases to perhaps 200 MMcfd before moving to winter withdrawals. The maximum line represents the maximum injection or withdrawal ever achieved for a particular calendar month in the 16-year period. It illustrates the fact that SoCalGas has withdrawn gas in August and September in some years. An interesting feature shown in the minimum profile is that there have been years in which SoCalGas

withdrew very little gas in any given month – and in fact shows the lowest withdrawal for January was actually a net injection, presumably a very warm January.⁵¹

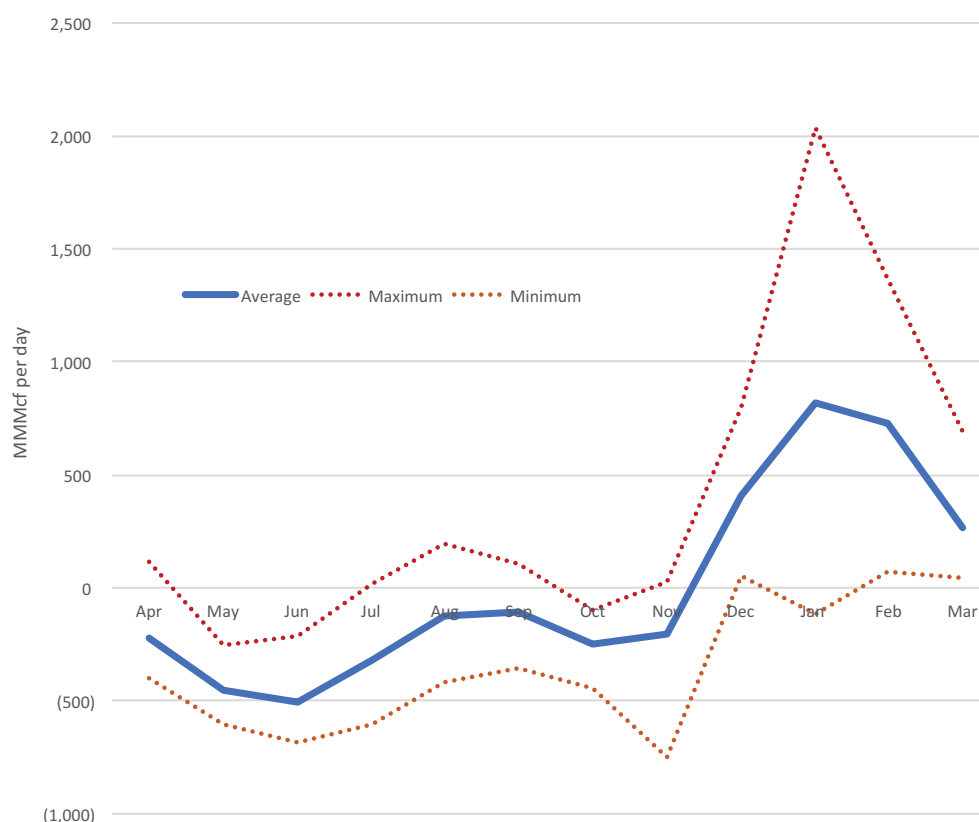


Figure 15. SoCalGas Observed Monthly Injection (negative) and Withdrawal (positive)

Profile: 2001 – 2015

Source: Aspen Environmental Group compilation of operational data posted on SoCalGas Envoy™

51. SoCalGas’ “winter balancing rules” demonstrate the importance of storage in operating this system. These tighter balancing rules took effect in late winter as the storage inventory dropped, and were designed to preserve remaining gas in storage. Stage One required customers to schedule and deliver into the SoCalGas system at least 50% of the gas they burned over five-day periods (recall that the normal balancing rules allow balances to accrue over a 30-day period) during the November through March “winter” season. Once storage inventory dropped to “threshold 1” (defined as the minimum amount of gas required to meet a peak day plus 20 Bcf), customers had to deliver 70% of their burn every day. When inventory dropped further, to “threshold 2” (defined as the peak day minimum requirement plus 5 Bcf), customers had to bring in 90% of their scheduled burn every day. Trading of imbalances was explicitly not allowed to offset the delivery minimums. These rules were eliminated in 2015 and replaced with a rule allowing SoCalGas to call operational flow orders for under-deliveries of customer-owned gas into its system, giving the utility an immediate mechanism to direct customers to get into balance. CPUC Decision No. 15-06-004.

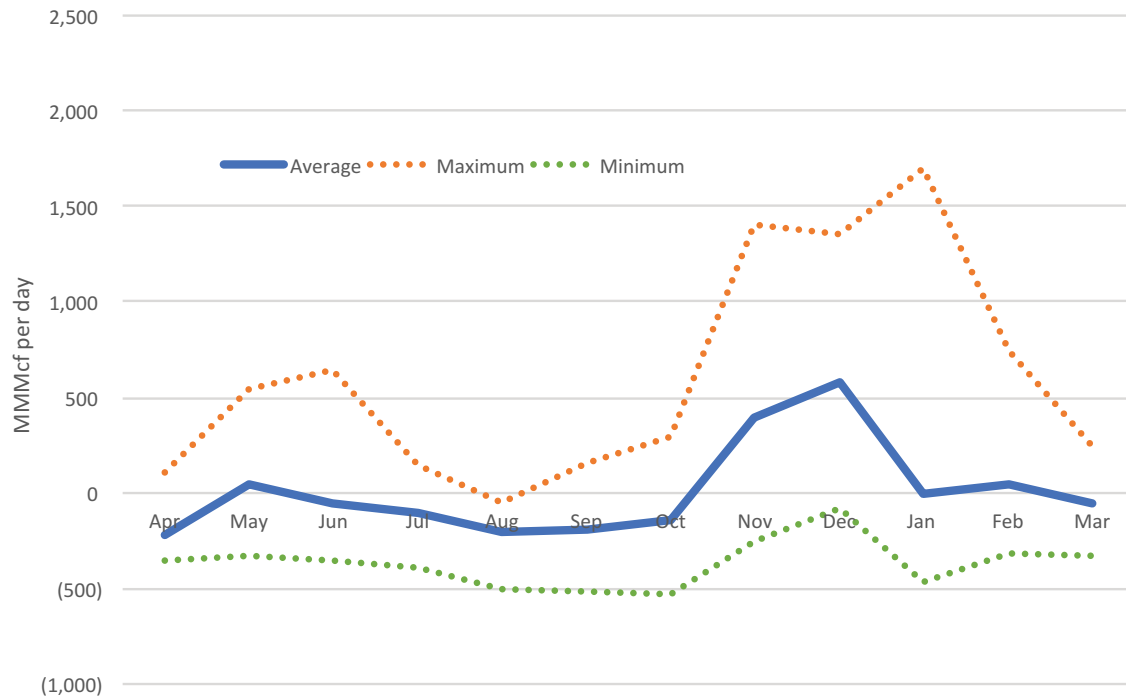


Figure 16. PG&E Observed Monthly Injection (negative) and Withdrawal (positive)

Profiles: 2001 - 2015

Source: Aspen Environmental Group compilation of Operational Data posted on PG&E Pipe Ranger

The injection and withdrawal profile among the independent gas storage providers (Figure 17) is much flatter than for either SoCalGas or PG&E (Figure 16) because their clients are using the storage for much shorter-term price arbitrage or market needs for which the operations were designed. They do display a small increase in withdrawals in winter and an increase in injections mid-summer, but the range is much smaller than for PG&E or SoCalGas as the independent operators are not obligated to provide supply to help meet peak demand.

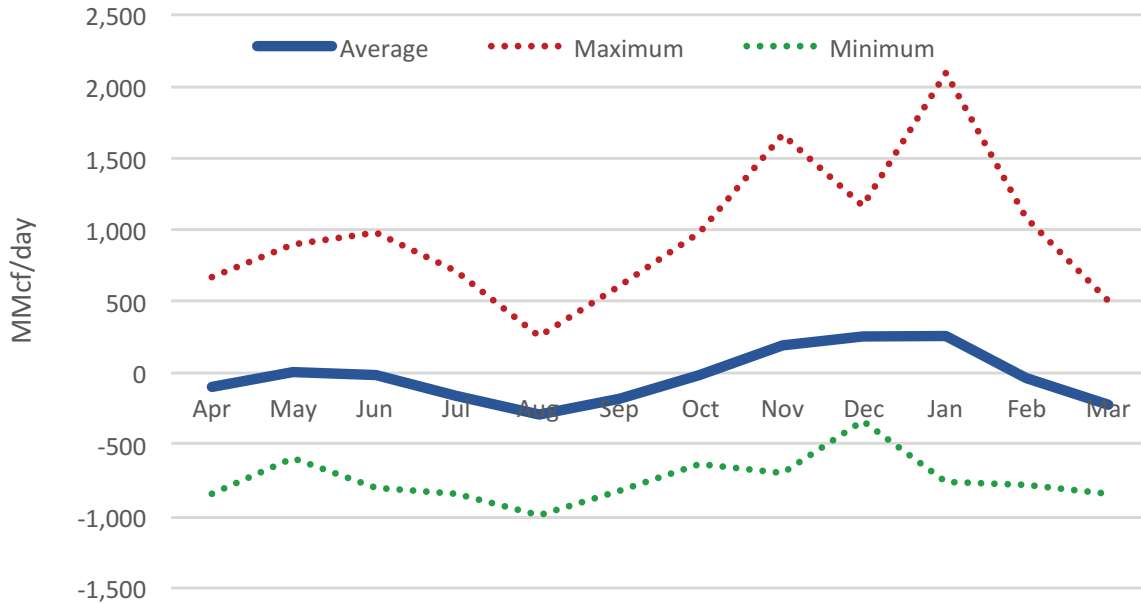


Figure 17. Independent Storage Observed Monthly Injection (negative) and Withdrawal (positive) Profile: 2001 – 2015

Source: Aspen Environmental Group compilation of Operational Data posted on PG&E Pipe Ranger

How SoCalGas operates storage also affects deliveries to San Diego because SoCalGas can use storage to serve the LA Basin, and thereby preserve flowing supply to serve SDG&E.⁵² Without this ability, days of insufficient gas supply would turn into a choice between serving San Diego and serving LA. This finding was demonstrated in hydraulic simulations that were subject to independent review by LANL and Walker & Associates. The simulation also shows SoCalGas would have to curtail non-core load in these conditions.

52. Supply comes in to SoCalGas on its Line 2000 fed by EPNG's southern mainline and goes south at Moreno Station to serve San Diego.

Without Aliso Canyon, SoCalGas' system becomes much more constrained because other storage facilities are located farther away from load, are smaller, or have less injection and withdrawal capability. The Playa del Rey facility has very small capacity; it can be emptied very quickly but has so little compression capacity that it takes nine days to refill.⁵³ La Goleta, located on the coast on the northwestern side of the service area, acts more as a local load-pocket balancer, accommodating the limits on the ability to move gas back and forth from the Basin, out to the Ventura area, and back. Honor Rancho has picked up the overall system balancing work but has less than half the injection and withdrawal capability of Aliso Canyon. Honor Rancho's effective injection capability of 235 MMcfd is less than 10% of total demand on a high demand day (CEC, 2016e). The Summer 2016 Aliso Canyon Reliability Action Plan called for tighter balancing provisions recognizing the much more limited capabilities of the system with less storage. SoCalGas' customers supported those revisions in a settlement adopted by the CPUC (CPUC Decision No. 16-06-021).

In summary, the storage owned by PG&E and SoCalGas operates generally the same way, though SoCalGas sometimes has to use gas from storage in the summer's hotter months and depends much more on storage than PG&E to balance its system. Both depend on storage to meet winter peak load. There is some difference in the withdrawal patterns between the two utilities, and in northern California the independent storage allows arbitragers to inject and withdraw multiple times per year based on short-term market dynamics.

53. Playa del Rey has a working gas maximum inventory of 1.8 Bcf and an injection rate of 0.2 Bcf. See Aliso Canyon Action Plan to Preserve Gas and Electric Reliability for the Los Angeles Basin. http://www.energy.ca.gov/2016_energy_policy/documents/2016-04-08_joint_agency_workshop/Aliso_Canyon_Action_Plan_to_Preserve_Gas_and_Electric_Reliability_for_the_Los_Angeles_Basin.pdf (Accessed July 2017).

1.1.2 How Storage Affects Natural Gas Prices in California

One might expect natural gas prices to be higher in winter than in summer, owing to winter's higher seasonal demand. Consequently, one also might expect storage to reduce winter prices. To the extent that a gas utility could serve some of its winter demand using gas from storage that was purchased at lower summer prices, the blended price to consumers would be lower than if those consumers faced the natural gas market price each month.

New York and New England are examples of markets that do not have underground gas storage close-by and are regularly short of pipeline capacity to meet winter needs. Prices in markets without storage regularly spike many times the price in California. Figure 18 displays prices at California, Henry Hub, and Massachusetts. The California price tracks relatively closely to the Henry Hub price.⁵⁴ We cannot know what prices in California would look like without underground gas storage, but a combination of no storage and insufficient pipeline capacity might reasonably expose California to price volatility and spike magnitudes similar to New England's.⁵⁵

54. Henry Hub is the benchmark measure of U.S. national price; it is used to price forward contracts on the New York Mercantile Exchange (NYMEX). The hub is located in Erath, Louisiana and some 14 different pipelines interconnect there. Considerable underground and salt cavern storage is located within reasonable access of Henry Hub or pipelines that connect to it.

55. During the 2000-2001 California power crisis, low gas storage inventories combined with early season cold (and some potential price manipulation) caused natural gas prices to spike. Storage injections were low that year because EPNG's southern mainline near Carlsbad exploded in August 2000 and was out of service for several months. A CPUC staff report also cited low precipitation that year that limited hydroelectric power and kept demand for gas high. It also cited non-core customers having filled only half the volume of storage to which they were entitled. An Assembly committee investigation concluded that EPNG used a contract for capacity on the EPNG pipeline (held by affiliate El Paso Merchant Energy) to manipulate the market. Chief ALJ Curtis Wagner at FERC also found that EPNG illegally exercised market power by withholding capacity. Essentially, EPNG did not tell shippers who nominated to constrained receipt points that other unconstrained receipt points were available for use. See "FERC Judge says El Paso Unit Withheld Natural Gas Supplies from California," Oil and Gas Journal, September 24, 2002. Found at <http://www.ogj.com/articles/2002/09/ferc-judge-says-el-paso-unit-withheld-natural-gas-supplies-from-california.html> (Accessed May 2017).

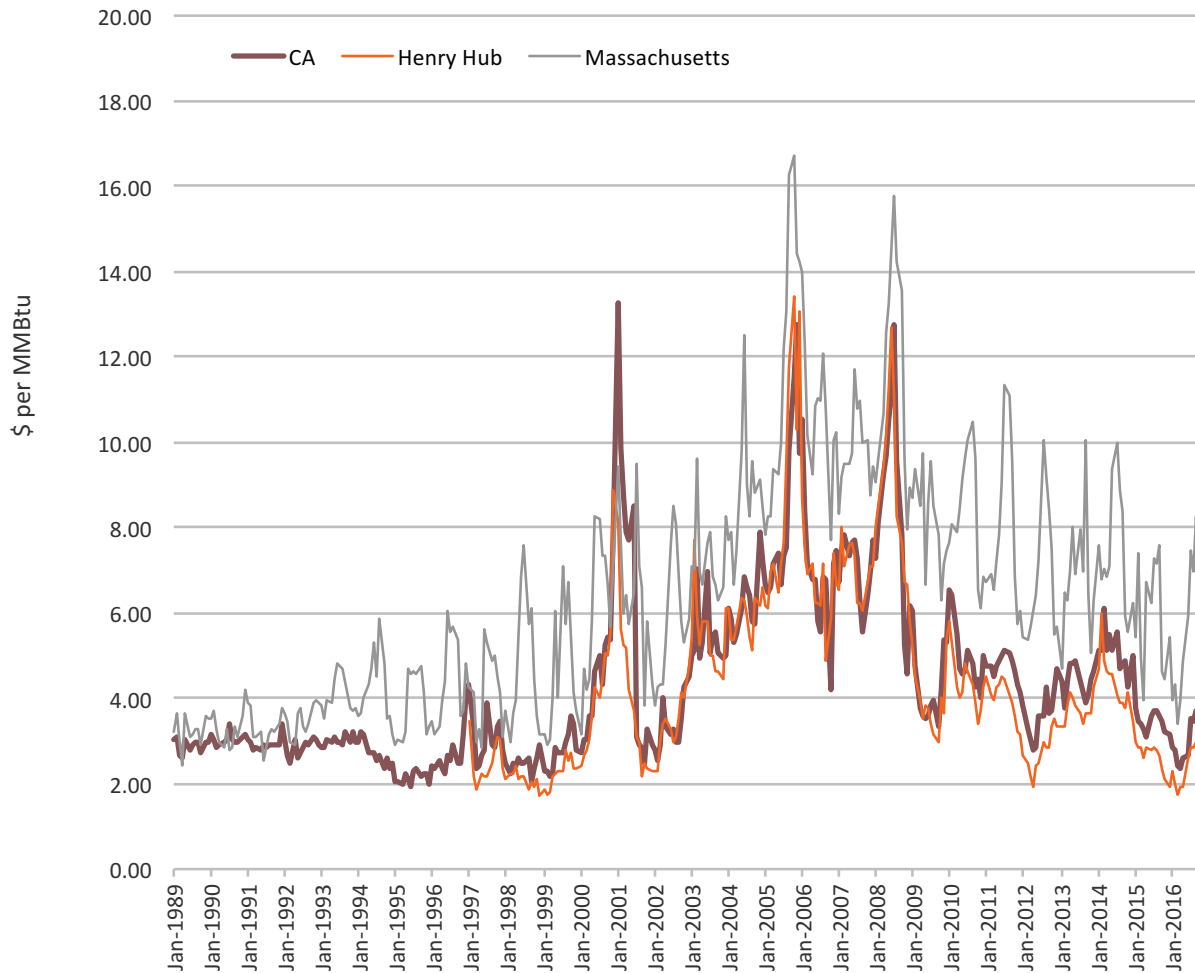


Figure 18. California, Massachusetts, and Henry Hub Natural Gas Prices

Source: Energy Information Administration

Consultancy ICF prepared a 2009 study for the CEC that provides an excellent review of gas storage economics and their impact in California. ICF provided a conceptual analysis of the value of storage from a public and private perspective. It noted that during the 2000-2001 power crisis “additional working gas and/or deliverability would have mitigated some of the disruptions in the electricity market and could have had significant positive impacts for the broader economy in California. More broadly, even a cursory examination of gas industry trade publications indicates the importance of storage inventories on natural gas price levels.” ICF also noted that storage market participants are not homogeneous: different participants value different aspects of storage differently and that California has been seen as an industry leader in fostering storage investment at the “right” level (ICF International, 2009).

1.1.3 How the Natural Gas System Treats Generators and Affects Electricity Reliability

This section describes the State's reliance on gas generation for electricity reliability. It highlights how that role has changed and how the gas system's rules were set up when gas was not as important for electricity reliability. Electricity generators are non-core customers. They have no more and no fewer rights to priority of service than any other non-core customer. They are subject to the same nominations and balancing rules as any other non-core customer. In theory, they should receive no special treatment.

In reality, generators receive lower priority of service than other non-core customers. Regardless of the curtailment rules specified in adopted CPUC policy or gas utility tariffs, from the perspective of the gas system operators, the electricity system has more options than other non-core gas customers, such as the ability to shift generation to plants located elsewhere, use demand response, or to import more power. Other non-core gas load such as oil refining does not have this flexibility. Curtailing the refinery industry can create significant consequences. Sudden outages of either electricity or natural gas service to a refinery can damage refinery equipment.⁵⁶ It can take days to bring a refinery back up once it is shut down. Electric utilities often preserve service to refineries during outages by placing them in protected load blocks.⁵⁷ SoCalGas, in 2016, received approval to protect from curtailment a minimum quantity of natural gas load for each of the refineries to avoid a sudden and complete shutdown.⁵⁸ So, while other non-core customers, by the letter of the rules, should share in gas curtailments after the first 40% of electric generation load is cut, this does not happen in practice and electricity generators will still likely take the brunt of curtailments. The Aliso Canyon technical assessments and reliability action plans released in April 2016, August 2016, and May 2017 reflected the expectation that electricity generation will be curtailed first.

More generally, storage was built to serve peak winter load for core customers and was not designed and built to serve peak electric generation. At the time the gas system was

56. The CEC, reflecting the importance of petroleum to California's economy, held a workshop on June 17, 2016 to obtain industry testimony on some of the physical risks and impacts of either electricity or natural gas outages at the refineries. See http://www.energy.ca.gov/2016_energy_policy/documents/2016-06-17_workshop/2016-06-17_presentations.php (Accessed July 2017). See also CEC, 2015 Integrated Energy Policy Report and work of the Petroleum Market Advisory Committee.

57. This approach was approved in CPUC Decision No. 01-04-005.

58. CPUC Decision No. 16-07-008. SoCalGas' submission to implement these tariff changes, allowing each refinery customer to indicate their "minimum usage requirement," can be found at <https://www.socalgas.com/regulatory/tariffs/tm2/pdf/5089> (Accessed August 2017).

designed, electric generation primarily used fuel oil, coal, or hydropower, not natural gas.⁵⁹

⁶⁰ The gas system offered discounted rates to customers with seasonal or intermittent load, which helps to round out use of the system, that otherwise would have been entirely paid for by core customers. This is reflected in CPUC Decision No.62260, from July 1961:

A gas utility may affect economies, and thus provide firm service at lower rates, by selling gas during such off-peak periods for industrial consumption on an interruptible basis. The interruptible class of customers is thus an important class, both from the standpoint of the utility and from the standpoint of the customers. However, it is fundamental that interruptible industrial gas is not sold on such terms as would endanger the required firm supplies or as would place an economic or price burden on firm customers. This fundamental principle is also applicable to sales of transmission pipelineable quantities of gas.

As a general proposition when gas is available for use by interruptible customers, the choice of burning gas or an alternate fuel lies with such customers and is practically wholly dictated by value and price considerations, including air pollution regulations and the economics of investment in standby or storage facilities as well as the direct influence of the relative costs of the respective fuels. It follows, therefore, that interruptible industrial gas prices generally cannot exceed the costs of using alternate fuels. In California, the alternate fuel is almost without exception fuel oil.

In some cases, generators “lean” on the system and see how far they can get without incurring a price penalty. Many pipelines do allow informal flexibility as long as this does not compromise their systems. Load diversity helps allow this to the extent one customer’s over-delivery offsets another’s under-delivery. Otherwise, generators have to either stay in balance like other customers or be penalized. Neither PG&E nor SoCalGas (or SDG&E for

59. As late as the mid 1980’s, PG&E had power plants with adjacent steam boilers, one running on natural gas and the other on fuel oil.

60. The practice of curtailing gas to electric generators was reinforced in the 1970’s, when natural gas was in short supply in interstate markets. Many states experienced natural gas curtailments, including California. See U.S. Department of Energy, 1978 Distributed Energy Systems in California’s Future: Interim Report Volume I, Section 4.1.3. Page 49. Congress directed states, via the Natural Gas Policy Act of 1978, to adopt end-use priorities to allocate gas to highest-priority uses during these times of shortage. The Fuel Use Act, also adopted in this same period, prohibited use of natural gas as a fuel for base load power generation. The Fuel Use Act is found at Public Law No. 100-42. However, the 1978 Public Utilities Regulatory Policy Act allowed gas to be used in cogeneration. As supply concerns eased and natural gas markets liberalized, enactment of the Public Utilities Regulatory Policy Act allowed gas fired cogeneration developers to become some of the first non-utility, or merchant, generators. They offered scales of investment and risk with lower capital costs, ease of siting, and time to construct that were faster than alternatively-fired units. See Elder, “Implications of Greater Reliance on Natural Gas for Electricity Generation,” American Public Power Association, 2010. See also, Tussing and Tippee, “The Natural Gas Industry: Evolution, Structure and Economics,”1995.

that matter) offer tariffs with more flexible features to electric generators. Generators are expected to follow the same balancing and other tariff rules as other non-core customers.⁶¹

By and large, generators tend not to subscribe to storage service.^{62,63} A review of SoCalGas' "Index of Customers" in December 2015 showed that none of the gas storage was sold to generators. This means that generators were not direct users of tariffed natural gas storage service, not even to manage their own imbalances. It is possible that some gas marketers who do subscribe to storage could have used their storage rights to help manage imbalance accounts for generators to whom they sold gas. In a given nomination window, a marketer could, in theory, change their nomination to inject or withdraw more gas to correct an imbalance (Appendix 2-1 contains a description of the nomination process). The five nomination windows each day, however, do not coincide with the hours in which a generator might want to vary their usage, nor do they provide the opportunity to submit a variable nomination.⁶⁴

While generators do not subscribe to storage service, they do benefit from storage and this benefit helps assure electricity reliability. Technical analyses in the Aliso Canyon Action Plan demonstrate the risk to electricity system reliability when the ability to use storage is diminished. This benefit occurs by virtue of the way the utilities use storage to balance their system. SoCalGas uses storage to balance its system on an hourly basis, while allowing the liberal balancing tolerances, that yield great flexibility to customers, to vary their loads within a gas day. SoCalGas could use injections to eliminate excess gas or use withdrawals to provide additional gas supply and even go from one to the other within a gas day. Other electricity systems, without storage, may use hydro-electricity, imports, economy energy sales, demand response, pumped hydro storage, and now battery storage, to manage their swings in demand.

61. Some interstate pipelines offer hourly load service tailored to generator needs. But those services cost more than normal firm transportation service, and unless the generator is an integrated utility they cannot pass the cost on to ratepayers. So, generators avoid buying gas from these pipelines.

62. ICF's 2009 study for the CEC also made this point.

63. An exceptional case occurred when a new independent gas storage facility was denied a Certificate of Public Convenience & Necessity (CPCN) by the CPUC. The facility had contracted for all of its capacity with a municipal utility (not subject to CPUC jurisdiction) for the purpose of enhancing reliability to a large gas-fired power plant and several cogeneration facilities. Despite the contract, the CPUC denied permission to construct the Sacramento Natural Gas Storage (SNGS) project, citing concerns about public safety.

64. There is some talk within the industry of potentially allowing nominations for hourly-variable quantities. Whether they succeed or not remains to be seen, as does how such can be implemented without access to gas storage somewhere along the pipeline. We return to this subject in discussing alternatives to gas storage.

ICF described the role of gas storage this way:

Natural gas storage capacity in close proximity to the firming generator offers a physical option to manage pressure fluctuation resulting from intermittency. The requirement to manage the pressure in the pipeline in proximity to the plant and throughout the system is the combination of compression and a source of gas. Since the gas is moving at a speed of 15 to 30 miles per hour in the pipeline ... the source of gas must be located close enough to the line segment where pressure may be dropping to fill the line pack. Compression with no source of gas on the inlet side of the compressor is not sufficient to manage pressure. If gas can be withdrawn from storage close to the firming plant, either directly upstream of the compressor or utilizing compression at the storage facility, pressure can be stabilized and managed as the firming plant ramps up (ICF International, 2001).

Other regions do not depend on natural gas for electricity in the same way California does. Many of these regions have shifted from dependence on coal, oil, or nuclear power to using gas more as a baseload while California is shifting away from gas and increasingly relies on renewable energy. Also, in many of those regions, the gas-fired generating plants have dual-fire capability and air permits to allow the use of other fuels. The Midwest System Operator (MISO), for example, has 6.6 GW of dual-fired capability within its footprint (MISO Policy & Economic Studies Department, 2013). In the Northeast and Southeast, generators commonly have back-up fuel capability for times when natural gas is not available; both of these markets are pipeline-capacity constrained and have no underground gas storage facilities located within them.⁶⁵ Finally, in some of those regions, power plants commonly have reduced gas availability in winter months when pipeline capacity serves seasonal winter heating load. In New England for example, even if a generator was willing to pay for firm capacity, it has long been common for pipelines to offer firm service to new load only for summer and shoulder months.

The relation between load, pipeline capacity, and storage in California also differs from other parts of the country where without storage they would have to build pipeline capacity to meet their gas load winter peaks. If there is no summer gas load that can use that capacity, consumers pay for capacity that sits unused during those months. Many of those regions use smaller above-ground gas storage facilities known as liquid natural gas (LNG) needle peakers. The needle peakers do not address the monthly average day peaks in winter (greater pipeline capacity is still being built to address that), but they address the extreme “needle” peaks that can occur on an especially cold day within a month.

65. Georgia is another example, where the electric utility would not even buy power from a generator that does not have back-up fuel.

California's gas storage system provides back-up for contingency events affecting electricity generation. Contingency events on the electricity system can result in a sudden need to increase the burning of natural gas in power plants. NERC has contingency reserve requirements that require unloaded generation be available to be fired up and operate to cover contingency events such as the loss of generation or the loss of a transmission line. Such resources must be able to get up and running on a 15-minute notice (NERC BAL-002 Requirement 4). Once activated, the balancing authority has 60 minutes (and sometimes only 30 minutes) to restore the contingency reserves or have resources standing by to respond to the next potential contingency event (CAISO, 2015).

There can also be local areas with limited import capability and fewer native generating resources. LADWP, for example, is one of these. The city of Riverside is another (SCAQMD, 2016a). Riverside stated that it must fire up gas generation should its single transmission import line go down.⁶⁶ Pasadena is another (CAISO, 2016a).

For winter 2016-17, the joint agencies (i.e., CPUC, CEC, CAISO and LADWP) performed a technical assessment and calculated that a minimum of 22 MMcfd of gas would be needed to avoid blackouts after shifting as many resources as possible elsewhere and with no contingency events occurring. In the case of a most severe single contingency event (known as an "n-1" event), the minimum increases to 74 MMcfd, and 96 MMcfd should an n-1 event occur for both CAISO and LADWP (CPUC, 2016f). The amount of gas required to keep the lights on in the summer after shifting resources increases by more than an order of magnitude to 1,750 MMcfd for a 1-in-10 peak day and 1,870 MMcfd with an electricity n-1 event.⁶⁷

Importantly, contingency events, being unpredictable, would occur at a random point during a gas day. The gas quantity nominated and scheduled in advance would be insufficient to serve this additional gas requirement. In this instance, reliability is achieved by virtue of PG&E and SoCalGas being in a position to provide a balancing service that accommodates changes in gas demand. California's gas storage is what allows them to do this today.

Such contingency events can transcend California's agencies and balancing authorities. As part of its summer 2017 reliability assessment, NERC coordinated with Western Electricity Coordinating Council (WECC) to analyze reliability risk for California and the potential for effects to cascade into the western electricity interconnect. WECC particularly assessed generation availability and unit stability within the LA Basin, whether transmission lines

66. Briefing discussion with City of Riverside on Aliso Impacts, April 2016.

67. Aliso Canyon Risk Assessment Technical Report Summer 2017 Assessment, May 2017, p. 17. Shifting generation to locations outside the LA Basin is more achievable in winter than in summer because winter electricity demand is lower, requiring fewer plants to operate to meet demand and lower loading on transmission lines.

would be overloaded and whether low generation in the LA Basin could result in insufficient voltage support that could result in system collapse and risk undermining the entire western interconnection. NERC concluded the following:

There is a minimum amount of generation that must be online in the L.A. Basin to provide voltage support to the local system and allow power to be imported. Without this generation, there is a high likelihood of voltage collapse within the L.A. Basin and risk to the interconnection if such a collapse is not quickly isolated. LADWP and CAISO have the detailed tools to determine the minimum level of generation that must remain on-line for system stability and have estimated 1300 MW to be the “must-run” capacity to support transmission import capability. WECC’s analytics affirmed that this is a reasonable estimate (NERC, 2017).

In California, electricity balancing authorities worry about wildfires (California Climate Change Center, 2012). Fires create the risk of either burning a major transmission line or de-energizing it for a time. Under these conditions, utilities are able to call on gas-fired generation to replace generation made inaccessible by fire. The Blue Cut fire in August 16, 2016 is an example of an event which caused additional gas supply to be called upon to support electric reliability.⁶⁸ Every year, thousands of acres of forests in California and elsewhere burn, mainly in summer months. For example, there were 2,900 fires burning on 106 square miles across California in July 2017, more than twice last year’s average (May, 2017). During recent wildfires in Santa Rosa, hundreds of power poles and the lines and transformers they carried exploded. When fires occur, they sometimes force electric transmission lines offline (e.g., WECC, 2002; CAISO, 2002, 2003, 2007, 2008; FERC, 2013), which can cause sudden loss of generation capacity and may last many days, similar to the intermittency occasionally experienced by wind and solar generation. These losses hamper the State’s ability to provide adequate power to load centers, particularly during the peak electricity demand season. Moreover, wildfires often occur during hot weather, when the demand for air conditioning-driven electricity is highest. This combination of factors increases the reliance on backup strategies, including gas generation. Gas generation may require sudden supplies of gas served by underground storage, to provide local generation and, when necessary, load curtailment. Wildfire frequency and intensity may be increasing with climate change (e.g., U.S. EPA, 2016).

68. Operating data from SoCalGas’ Envoy system show total gas system sendout on the day of the Blue Cut Fire of 3,438,000 Dth, with 410,000 Dth withdrawn from underground gas storage and system receipts of only 3,028,000 Dth. Envoy archives also show that SoCalGas had a low operational flow order (OFO) in place for this event asking shippers to bring their supplies within 5% of demand. If SoCalGas posted the archived hourly data one might be able to explain the apparent discrepancy by which total receipts plus withdrawals exceeded sendout for the day (as offset by individual hours in which sendout was higher than receipts).

Gas-electric coordination efforts nationwide began after release of the American Public Power Association's natural gas study in 2010 and the extreme southwest cold in February 2011 that led to electricity outages and natural gas curtailments (discussed above in Regulatory and Operational Options (Including Market Rules) to Help Replace Underground Gas Storage). Several of the organized markets and the FERC began to focus more attention on linkages between gas used for electricity generation and the ensuing reliability issues. Discussions have focused on the nomination windows, an arcane provision still in many tariffs known as the "no-bump" rule that can be particularly troublesome to generators, linking the start hour of the gas day with the start hour of the electricity day, and other possible remedies (Black & Veatch, 2012). Although many meetings of the North American Energy Standards Board (NAESB) occurred, various reliability transmission organizations conducted studies, and FERC held a rulemaking, progress has been modest. CAISO has added a staff position to focus on gas-electric issues.

The above discussion demonstrates the State's reliance on natural gas for electricity reliability. It highlights how that role has changed and the gas system's rules being set up when gas was not as important for electricity reliability.

1.2 Factors that May be Causing Role of Gas Storage to Change

The role of gas storage may be changing as markets and policies evolve. Specific instances we can identify now include price changes, demand changes, and generation changes.

Prices

Lower prices with reduced volatility have reduced the value obtained from use of gas storage to seasonally arbitrage gas. Accordingly, consumers and risk managers may decide not to hedge. Arbitrage itself does not require physical storage because financial contracts can be purchased that lock in winter prices ahead of time. (Financial arbitrage cannot address reliability in the way that physical storage can). The physical storage owned and used by the utilities for their core customers, however, represents a depreciated asset so the cost to use storage may be less than the transaction cost of a seasonal financial hedge contract. This may make physical storage financially more attractive. Customers and regulators also might be more (or less) comfortable with the operational risks and financial exposures of physical storage than with financial contracts. Financial contracts also are typically kept confidential, reducing market transparency, whereas storage injection and withdrawal volumes are at least reported, which plays some role in enhancing market efficiency and competition and therefore prices.

Flatter prices (i.e. lower price volatility) as documented in Figure 19, may also reduce interest in the short-term arbitrage provided by independent storage.⁶⁹ Recall that gas marketers largely use independent storage for shorter-term price arbitrage, and to enhance liquidity. Contracts for that storage are often multi-year so changes to them may lag behind market conditions, but anecdotal reports indicate that reduced price volatility has reduced arbitrage opportunities, and thus reduced subscription to independent storage. A look at the SoCalGas Index of Customers for underground gas storage from December 2015 versus the list of contract holders in April 2017 shows that the number of non-core customers and gas marketers holding storage rights decreased from about 35 Bcf to only 3.2 Bcf. The more recent part of that decrease was likely caused by the situation at Aliso Canyon. Also, SoCalGas' announced in February 2017 that its Storage Safety Enhancement Plan (SSEP) would significantly further reduce its injection and withdrawal capability through late 2017.⁷⁰

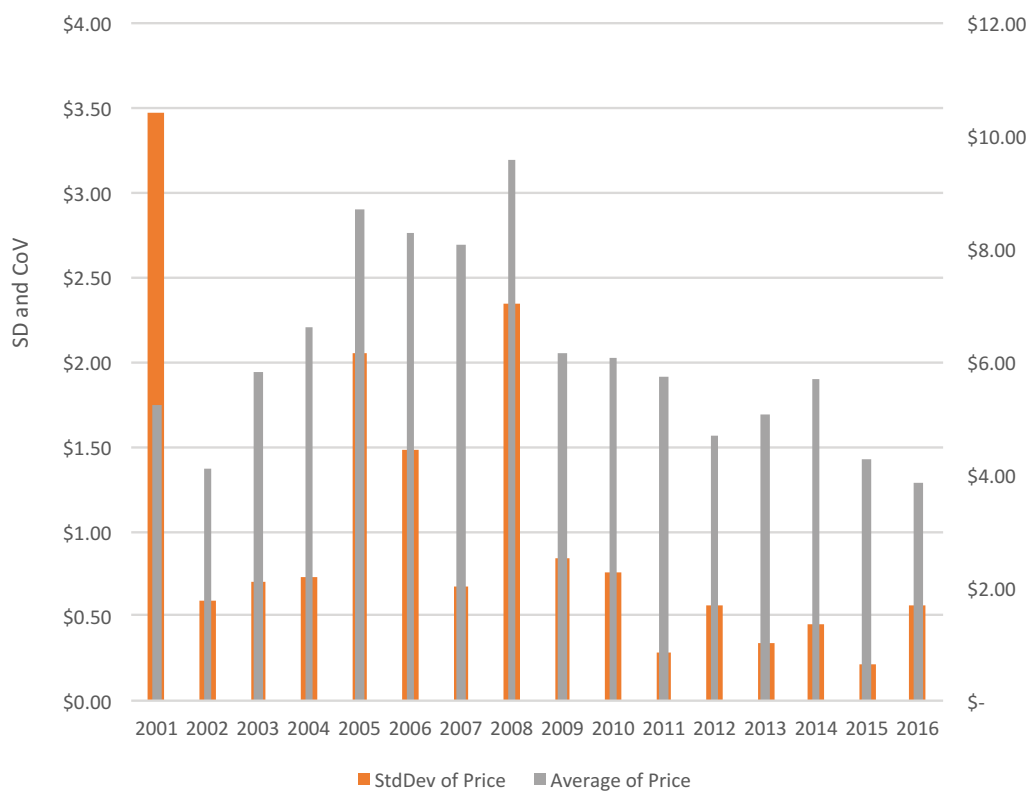


Figure 19. California Natural Gas Price Volatility

Source: Aspen Environmental Group analysis

69. Prices are the same California Citygate prices reported by EIA as used in Figure 13.

70. The CPUC directed SoCalGas on March 16, 2017 to modify the Storage Safety Enhancement Plan (SSEP) to preserve withdrawal capability of 2.046 Bcf.

A Potential Shift in the Use of Independent Storage

At a public customer meeting on May 11, 2017, PG&E announced a proposal to close its Los Medanos and Pleasant Creek gas storage facilities based on an assessment of reliability. The cost of this closure was not released to the public but the proposal was included in their 2019 Gas Transmission and Storage Rate Case filed with the CPUC on November 17, 2017 (CPUC Application of PG&E). PG&E said it would reconfigure its gas services to more explicitly focus on intra-day balancing and contract with the independent storage providers to provide the gas needed to meet core winter requirements. This would essentially restructure the independent storage providers by giving them an obligation to serve core customers. No reliability or system gas analysis was released to the public with the meeting, and PG&E retreated to settlement discussions (confidential under CPUC rules) to discuss details. As of October 1st, the proposal has not yet been formally filed at the CPUC and remains subject to litigation and approval there. If approved, this plan would represent a profound shift in the use and role of independent storage in California.

Demand changes

Declines in the use of natural gas would also reduce the need for storage, all else being equal. The California Energy Commission (CEC) and the two gas utilities all forecast natural gas demand (total, peak, and electric generation demand) to decline over the next ten years. PG&E, in fact, forecasts demand to decline at an average rate of 0.6% through 2035 (2016 California and Electric Utilities 2016). About one-third of that is attributable to energy efficiency among core customers. The other two-thirds is attributable to a combination of increasing renewables offsetting gas-fired generation (which decreases electricity generation demand for natural gas), along with a significant increase in gas transmission rates charged to generators (which also decreases electricity generation for natural gas). In describing its forecast in the 2016 CGR, PG&E said that greater use of gas-fired generation to back-up renewables with load following and other ancillary services was likely, but was not captured in the forecast. The CGR does not report on or address hourly gas load. That means that the utilities have no published estimates of the impact on their gas systems from significant changes to use patterns by generators – and no analysis beyond what SoCalGas performed for the 2014 WIEB study or the April and August 2016 Aliso Canyon technical reports.

Demand for gas will change because California has been adding additional intermittent renewables to the grid that will reduce the aggregate need for burning gas in power plants. However, the remaining use of gas may be “peakier,” or more variable because gas-fired plants are increasingly called upon to meet the sudden increases in net electricity demand that occur, for example as people get home in the afternoon and begin to consume electricity just as solar production begins to wane. The gas system was not configured to support large increases of sudden use in the afternoon. Currently, the system accommodates large increases either serendipitously, or because storage has been available and the utility has sufficient control to allow it to make up the imbalance created on its system when the generator fires up.

The public record does not yet provide detailed studies with stakeholder review examining the ability of California's gas utilities to serve large ramps in electric generation. ICF has done some general work in which they suggested enlarging pipeline segments near power plants in order to increase line pack capability. ICF also noted that the capabilities of marketers to provide shaped supply (i.e., other than on an even, ratable basis as required now) will depend on the underlying infrastructure including such enlargements (Crook, 2012).

One study performed for the Western Interstate Energy Board (WIEB) includes a look at how natural gas use patterns might change with more renewables generating electricity in California.⁷¹ The study does not assess system operations without use of underground gas storage. Its findings are public but the underlying transient hydraulic analysis was conducted by SoCalGas and was not subject to detailed critical review.⁷² SoCalGas' analysis for the WIEB study found that in a 50% renewables penetration case, SoCalGas could handle afternoon ramps as gas-fired generation came on to replace renewables, as long as supply and demand were already matched and its system was therefore in balance. SoCalGas added the further caveat that the dispatch of more "quick-start" gas-fired generations could cause dramatic pressure drops that would look much like a system failure to gas system operations control staff.

SoCalGas warned in the Quadrennial Energy Review (QER) conducted by DOE in 2014 that quick-start plants were changing use of gas on its system.⁷³ SoCalGas and SDG&E deliver natural gas to 79 individual power plants representing 20,000 MW of generating capacity. The relative locations of those plants are shown in Figure 20.

71. Energy & Environmental Economics, Inc., Natural Gas Infrastructure Adequacy in the Western Interconnection: An Electric System Perspective (2014). Aspen Environmental Group provided support to the CEC's participation in this study.

72. While Western Interstate Energy Board (WIEB) tried to use a contractor to build and analyze a hydraulic database, they found no sufficiently detailed public source of the necessary data that would allow them to produce useful results. SoCalGas therefore presented its analysis and results to a working group that included representatives of the California Energy Commission, Lawrence Berkeley National Lab (LBNL) as independent observers for Department of Energy (DOE), and WIEB. Aspen Environmental Group participated in the WIEB working group on behalf of the CEC. SoCalGas worked with the Joint Agencies in a similar way that they did to compile the Summer 2016 Aliso Canyon Risk Assessment Technical Report.

73. Presentation of Beth Musich (2014), found at https://energy.gov/sites/prod/files/2014/07/f18/qermeeting_denver_musich_presentation.pdf. Accessed May 2017. Musich cited those plants recorded a maximum load in winter of 1,000 MMcf (on November 13, 2013) and a maximum in summer of 1,835 MMcf (on August 13, 2012).

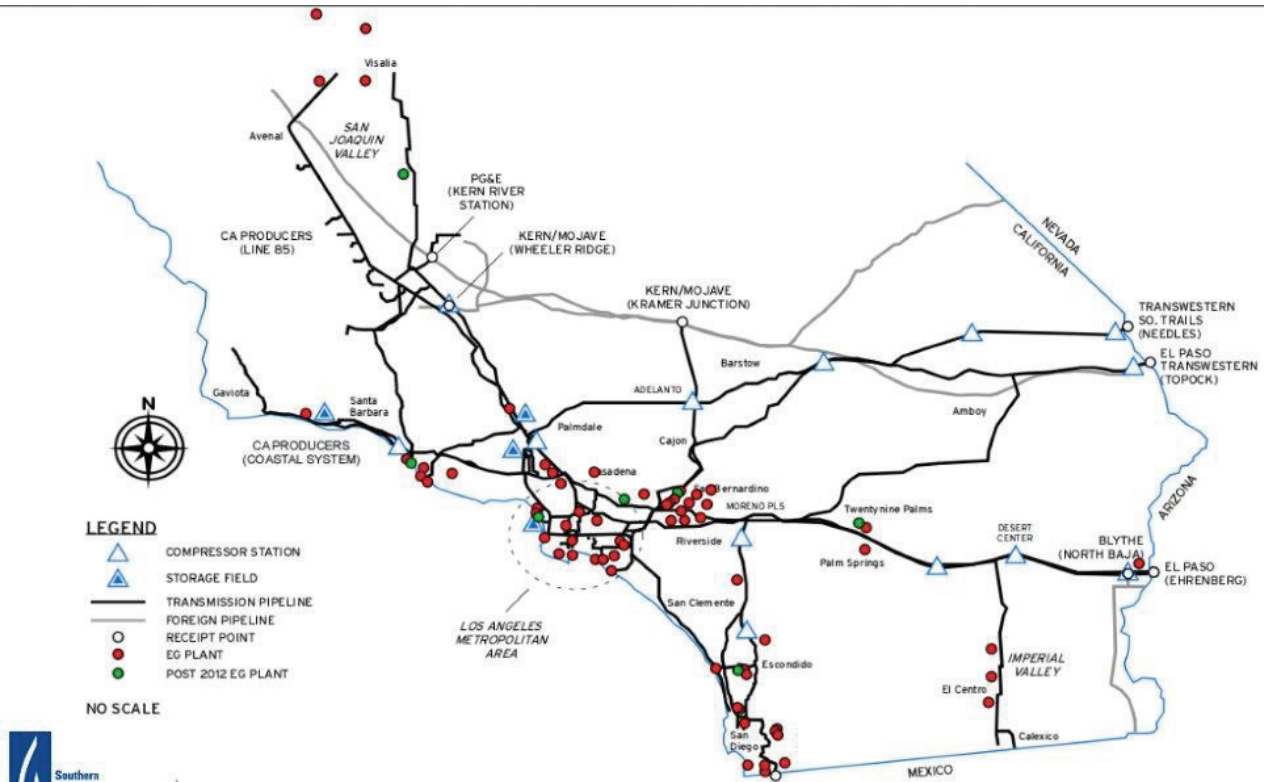


Figure 20. SoCalGas and SDG&E Electricity Generation Customer Locations

Source: SoCalGas DOE QER Presentation

The newer plants have been built with quick-start technology that can fire up to full operation in as little as ten minutes. More specifically, they take nine minutes to go from zero to 50% of their hourly demand and one minute to ramp up from there to full output. This demand profile contrasts starkly to older power plants that take up to two hours to go from zero output to full generation. SoCalGas noted that it sees a drop in system operating pressure of 40 psig, and has seen a drop of up to 70 psig, due to firing up quick-start plants. The sudden drops in pressure are illustrated in Figure 21.

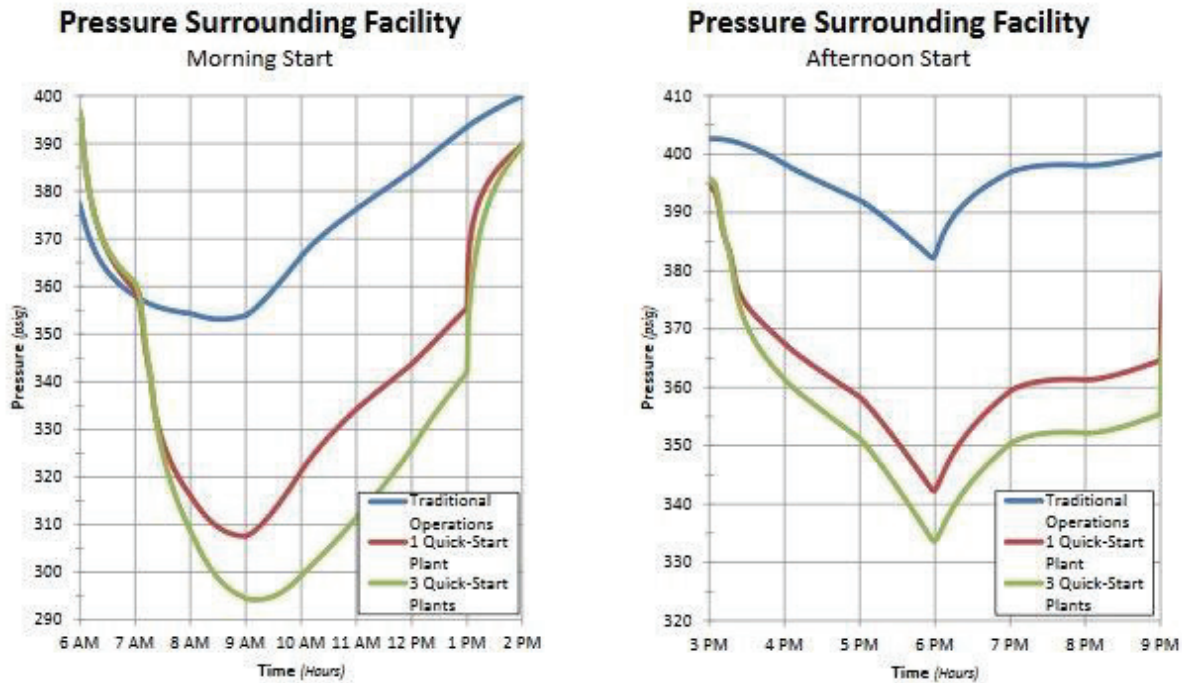


Figure 21. SoCalGas Pressure Drop with Quick-Start Units

Source: SoCalGas Contribution to WIEB Study

In trying to assess reliability impacts in the aftermath of the 2015 Aliso Canyon incident, the joint agencies learned that SoCalGas uses Aliso specifically to help balance its system. PG&E indicated during the WIEB study that its Los Medanos field, located in the Highway 4 corridor near several key power plants and refineries, is useful to them for handling afternoon ramps by power plants.⁷⁴

Conclusion 2.9: Without gas storage, California would be unable to accommodate the electricity generation ramping that now occurs nearly every day and that may increase as more renewables are added to the grid.

74. Interview with CEC staff.

1.3 Impacts on performance or gas delivery from problems at gas storage facilities.

A list of gas storage facility incidents, including Aliso Canyon, appears in Table 9. Additional details on some of these events can be found in a 2007 history of gas storage facility incidents compiled for the Sacramento Natural Gas Storage facility (Weatherwax).

Other than re-dispatch of the electricity system by CAISO and LADWP in the aftermath of the Aliso Canyon well leak, the only other incident that appears to have affected customers is the PG&E McDonald Island incident in December 2015. That event was not a failure of the McDonald Island facility per se, but rather human error. A valve left open after maintenance work allowed undehydrated (i.e., “wet”) gas into the distribution system, which then froze due to cold temperatures. Reports of leaks from the now-closed Montebello gas storage field that resulted in local evacuations of residents and complaints about Playa del Rey are easy to find in the press.⁷⁵ This is not saying the system can withstand all interruptions in storage service, just that these incidents were not large enough, or occurred at a time when they could have little impact.

Table 9. Gas Storage Facility Incidents and Impact to Customers.

Owner	Field	Year	General Nature of the Incident	Impact to Customer Service
PG&E	Los Medanos	2011	Valve failure in open position during hydrotest resulted in gas leak	None
PG&E	McDonald Island	2016	Small leaks discovered due to testing in wake of Aliso Canyon leak; DOGGR mandates testing regimen	Field shut during summer; no impact to deliveries
PG&E	McDonald Island	2015	Whiskey Slough valve left open allowed “wet” gas into Line 57B and then froze in a district regulator and pressure limiting station	Communities of Discovery Bay and Byron lost gas service on a cold day; customers sent to warming centers
PG&E	McDonald Island	1993	Explosion in gas conditioning (moisture extraction) plant	None
PG&E	McDonald Island	1974	19-day fire sparked by explosion during drilling of new well	None
PG&E	McDonald Island	1982	levee broke; island flooded	None
SoCalGas	Aliso Canyon	2015	Well blowout due to the breach of an injection well casing. Safety valves had been removed in the 70s, causing the leak to persist unabated until discovered.	Mitigation measures and mild weather prevented gas curtailments and electricity blackouts
SoCalGas	Aliso Canyon	2013	Production casing leaks at depths adjacent to oil production sands	None

75. See, for example, http://articles.latimes.com/1990-08-05/news/we-133_1_underground-natural-gas-storage. Accessed July 2017.

Owner	Field	Year	General Nature of the Incident	Impact to Customer Service
SoCalGas	Aliso Canyon	2008	Well casing corrosion - 400 psig at surface	None
SoCalGas	Aliso Canyon	1994	Well crushed during Northridge quake	5-day field outage but demand down after quake so impact unclear
SoCalGas	Aliso Canyon	1975	Sand erosion in piping led to a blowout and well fire	None - partial shutdown of operations
SoCalGas	East Whittier	1970s	Gas migration - injected gas being produced by a nearby well	None - field shut in 2006; removed from rate base in 2009
SoCalGas	Honor Rancho	1975 - 2008	Gas migration from Castaic to surface via faults	None - impacted oil production in nearby wells and killed trees at surface
SoCalGas	Honor Rancho	1992	Casing shoe leak due to sidetracking	None
SoCalGas	Montebello	1950s -1980s	Gas migration due to original grout not withstanding higher pressures	evacuations
SoCalGas	Montebello	2003	Gas migration due to original grout not withstanding higher pressures	evacuations - ultimately resulted in storage field closure in 2003
SoCalGas	Playa del Rey	1940s -2008	Gas migration into Venice structure via faults and wellbores	None - some stored gas lost
SoCalGas	Playa del Rey	2013	Well over-pressurized during injection, causing vent valve to release gas. Brief fire and shut in of facility	None
SoCalGas	Playa del Rey	2003	Broken compressor valve led to activation of a vent valve, spraying a gas/oil mist that coated surrounding homes	None
Standard Oil of California	El Segundo	1993	Gas migration due to caprock not being gas tight/faulted	None - field closed in 70s after gas detected in a nearby housing development
Wild Goose	Wild Goose	1999	Leaking flange discovered due to pressure increase	None

Source: Aspen Environmental Group compilation

1.4 Alternatives to Underground Gas Storage (to 2020)

The first portion of this section considers facilities and supply options that could help replace underground gas storage. The second portion looks at operational and market changes that might reduce the need for storage. In both sections, we focus on what is known now and expectations to 2020. Many, but not all, of the alternatives reviewed come from suggestions in the Joint Agency reliability action plans or public comment. Virtually no detailed studies are available in the public domain looking at using these to specifically replace any aspect of underground gas storage and some may find the analysis here limited. Even based on this limited assessment, we find that these alternatives cannot address the overarching need to use stored gas to meet winter demand (or balance the gas system on an intraday basis) by 2020, either because they provide insufficient relief, impose extraordinary costs or take too long to construct.

Recall the seven uses of gas storage as described above:

1. Meeting higher demand in winter months
2. Sustaining flat aggregate wellhead production by producers serving California
3. Meeting individual daily needle peaks in winter and summer
4. Intraday balancing of transportation nominations for all customers (but especially key to electricity reliability)
5. Local stockpile in case of pipeline failure or reduced interstate supplies
6. Seasonal and short-term price arbitrage
7. Allowing market liquidity

The magnitude of gas required to meet winter demand and winter peak demand dominates these uses. Any viable replacement in the 2020 timeframe would have to demonstrate that it could effectively match supply to demand in the winter. Consequently, the following sections first assess whether a given approach could replace gas storage for the purpose of meeting winter demand.

1.4.1 Facility, Supply and Demand Options that Could Help Replace Underground Gas Storage

Here, we identify and assess options that could increase capacity or decrease demand and in so doing could help replace the need for underground gas storage. We describe pertinent details for each, as well as offer ballpark costs and note potential safety considerations. They include adding new intrastate and possibly some interstate pipeline capacity, new

electric transmission, LNG or CNG in containers, LNG peak shaving units, renewable natural gas, and energy efficiency and demand response. All entail significant cost; none could completely replace underground gas storage by 2020, although some could reduce the need for storage in this timeframe.

New Pipeline Capacity. Both our intrastate pipeline capacity and interstate capacity are too small to meet winter peak demand without gas from storage. Table 6 shows calculations of the amount of pipeline capacity required to meet the forecast level of winter peak demand for 2020, if underground gas storage is eliminated. All else being equal, meeting winter demand would require building 4,334 MMcfd (4.3 Bcf per day) of new intrastate pipeline capacity. As a rule of thumb, a single large-diameter (i.e., 36" or 42") pipeline and associated compression can deliver at least 1,000 MMcfd. In other words, replacing storage would entail building at least four additional pipelines and associated compressor stations (if existing compressors do not have excess horsepower to support the new pipelines). This new capacity will need to run from interconnects with the interstates to the interconnects where gas storage currently delivers into the local transmission system. The pipelines downstream of storage should already be appropriately sized. Table 1 showed 10,631 MMcfd (10.6 Bcf) of firm interstate capacity able to deliver gas to the state line. Interstate pipeline capacity of 10.4 Bcf is not sufficient to meet the design peak demand of 11.8 Bcf. So, besides the intrastate capacity of 4.3 Bcf per day, California would also need additional interstate pipeline capacity of approximately 1.2 Bcf per day.

The FERC approves construction of interstate pipelines and its policy does not provide a large barrier to construction. For over twenty years, FERC policy has been to approve expansions, subject to environmental review and mitigation, whenever a sponsor is willing to take the risk of potential unsubscribed capacity at rates using a well-understood cost recovery methodology. EIA's posting giving an overview of the process for building interstate pipelines cites an average time for FERC review of 15 months and an average overall from announcement and open season to solicit shipper commitments to the pipeline in-service date of three years (U.S. EIA Natural Gas Pipeline Development and Expansion, 2017).

Ruby Pipeline, which runs 42" diameter pipe the 680 miles from Opal, Wyoming to Malin, Oregon with four compressor stations is the most recent greenfield addition to western pipeline capacity (FERC Docket No. CP09-54). Its sponsor announced launch of an open season to solicit binding shipper commitments in February 2008 (*Energy Business Review*, 2008). It filed its request to be granted a certificate of public convenience and necessity (CPCN) in January 2009. The final Environmental Impact Statement (EIS) was published in January 2010 and FERC granted CPCN approval in April 2010. Construction began that July (which suggests the pipe was ordered before the final CPCN was granted) and the pipeline was placed into service one year later, in July 2011. Fourteen shippers hold contracts for firm transportation totaling about 1 Bcfd (this is less than the full 1.5 Bcfd of capacity Ruby offers, which implies its sponsors took the financial risk on the difference between those

commitments and the full 1.5 Bcfd).⁷⁶ Ruby reported to FERC a near-final total cost of \$3.55 billion, some \$590 million more than estimated. Rates for firm transportation on Ruby run \$1.14 per Dth of space reserved plus \$0.01 for every Dth transported (FERC Docket No. CP09-54).

If the utilities were going to build new intrastate capacity inside California, they would apply to the CPUC. California's intrastate pipeline capacity involves obtaining approvals, doing the design work, and completing the associated environmental impact work to expand. SoCalGas filed an application to build a new segment of pipeline that would have connected its northern mainline to its southern mainline using a route generally running from Adelanto to Moreno. In that application (A. 13-02-013), SoCalGas argued it only needed to ask permission to recover the cost of the facility in rate payments. The CPUC ruled that a complete showing of need with environmental assessment was required before construction could begin. After hearings and proposals for alternatives, the CPUC, in Decision No. 16-07-015, denied permission to construct.

The most recent expansion of mainline capacity within the state may be PG&E's expansion in 1993 from Malin, through Antioch (with a connection to storage at McDonald Island), ultimately terminating at Kettleman. This major expansion doubled the capacity of the mainline bringing gas in from Canada at Malin, and allowed that gas to flow all the way south to Kettleman. This allowed some gas from the south to be displaced or swapped such that customers in southern California could purchase Canadian gas. The expansion was the California portion of what was known as the PGT/PG&E Expansion Project and ran all the way to Alberta. At the time, the PGT/PG&E Expansion was said to cost more than \$1 million per mile (Bechtel PGT/PG&E Pipeline). For the much more recent example of Ruby Pipeline, construction costs totaled \$5.2 million per mile (or \$3.6 billion for its approximate 700-mile distance) with a capacity of 1.5 million Dth per day.⁷⁷

Perhaps constructing a new pipeline in California will cost less than the recent example of Ruby Pipeline. Sometimes pipelines can add a second line between compressor stations (known as "looping" because it creates a loop between the two stations). Subject to confirmation, most of the intrastate capacity existing within California is already looped. Sometimes a compressor is sized low relative to the maximum pressure a pipeline can achieve such that capacity can be added cheaply by merely adding compression. This may be feasible for Ruby or Kern River or Gas Transmission Northwest (GTN). El Paso Natural Gas (EPNG) may have existing capacity that is under-utilized that California could obtain and avoid building a complete new pipeline for the full length between supply basins and the state line.

76. A Dth is 10 therms and is equal to 1 MMBtu. Pipeline tariffs typically state rates in dollars per Dth per month and capacity is reserved in Dth per month.

77. Or about 1.44 Bcf per day assuming a heating value of 1.04 million Dth per Bcf.

Constructing even one pipeline and getting it into service by 2020 is close to infeasible at this point given the time it takes for policy approval, environmental analysis, obtaining right-of-ways, and construction. Constructing one or two by 2025, however, might be achievable; and, if the demand forecasts are correct, the new pipeline capacity needed to replace storage would be smaller by then.

Ruby may be a reasonable proxy for the type of facilities (in terms of pipeline diameter and compression) and the total mileage needed to cover Topock to Malin, using the assumption that existing routes are the natural paths for expansion, which seems reasonable as a first cut.⁷⁸

Finding: Based on recent pipeline construction costs, we estimate a total cost of close to \$15 billion to add 4.3 Bcfd of large-diameter intrastate pipeline capacity and one new interstate pipeline, should California have no underground gas storage.

Converting this \$15 billion capital, or investment, cost to a cost per Dth would require assuming a capital to debt structure and a forecast of throughput over some cost recovery period. Whatever the rates turn out to be, customers would be paying for the entire capacity year-round, but only use it part of the year. The annual revenue requirement for underground gas storage is undoubtedly lower than that, with the caveat that new safety requirements may impose higher costs to refurbish and operate those facilities.

Replacing storage with a dependence on supplies delivered through new pipelines will introduce new risks to the gas system. The West (outside of Alberta) has little underground gas storage capacity and lacks the geology to build more storage. The locations that could host storage tend not to be located near interstate pipelines and the West is largely disconnected from the so-called “production-area” storage of the Gulf Coast (see Figure 2 to see where storage is located US-wide). Consequently, eliminating storage in California and replacing it with pipeline capacity means we must assume 4.3 Bcf more production would be available as needed to match California’s full demand on a peak day. In a competitive market and with proved reserves available to produce gas and even export it, this does not seem unreasonable.⁷⁹ That being said, this study does not perform a supply-demand analysis to look at production by supply basin and their capability of meeting California peak demand or what other gas market adjustments might occur if California had no gas storage. However, the choice of replacing storage with new pipelines would move control of some reliability issues out of the State.

78. Online distance calculators suggest 256 miles from Topock to LA and 572 miles from Malin to LA, so Ruby’s 680 miles might be a little shorter than what we could end up needing to build to replace storage

79. See CEC, 2017 Natural Gas Outlook, forthcoming, and Energy Information Administration, Annual Energy Outlook 2017.

Finding: Supplying California's full winter peak day demand completely with gas delivered via pipeline on the day it is needed instead of using gas stored in California pushes the problem of matching supply with demand onto upstream gas pipeline operators and producers.

Conclusion 2.10: Construction of additional pipelines to replace underground gas storage in the 2020 timeframe would cost approximately \$15B, would be extremely difficult to get done by 2020, and would shift the risk of supply not meeting demand to upstream, out-of-state supplies.

LNG Peak Shaving. LNG peak shaving units with tanks to store the liquefied gas above ground could replace underground gas storage.⁸⁰ California has not needed LNG peak shaving units because we have underground gas storage, but nearly 100 of these facilities exist in the U.S. today. The one nearest to California is in Lovelock, Nevada. Large gas utilities and pipelines such as Atlanta Gas Light and Florida Gas Transmission own several such facilities. Besides Atlanta, Memphis, Omaha, and Minneapolis are among the cities where meeting winter peak demand is facilitated by LNG peak shavers. These units provide above-ground gas storage: they take pipeline gas that is excess to requirements in low demand seasons, chill it into LNG and store it in a large tank, then reheat it when needed to meet demand and inject it back into the pipeline. At one time, the combined sendout capacity of LNG peaking plants in the U.S. represented about 10% of total peak capacity (Mesko, 1996). The Gas Technology Institute offers extensive information about operating such peak shaving facilities (2013). Chicago Bridge and Iron Company (CB&I) has built more than 90 of these facilities in the U.S. and elsewhere.⁸¹ Accordingly, training technology and expertise to build these facilities is readily available.

80. LNG is natural gas that has been chilled to its liquid state, where it takes 1/600th the of the space it takes up as a gas.

81. See <http://www.digitalrefining.com/data/literature/file/1247008557.pdf> for more detail on CB&I's experience in this area, including photographs of facilities.

Three recent projects illustrate what such facilities might cost California; their costs and capabilities range widely.^{82, 83, 84} Taking the simple average of these projects' capital cost per MMcf of sendout, is \$2.25 million. Replacing 4.3 Bcf of underground gas storage with above-ground LNG peak shavers works out to a capital investment of approximately \$9.675 billion. This capital investment would ostensibly be recovered through rates over time from customers deemed to benefit from the facility.

Liquefaction (chilling) pipeline gas requires energy, as does vaporizing (reheating) it back to its gaseous state. This energy use would produce GHG emissions and potentially criteria pollutants. Siting and land requirements may pose obstacles, depending on the sites selected.

Storing LNG also poses safety concerns. A blast in 2014 at a Williams Partners facility in Plymouth, Washington (located along The Williams Companies' Northwest Pipeline) injured five people and caused \$46 million in damage. The blast occurred when the plant returned to liquefaction activities at winter-end. The Pipeline and Hazardous Materials Safety Administration (PHMSA) failure investigation report cited auto-ignition of a gas-air mixture left in a pipe after routine winter-end purging as the apparent cause (PHMSA, 2016).

Finding: California could replace all underground gas storage required today with LNG peak shaving units and meet the 11.8 Bcf extreme winter peak day demand forecast.

Conclusion 2.11: Replacing all underground gas storage with LNG peak shaving units to meet the 11.8 Bcf extreme winter peak day demand forecast for 2020 would be extremely difficult to permit and would require about \$10B.

82. Puget Sound Energy (PSE) is currently in the process of constructing its Tacoma LNG plant (Puget Sound Energy, 2017). The facility will be located at the Port of Tacoma. Tacoma LNG will liquefy and store pipeline gas until needed on a later day, thereby providing peak gas supply to the PSE Seattle-Tacoma service area. Tacoma LNG will also provide cleaner fuel (replacing bunker fuel) for ships traveling between Tacoma and Alaska. The facility will be able to liquefy 20.7 MMcf of pipeline gas into 250,000 gallons of LNG. It will then be able to vaporize the liquid gas and send 66 MMcf back into the pipeline (City of Tacoma, n.d.). Its single LNG tank will be able to store eight million gallons of LNG, which equates to 661 MMcf. The anticipated installed cost of the facility is \$310 million (Ecology and Environment, Inc., 2015).

83. The second project, the Pine Needle LNG storage facility in Guilford County, North Carolina, was placed into service in 1999 and interconnects to Transcontinental Pipeline. Pine Needle has the capability to liquefy 20 MMcf of natural gas (similar to the 20.7 MMcf capability of the Tacoma LNG facility). Its ability to store the equivalent of 4 Bcf, however, is about six times more than at Tacoma and its ability to vaporize and return to the pipeline 400 MMcf is also significantly more than Tacoma. The cost to build Pine Needle was \$106 million, in then-current dollars (Pine Needle LNG Company, LLC, 2010).

84. The third project, Yankee Gas Service's (Yankee) LNG facility in Waterbury, Connecticut was placed into service in 2009 at a then-current cost of \$108 million. Yankee offers 6 MMcf of liquefaction capacity, 1.2 Bcf of storage, and 60 MMcf of vaporization capability (CBI, 2008).

Containerized LNG. Intermodal containers designed to specifications approved by the International Organization of Standardization (ISO) can deliver liquid natural gas to remote customers. These containers are 40 feet long and 8 feet square, with fortified walls and protective frame structures outside the perimeter of the tank. They can fit on any type of transport that can carry a standard shipping container and container ships, railways, or trailer trucks can all deliver containerized LNG.

The ISO containers can hold the liquefied gas for up to 75 days (meaning they can serve as storage). Returning them to pipeline gas requires use of a portable vaporizer (re-heats the chilled liquid to its gaseous state). Each container can hold up to 10,000 gallons, which when converted back to ambient air temperature is 0.830 MMcf of natural gas. (A relatively efficient gas-fired power plant would use between 8 MMcf to generate 1 MW for an hour, so approximately 10 containers would be required per MW), or a 50-MW gas fired electric generator would require 500 containers — for enough natural gas to generate electricity for one hour. A number of applications can serve as examples for California.⁸⁵

Conclusion 2.12: The number of containerized LNG units required to generate each MWh suggest containerized LNG does not appear viable at the scale required to replace California's 4.3 Bcfd winter peak need for underground gas storage use. It may, however, have application in meeting system peaks for a few hours or supporting power plant demands for a few hours. Though it would require 2,000 containers to support a 50 MW

85. In terms of known uses, EIA cites a 90,000 gallons per day, three-unit plant under construction at Port Allen, Louisiana that will take containerized LNG to users located far from natural gas pipeline service. EIA also cites use of containerized LNG coming from Florida to supply a 120-MW power plant the island of Jamaica is converting from oil. That appears to use 22 containers of LNG per day, without saying how many hours the plant would operate each day or at what level of output. In a demonstration project, late in 2016, two LNG containers (manufactured by Hitachi) were hauled to Fairbanks, Alaska on the Alaska Railroad and then 4.5 miles via flatbed truck (Alaska Railroad, 2016). They returned to Port MacKenzie to be refilled with LNG before returning on the next overnight freight to Fairbanks. Local news reports on briefings to first responders suggest the Federal Railroad Administration encourages responders to let the gas vent, should a puncture occur. The Railroad believes transportation by rail will be safer than via truck and safer than the risk associated with other petroleum products shipped by rail to Fairbanks currently. Others disagree (Buxton, 2015).

Hawaii Gas is using containerized LNG purchased from Fortis in British Columbia and a small liquefaction facility owned by Clean Energy in Boron, California (Hawaii Gas, 2016). The Hawaii project consists of 70 ISO-certified containers, 2 new cryogenic pumps, 3 new LNG vaporizers, and an LNG pump skid. EIA reports Hawaii Gas is still exploring building the infrastructure to support docking of bulk LNG tankers to floating regasification and storage units. Hawaii consumes only 3 Bcf of natural gas per year, the lowest in the U.S., none is used for power generation and the LNG will replace only 30% of the syngas that Hawaii Gas manufactures from naphtha. The capital expenditure for the LNG container project shown in Hawaii Gas' application to the Public Utilities Commission of the State of Hawaii is \$12.8 million (Hawaii Public Utilities Commission, 2014). Some parts of the application were redacted and so it is not clear if the capital expenditure includes the cost for Hawaii Gas to purchase the 70 containers (CEC, 2016b).

power plant for four hours, and these containers would have to be transported to a power plant, which would incur potential safety issues, increased emissions, and complexity.

CNG In A Box™. Compressed gas (which is different than liquefied gas) stored in containers,⁸⁶ such as the GE version trademarked as “CNG In A Box” could perhaps provide some storage service. GE presented this concept in comments filed at the CEC after the April 2016 Joint Agency Workshop on Aliso Canyon Action Plan for Local Energy Reliability in Summer 2016 (CEC, 2016e). The container includes the compressor, a gas dryer, a gas cooler, pressure relief valves, and a blowdown tank (see Figure 32). Quotes run about \$600,000 for one container that can compress between 1.5 and 2.5 MMcfd. That does not include interconnection from the container to a pipeline and back or from a pipeline to the container to a power plant, and additional “tube” trailers would be needed to store gas after compression.

GE suggested 1 compressor box plus 12 tube trailers and 2 pressure reduction skids could cover 4 hours of generation by a single 50 MW LM 6000, although the box requires a whole day to compress that much gas at a rate of 0.5 MMcf per hour. Replacing the full 4.3 Bcf pipeline capacity deficit California would face, absent underground gas storage, would require close to 8,000 boxes and would only deliver for one day before needing a day to compress again. They could not cover the multiple days of gas from storage often needed in the winter.

Four hours of gas to a 50 MW combustion turbine is the rough breakeven point; at less than that, the CNG appears to be more economic than the LNG.⁸⁷ Safety and the implications of a more distributed gas system with storage located nearer to end-users become the issue. However, no data on reliability or leak rates appears available.

Conclusion 2.13: As with the containerized LNG, far too many “CNG In A Box” containers would be needed to replace California’s underground storage, but applications such as providing a few hours of gas at a specific location such as a peaking power plant or a refinery could make sense.

86. CNG is sometimes also used in vehicles.

87. Liquefying gas costs more than compression, but LNG can store more gas per container.



Figure 32. GE's CNG Technology Solution

Source: Photo courtesy of BHGE

LNG via Ocean Terminal. LNG import terminals in California have presented controversy (in no small part due to safety concerns not discussed here) including a facility proposed in the 1970s at Point Conception and five or more proposals presented in the mid-2000's. Based on this experience, this analysis does not contemplate building multiple LNG terminals along the California coast. Sempra, however, did build and still owns an LNG import terminal at Ensenada in Baja, Mexico known as Costa Azul. This facility can deliver up to 1 Bcf per day of natural gas into pipelines.⁸⁸ The configuration of SoCalGas' system means that SDG&E receives virtually all of its gas via the Moreno to Rainbow corridor coming from the EPNG southern mainline that also serves Los Angeles.⁸⁹

88. The Costa Azul storage tanks can hold 320,000 cubic meters of liquefied gas (which converts to 6.9 billion cubic feet reheated back to gaseous state). Costa Azul connects through the Transportadora de Gas Natural de Baja California (TGN) pipeline to a lateral pipeline that crosses the International Boundary to deliver gas into the SDG&E system at Otay Mesa. The border crossing at Otay Mesa is sized to accept up to 400 MMcfd. Low natural gas prices resulting from the shale boom mean that the economics do not support LNG imports and the facility, while fully subscribed and paid for via reservation charges, remains little used. EIA reports that imports have averaged only 4% of the terminal's nameplate capacity since 2011.

89. Flows on that lateral pipeline are southbound only, meaning that physically, the gas imported as LNG cannot flow further north than the SDG&E system.

Serving SDG&E load with gas imported as LNG would allow more flowing supply to continue on into the LA basin, thereby augmenting SoCalGas' operational flexibility.⁹⁰

The Joint Agencies' Action Plans raised the possibility of using the Sempra LNG terminal in this way. Hydraulic simulation performed by SoCalGas for the agencies in preparing the reliability action plans demonstrates how Moreno Station becomes the pivot point for the SoCalGas system when Aliso Canyon is not available. As pressures inside the LA basin drop, the SoCalGas operators end up having to decide whether to send gas reaching Moreno into the basin versus down the Rainbow line into San Diego. SDG&E's load is forecast to vary in a normal temperature and hydro-electric production year from a low of 268 MMcf per day in May and a high of 386 MMcf per day in December, averaging 337 MMcf/d. These values are shown in Table 10. In a 1-in-35 cold and dry hydro year (not shown in the Figure), December demand is forecast at 430 MMcf/d. The load in San Diego that can be served from Costa Azul LNG terminal can offset some of the need for gas from underground storage.⁹¹

Table 10. SDG&E Gas Demand Forecast: Normal Temperature and Hydro.

	2017 (MMcf/d)												
Customer Class	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Average
Core	200	204	167	150	119	102	94	91	92	103	153	212	141
Non-core	158	167	141	149	149	238	250	257	274	198	167	174	194
Co. Use & LUAF ¹²	3	3	3	3	2	3	3	3	3	3	3	4	3
Total	361	374	311	302	270	343	347	351	369	304	323	390	337

12 Company use is compressor fuel; LUAF is "Lost and Unaccounted For," some of which is vented, leaked, meter error, or differences between calendar month and meter read cycle.

Source: SDG&E, 2016

90. One might wonder if moving gas south from Ehrenberg on North Baja and then west on TGN to Otay Mesa and into San Diego is an option. Analysis of the throughput on North Baja showed an average use of 326 MMcf/d with a maximum in August of 449 MMcf/d, meaning that the pipeline is sufficiently utilized that it cannot provide the same certain quantity needed to meet SDG&E gas load as the LNG terminal can. See <http://www.tcplus.com/North%20Baja/SharedFolder/DisplayFile/c27101a64d2b4af9462997202cf1a81193e68974?downloadType=Presentations>, slide 53 (Accessed July 2017).

91. To date, the Sempra utilities have, without being very specific, cited concerns about running afoul of rules designed to limit favoritism in transactions between corporate affiliates as an obstacle. But discussions with FERC and CPUC staff have produced no compelling reason that any affiliate transaction rules stand in the way of completing the purchase of LNG and delivering it in this way. No comments from SoCalGas on the Joint Agencies Reliability Action Plans suggesting this idea have cited any reason why using Costa Azul to serve SDG&E is physically infeasible.

LNG costs more than domestically-produced natural gas transported to San Diego via pipeline. (LNG prices have dropped considerably and are now trading at perhaps double U.S. domestic natural gas prices delivered via pipeline (Thomas, 2017).) In addition, SDG&E and Sempra have no obligation to buy gas for non-core customers, which represent a portion of the SDG&E gas load, and thus would require some sort of additional regulatory approval to use LNG to serve SDG&E. Several power plants are located along the international boundary and the pipeline between Costa Azul and Ehrenberg. Review of flows and contracts on that pipeline as well as LNG cargos shows that the power plants are not being served by LNG from Costa Azul but from gas flowing from EPNG into Baja Norte and Transportadora and there is not sufficient capacity free on those pipelines to serve SDG&E.

The cost of an average of 337 MMcfd (total SDG&E gas demand forecast in Table 10) for five years at an assumed likely price of \$3.50 per MMBtu is \$2.2 billion. If LNG were purchased and delivered into SDG&E at a world price of \$6 per MMBtu, the annual cost would be \$3.7 billion (Thomas, 2014). This represents a net cost increase of \$1.5 billion over pipeline-delivered natural gas over the five years. It is not clear that SoCalGas would in fact have to pay the world LNG price; a 2006 settlement of anti-trust claims requires Sempra LNG to sell and SDG&E and SoCalGas to purchase LNG supplies up to 500 MMcfd at the California border price minus two cents for 20 years.⁹² At the same time, SoCalGas indicated in response to data requests in Application No. 13-12-013 that it required CPUC authorization before purchasing gas from Sempra's Costa Azul LNG facility, and that it had not investigated purchasing it due to a landed cost of LNG of \$15.65 Per MMBtu reported by FERC (SoCalGas, 2014a). As the settlement applies to volumes "that Sempra Companies currently have contractual rights to purchase and that Sempra Companies do not deliver or sell to: (1) CFE; or (2) other Mexican entities," and no such sales of LNG have yet occurred, it may be that Sempra no longer holds such commodity purchase rights.

Prior CPUC action facilitates importing LNG into southern California; in 2006, the CPUC approved creation of the receipt point at Otay Mesa and integration of the gas transportation rates of SoCalGas and SDG&E. Combining their two rates was approved on the basis that a single transmission rate would enable customers of both utilities to receive gas from Otay Mesa on an equal footing, avoiding so-called rate "pancaking" in which costs of one system are layered on top of those from another (CPUC Decision No. 06-04-033, 2007). Sempra LNG argued in this proceeding that gas delivered at Otay Mesa would benefit

92. The "Continental Forge" settlement (available at https://www.sdge.com/sites/default/files/regulatory/AppendixA_0.pdf, (Accessed April 2017) addressed claims arising from the 2000-2001 power crisis accusing SoCalGas and SDG&E of involvement in price manipulation. The settlement was approved on July 20, 2006 by the Superior Court of the State of California, County of San Diego, J.C.C.P. Nos. 4221, 4224, 4226, and 4228. A separate settlement was entered into related to claims by Southern California Edison and by California's Attorney General on behalf of the CPUC. The CPUC in Decision No. 06-12-34 closed all of its proceedings investigating the actions of SoCalGas and SDG&E citing the settlements.

customers because it would travel less distance than gas delivered via Ehrenberg and that it would enhance system and supply reliability.

Since the willingness to build new large ocean terminals is likely low (discussed above), the Joint Agency Action Plan team did explore the possibility of bringing an Excelsior-type barge with on-board liquefaction capability to the southern California coast. These are commonly known as FSRUs, or floating storage regasification units. The agencies abandoned the idea after discussion with SoCalGas, which indicated the delivery of those supplies into the LA basin would require the addition of compression. No hydraulic simulation of the gas system was conducted to demonstrate this and there may be FSRU's available today that can achieve high pressure sendout (Excelerate Energy, 2017).

In short, using the existing LNG terminal at Costa Azul can be implemented now and without building any new physical facilities.⁹³

Conclusion 2.14: Augmenting gas supply to San Diego with LNG from Sempra's terminal in Mexico would provide a short-term, albeit relatively small (on the order of 300 MMcfd), impact on the need for gas storage in Los Angeles at a small marginal cost, and would not require construction of new facilities.

Fuel Switching

Renewable Natural Gas and Power-to-Gas. The label 'natural gas' came about when naturally-occurring gas produced from underground reservoirs became available to replace gas that was manufactured from coal in various towns and consequently known as "town gas." Methane gas, or CH₄, can in fact be produced via a number of methods from a variety of sources. Biogas is called 'renewable' when it is produced from the natural decomposition of organic matter in landfills, livestock manure, and wastewater treatment plants (Environmental and Energy Studies Institute, 2010). Once processed to remove impurities and meet existing pipeline standards, it can be injected into the utilities' natural gas pipeline systems and the CPUC refers to it as "biomethane (CPUC Decision 14-01-034)."⁹⁴

Biogas can be produced from food waste, animal waste, or captured from landfill decomposition. Appendix 2-6 outlines progress with renewable natural gas. Food waste can be diverted from landfills into biogas production (CalRecycle, n.d.). In fact, California recently implemented AB 1826 (Chesbro, 2014), requiring the recycling of organic waste by source generators of that waste, and AB 341 (Chesbro, 2011), which mandates that 50% of organic waste be diverted to productive uses by 2020. Both of these efforts will lead to the

93. The degree to which the LNG needle peakers or the terminal's vaporization can load follow within a gas day requires additional investigation.

94. CCST has a separate study under way at the request of the CPUC to conduct an independent scientific assessment of the minimum heating value and maximum siloxane specifications for the delivery of biomethane to public gas pipelines.

collection of food and other waste streams that are high in organic content for digestion. According to CalRecycle, approximately 6 million tons of food waste are landfilled every year (CalRecycle, 2016). The East Bay Municipal Utility District (EBMUD) found the average value of methane production from food waste to be 11,400 ft³/ton of total solids (U.S. EPA, 2008). Assuming that half of the total landfilled food waste is diverted to anaerobic digestion, the annual quantity of methane available from food waste in California is 34,200 MMcf. This equates to 94 MMcfd, or only 1.5% of the 6,072 MMcfd average daily California gas demand for 2016 shown in the California Gas Report. Even if the biomethane quantity were higher, the impact for storage depends on its production profile: if its production cannot be tailored to follow demand patterns, then it has no beneficial impact to the state's need for underground gas storage.

Finding: In addition to the fact that only small amounts of renewable natural gas are likely to be available by 2020, storing this gas to help meet winter demand and to provide daily ramping would still require use of underground gas storage.

Diesel Fuel. In theory, virtually any gas-fired generator can be configured to burn diesel fuel. Until around 1990, it was common for the electric utilities to switch between natural gas and diesel, or even low sulfur waxy residue (LSWR) depending on natural gas availability and price. Southern California Edison (SCE), for example, owned 120 miles of liquids pipeline extending from Bakersfield to Long Beach, one tank farm, several storage facilities adjacent to 7 electric generating stations, and 11 heating and pumping stations. Initially, these facilities provided the primary fuel supply to SCE power plants. They became secondary in the 1980s when natural gas became the fuel of choice for economic and environmental reasons, after which they were used only for emergency back-up fuel.⁹⁵ This lasted until August of 1999, when the CAISO agreed the dual-fuel requirement was “no longer required for electrical system reliability (CPUC Decision No. 03-07-031, p. 2).” The CPUC approved the sale of the facilities in 2003 and noted that many of the “station facilities” (i.e., those within the foot print of the power plant) were removed.

Today only a handful of the gas-fired generators in California hold air permits to burn diesel or any petroleum-based fuel other than natural gas.⁹⁶ The older facilities that used to hold such permits realized they would not be able to renew them, due to air quality concerns, and removed the holding tanks, spill capture berms, and other equipment needed to burn liquid fuels. Newer power plants, especially those constructed by independent generators, never even installed the equipment needed to burn diesel fuel or oil, due to the expense. These decisions were also heavily influenced by their economics – any increase in cost

95. According to the EIS for Lodi Gas Storage's Kirby Hills expansion, the last time power plants switched to fuel oil because gas was not available was a 10-day period in winter 1998-99. See http://www.cpuc.ca.gov/environment/info/aspen/kirbyhills/pea2/1_intro.pdf, p. 1-3 (CPUC).

96. The exception being LADWP. There may also be a handful of small peaker turbines that can still burn diesel.

directly reduced profits. Additionally, their non-recourse lending agreements concurred that there was no need for back-up fuel because with California's excess pipeline capacity and vast underground gas storage resource, natural gas would always be available at some price.

Critics of the 2016 Aliso Canyon Action Plan suggested that a relatively new fuel, known as Amber 360, should be available to allow power plants to burn a diesel-like product with drastically lower air quality consequences. LADWP has three key power plants, isolated from CAISO, which have maintained the physical ability to burn diesel for black start purposes.⁹⁷ LADWP explored market opportunities to obtain Amber 360 and found that the fuel was not available in the quantities needed. Their turbine manufacturer also stated that the metals content of the fuel would void their warranty on the generators. LADWP was able to find a low-nitrogen diesel (below what is typically contained in CARB diesel) from its existing supplier of fleet vehicle fuel and applied to the South Coast Air Quality Management District (SCAQMD) for a permit to test and use it at the three power plants.

SCAQMD held hearings in which it questioned witnesses not only about the diesel fuel burn plan but about the risk to electricity reliability absent the ability to burn diesel and subsequently granted the variance (SCAQMD, 2016). LADWP has indicated this fuel was available at the market price for diesel.⁹⁸ Units had to be recommissioned to run on diesel fuel, existing bunkers filled in anticipation of potential curtailment, and revisions made to fuel handling protocols. Although dealing with diesel is difficult, LADWP has this option available in case it is needed to maintain electric reliability. This short-term option is not available to other generators.⁹⁹

Changes to electricity sector demand

Options that would reduce the use of gas used for electricity generation are to bring in electricity through new transmission, store electrical energy (instead of chemical energy stored in gas) to use to meet peak demand, or reduce the demand through energy efficiency and demand side management approaches. None of these would significantly help to meet the winter peak demand in the 2020 timeframe but could alleviate the use of gas storage in the summer.

Finding: Gas-fired furnaces overwhelmingly supply building space heating in California and this use results in the winter peak demand for gas. California has no policies specific to

97. "Black start" is what operators call bringing the electricity system back from complete blackout with all facilities out. The controls used on a black start unit include a DC auxiliary support system, an ignition source, a gas turbine and a diesel generator (Morris, 2011).

98. Email correspondence with LADWP's Marlon Santa Cruz, 2/14/17.

99. Because of the limited nature of this option, we did not assess the broader petroleum market implications (i.e., price and availability) greater use of diesel fuel would also have.

electrification of building heat, therefore the source of building heat will not likely switch to electricity for several decades (for more information, see Chapter 3).

The highest recorded total gas demand in the recent five-year period was 11.2 Bcfd (December 9, 2013), and the highest projected 2020 peak winter demand is 11.8 Bcfd (Table 6). However, statewide gas import capacity is limited to 7.5 Bcfd, leaving a maximum winter shortfall of 4.3 Bcfd. Monthly-average gas demand for electric generation in winter months (November through February) is 2.1 Bcfd (EIA, 2017). Curtailing all electric generation in favor of core customers, even if this were advisable, would therefore be insufficient to meet peak winter demand. As the remaining demand would still be well above the State's maximum import capacity, gas storage would still be required.

Conclusion 2.15: No method of conserving or supplying electricity—including electricity storage (batteries, pumped hydroelectric, compressed air storage, etc.), new transmission, energy efficiency measures, and demand response—can replace the need for gas to meet the winter peak in the 2020 timeframe. The winter peak is caused by the demand for heat, and heat will continue to be provided by gas, not electricity, in that timeframe. Gas storage is likely to remain a requirement for reliably meeting winter peak demand.

Although changes to the electricity system in the 2020 timeframe will not obviate the need for gas storage in winter, electricity, primarily used for air-conditioning, drives the summer peak in gas demand. Gas-fired electricity demand averages 2,830 MMcfd in August (the highest demand month for gas for electricity over 2011-2016) with a 16-year peak demand of 3,460 MMcfd in July 2006 (EIA, 2017). Modifications that would result in lower gas-fired electricity demand would affect the need for gas storage in the summer.

The potential utility of various changes to the electricity system are described below.

Expanded Electric Transmission Capacity to Reduce Gas Use. Importing more electricity from out-of-state or adding transmission to move more in-state renewables to load centers would displace gas-fired demand by generators in California. In fact, upgrades completed in 2017 are estimated by CAISO to reduce the need for gas-fired generation in the Los Angeles Basin by an estimated 1,000 MW (CAISO, 2016c; CEC, 2017b). Per CAISO, some 56% of the total 74,102 MW of generation in California is gas-fired (Millar, 2017; CAISO, 2017). That gas-fired generation operates at increasingly low load factors. Various generators have threatened to retire their gas-fired facilities because they do not produce enough revenue (RTO Insider, 2016).¹⁰⁰ CAISO can enter into reliability must-run (RMR) contracts if a unit is needed to provide reliability.

100. See also presentations from an April 2017 Joint Agency workshop in the CEC's IEPR to explore the impact of economic retirements. At http://www.energy.ca.gov/2017_energypolicy/documents/2017-04-24_workshop/2017-04-24_presentations.php (Accessed July 2017).

New transmission requires long lead times that extend beyond the 2020 focus of this chapter and come within the planning purview of the CAISO. Like the 2016 upgrades, there may be shorter-term projects that might be completed quickly, as identified in the Renewable Energy Transmission Initiative 2.0 (RETI 2.0). The projects identified in the RETI 2.0 process, MW of deliverability, and total cost are shown in Table 11. Together, they comprise as much as 15,000 MW of electricity that could potentially displace use of natural gas in California at a collective cost of \$6.6 billion. Transmission costs would similarly need to be turned into an annual revenue requirement and then spread over assumed usage to arrive at a per kwh cost to consumers. This excludes any new generation that might need to be built.

Table 11. Potential Electricity Transmission Projects.

Resource Area	Additional Deliverability (GW)	Cost (\$ 000's)	Cost (\$000)/MW Deliverability
Tehachapi*	4.5	\$2,100,000	\$467
Victorville/Barstow/Riverside	3.7	\$34,000	\$9
Imperial Valley	1.3	\$1,000,000	\$754
San Joaquin Valley	1.3	\$440,000	\$336
Solano	0.9	\$35,000	\$40
Sacramento Valley	2.1	\$3,000,000	\$1,429
Lassen/Round Mountain	1.3		
TOTAL	15	\$6,609,000	
Average			\$506

* - TRTP cost data taken from: https://www.hks.harvard.edu/hepg/Papers/2010/Pizarro_Pedro_HEPG_Feb2010.pdf

The extent to which additional transmission offsets gas consumption depends on the number of hours the gas-fired power plants would have to run in the absence of the resources carried by that transmission. If 15 GW operates for 8 hours per day,¹⁰¹ this equates to approximately 0.8 Bcfd of gas load reduction, or about 30% of the calculated 2.8 Bcf needed to meet average summer peak gas requirements. Replacing all of this intrastate capacity to meet summer peak forecasts using electricity imports therefore would require a very large amount of new electricity transmission capability, about 50GW (and associated electricity generation) (CAISO, 2017).¹⁰²

The TransWest Express transmission project from Wyoming to near Las Vegas is an example of the kind of long distance bulk transmission project that might be required. TransWest

101. At an assumed heat rate of 7,000 Btu per kWh.

102. The forecasted 1-in-10 year summer peak for CAISO alone for 2017 was 48,845 MW.

Express will run 730 miles with the ability to deliver 3,000 MW of power. The project will cost about \$3 billion. This project has been under design and study for more than 10 years already. Construction might begin in 2018 and be completed by 2020 (TransWest Express). This kind of project represents less than 6% of the 52,000 MW required to replace gas from storage on a summer peak day.

These estimates are only a first analysis. Detailed power system load flow analyses combined with electricity dispatch analysis, would be required to estimate the marginal capability of transmission lines to relieve constraints in specific locations as well as the average heat rate and number of hours the associated new generation would be available and operating and whether this generation is dispatchable in coordination with demand. This first cut also does not estimate how much new generation might need to be built.

Electricity Storage

Until significant electric-based heating technologies are deployed, electricity storage would play almost no role in mitigating the need for gas storage to meet peak winter demand for gas. However, energy storage could help to reduce the summer peak demand for gas as this demand is driven by electricity generation, albeit at some significant expense.

Electricity storage can reduce summer demand for gas-fired electricity generation up to a point, but there is no type of energy storage we are aware of that can provide electricity storage for more than 48 hours (only a handful of storage facilities worldwide have storage capacities that exceed this). Appendix 3-2 describes various energy storage technologies and their capacities. Energy storage is very expensive compared with gas generation capacity, and even relatively inexpensive technologies such as pumped hydroelectric storage (PHES) and compressed air energy storage (CAES) would be prohibitively expensive to build for several weeks or months of storage capacity. (Moreover, PHES and CAES both have severe siting constraints that limit their widespread use.) For more information, see Energy storage section of Appendix 3-2.

Shorter-time gas balancing requirements, including interday and intraday demand variation, can in principle be handled with various types of energy storage, when the variation in gas demand is primarily driven by electricity generation changes. Electricity storage could reduce the need for gas-fired generation in hours when renewables are insufficient (Kintner-Meyer, 2013). That would offset some of the intraday variability in gas requirements by electric generators that helps drive the need for gas storage, thus addressing part of the electricity ramp-up problem. All storage technologies, including PHES, electromechanical (mainly CAES and flywheel) electrochemical (battery) and thermal storage can provide useful capability in these time domains, though certain technologies, such as batteries and flywheels, are capable of much faster response times and ramping rates than others. However, multi-day electricity demand spikes caused by renewable intermittency may go beyond the capabilities of existing storage technologies.

Figure 22 displays Electric Power Research Institute's most recent cost comparison among some types of energy storage technologies. All systems have capital costs of $> \$100/\text{kWh}$ of stored energy, with PHES and CAES presenting the lowest costs, and battery technologies being much higher. However, battery costs are projected to fall in cost over the next few years (see Figure 23).

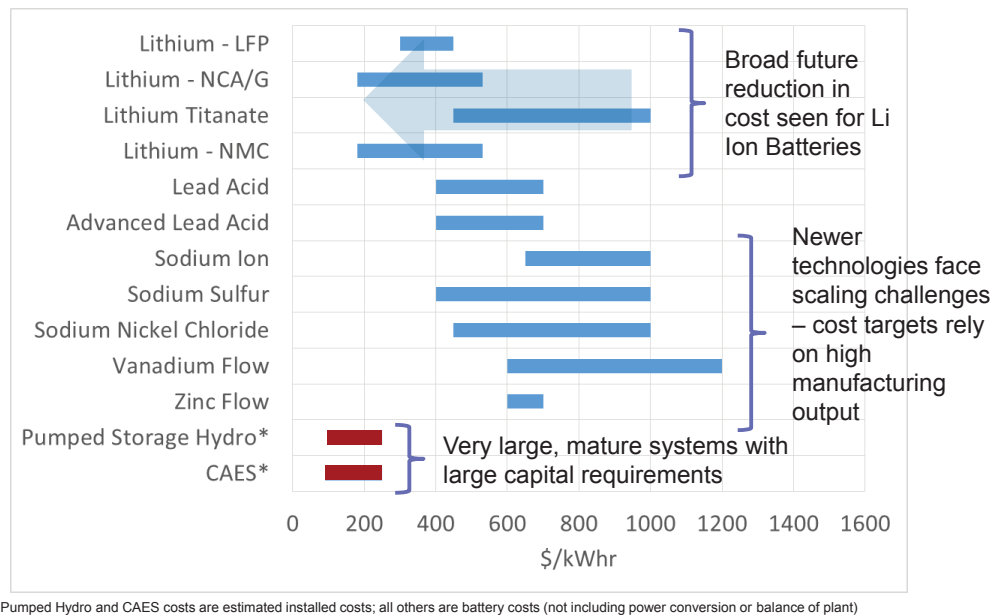


Figure 22. 2015 Energy Storage Technology Cost Comparison.

Source: Kamath, H., Electric Power Research Institute, 2016.

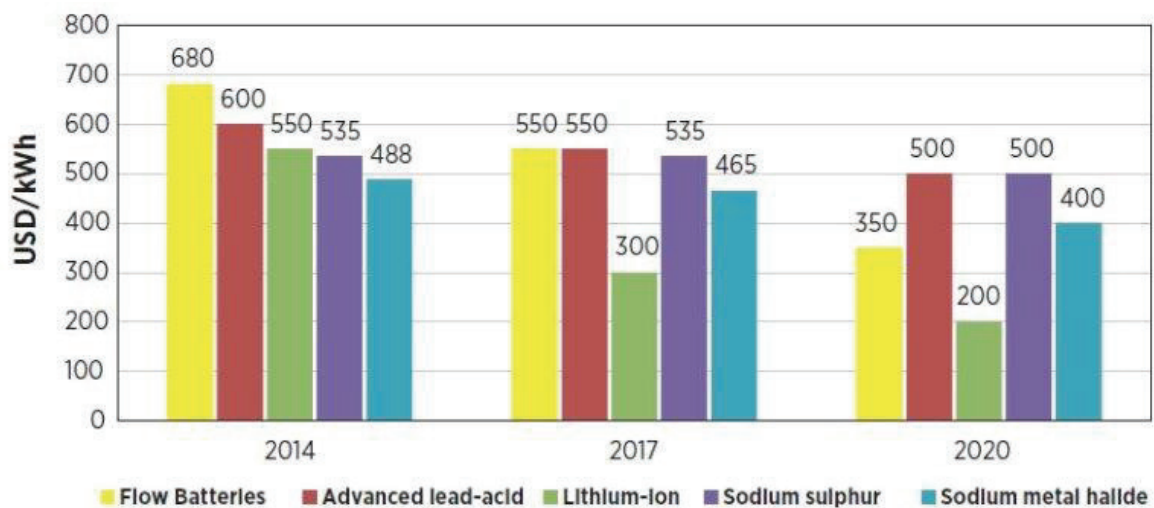


Figure 23. Battery Technology Cost Projections.

Source: AECOM, 2015

The cost of energy storage depends on the duration of the storage required relative to the system's rated power capability. For purposes of cost comparison, we assumed the system requires four hours of energy storage capability. Lazard estimates the cost of a four-hour lithium ion energy storage installation to be between \$417 and \$949/kWh, or \$167-380 million for a 100 MW, 400 MWh system (Lazard, 2016).¹⁰³ Assuming each MW of electricity storage offsets use of 7 MMBtu of natural gas per hour in an efficient gas-fired power plant, a system of this size can replace the output of a 100 MW power plant for four hours, and reduce gas demand by 700 MMBtu per hour.¹⁰⁴

Finding: Meeting all of California's 2,830 MMcf of unmet summer demand via electricity from energy storage would require approximately 420,000 MWh of electricity storage. Cost estimates for energy storage are evolving rapidly. The current cost of a 420,000 MWh electricity storage system capable of offsetting all gas storage for a peak summer day would be approximately \$174 billion at the current low end of Lazard's (2016) cost range estimate (\$417/kWh). If costs fall an additional 75%, the cost would be \$44 billion to offset the summer peak demand for electricity, but this would do little to address the winter peak driven by demand for gas-fired heat.

Pursuant to current mandates, SCE must procure a total of 580 MW of electricity storage; PG&E 580 MW and SDG&E must procure a total of 165 MW, all by 2020 (CPUC Decision No. 13-10-040). The mandate does not specify how long this amount of power must be provided by storage. Assuming each MW of electricity storage offsets use of 7 MMBtu of natural gas per hour, the total of 1,325 MW utility storage mandate can offset 9,275 MMBtu per hour of pipeline or storage withdrawal capacity. This means the current CPUC storage mandate of 1,325 MW of energy storage in one hour could offset roughly 8% of the hourly gas requirement for electricity in the peak summer month that might otherwise need to be pulled from underground gas storage, assuming four hours of storage capacity. To mitigate the entire peak gas demand, about 105,000 MW would be required.

Finding: Current CPUC storage mandates could offset roughly 8% of the peak gas requirement for electricity in the peak summer month (assuming four hours of storage).

Energy Efficiency and Demand Response

Energy efficiency and demand response could reduce the need to withdraw gas from underground storage especially on summer days when the utilities are withdrawing gas

103. It also gives "unsubsidized" levelized costs and breaks out capital versus O&M, for different deployment function scenarios.

104. Note that a 129 MW lithium-ion battery storage project is under construction today in Australia. That project is being constructed by Tesla and Neoen. In addition, a 200 MW battery storage project has been proposed for the Drax power station in Yorkshire, England. The Drax CEO cited the battery's ability to provide "capacity, stability, and essential grid services."

to meet the afternoon electricity generation ramp, but this impact is likely to be small.¹⁰⁵ Energy demand forecasts already incorporate projections of existing and future energy efficiency measures. Those forecasts however, are still in the process of being updated to account for the requirement in SB 350 (De Leon, 2015) to double energy efficiency by 2030. In contrast, it appears that recent estimates of potential demand response are not included in those estimates. The following discusses the tools for demand response in more detail. Demand response is usually called on to deal with peak load and cannot likely displace the routine use of gas storage for intraday gas balancing. The following quantifies natural gas savings through energy efficiency and demand response.

105. The Joint Agency Action Plans for summer 2016 and winter 2016-17 included mitigation measures which, for the first time, rolled out a Flex-Alert type request for core gas consumers to reduce demand on days of gas system stress, in addition to other new programs. EDF criticized the agencies for not achieving greater demand reductions via energy efficiency in a Senate hearing on SB 57 and the County of Los Angeles' consultant cited large reductions achievable via energy efficiency. The reductions they cited turn out to match the energy efficiency estimates shown in the CGR and are already incorporated into the demand forecast used for analysis here.

Energy Efficiency

Developing the forecasts for how much gas would be saved through energy efficiency (EE) starts at the CEC. The CEC develops a demand forecast that includes historical EE from adopted programs, building codes, and appliance standards.

Committed savings (shown in Table 12) are those forecast to be achieved by programs approved by the CPUC and will reduce natural gas demand considerably from what would otherwise be forecast. They include technology measures that have been installed in the past because of utility efficiency programs, building codes, and appliance standards (or those programs that have been funded and have established targets) and these effects are cumulative from their first implementation. As reported in Table 12, committed EE programs were forecast to reduce residential gas demand by 31.2% by 2015 compared to 1975 levels, and 33.3% by 2020. This yields incremental savings of 43 MMcfd for SoCalGas and 30 MMcfd for PG&E, by 2020.¹⁰⁶

Table 12. Committed Natural Gas Savings.

Year	Committed Savings*	Consumption* (MM therms per year)		Committed Savings (MMcf per day)	
		SoCalGas	PG&E	SoCalGas	PG&E
2015	31.2%	7360	4672	629	399
2016	31.6%	7361	4677	638	405
2017	32.0%	7363	4682	646	411
2018	32.5%	7364	4688	655	417
2019	32.9%	7366	4693	664	423
2020	33.3%	7367	4698	672	429
2021	34.1%	7362	4702	688	439
2022	34.9%	7357	4706	703	450
2023	35.7%	7351	4710	719	461
2024	36.6%	7346	4714	736	472

* Values taken from the 2013 CED 2014-2024 Final Forecast (interpolation used between observed years)

Source: CEC, 2014b

106. The CEC is developing but has not yet deployed a methodology to forecast electricity demand on an hourly basis. It is unclear if it will also develop a methodology to produce hourly natural gas demands.

The next step adds a second tranche of savings. This is known as additional achievable energy efficiency (AAEE). The forecast of AAEE is created by the CEC based on the Potential & Goals study results, which, in turn, is prepared by the CPUC's consultant (Navigant, 2013).¹⁰⁷ The CPUC and CEC sponsor several meetings among stakeholders to allow input into the Potential & Goals study assumptions and results, including via the CEC's Demand Analysis Working Group (DAWG).¹⁰⁸ AAEE is updated on a cycle intended to be roughly annual and is used both as an input to the California Energy Demand Forecast and by the CPUC in setting investor-owned utility program budgets. The latest AAEE for the electricity sector is shown in Table 13. By 2020, the forecast suggests potential incremental savings of 157 MMcf if all the electricity-side AAEE directly displaces gas-fired generation.¹⁰⁹

Energy efficiency by non-electric generation gas demand is also included. Table 14 shows natural gas-related AAEE by 2020 of 16.1 MMcf for PG&E, 24.5 MMcf for SoCalGas and 2.8 MMcf for SDG&E, a total of 43.4 MMcf. No record of the municipal gas utilities being incorporated into the AAEE could be found and doing so would likely have little impact due to their small total size.

107. See also <http://www.cpuc.ca.gov/General.aspx?id=6442452620> The method estimates technical potential, economic potential and market potential. A list of the key parameters and the assumptions surrounding them is provided in Appendix 2-5. The study's five scenarios do not comprise a full Monte-Carlo assessment of the uncertain parameters, but are intended to reflect the range of potential outcomes stakeholders were willing to accept for planning purposes. "Low" cases tend to assume lower penetration of emerging technologies relative to the base case, higher electricity demand and prices, higher incremental measure costs, and conservative assumptions on future codes and standards relative to the base case. "High" AAEE cases have opposing assumptions.

108. DAWG activities are covered at <http://dawg.energy.ca.gov>.

109. Such an assumption may not be reasonable. The electricity demand should actually be run through an electricity production cost model to determine how generation resources will be dispatched to meet that demand. Such a model will estimate the change in gas demand from a given change in electricity demand.

Table 13. Additional Achievable Energy Efficiency (Electric).

Year	AAEE* (GWh/y)			Marginal Generation** (MMcf/day)				Average Resource Mix*** (MMcf/day)			
	SCE	LADWP	PG&E	SCE	LADWP	PG&E	Total	SCE	LADWP	PG&E	Total
2015	63	286	56	1.6	7.0	1.4	10.0	0.9	4.2	0.8	6.0
2016	875	540	792	21.6	13.3	19.5	54.4	12.9	8.0	11.7	32.6
2017	1812	871	1612	44.7	21.5	39.7	105.9	26.8	12.9	23.8	63.4
2018	2922	1361	2638	72.1	33.6	65.0	170.7	43.2	20.1	39.0	102.2
2019	3742	1770	3366	92.3	43.7	83.0	218.9	55.3	26.1	49.7	131.1
2020	4492	2147	4032	110.8	52.9	99.4	263.1	66.3	31.7	59.6	157.6
2021	5301	2255	4774	130.7	55.6	117.7	304.1	78.3	33.3	70.5	182.1
2022	6077	2363	5484	149.8	58.3	135.2	343.3	89.8	34.9	81.0	205.7
2023	6888	2464	6210	169.8	60.7	153.1	383.7	101.7	36.4	91.7	229.8
2024	7669	2549	6904	189.1	62.9	170.2	422.2	113.3	37.6	102.0	252.9

* - http://www.energy.ca.gov/2015_energy_policy/documents/2016-01-27_additional_aee.php

** - this approach assumes that 100% of generation reduced by EE is gas generation

*** - this approach assumes that 59.9% of generation is from natural gas resources, consistent with CEC values

Source: CEC, 2017c

Table 14. Additional Achievable Energy Efficiency (Natural Gas).

Year	Savings by Gas Utility (MM Therms/y)				Savings by Gas Utility* (MMcfd)			
	PG&E	SoCalGas	SDG&E	Total	PG&E	SoCalGas	SDG&E	Total
2015	1.8	2.9	0.7	5.4	0.5	0.8	0.2	1.5
2016	11.8	22.7	1.9	36.4	3.2	6.2	0.5	9.9
2017	19.6	40.3	3.1	63.0	5.4	11.0	0.8	17.2
2018	30.7	56.5	5.0	92.2	8.4	15.5	1.4	25.3
2019	44.0	72.8	7.4	124.2	12.1	19.9	2.0	34.0
2020	58.7	89.5	10.1	158.3	16.1	24.5	2.8	43.4
2021	72.1	106.6	12.2	190.9	19.7	29.2	3.4	52.3
2022	85.2	124.2	14.5	223.9	23.3	34.0	4.0	61.3
2023	98.6	142.4	16.6	257.6	27.0	39.0	4.5	70.5
2024	113.5	161.9	18.8	294.2	31.1	44.3	5.1	80.5

* Values taken from the 2015 IEPR Proceedings

Source: CEC, 2015

AAEE is not adopted as a “point estimate,” but is actually a range of values.¹¹⁰ Figure 24 shows the range of adopted AAEE scenarios. The “mid” case is the CEC’s basic reference case. The 2013 Potential and Goals Study describes the approach to estimating AAEE. The AAEE forecast is then turned into EE targets for the gas utilities by the CPUC (Table 15). The latest were adopted in CPUC Decision 15-10-028. These adopted targets include both AAEE and committed savings and are incorporated directly into the gas utility forecasts presented in the California Gas Report (CGR), including the winter peak day forecasts. These EE estimates are clearly lower than the deficit in winter gas requirements that today is met with gas from underground storage.

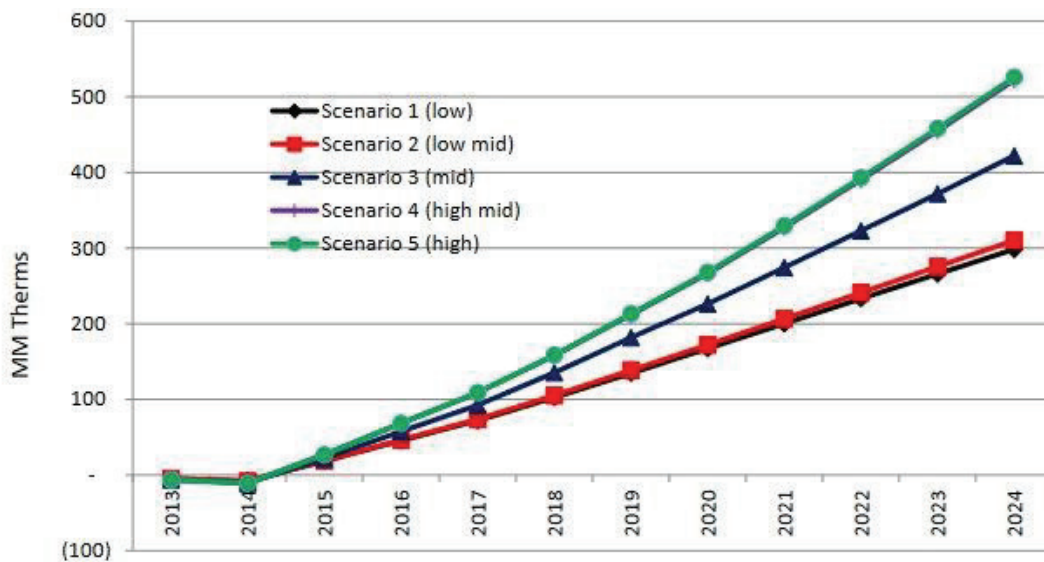


Figure 24. Adopted Natural Gas AAEE.

Source: CEC, 2015

110. The 2013 Potential and Goals Study describes the approach to estimating AAEE. The method estimates technical potential, economic potential and market potential. A list of the key parameters and the assumptions surrounding them is provided in Appendix 2-5. The study’s five scenarios do not comprise a full Monte-Carlo assessment of the uncertain parameters, but are intended to reflect the range of potential outcomes stakeholders were willing to accept for planning purposes. “Low” cases tend to assume lower penetration of emerging technologies relative to the base case, higher electricity demand and prices, higher incremental measure costs, and conservative assumptions on future codes and standards relative to the base case. “High” AAEE cases have opposing assumptions.

Table 15. CPUC Adopted Targets for Gas Utility Energy Efficiency.

Year	PG&E		SoCalGas		SDG&E	
	Annual (MM therms/y)	Daily (MMcf/day)	Annual (MM therms/y)	Daily (MMcf/day)	Annual (MM therms/y)	Daily (MMcf/day)
2016	18.4	5.0	29.1	8.0	3.2	0.9
2017	18.6	5.1	30.3	8.3	3.3	0.9
2018	20.9	5.7	29.4	8.1	3.9	1.1
2019	21.1	5.8	30.6	8.4	3.9	1.1
2020	21.7	5.9	30.6	8.4	4.0	1.1
2021	21.8	6.0	28.6	7.8	3.7	1.0
2022	22.4	6.1	28.5	7.8	3.7	1.0
2023	23.2	6.4	28.2	7.7	3.8	1.0
2024	23.9	6.5	28.1	7.7	3.8	1.0

Source: CPUC, 2015e

These estimates do not yet reflect the full effects of SB 350 (De Leon, Chapter 547, Statutes of 2015) which requires a “doubling” of cumulative statewide EE based on the mid-case estimate of AAEE adopted in the California Energy Demand Forecast Update 2015 – 2025 by 2030. PG&E estimated in the 2016 CGR that a simple interpretation of the bill (without regard to cost-effectiveness) represents an increase of 600 million therms above current EE levels by 2030 which they say equates to 156 MMcf per day. If achieved every day, this could free up the need to meet that same demand with gas from storage, a relatively small portion of California’s 4.3 Bcfd shortage on a peak day.

Finding: Energy efficiency measures including the combination of committed savings for natural gas, combined with the reductions expected from AAEE (ignoring the uncertainty in its calculation) and the doubling required under SB 350, appear to total less than 400 MMcfd (assuming all of the electric side savings reduce the need for gas-fired generation). If achieved every day, this could remove the need to meet that same demand with gas from storage, but comes nowhere near offsetting California’s 4.3 Bcfd shortage on a winter peak day or any other winter day. The actual impact would depend exactly which measures are adopted, what technologies are affected, and what the hourly use pattern changes are.

Demand Response Gas Savings

While the EE estimates appear to have already been incorporated into the demand forecasts, there appears to be some potential to reduce gas demand through demand response (DR) measures that are incremental to forecasted values. Demand response potential is incorporated into electricity demand forecasts to the extent that demand response measures are load modifying. On a statewide basis, only 140 to 220 MW of load-modifying demand

response potential is included in the CEC electricity demand forecasts, used by CAISO for transmission planning work and the CPUC for procurement decisions (CEC, 2016a).

The CPUC commissioned LBNL to estimate demand response potential. The Phase 2 report released in March 2017 shows system-wide potentials for fast demand response totaling 5,600 MW in 2020 and 7,300 MW by 2025. These totals are shown in Table 16. Converting this to a gas capacity requirement requires assuming a heat rate for the associated generation. It also requires assuming not only the number of hours the generation would operate but assuring the gas delivery capacity is available in every hour. Table 17 shows this two-step conversion of the potential demand response to their corresponding gas pipeline capacity reduction impact, using the same power plant heat rate of 7 MMBtu per MWh as earlier. Reducing the summer system peak by 5,600 MW translates to a gas demand reduction and the need for more than 900 MMcf of gas pipeline capacity. If less efficient power plants were the ones displaced on peak, then the pipeline capacity reduction would be correspondingly higher.

Figure 11 shows about a 1 Bcf increase in the flow rate needed over the course of the day for SoCalGas on September 9, 2015. That equates to an increase of about 42 MMcf per hour in gas demand. The 2020 estimate of DR for southern California is ~23 MMcf per hour, implying that DR could offset more than 50% of the increase in hourly demand caused by electricity generation in afternoon hours). DR, however, by its very nature cannot be called upon every day.

Table 16. Electricity Demand Response Potential.

Year	Electric DR Potential (MW)					Total
	PG&E	SCE	SDG&E	LA System Peak ¹³	LA IRP*	
2020	2300	2400	170	599	175	5644
2025	2900	2900	260	724	475	7259

13 This method applies the demand response/system peak ratio of SCE to LADWP.

Source: LBNL, Aspen Environmental Group, and Alstone, et al., 2017

*LADWP, 2016

Table 17. Gas Pipeline Capacity Reduction from Electric DR.

Year	MMcf per hour						MMcf per day					
	PG&E	SCE	SDG&E	LA System Peak	LA IRP	Total	PG&E	SCE	SDG&E	LA System Peak	LA IRP	Total
2020	15.6	16.2	1.1	4.1	1.2	38.2	373	390	28	97	28	916
2025	19.6	19.6	1.8	4.9	3.2	49.1	471	471	42	118	77	1,178

Source: Aspen Environmental Group

In conjunction with the May 22, 2017 Joint Agency workshop to discuss summer 2017 reliability risk, the CPUC released estimates that customers achieved 1.68 MMcf of 2016 summer DR (largely through electricity programs) and that “marketing and outreach” accounted for an additional 12.5 MMcfd. Marketing and outreach includes Flex Alerts, press conferences, and news coverage. Those estimates are more fully detailed in a separate CPUC staff report, where they are broken out by specific program (CPUC, 2017d). The LBNL DR study, however, suggests significant impacts, based on the medium DR scenario. However, DR (by definition) is something to be used relatively infrequently and cannot routinely reduce peak hourly gas demand during summer days. Table 18 provides summary comments for each of the supply and demand options evaluated in this section.

Finding: The demand response potential appears large enough to offset a good portion of the withdrawal from storage needed to support intraday load balancing by electricity generators but demand response cannot be called upon routinely enough to fully replace the need to use gas from underground storage.

*Table 18. Supply and Demand Options to Replace Gas Storage
(Assuming No Outages on Gas System and No Forecast Error).¹¹¹*

Physical Alternatives to Storage	Rough Cost Estimate (\$2017)	Summary Comments
Alternatives that could completely offset the need for 4.3 Bcfd gas storage in winter		
New Intrastate Pipeline Capacity	~\$15 Billion	<ul style="list-style-type: none"> • Not achievable by 2020 • Maybe one or two pipelines by 2025 • As peak demand declines the needed expansion quantity would also decline • Addresses winter but probably not intraday needs • May pose siting issues to reach load centers • Requires environmental review and mitigation
LNG Peak Shavers	~\$10 Billion	<ul style="list-style-type: none"> • Depending on size, could require 4 to 10 units • Unclear effectiveness to load follow during the gas day • Conversion from gas to LNG and back requires energy that would increase GHG and criteria pollutant emissions • Poses siting and safety concerns
Alternatives that could reduce the need for gas storage somewhat		
LNG Via Ocean Terminal	\$332 million per year incremental cost to purchase 315 MMcfd of LNG	<ul style="list-style-type: none"> • Use of Semptra's Costa Azul to serve SDG&E (an average of 315 MMcfd) appears immediately feasible • Would allow pipeline supply to serve LA, reducing need to pull gas from storage for LA. • Not clear if reduction in withdrawals from storage in LA is 1:1 with gas demand on all days but at least 200 MMcfd (~5%) seems reasonable to consistently expect • Increases GHG and criteria pollutant emissions from LNG transport and vaporization
Alternatives that will have little impact on winter gas storage requirements		
New Electric Transmission Capacity to Reduce EG Gas Use	\$6.6 Billion identified in RETI 2.0 that could deliver 15,100 MW	<ul style="list-style-type: none"> • 15,100 MW is equivalent to 800 MMcfd or 27.5% of the 2.9 Bcf needed on an average gas summer peak day, so this transmission doesn't offset entire summer peak demand • Would not address the winter peak because winter peak is caused by burning gas for heat • Wouldn't address intraday gas balancing need
Containerized LNG	Infrastructure cost of \$13 million for 1 Bcf per year plus 440 containers (Hawaii Public Utilities Commission, 2014).	<ul style="list-style-type: none"> • Not Utility-Scale (10 Containers per MW) but may have limited application for intraday balancing at power plants • Poses additional siting and safety risks plus emissions with conversion from gas to LNG and vice versa

111. Note that all of the discussion on the quantity of storage needed assumes no outages on gas system and no forecast error.

Physical Alternatives to Storage	Rough Cost Estimate (\$2017)	Summary Comments
CNG In a Box	\$600,000 for ~2 MMcf/d, so 500 MMcf/d (for example) amounts to \$150 million (excludes pipeline interconnection costs). 8000 containers would cost \$4.8 billion.	<ul style="list-style-type: none"> • Not Utility-Scale but may have limited application for intraday balancing at power plants • Requires many containers and poses additional siting and safety risks • Takes a whole day to compress and fill container
Electricity Storage	\$273 million for each 100 MW/4-hr system	<ul style="list-style-type: none"> • Can address intraday balancing with 4- and 8- hour storage, but cannot address winter gas requirements
Diesel Fuel	Assuming CARB-standard diesel @\$3.00 per gallon and 7.2 gallons per MMBtu = \$21.6 per MMBtu	<ul style="list-style-type: none"> • Not desirable for AQ reasons and would need to reinstall handling and on-site storage equipment largely removed in 1990s • Amber 360 is “cleaner” but even if enough were produced and available, need to address the generator warranty void
Renewable Natural Gas and Power-to-Gas	~\$30 million to process about 100 MMcf/d to pipeline quality plus up to \$3 million per interconnection. Hydrogen Business Council says P2G would be 2.5X current natural gas price by 2030.	<ul style="list-style-type: none"> • Not available at scale by 2020 and production profile does not help solve gas storage problem.
Energy Efficiency (EE) and Demand Response (DR)	EE is required under statute so will be a sunk cost	<ul style="list-style-type: none"> • EE is already in the demand forecast • Gas utilities suggest a gross read of the SB 350 requirement to double EE by 2030 implies an additional reduction of 156 MMcf/d ignoring cost-effectiveness • Additional potential electricity DR could reduce the need for intraday balancing • Implementation would require examination of how often that DR could be used • DR used to curtail electric generation in favor of core customers would be insufficient to meet peak winter demand • Statewide gas import capacity is limited to 7,511 MMcf/d. Monthly-average gas demand for EG in winter months is ~2,000 MMcf/d • The highest recorded total gas demand (EG + non-EG) in the recent five-year period was 11,157 MMcf/d (December 9, 2013) • Curtailing all EG would subtract 2,200 MMcf/d of demand from this day, but this is still well above the State’s maximum import capacity - e.g., gas storage would still be required

Conclusion 2.16: We could not identify a technical alternative gas supply system that would meet the 11.8 Bcfd extreme winter peak day demand forecast and allow California to eliminate all underground gas storage by 2020. Two possible longer-range physical solutions are extremely expensive, carry their own risks, and would incur barriers to siting. The potential benefits of other approaches that were examined are either small, cannot be estimated at this time, or have negative impacts such as dramatic increase in air toxins and greenhouse gas emissions. No “silver bullet” can replace underground gas storage in the 2020 timeframe.

1.4.2 Regulatory and Operational Options (Including Market Rules) to Help Replace Underground Gas Storage

Regulatory or operational changes may help reduce the need for underground gas storage. This section evaluates proposed or already implemented changes to gas market regulation from two perspectives (1) the degree to which they can reduce or eliminate the winter peak demand problem and (2) the degree to which they can reduce the need for natural gas storage at other times during the year.

This subsection considers eight potential changes. Some of these are already being implemented as mitigation measures to help reduce the risk of electricity outages stemming from the limited availability of Aliso Canyon. They include:

- Tighter Balancing Rules
- Core Customers Balancing to Load Instead of Forecast
- Greater Use of Line Pack
- Closer Gas-Electric Coordination
- Shifting to Out-of-Area Generation on Gas-Challenged Days
- Day-Ahead Limits on Gas Burn
- Shaped Nominations and Flexible Services
- Weekend Natural Gas Market

Tighter Balancing Rules. Tighter balancing rules could reduce the winter peak demand somewhat and reduce the need for storage at other times. System imbalances are differences between supply and demand that can be caused by customers’ scheduling less gas for delivery than their actual usage. The technical assessment group that prepared the analysis underlying the Joint Agency mitigation measures for summer 2016 identified that system imbalances as small as 150 MMcfd could require SoCalGas to pull gas from Aliso Canyon.

Based on this, the technical assessment group recommended tightening the balancing rules for non-core customers. The agencies also asked SoCalGas to prepare a hydraulic analysis to determine the impact of keeping receipts and demand within 5% of each other. The analysis showed that balancing non-core load to within 5% improved operating pressures by enough to reduce the risk of curtailment to customer load (CPUC, 2016d).

Many customers (including generators) objected to the imposition of daily balancing. They and SoCalGas ultimately settled, agreeing that SoCalGas could make greater use of its relatively new authority to declare daily operational flow orders (OFOs) for low pressure, and that SoCalGas could simultaneously call an OFO for high pressure. Essentially, this allows SoCalGas to require daily balancing for a single day at a time instead of making the tighter balancing requirement a standing one that applies to every day. The CPUC approved this settlement in Decision No. 16-06-021 and extended it in Decision No. 16-12-015.

A standing rule to balance every day does not allow customers any room for error in matching supply and demand. Storage is essential to allowing flexibility. Pipelines that do not have storage allow very little flexibility. If California did not have underground gas storage, the State likely would never have allowed balancing provisions to be so liberal. Should storage be reduced and consequently system slack reduced, regulators will undoubtedly have to consider tighter balancing rules.

Core Balancing. As discussed previously, the utilities' core procurement groups must balance their loads, but they do not have to balance to actual load like non-core customers do. Rather, they balance to their forecast of core load. The current rule allows core to be deemed in balance even when there is a large difference between forecast and actual load. Misforecasting core load can result in a system imbalance that must be cured with gas from storage. Non-core customers recommended, in SoCalGas' triennial cost allocation proceeding (TCAP), that the utility be required to balance core load to actual load instead of only the forecasted load. The difference between forecast and actual load, especially in the winter months, can be large enough to necessitate use of underground gas storage even when the non-core load is perfectly in balance. Allowing core to balance to an erroneous forecast essentially gives core more liberal balancing rules than non-core, leaving non-core customers bearing the brunt of insufficient storage availability to buffer imbalances.

Essentially, the system accommodates forecasting errors on the part of core customers. Arguably, both PG&E and SoCalGas could improve their daily core load forecasts since they have years of intimate, direct experience developing the forecast and managing core demand. From their experience, they know which core customers on which parts of their system are more or less weather-sensitive than others and how weather variation affects demand. They also know how often they miss their own daily load forecast and the reasons

for forecast errors.¹¹² Neither PG&E nor SoCalGas are currently obligated to balance core load to their day-ahead forecasts, nor do they reveal how different their forecast is from actual core load. Non-core customers have argued that the installation of smart meters should allow for improvements in forecasting core load such that this change should be feasible. The settlement agreement in SoCalGas' TCAP, Decision No. 16-12-015, required SoCalGas to file an application "to address the feasibility of incorporating [smart meter] data into the core balancing process," including testimony regarding costs and technical issues. They filed their application on October 2, 2017 (SDG&E, 2017; SoCalGas, 2015). No similar order applies at this time to PG&E but its upcoming Gas Transmission & Storage rate case.

Tackling this issue may require understanding daily core load forecasting and how to narrow its associated range of error and imprecision. Success would undoubtedly require a change of mindset and possibly incentives for the utility to be more precise and not use slack in the system to make up for lack of precision in the forecast. This precision around daily core load forecasting would be new territory for the California gas utilities, but any reduction in imbalances reduces the need to use gas storage. Without data from utilities on their core load forecast errors, quantifying potential benefits of this strategy is not possible.

Greater Use of Line pack. Greater use of the line pack essentially means operating the gas system at higher pressures to compress more natural gas into the pipelines for use during high demand periods. Greater use of line pack would not obviate the problem of meeting peak winter demand nor would it have much impact on other uses for storage.

As explained earlier, line pack is the gas in a transmission pipeline or distribution main that keeps the line pressurized. Linepack must be sufficient to allow customers to take gas out of the pipeline without pressures dropping so low that gas stops flowing. The fact that gas is compressible allows gas molecules to be packed closer together, pushing more gas in to occupy a given segment of pipeline. On the high end, the safe maximum allowable operating pressure of a line limits the amount of line pack. On the low end, line pack must maintain the sufficient pressure differential between inlet and outlet points required for gas to move.

Gas distribution companies routinely use the line pack of their pipelines as temporary storage by "packing" the gas in their lines overnight and drawing the pack down first thing in the morning when demand peaks. This ensures a "full" pipeline as the new gas day starts, and leaves enough gas in the system after the peak to help meet demand over the rest of

112. These daily forecasts are updated using more precise short-term (sometimes day-ahead) weather forecasts very close to the time of gas delivery and are not the same as the longer-term, weather standards used for system planning and cost allocation.

the day. Packing prevents low gas pressure and outages that would otherwise occur during hours of the day when natural gas use is heavier, given that supply comes in at a flat rate, the same each hour. In this way line pack helps accommodate short lived, relatively small, and relatively predictable imbalances between demand and supply in certain hours of the day.

First, the natural pull of supply and demand will result in limited potential to use pipelines as storage beyond the current use of line pack in its diurnal pattern (gas always moves towards the lower pressure or open valve). The packed gas would flow downstream unless the transmission system is “shut in” to keep all of the packed gas within the transmission system.

Second, a gas distribution company would need to continuously pack the gas network, not just overnight as one does now, but in every hour with demand lower than the peak hour. Doing this can mean that the amount of gas in the pipelines would at times exceed the amount needed to meet demand and this condition may cause adverse operational issues. For example, if demand to use the increased line pack did not materialize, the operator would be faced with potentially unsafe operating pressures and have to find a way to release the excess gas. Expanding the use of line pack to replace California’s underground gas storage would trade risks associated with storage for risks associated with higher pressure use of pipelines and may violate best practices and safety norms.

Another issue may be that contractual gas day amounts may limit the amount of gas that can be “packed” in the transmission pipeline system; someone would need to provide more gas for packing into the line. Gas distributors and pipelines do require customers to deliver gas for “shrinkage” (i.e., gas used to run compressors and gas that is lost in measurement discrepancies); if the gas company has room in its system to accommodate some increase in the standard percentage above expected demand that all customers deliver, the action would represent an increase in the cost of gas that all customers would pay in order to buy and deliver more gas to the distribution company every day.

Another constraint is posed by the fact that there are likely not enough hours after the morning peak occurs to repack the lines to meet the afternoon and early evening peaks without using gas from underground storage. Figures 21 and 22 show the result of a 1,700 MMcfd change in demand between 6am and 6pm. This led to a 150 psig change in pressure on SoCalGas’ northern system and a constant 75 psig drop they found unacceptable on their lower pressured LA Basin system measurements at El Segundo and Los Alamitos. This pressure drop occurred with maximum withdrawals from three storage fields (while Aliso Canyon was unavailable). SoCalGas claims to use all its pack and draft ability in a given operating day to help balance its system (Shell Energy North America, 2009). Their hydraulic simulations are constrained to restore the system line pack. In other words, if the operators in Gas Control sees pressures dropping within a gas day such that it is not sure it can restore line pack overnight, it will curtail non-core load to preserve system integrity to serve core load.

Similar hydraulic results for PG&E are not available in the public domain. PG&E may have much more line pack than SoCalGas, owing to the longer distance of its transmission lines from the receipt points to its load centers. The distance from Malin and Topock to Antioch (near McDonald Island) is 356 and 545 miles, respectively, while the distance from Topock and Ehrenberg to LA is 275 and 227, respectively. SoCalGas doesn't report line pack, or the status of hourly operating pressures that indicate whether its system is in a pack versus draft condition, but PG&E does. The CPUC reviewed the differences between the pack and draft capabilities of the two systems in response to requests to change the balancing rules and switch to an operational flow order regime for SoCalGas in 2014. The result was a finding that SoCalGas often runs its line pack from minimum to maximum levels within a gas day and that there is no additional line pack capability available for gas operations (CPUC, 2015a).¹¹³

PG&E, on the other hand, has about 650 MMcfd of line pack (see Figure 25) and calculates the need for OFOs based on its daily pack versus draft conditions, or how much line pack remains, and projects its rise and fall over the work week. Typically, gas supply is relatively flat over the week, but demand is lower on weekends. PG&E's line pack therefore tends to become increasingly depleted as the week progresses and then recovers over the weekend with the natural ebb and flow of weekday versus weekend demand. Typically, within a day the system recovers line pack at night before the following gas day begins. When pipeline inventory deviates from these boundaries, PG&E calls OFO's asking customers to eliminate their imbalances to bring inventory back into its acceptable range. SoCalGas, in contrast, focuses its OFO calculations and protocols solely around the difference between receipts and demand (and nominations to withdraw from storage) every single day.

113. See also Finding of Fact 26: "Applicants' (referring to both SoCalGas and SDG&E) system lacks sufficient pack and draft capability to provide balancing services by way of line pack." On PG&E having more line pack than SoCalGas, see Finding of Fact 23.

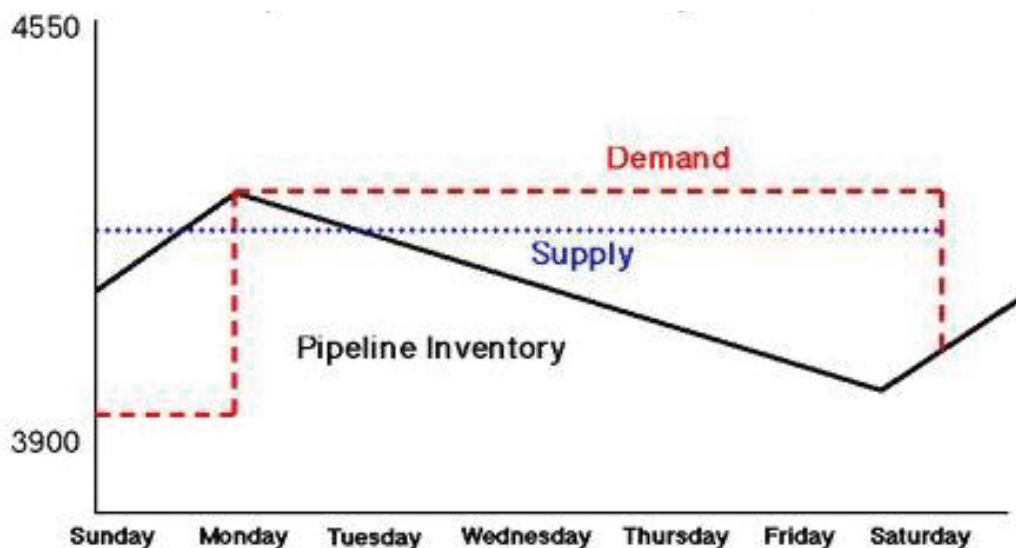


Figure 25. Illustration of PG&E Pipeline Inventory Linepack Variation During the Week.

Source: PG&E Pipe Ranger, n.d.

Verifying the utilities' stated line pack limits would require detailed work using hydraulic network modeling software and detailed specifics. Such modeling would elucidate the intricate relationship between line pack, efficiency, supply, and demand on the network to determine to what extent line pack gas can be "stored" in the pipeline while the system is in use. Such modeling cannot be done without obtaining and using the detailed data from the utilities not currently available in the public domain. The information available suggests it does not seem physically practical to simply increase reliance on line pack as a way of meeting the larger imbalances on PG&E or SoCalGas.

A dedicated piece of pipe can consistently store gas similar to a storage field (FERC, 2011).¹¹⁴ It may be possible in specific situations to add additional pipeline segments near power plants and potentially loop them in with the existing segments, or simply replace a segment with larger diameter pipe. This additional space might be allowed to hold extra line pack. The operational caveats from above apply: the segment would need to be valved off so that the line pack cannot migrate to lower-pressured parts of the local transmission or distribution system; it takes a radically different gas system configuration to pull this off.

114. The nearly 1,000-mile EPNG system has perhaps 1 Bcf per day of line pack (supporting a prior point that longer systems tend to have more line pack) and still requires customers to remain in balance.

ICF International explored the idea of adding pipeline segments near power plants to some degree in the 2011 study, “Integrating Variable Renewable Electric Power Generators and the Natural Gas Infrastructure,” in which they illustrated the benefit of expanding a lateral pipeline from 10” to 14” (off a 16” 83-mile mainline) to serve a 100 MW combustion turbine. ICF expected the turbine’s gas requirement would increase from 100 MMcfd to 180 MMcfd in response to decreases in output from a nearby wind farm, ostensibly an example of renewable generation’s intermittency. That increase in gas requirement could cause the gas inlet pressure to the turbine to drop enough to trip the unit off. ICF found that increasing the pipeline diameter by 4” would increase gas supply within the lateral pipeline by 3 MMcf and reduce the pressure drops occurring at the combustion turbine.¹¹⁵ It is not clear, however, that the line pack would be sufficient to provide the entire hourly gas requirement of the power plant.

ICF performed another study for the Interstate Natural Gas Association of America (INGAA) Foundation, “Firming Renewable Electric Power Generators: Opportunities and Challenges for Natural Gas Pipelines” (INGAA, 2011). Here ICF analyzed the impact on both line pack and operating pressures in additional scenarios using transient hydraulic modeling. They found that shorter nomination cycles helped stabilize line pack somewhat but did not conclude whether the line pack would be sufficient to supply the plant’s higher gas demand (ICF International, 2009) or the ability of the gas system to use line pack to supply the ramp requirement over all hours required. ICF did note the importance of underground gas storage as a system “shock absorber.”

Finding: Utilities and pipeline companies already use the line pack they have available. Using line pack beyond the normal operational ranges in use today creates a safety concern because a section of overfilled pipe could lead to over-pressurization and potential release of gas.

Closer Gas-Electric Coordination. The goal of operating with less gas storage has led to focus on operating with tighter margins by increasing coordination between the natural gas and electricity systems to thereby reduce unnamed inefficiencies that would in turn result in needing less gas from storage. Gas-electric coordination aims to reduce reliance on physical storage to make up for unplanned deviations between generation needs and gas availability. Such coordination might reduce the winter peak demand, but quantification of this will require further study including hourly dispatch modeling rather than planning models. Coordination will also help with other uses of storage.

115. This scenario is also remedied by installing a compressor at the compressor turbine; many of the independent generators funded via nonrecourse financing installed their own compressors and in some cases doing so was a condition of financing.

Project GECHO, an ARPA-E project led by Newton Energy Group and Los Alamos National Laboratory suggest that gas and electric demand can or should be co-optimized. Economic theory certainly suggests that hourly natural gas prices and hourly nominating periods, would cause greater optimization of the two systems by virtue of delivering more accurate price signals during those key hours in which natural gas is of higher value owing to higher demand. Reductions in physical storage would increase the variability of the value of storage between hours. Price signals to reduce natural gas use could also help preserve electric reliability.

California's balancing authorities have already made improvements in coordinating actions. Operating room personnel talk to each other almost daily; and, during times of system stress, they may talk to each other multiple times per day.¹¹⁶ They hold table-top exercises and conduct analyses of how much gas use could be reduced by reorganizing the electricity system dispatch and the limits of doing so. They schedule maintenance during low demand periods and move generation to alternate plants. These actions were spurred by the February 2011 southwest cold spell, discussed previously herein. All these efforts were expanded with the constrained operations at Aliso Canyon. Some of the specific coordinating changes recommended in the Aliso-related joint agency reliability action plan required changes to CAISO's tariff. These and a description of related actions are described in Appendix 2-7.

Nevertheless, these efforts do not constitute an hourly or sub-hourly economic co-optimization to reflect the time-value of gas. Similar processes were used in the past to schedule power plant dispatch but were not as effective as the use of modern organized wholesale market optimization algorithms.

A broader effort to promote coordination seems unlikely to succeed given the effort expended since 2012 with the open FERC rulemakings and NAESB discussions. Specific coordination efforts such as those requested by CAISO in response to Aliso Canyon are arguably more likely to be tractable enough to produce useful results. However, even with all of the above coordination actions – and when only Aliso Canyon service operations are constrained – the system operators remain concerned there will be days when we need more gas than we can get from storage.

Shifting to Out of Area Generation On Gas-Challenged Days. Not having gas storage will increase the frequency at which the gas system cannot meet all demand at assumed weather conditions (see Figures 16 and 17). In the 2016 summer and winter risk assessment

116. A pre-Aliso summary of CAISO gas-electric coordination activities by the CAISO's Director of Regional Operations Initiatives is available from a November 2014 CEC workshop on the subject. Found at <https://efiling.energy.ca.gov/Lists/DocketLog.aspx?doctnumber=15-IEPR-04> "NG Electricity Coordination and Effects on NG System CAISO Brad Bouillon" (2014a; accessed May 2017).

technical reports (and now summer 2017, too) CAISO documented some ability to shift generation to plants located outside the LA basin and some outside the SoCalGas service area on gas-challenged days. The ability to shift generation was smaller in the summer than in the winter because the summer had higher electricity demand resulting in higher loading of the transmission lines and more plants in operation. This meant most plants were already operating and being dispatched which left fewer alternatives to shift towards. In winter, their analysis found lower loads, which meant fewer plants were operating, transmission import lines were less loaded, and greater imports were feasible to replace generation from plants located in or near the LA Basin. The conclusions were reached through power load flow analysis (such as with GE's positive system load flow platform) used to test loading of transmission lines as electric generation is shifted away from gas pipeline systems facing gas constraints. Then by performing a dispatch analysis (as with production cost model) to determine how many hours the replacement plants must run to meet all electricity demand and satisfy NERC reliability requirements.

No similar analysis is available for generators who receive natural gas from PG&E. Moreover, the specific modeling results remain confidential due to FERC rules to protect market quality and prevent market manipulation. That being said, in the southern California analysis, the shift in generation logically would have been to units that are served from pipelines, such as Kern River instead of by SoCalGas.

To the extent that generation is shifted, three negative consequences occur. First, the “go to” plants represent a second-best solution from an economic efficiency perspective, otherwise they would not be available to operate in lieu of the first-best set of plants.

This uneconomic dispatch that results from not using the most efficient generating units to produce electricity means electricity production costs, and thus costs to consumers, will increase. The second negative consequence is that using less efficient generators means the overall quantity of gas burned will be higher (though it will be in places where the gas is accessible). The third negative consequence is that burning more gas in less efficient plants means the emissions of greenhouse gases and criteria pollutants will be higher.

The fact that CAISO's analysis suggests other generators can replace the local gas-fired generation does not guarantee that shifting will be feasible on the day needed. Rather, their analysis is a planning analysis; in real-time, the ability to shift generation will depend on which plants have forced or unforced outages on the day in need. The analysis also assumed there were no electricity transmission outages affecting the ability to replace some of the generation with imports, or to get it from the substitute units into the load centers and that gas was in fact available to those other plants. The latter assumption may be particularly optimistic on very cold days that affect not only California demand but demand located between California and producing areas, supply deliverable to California, or regional price differentials that cause suppliers to prefer sales to markets other than California.

Finding: Opportunities to shift to out of area generation on gas-challenged days are limited and not reliable.

Day-ahead limits on gas burn. Beginning summer 2016, CAISO, with approval from FERC, implemented a procedure giving themselves the authority to give burn limits to individual generators. Using this authority, CAISO can direct gas to specific units needing generation in order to avoid electricity blackouts, regardless of economic dispatch. LADWP implemented a somewhat similar procedure in which it fixed its gas burn quantity, nominated that quantity, and then met any shift in requirements with other resources. By specifying and limiting the gas burn day-ahead, the electricity system essentially sets a maximum on its gas nomination for the next day and seeks to avoid going “over” the maximum quantity the gas system can deliver on the next day. In essence, via these measures, the gas system now limits the electricity system.

This helps in the context of not having full output available from Aliso Canyon and was intended as a short-term measure. If there was no gas storage in California, the balancing authorities might instead propose that they calculate a minimum gas need and design the gas system around how to deliver it.

Finding: The technical assessments for the Aliso Canyon Reliability Action Plans indicate day ahead limits would be helpful, but not a full solution for the winter peak demand. It cannot, for example, eliminate error in the weather forecast.

Shaped nominations and Flexible Services. Natural gas wells, absent problems, produce gas on a flat hourly basis over the course of a day. Some of the difference between production and demand goes into storage in facilities near producing areas. Figure 2 showed the relative locations of gas storage fields across the U.S.; much of the storage in Texas, Oklahoma, Kansas, or Louisiana would be considered “production area storage,” whereas the storage in California is considered “market area storage.” Some work is going into the idea of allowing gas nominations to vary over the course of a gas day, whereas today they are fixed (consistent with production patterns). If gas could flow into California on a shaped basis within the gas day, the need for gas storage to support intra-day balancing would be reduced.

Canadian producers might be able to use the AECO-C™ commercial natural gas storage hub in Alberta to support shaped nominations on the GTN pipeline to some degree. Kern River might be able to allow some amount of shaped nominations if the Magnum storage project proceeds.¹¹⁷ In both cases, that possibility may depend on how much of the storage capacity

117. Magnum is to consist of 4 solution-mined storage caverns capable of storing 54 billion cubic feet (Bcf) of natural gas, for three to four turns per year and with peak injection of up to 360 MMcfd and withdrawal of up to 500 MMcfd. It will be connected to Kern River via a newly constructed 61-mile-long header pipeline. See http://westernenergyhub.com/pdf/Magnum-Gas-Midstream_Open-Season-Press-Release.pdf (Accessed April 2017). FERC approved Magnum’s request to slightly alter the geographic location of its facilities and for market-based rates in November 2016, and has since approved Magnum’s request of an extension of time to July 2017 to file its construction compliance plan. Magnum estimates 3.5 years from granting of the CPCN to completing construction and being available to provide service. See FERC Dockets CP10-22-000 and CP16-18-000.

the pipeline itself controls. The shaped nominations would still need to match the hourly load shape, and storage located several hundred miles away would be unable to respond to short-notice changes, making this solution insufficient for all situations. Appendix 2-8 describes experience with flexible nominations in other states.

Finding: If California had no underground gas storage to support shaped nominations, storage somewhere upstream would be required to support the variation in load. However, this remote storage would be unable to respond to short-notice changes.

A gas system without underground gas storage might require costs to be reallocated such that they more accurately reflect use of the system. The cost allocation principles adopted in the 1986 initial unbundling order and later amplified in the 1992 gas marginal cost decision focus on “cold year throughput” and winter peak demand (CPUC Decision Nos. 86-12-009 and 92-12-058). A system without storage or with less storage may need an allocation that more accurately fits actual use of the system, and particularly, monthly or hourly use of the system. As the electric system moves to Time of Use rates in order to send more accurate price signals, a gas system without storage might need something similar. More precise price signals, in theory, should reduce peak usage.

California also seems to have reached a point at which we are no longer willing to allow electric generation or refineries and other key non-core users to bear gas curtailments.¹¹⁸ If that is so, then the old framework in which most costs were allocated to core customers with non-core customers getting lower rates to fill in the gaps when the pipeline is less used no longer matches our policy desire to essentially give these generators and refineries firm service.

Weekend gas market. A weekend gas market could help to reduce, but not eliminate the need for storage. The electricity market operates 24/7, but natural gas is transacted in less than eight hours a day. Once the market stops trading (around noon East Standard Time) for tomorrow’s business, it becomes not only thinner in terms of uncommitted volumes available but in terms of bodies at a desk available to suppliers. Customers with smaller loads may have a problem finding a supplier available, and even a significant user like LADWP has indicated difficulty. California cannot by fiat require gas suppliers to be available after the timely nomination window. It can, however, encourage in-state participants to the NAES Board gas quadrant discussion to support 24-hour markets. (It is also possible that tighter markets without storage in California would induce marketers

118. See for example letter from CEC Chair Robert B. Weisenmiller to Governor Brown saying he would deliver an action plan to prevent electricity blackouts while Aliso capacity was diminished (can be found at http://docketpublic.energy.ca.gov/PublicDocuments/16-IEPR-02/TN210801_20160322T100019_212016_Letter_from_CECISOCPUc_to_EGB.pdf (Accessed October 2017)). That action plan was delivered along with a technical assessment on April 20, 2016 and has been referenced previously in this report. Also, previously referenced was a June 17, 2016 workshop about impacts to oil refineries.

and suppliers to expand their availability.) 24-hour markets would make it easier for gas customers to balance their supply receipts with actual demand, particularly in providing a remedy for the issue of having to buy and nominate gas on Friday to meet demand through the weekend and into Monday. Storage (inside California or out) may still be needed in order for customers to balance flat production against lower weekend demand, but storage would not be needed by the utility and the Monday problem could be eliminated.

Summary of Market Mechanisms

Table 19 summarizes operational and market mechanisms which could reduce dependence on underground gas storage. Regulatory and operational changes can help, but do not eliminate the need for underground gas storage to meet winter demand and do not seem able to have much further impact on our use for daily balancing.

Some of these operational and market alternatives are already being implemented given the reduced use of Aliso Canyon; they are therefore already achieving what they can in the SoCalGas system. If all storage were eliminated, implementation of the market and operational alternatives would need to expand to cover the PG&E system. In particular, the balancing rules would likely need to become even tighter. The change to core balancing rules should help to reduce the need for storage, depending on the error range between daily forecasts of core demand and actual core demand, and how much of that error we can eliminate – an unknown at present. The market changes that require approval outside of California do not lend themselves to more accurate quantification of benefit. Moreover, they require outside approvals that do not appear obtainable by 2020, even though we note several changes were adopted quickly as part of the reliability action plan to avoid electricity blackouts with Aliso Canyon's reduced capabilities.

Table 19. Operational and Market Alternatives to Underground Gas Storage.

Tighter Balancing Rules	<ul style="list-style-type: none"> Sempra has moved to 8% balancing. Can reduce to 5% balancing on a daily basis when needed. These changes have reduced need to use gas storage by 0.15 Bcfd.
Balancing Core to Actual Load Instead of Forecast	<ul style="list-style-type: none"> Sempra filed proposal in September 2017 as required (CPUC review pending). Could reduce use of storage for difference between actual load and forecast.
Greater Use of Linepack (the ability to store gas by compressing it into the pipelines)	<ul style="list-style-type: none"> Raises safety concerns as Sempra has very little linepack. They can only store about ~0.13 Bcfd by compressing gas in their pipelines. They strive to get their system back into balance before the start of each gas day. PG&E has ~0.4 Bcfd of linepack and already uses what it has. If new intrastate pipeline capacity were added, linepack capability might increase by 50%.
Closer Gas-Electric Coordination	<ul style="list-style-type: none"> Unprecedented levels of coordination implemented after the Aliso event means further gains will be more difficult. There could be benefits from formalizing joint reliability planning.
Advance Notice on Expected Burn and Day-Ahead Limits on Gas Burn	<ul style="list-style-type: none"> Both electricity balancing authorities are doing this now for southern California. Advance notice aids generators in complying with tighter gas balancing. When gas burn is limited, it creates uneconomic dispatch. No studies available on feasibility for northern California or that calculate minimum EG gas burn needed to prevent blackouts.
Shifting Generation to Out-of-Area	<ul style="list-style-type: none"> When available, shifting to other generators outside a constrained gas area can avoid the need to pull gas from storage. However, higher electricity prices will result from uneconomic dispatch. No studies are available on feasibility for northern California or that calculate minimum electricity generation gas supply needed to prevent blackouts.
Shaped Nominations and Hourly Gas Market	<ul style="list-style-type: none"> Hourly natural gas prices would require industry-wide acceptance. Could potentially send price signals to reduce gas consumption during peak hours or hours when storage would have provided balancing service. Shaped nominations would require the support of some storage or available linepack.
Weekend Natural Gas Market and Nominations	<ul style="list-style-type: none"> Requires industry-wide acceptance. Prior discussions of this concept were not fruitful. Could help all customers and shippers (but especially electricity generation) by eliminating the Friday nomination for Sat/Sun/Monday. Would allow more realistic opportunity with balancing loads on weekends.

Finding: Regulatory and operational changes can help to reduce reliance on underground gas storage, but will not eliminate the need for these services.

Conclusion 2.17: Operational and market alternatives do not eliminate the need for underground gas storage to meet winter demand, which serves to overcome the physical difference between peak winter gas demand and the capacity of pipelines to deliver gas. Nor will these measures have much impact on reducing the need to use storage for daily balancing.

1.5 How will new integrity and safety rules affect natural gas reliability?

New safety regulations for storage operations and maintenance by both state and federal authorities were adopted following the Aliso Canyon well leak starting with the Division of Oil, Gas and Geothermal Resources (DOGGR)'s Emergency Regulations in January 2016 (California Department of Conservation, 2016). In July 2016, DOGGR released a discussion draft of proposed permanent regulations that would apply to all storage operators. Those regulations remain to be finalized in 2017.¹¹⁹ The federal government enacted regulations to address the need for safe and reliable operations of natural gas storage fields after the Aliso Canyon gas well loss-of-containment (Government Publishing Office, 2016). These regulations were the first to cover “downhole facilities” including wells, wellbore tubing and casing or the operations, maintenance, integrity management, public awareness, and emergency response activities associated with these downhole facilities.

These new regulations affect the natural gas storage capability in California because the reduced effective well diameter reduces injection and withdrawal rates, limiting the ability of the UGS facility to store or withdraw gas over short time periods. Additionally, wells will have to be taken out of service more often for testing (with longer outages should the tests indicate additional maintenance is required). The new regulations could also increase the cost of the UGS facilities when tubing, packer, and new wider-diameter tubing must be purchased. If increased costs are not recovered in a rate case, operators could also retire or abandon wells because they could not afford to meet the new regulations. This would reduce the amount of gas stored, injected, or withdrawn at the UGS facility.¹²⁰ Highlights of the new requirements include:

119. See Discussion Draft, California Code of Regulations, Title 14, Chapter 4. Development, Regulation and Conservation of Oil and Gas Resources, Article 4 (California Department of Conservation, n.d.). Requirements for Underground Gas Storage Projects. At <http://www.conservation.ca.gov/dog/Documents/GasStorage/Public%20Discussion%20Draft%20-Requirements%20for%20Underground%20Gas%20Storage%20Proj.pdf> (Accessed May 2017). The comment period on these proposed rules ended July 13, 2017. See: <http://www.conservation.ca.gov/dog/Documents/GasStorage/Public%20Discussion%20Draft%20-Requirements%20for%20Underground%20Gas%20Storage%20Proj.pdf>. Accessed July 2017.

120. Depending on interconnectivity within storage facilities that have more than one reservoir, such as Aliso Canyon, total storage capacity may also be reduced according to which wells are taken out of service.

- Improved inspection and leak protocol for all wells, pipelines, wellheads and a 100' radius from the wellhead. (PHMSA)
- Demonstration of the integrity of the underground storage reservoir or cavern using appropriate monitoring techniques for integrity changes, such as the monitoring of pressure and periodic pressure surveys, inventory (injection and withdrawal of all products), product levels, cavern subsidence, and the findings from adjacent production, water and observation wells. (DOGGR)
- Injection and withdrawal will no longer be allowed to occur through production casings; operators will instead be limited to use of only the tubing inside the production well casing. (DOGGR)
- Mechanical Integrity Testing (MIT) pursuant to SB 887 (which also requires each operator to have an MIT plan in place by January 2018).

Under Order 1109, applying only to SoCalGas, DOGGR required SoCalGas to complete six tests - aimed at demonstrating the safety of Aliso Canyon before it could return to injection.¹²¹ In performing these tests, SoCalGas removed the old tubing and replaced it with larger-diameter tubing. As of fall 2017, SoCalGas had completed testing (and any associated remediation work) on 52 of the total 113 wells at Aliso Canyon and made them available for withdrawal.¹²² The regulations give SoCalGas one year to test and remediate remaining wells or to put them permanently out of service. SoCalGas must also determine the rate to conduct the tests, replace tubing, and perform other remediation that may be found necessary as the tests are conducted.

Preliminary indications from SoCalGas to the joint agencies preparing the reliability action plans are that no more than 50 to 60 wells out of the 113 will ever be available again, absent drilling of new wells. Withdrawal capability using the wells tested to date at current inventory of ~ 14 Bcf is currently 320 MMcfd (CEC, 2017b). This could rise to 500 MMcfd if some reinjection occurred – more gas in the field would raise pressures and allow the 14 Bcf in the field to be withdrawn at a faster daily rate. It would also increase if additional wells passed through the testing and tubing replacement process so that there were more wells available. In reality, the field might never again be capable of supporting the 86 Bcf of inventory, 413 MMcfd of injection, and 1,860 MMcfd withdrawal it once provided.

121. SB 380 (Pavley) Chapter 14, Statutes of 2016 subsequently codified the process for returning Aliso Canyon wells to service.

122. SoCalGas applied to the CPUC and DOGGR in November 2016 for approval to return these same wells to injection service; that request was granted in July 2017. The County of Los Angeles subsequently obtained a temporary injunction on any injection; California's 2nd District Court of Appeals lifted that injunction on July 29, 2017. See <http://mynews1a.com/life/2017/07/30/aliso-canyon-safe-ok-to-reopen-dramatic-reversal-by-appeals-court/>. Accessed July 2017.

SoCalGas announced on February 15, 2017 that it would immediately implement a Storage Safety Enhancement Plan (SSEP) in all of its gas storage facilities to comply with the DOGGR regulations that, on that date, were still in draft form. This work would conduct the same six tests as those required at Aliso and reconfigure the wells at the La Goleta, Honor Rancho, and Playa del Rey storage fields to tubing flow only. Some work started March 1, 2017 and SoCalGas planned that all wells not converted by April 1 would be temporarily plugged until they were tested and the tubing replaced. This plan would have reduced the withdrawal and injection capacity of each of the storage fields – reducing it to virtually zero for this summer (CPUC, 2017a). It would also permanently reduce injection and withdrawal capability going forward unless additional wells are added. Owing to reliability concerns, the CPUC, on March 16, 2017, directed SoCalGas to modify the Storage Safety Enhancement Plan (SSEP) in order to maintain withdrawal capability of 2.065 Bcf per day at the other fields and 2.420 as other wells are tested and become available for withdrawal at Aliso Canyon.

PG&E began talking about impacts from the proposed permanent DOGGR rules earlier this year. It briefed State agencies in early 2017 and met with customers and rate case participants in May. PG&E finds that moving to tubing-only would reduce injection and withdrawal capability by 40%, absent drilling new wells.¹²³ They project an increase in operation and maintenance (O&M) of over 200% per year to perform the annual integrity assessments and an increase in capital expenditure by 40%, including the drilling of 50 new wells to maintain current withdrawal capacity. Without those new wells, PG&E would be unable to withdraw the 1,270 MMcfd of withdrawal capability reserved to serve core customers in winter months. These projected costs appear to have led PG&E to announce in a customer meeting on May 11 that it would seek to retire its two smaller gas storage fields and replace them with gas from the independent gas storage fields.¹²⁴ More information will become public once PG&E files its next Gas Transmission and Storage rate case in the fall.

Taking the current utility-owned withdrawal capacity of 4.8 Bcf, less 40%, leaves 2.9 Bcf per day withdrawal capability (when the fields are at maximum inventory). This 2.9 Bcf plus California's intrastate pipeline take-away capacity of 7.5 Bcf yields a maximum servable demand of 10.4 Bcf per day assuming no gas pipeline or compressor facility outages of any kind. This would be adequate to serve 2020's aggregate statewide 1-in-10 winter peak day

123. PG&E Storage Update Meeting with CEC, January 18, 2017. Logically, going to tubing-only instead of injecting through tubing and the casing reduces the volumetric flow capacity. The CPUC, in its July 19, 2017 report "Aliso Canyon Working Gas Inventory, Production Capacity, Injection Capacity and Well Availability for Reliability" noted one of its key uncertainties in calculating how many wells are needed for reliability is that "the performance of wells using tubing-only flow as required by Senate Bill 380, as opposed to flowing gas through tubing and casing."

124. We submitted to PG&E a request for a copy of the 'reliability and cost' analysis mentioned by Senior VP Mel Christopher at the meeting. It was not available to us prior to the time of publication.

demand of 10.249 Bcf shown in Table 6. It would not, however, be enough to serve the 2020 forecast of a 1-in-90 winter peak day demand of 11.845 Bcf. Thus, after taking into account the reduction in storage from the new rules, California's utilities would not be able to meet any demand above 10.4 Bcf per day. As described previously, in its 2018 Gas Transmission and Storage (GT&S) rate case, PG&E proposed replacing the reduction of storage by contracting with independent storage. SoCalGas does not have this option because there is no independent gas storage connected to its system.

In theory, operators could replace the lost capacity by drilling additional wells sufficient to meet the 2020 winter peak with implementation of the DOGGR rules. Pursuant to Public Utilities Code Section 1005, utility capital investments over \$50 million require submission of and CPUC approval of a CPCN. Given that no such applications have been filed yet and assuming 12 months at least to process and approve, it might be barely possible to do the planning, obtain the regulatory approvals, and drill any new wells by 2020.

Conclusion 2.18: In the 2020 timeframe, California's utilities will need to replace some, if not all, of the storage capacity that will be lost by complying with new California regulations to continue to meet peak winter demand. California's independent storage providers will also need to replace some, if not all, of their lost injection and withdrawal capacity, if they want to maintain historic operating levels.

Pipeline safety measures will also have an impact. The CPUC (in Rulemaking 11-02-019) and PHMSA adopted more rigorous requirements for pipeline integrity management after the September 2010 explosion of a PG&E high pressure gas transmission pipeline at San Bruno that killed nine people and destroyed 38 homes. Those integrity management obligations require the utilities to conduct in-line inspection or take pipelines out of service for hydrostatic testing. When anomalies are found, depending on their severity, the operator may have to take pipeline segments out of service until remediation can be performed. In some cases, the utility must secure various local and environmental permits before the work can be performed.

For example, SoCalGas currently has Line 3000 out of service while remediation work occurs. Additionally, its southern mainline is operating at 80% of maximum allowable operating pressure (MAOP), which reduces capacity by about 200 MMcfd, until hydrostatic testing of the line can occur.

The CPUC directed both utilities (in Rulemaking 11-02-019) to develop pipeline safety plans. PG&E proposed spending \$2.2 billion over 4 years on work consisting of strength testing, in-line inspection (ILI), upgrades on various segments to allow ILI, the replacement of 186 miles of pipeline, and the automation of 228 valves. PG&E's plan and implementation timeframe is summarized in Figure 26.

Work Streams	2011	2012	2013	2014	Phase 1
Strength Testing*	236 miles**	185 miles	204 miles	158 miles	783
Pipeline Replacements	0.3 miles	39 miles	64 miles	82 miles	186
ILI Upgrades	--	78 miles	121 miles	--	199
In-line Inspections	--	--	78 miles	156 miles	234
Valve Automation	29 valves	46 valves	90 valves	63 valves	228
Records Integration	Data Validation, MAOP Calculations, Integrated Asset & Work Management				
Interim Safety Measures	Pressure Reductions, Leak Surveys, Aerial Patrols				

Figure 26. PG&E Pipeline Safety Enhancement Plan.

Source: PG&E

SoCalGas (including affiliate SDG&E) proposed spending \$1.43 billion to modify 541 valves, install backflow valves (or check valves) to prevent gas from flowing into sections intended to be isolated from other connected lines, expand private radio networks, install remote leak detection equipment, and increase patrols and leak survey activities. The two would also pressure test or replace 385 miles of pipeline (CPUC, 2014a). Current work has Line 3000 out of service while remediation work occurs. (Envoy™ currently shows Line 3000 expected to be back in service sometime in the fourth quarter of 2017). Additionally, SoCalGas' southern mainline is operating at 80% of MAOP, which reduces capacity by about 200 MMcfd, until hydrostatic testing of the line can occur.¹²⁵ SoCalGas also has an outstanding request in A. 15-09-013 for a CPNC to build a new 47-mile line paralleling its existing Line 1600 from the Rainbow Metering Station in Riverside County to San Diego. This project is said to be needed so that Line 1600 can be taken out of service and pressure-tested pursuant to CPUC rules. SoCalGas and SDG&E estimated construction costs of \$596 million (SDG&E and SoCalGas, 2015).

The storage integrity work needs to be coordinated with remaining pipeline integrity work in order to preserve reliability. It appears PG&E is already thinking about impacts to reliability from the new storage rules (based on its briefings and rate proceeding discussions). It is less clear at this point that SoCalGas is synchronizing its SSEP with reliability planning, or what it might be thinking in terms of drilling replacement wells in

125. See Maintenance Schedules at <https://scgenvoy.sempa.com/>. Accessed July 2017.

the near-term. Implementation of the new DOGGR rules and coordination with pipeline safety enhancement plans provide a good opportunity to revisit and clarify the importance of reliable gas service to electric generators. This importance could be better reflected in California's natural gas services and tariffs.

What are the rate impacts of closing storage facilities?

There is little experience retiring gas storage facilities in the United States. California, however, has retired some.¹²⁶ All of these appear to have been retired for operational reasons. Some retirements could have been related to safety, but we do not have enough information to draw more precise conclusions about how safety related to these retirement decisions. Examples of storage facility retirements are given in Appendix 2-9.

Whether additional fields would need to be retired due to test findings is unclear at this time. Whether doing so entails a net cost or yields a net benefit seems to depend on the prices prevailing when the gas remaining in the field is sold and likely the value of the land involved. We cannot determine whether additional issues might arise if fields are retired.

At this time, there are more policy questions than answers about the process and implications of closing storage facilities. The utilities' financial concerns require that a significant portion of O&M costs be recovered in rates. What cost-benefit analysis will the CPUC use to assess the value added of storage vs. these new costs? At what level of cost will the CPUC or the utilities balk at the increased storage costs that have to be passed on to consumers? Would the CPUC approve of the utilities unilaterally abandoning the storage sites? How will the new rules apply to independent storage vis a vis the recovery of costs? Could independent companies declare bankruptcy and walk away?

126. Abandonment would be the formal regulatory term describing the state of a field, pipeline, or well that has been removed from service permanently, after environmental remediation and removal from rate base.

1.5.1 Financial Viability and Investment in Maintaining Storage Assets

The new safety and integrity rules may affect the financial viability of specific underground gas storage fields depending on the new spending required. There is some public information about O&M costs and capital expenditures for the utility-owned storage facilities. Appendix 2-10 explores that information to help readers understand the pattern of investment in these facilities that might affect their condition. It does not present a full valuation analysis. This information can also help form the basis to begin thinking about the financial value of these facilities that might need to be taken into account if California decided to retire any of these facilities.

Finding: PG&E and SoCalGas spent an average of \$500,000 per Bcf of cycling capability in 2015 on O&M at their storage facilities. Over time, those expenses appear to have increased at a rate similar to inflation. We could not determine, from information in the public domain, the condition of gas storage facilities or if O&M expense and capital expenditure has been sufficient to maintain the facilities or whether the independent facilities are in better condition and if this might be the case because they are regulated differently or because their owners focus on storage and storage alone.

Recommendation 2.2: DOGGR should conduct detailed facility condition assessments by independent analysts or with stakeholder review, and determine if the level of investment to date is adequate, taking into account the expected cost to implement the new DOGGR rules. This could include an assessment to determine what, if any, impacts occur as a result of different business and regulatory models for utility versus independent storage.

Simply adding the reported transaction and book values yields a very high-level total potential value of \$2 billion as an estimate of compensation (note that this does not address depreciation or other issues) that might be due to owners should California conclude that underground gas storage is not viable and decide to eliminate facilities. At the same time, the newer condition of the independent facilities, their owner's ability to focus on operating and maintaining them, and the competition that goes on inside a utility for budget dollars and in a rate case should at least make one pause and ask if we want our utilities to be in the gas storage business. Are there benefits or any reduction in risk to other business models? Answering that question goes beyond the question of viability but could be something the State wants to consider if it more expansively addresses the future of underground gas storage in California.

Again, this analysis cannot determine if O&M expense and capital expenditure has been sufficient. Any inability to invest adequate ratepayer dollars into utility gas storage facilities is a threat to viability and the CPUC will need to take into account likely higher spending requirements for underground storage going forward. This may be more difficult for the independent storage facilities since current market conditions limit what they can charge subscribers.

APPENDIX 2-1: Nominations, Scheduling, and Balancing

Non-core customers must nominate and schedule their delivery of gas supply with the utility. Nomination and scheduling is a request for a physical quantity of gas under a specific purchase, sales or transportation agreement to be delivered. It must be receipt and delivery point-specific. Essentially it is a nomination from a shipper to advise the pipeline owner or utility of the amount of gas it wishes to transport or hold in storage on a given day or days. A nomination will continue for a specified number of days or until superseded by another service request for the same contract.

Since many end-users use a third-party agent to handle their nominations, scheduling, and balancing, the end-user must also submit a matching nomination. In essence, this matching nomination is confirmation that the transaction is valid.

A utility uses the scheduled quantities to determine if there is enough capacity on their system to meet demand on a given day or if it has enough gas being delivered to meet all demand. When firm shippers schedule deliveries to a specific receipt point that exceed that point's capacity at the scheduled time, the utility (or pipeline) "cuts" or reduces the requested quantities pro rata. This occurs with each utility or pipeline from the customer all the way back upstream to where gas is produced at the wellhead.

Rules specified in both the PG&E and SoCalGas tariffs require customers to bring in each day what they will use that day, and deliveries are supposed to be evenly split, or, equal in each hour. A difference between a customer's usage and the volume of gas scheduled for delivery is called an "imbalance." With small imbalances, this free storage is provided within the pipeline's line pack.¹²⁷ In the case of an over delivery, the imbalance represents free storage. The utility must effectively store the extra gas in the pipeline. Conversely, a customer might bring in less gas than scheduled essentially use line pack to cover its nominated usage. Bigger imbalances cannot be addressed with line pack, and today are met with gas from underground gas storage. Both PG&E and SoCalGas use a portion of their storage assets to provide additional balancing services above and beyond what can be accommodated with line pack (PG&E Storage Assets Available for Balancing and Market Center, n.d.).

Under the 1990 CPUC transportation imbalance rules, both PG&E and SoCalGas permit a tolerance band around scheduled gas quantities so that small errors between usage and scheduled quantities are allowed and incur no penalty. In other words, customers can have up to a 10% difference between their actual monthly usage compared to the gas they bring into the system. Customers have an entire 30 days after the delivery month to clear

127. Line pack is gas that is maintained in a transmission pipeline or distribution main to keep it pressurized enough that customers can take gas out of it without pressures dropping so low that gas stops flowing. Line pack is discussed further in Chapter 2 Section 1.4, in discussing potential alternatives to underground gas storage.

their imbalances by delivering make-up gas supply to the utility, delivering less gas if the imbalance was positive, or by trading out the imbalance with another party on the system. Imbalances that are not remedied may be cashed out at penalty prices.

The utility staff group that buys and schedules gas deliveries on behalf of core customers are also subject to the 10% monthly tolerance but the imbalance is calculated relative to forecasted demand instead of the actual demand. This essentially means that they are not held accountable for forecast errors whereas non-core customers (including generators) are held accountable for forecast errors. Arguably, they are getting free balancing for the portion of their imbalance caused by forecast error. The utility system operators manage this core customer imbalance (after line pack and offsets by other customers are used) with storage.

It is also relevant that most natural gas purchase contracts, often using a form of agreement adopted as the industry standard by the North American Energy Standards Board (NAESB), specify a flat daily delivery of natural gas. If the user's requirements vary, the contract might include an option to "swing" up to a specified quantity. In other words, one might contract to purchase 11,000 MMBtu per day, with the ability to swing that purchase quantity up to 14,000 MMBtu. The 11,000 MMBtu base quantity is to be taken every day, and would likely be priced at the index price posted on the InterContinental Exchange (ICE), at say, "SoCal Border." If the user needs less than 11,000 MMBtu on a given day, it would either have to sell the excess gas into the daily spot market, leave it as an imbalance which must then be corrected next month by either trading it out, or paying the sale or buy-back penalty stated in the utility tariff. Alternatively, the customer can nominate to inject it into storage, assuming they have purchased rights to use storage.

Table 20. Nomination and Scheduling Cycles (PST).

Cycle	Nomination Time	Confirmation Time	Becomes Effective
Timely	11:00 am Day Prior	3:00 pm Day Prior	7:00 am Day Of
Evening	4:00 pm Day Prior	7:00 pm Day Prior	7:00 am Day Of
Intraday 1	8:00 am Day Of	11:00 am Day Of	12:00 pm Day Of
Intraday 2	12:30 pm Day Of	9:00 pm Day Of	4:00 pm Day Of
Intraday 3	5:00 pm Day Of	8:00 pm Day Of	8:00 pm Day Of

Source: Compiled by Aspen Environmental Group

Looking at the five scheduling cycles portrayed in Table 20, several points are worth noting. First, even the intraday cycles have a gap of three to four hours from when the nomination is submitted to when the nomination becomes effective and the gas flows. Second, the cycles do not allow one to swing up on a nomination to take more gas in just a few hours. The new nomination still represents a daily take, spread over 24 hours. If only 8 hours remain in the gas day, then the daily nomination's impact will be 8/24ths of the daily quantity nominated. Notably, the "timely" gas cycle nominations are due before the CAISO announces its natural gas dispatch at 1pm Pacific Time. This means that electric generators to a certain degree are "guessing" when they submit their gas nominations as to how much natural gas they will burn tomorrow.

The pipelines and gas utilities operate in a construct of a "gas day" that starts at 9am Central Standard Time (CST), nationwide, (meaning 7am Pacific Standard Time (PST) in California). That gas day is the same all across the country (whereas electricity varies by regional market). Gas is traded on the day prior to delivery, until about mid-day, after which fewer marketers are active and fewer have gas still available to respond to developments later in the day.

Appendix 2-2: Storage Fields in California and Key Characteristics

Facility Owner	Facility Name	County, City	Working Capacity ¹⁴	Type of Field	Approximate Facility Age	Other Info
SoCalGas	Aliso Canyon	Los Angeles, Porter Ranch (near Northridge).	86 Bcf, with 1,860 MMcfd withdrawal	Depleted oil (115 wells).	Purchased by SoCalGas in 1972, former oil field. Oil well records dating as far back as 1940's. (Half of SoCalGas' total of 229 storage wells are more than 60 years old, per Baker GRC testimony). ¹⁵	The facility occupies 3,600 acres of surface area. ¹⁶
SoCalGas	Playa del Rey	Los Angeles, Playa del Rey and part of Venice.	2.4 Bcf (have also seen 1.8 Bcf) with 400MMcfd withdrawal	Depleted oil (54 wells).	Oil well from the 1930's started operating in 1942. Purchased by SoCalGas in 1955.	There is a 2007 CPUC settlement due to suspected air/water contamination (see Fact Sheet). ¹⁷
SoCalGas	Goleta	Santa Barbara, Goleta.	21 Bcf & 400MMcfd withdrawal	Depleted oil and NG (20 wells).	6 oil wells from 1929, then extracted NG, prior to storage use in 1941. ¹⁸	Is SoCalGas' oldest facility in operation.
SoCalGas	Honor Rancho	Los Angeles, Santa Clarita/Valencia.	26 Bcf & 1000MMcfd withdrawal	Depleted oil (41 wells).	Purchased from Texaco in 1975. There are 23 former oil fields (Texaco) dating back to the 40's, 18 drilled since by SCG.	Facility is located 10 miles north of Aliso Canyon at Valencia
PG&E	Los Medanos	Contra Costa, Concord	16 Bcf	Depleted NG	PG&E converted to storage in 1976. ¹⁹	Parcel measures 318 acres.
PG&E	Pleasant Creek	Yolo, Winters	2.3 Bcf	Depleted NG	PG&E constructed in 1959.	Parcel measure 320 acres. ²⁰
PG&E	McDonald Island	San Joaquin	82 Bcf	Depleted NG	Originally produced NG for Standard Oil 1936. ²¹ PG&E purchased in 1958. Converted to storage early 1970's.	McDonald Island is below sea level and has contingency plans in place to continue operations when the Island floods. ²²
PG&E owns (25%) Private (75% Gill Ranch Storage LLC)	Gill Ranch	Madera, Mendota (~20 miles west of Fresno).	20 Bcf withdrawal = 650MMcfd	Depleted NG	Active NG extraction from 1943 - 1996; some limited production may still occur in a shallower formation. A. 08-07-032 & A. 08-07-033	Interconnection to PG&E Line 401, 27 miles to the west. (Gill Ranch Fact Sheet) ²³
Private (Brookfield LLC – acquired 2014) ²⁴	Lodi	San Joaquin, Acampo	17 Bcf withdrawal = 500MMcfd	Depleted NG	CPUC A. 98-11-012 for 10 wells. ²⁵	1450 acres surface space.
Private (Brookfield LLC)	Kirby Hills (operated as part of Lodi Gas Storage)	Solano, Fairfield	12 Bcf (inj & withd = 300MMcfd)	Depleted NG (15 wells + compressor and dehydrator	A. 05-07-017 and A. 07-05-009. ²⁶	Originally developed by Dow Chemical and purchased by Lodi ~ 2005. 6 miles to PG&E Line 400.

Facility Owner	Facility Name	County, City	Working Capacity ¹⁴	Type of Field	Approximate Facility Age	Other Info
Private (Brookfield – acquired 2015) ²⁷	Wild Goose	Butte, Gridley	50 Bcf (650MMcfd injection and 1200MMcfd withdrawal)	Depleted NG (+ processing, compressor and dehydration)	Produced NG 1950's-80's. Began operating as storage facility in 1999 and expanded twice: A. 96-08-058, A. 01-06-028 & A. 09-04-021.	First independent storage facility. Connects to PG&E Line 167. Connection to Lines 400/401 near Delevan added later. Company indicates that its natural shale formation is good for preventing seeping. ²⁸
Private (AGL)	Central Valley	Colusa, Princeton	11 Bcf Withdrawal = 300MMcfd	Depleted NG (9 wells, compressor, saltwater disposal well)	Produced NG 1954-1992. Converted to storage 2010; A. 09-08-008. ²⁹	2200 ft underground; rural location. Connected to PG&E Line 172 outside fence and 15 miles to and Lines 400/401.

14 Withdrawal capability reported is maximum withdrawal potential at full field inventory.

15 https://www.socalgas.com/regulatory/documents/a-14-11-004/SCG-06_P_Baker_Testimony.pdf (SoCalGas, 2014b)

16 https://www.socalgas.com/regulatory/documents/a-14-11-004/SCG-06_P_Baker_Testimony.pdf (SoCalGas, 2014b)

17 https://www.socalgas.com/documents/safety/pdr_storage.pdf

18 <http://www.independent.com/news/2013/may/23/la-goleta-gas-storage-questions-answered/>

19 http://www.pge.com/notes/rates/tariffs/tm2/pdf/GAS_3489-G.pdf

20 http://www.pge.com/notes/rates/tariffs/tm2/pdf/GAS_3543-G.pdf

21 <http://archives.datapages.com/data/specpubs/fieldst1/data/a007/a007/0001/0100/0102.htm>

22 <http://www.sfgate.com/business/article/Making-things-a-little-less-shaky-PG-E-pipeline-2555059.php>

23 <http://gillranchstorage.com/about-gill-ranch/faqs> and <ftp://ftp.cpuc.ca.gov/Environment/info/mha/gillranch/gillranch.htm>

24 <http://www.nasdaq.com/article/buckeye-closes-lodi-gas-sale-to-brookfield-infrastructure-analyst-blog-cm429612>

25 <http://www.cpuc.ca.gov/Environment/info/lodi/map.htm>

26 <ftp://ftp.cpuc.ca.gov/Environment/info/aspen/kirbyhills/kirbyhills.htm>

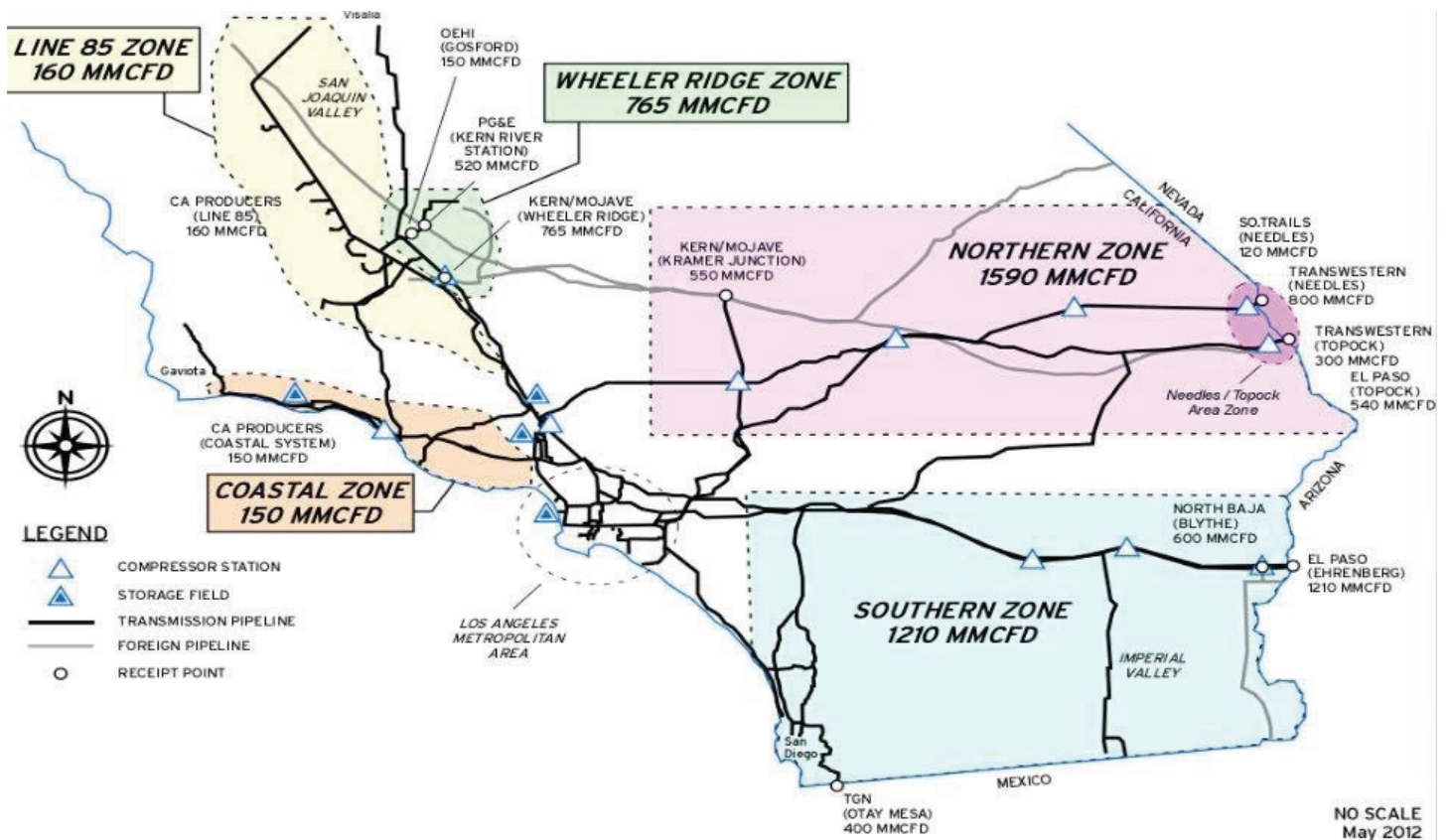
27 <https://www.pehub.com/canada/2015/6/brookfield-led-group-to-acquire-niska-gas-storage-for-912-mln/>

28 <http://www.niskapartners.com/our-business/natural-gas-storage/wild-goose/project-details/> (Niska, n.d.) (Rock Point Gas Storage, n.d.)

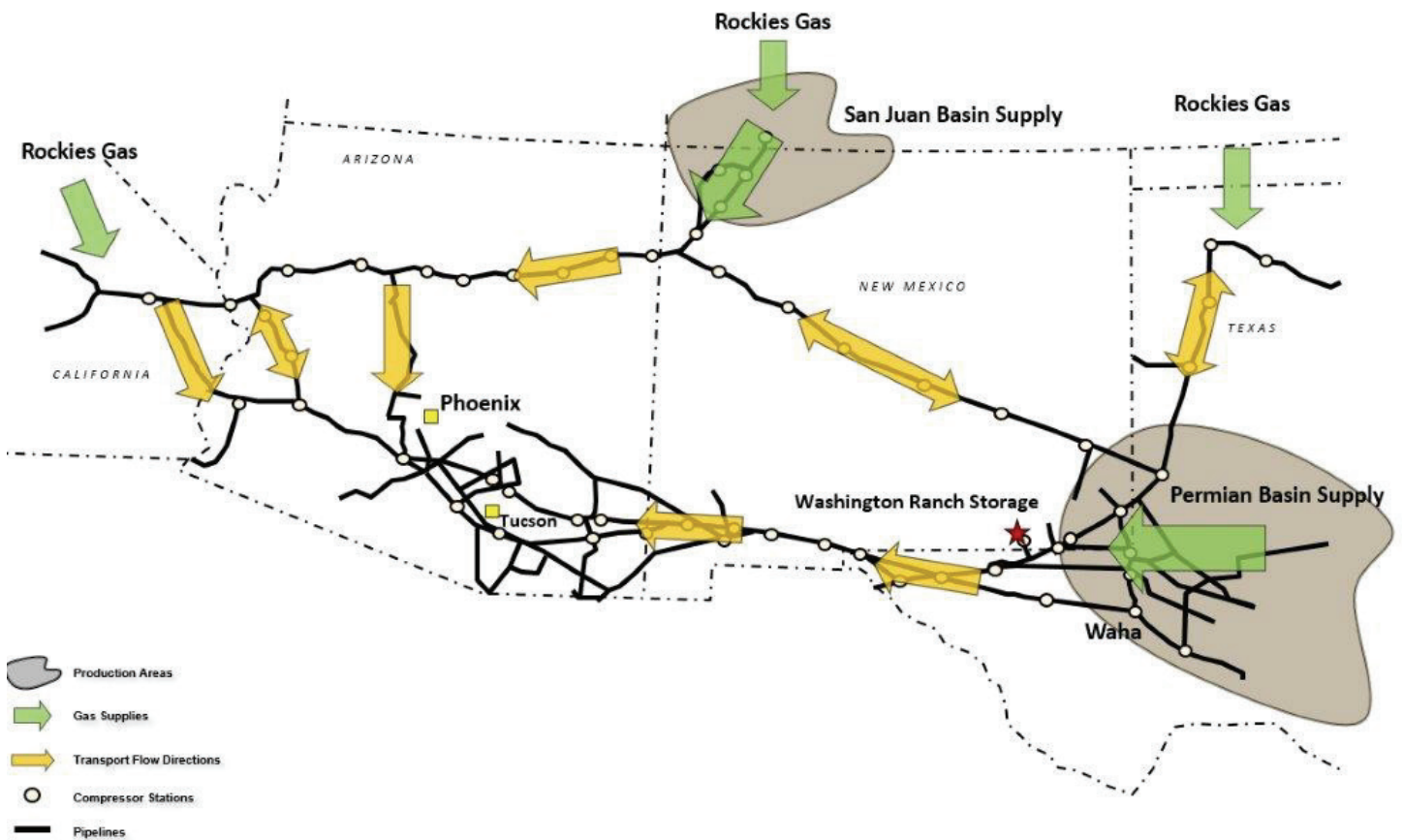
29 <http://cvgasstorage.com/localcommunity/overview.html>

Source: CEC and Aspen Environmental Group

Appendix 2-3: Natural Gas System Reference Maps and schematics



EPNG System Overview Supply Locations and Flow Direction





Appendix 2-4: Montebello Storage Field Decommissioning Dispute

SoCalGas received permission to operate the Montebello Gas Storage Facility by the CPUC in 1955. The field allowed 3 Bcf of working inventory on 23 Bcf of cushion gas using the top two sands formations in the Eighth Zone of the West Montebello oil field (CPUC Nos. 00-09-034 and 01-06-081). SoCalGas obtained rights to operate the facility through leases with the various land and mineral rights owners that comprised the Eighth Zone. Over the years, SoCalGas purchased some surface rights to the facility, but much of their access to and use of the property was achieved via mineral and surface leases. In 1991, SoCalGas decided to purchase the remaining property, and initiated eminent domain proceedings in cases where they were unable to negotiate purchases with the land and mineral rights holders. In support of eminent domain, SoCalGas argued the facility was needed to maintain gas reliability on their system.

In 1997, soon after initiating condemnation proceedings in the courts to obtain the additional land and mineral rights, SoCalGas made the decision that the Montebello Gas Storage Facility was no longer needed for operations. Then-State Senator Calderon called attention to claims that SoCalGas had been untruthful in pursuing condemnation at same time it had decided the field was not needed. The Commission's Consumer Services Division (CSD) conducted an investigation and concluded that, prior to SoCalGas' representations to the LA Superior Court, the facility was required for operations and thus fell under eminent domain. SoCalGas had 1) decided that the facility was not needed, 2) not used the facility in over a year, and 3) initiated environmental review to be used in connection with disposing of the facility. CSD also found that SoCalGas may have acquired, through eminent domain, mineral rights at a greater depth than needed and at prices below the fair market value required to compensate sellers.

SoCalGas disputed these conclusions but settled by donating \$3.5 million to the State's General Fund. The settlement also required SoCalGas to develop a course open to the public on professional responsibility and practice before the Commission, and to reduce rates in conjunction with refunding some of the mineral rights acquisition cost.

Appendix 2-5: AEEE Key Variables and Scenario Descriptions

Scenario Number	1	2	3	4	5
Scenario Name	Low case	Low-mid case	Mid case	High-mid case	High case
ET's	25% of model Results	50% of model Results	100% of model results	150% of Model Results	150% of Model Results
Building Stock	High Demand Case from 2011 IEPR	Mid Case from 2011 IEPR	Mid Case from 2011 IEPR	Mid Case from 2011 IEPR	Low Demand Case from 2011 IEPR
Retail Prices	High Demand Case from 2011 IEPR	Mid Case from 2011 IEPR	Mid Case from 2011 IEPR	Mid Case from 2011 IEPR	Low Demand Case from 2011 IEPR
Avoided Costs	High Demand Case from 2011 IEPR	Mid Case from 2011 IEPR	Mid Case from 2011 IEPR	Mid Case from 2011 IEPR	Low Demand Case from 2011 IEPR
UES	Estimate minus 25%	Estimate minus 25%	Best Estimate UES	Estimate plus 25%	Estimate plus 25%
Incremental Costs	Estimate plus 20%	Estimate plus 20%	Best Estimate Costs	Estimate minus 20%	Estimate minus 20%
Incentive Level	50% of incremental cost	50% of incremental cost	50% of incremental cost	50% of incremental cost	50% of incremental cost
TRC Threshold	1	1	0.85	0.75	0.75
ET TRC Threshold	0.85	0.85	0.5	0.4	0.4
Measure Densities	Estimate minus 20%	Estimate minus 20%	Best Estimate Costs	Estimate plus 20%	Estimate plus 20%
Word of Mouth Effect*	39%	39%	43%	47%	47%
Marketing Effect*	1%	1%	2%	3%	3%
Implied Discount Rate	20%	20%	18%	14%	14%
C&S Policy View	On-the-Books Initiatives	On-the-Books Initiatives	Expected Initiatives	Possible Initiatives	Possible Initiatives
Standards Compliance	No Compliance Enhancements, Compliance Rates Reduced by 20 percent	No Compliance Enhancements, Compliance Rates Reduced by 20 percent	No Compliance Enhancements	No Compliance Enhancements	Compliance Enhancements
Title 24 Updates	2005, 2008, 2013	2005, 2008, 2013	2016, 2019, 2022	2016, 2019, 2022	2016, 2019, 2022
Title 20 Updates	2005, 2006, 2008, 2009, 2011	2005, 2006, 2008, 2009, 2011	2016-2018 (Staggered introduction)	2016-2018 (Staggered introduction)	2016-2018 (Staggered introduction)
Federal Standards	Already adopted	Already adopted	Already adopted	Future Federal Standards	Future Federal Standards

Source: Navigant Consulting, p. 101. 2013 Potential and Goals Study. <http://www.cpuc.ca.gov/General.aspx?id=6442452621>

Appendix 2-6: Progress with Renewable Natural Gas

Many landfills have methane capture facilities, and a large number convert this biogas to electricity and sell that power to the grid or use it onsite.¹²⁸ SCAQMD recently made this harder by further reducing the acceptable level of NOx emissions from small engines and other regional air management districts are considering similar actions (SCAQMD, 2016a). Those that do not burn the gas on-site or feed it directly into vehicles may be able to inject this biogas into the pipeline; however, this requires a pipeline interconnection and significant investment to scrub the biogas of compounds for compliance with injection rules. Between landfills, wastewater treatment plants, and dairy manure digesters, a consultant

128. A CEC web page cites 56 landfill gas recover facilities existing in 1995, 42 of which collected gas to fuel 246 MW of electrical capacity. http://www.energy.ca.gov/biomass/landfill_gas.html (Accessed May 2017). AB 4037 (Hayden, Chapter 932, Statutes of 1988) prohibited the gas utilities from accepting landfill gas into their systems.

retained by SMUD estimated 1,980 MW of electrical capacity could rely on biogas in California, and twice that might be available West-wide.¹²⁹

Pursuant to AB 1900 (Gatto, Chapter 602, Statutes of 2012), the CPUC adopted standards on maximum concentrations for 17 compounds that may be found in biogas in California (Decision No. 14-01-034). Later, In Decision No. 15-06-029, the CPUC directed that the cost of complying with these standards to treat biogas and bring it to merchantable biomethane quality should be borne by producers, just as other gas producers who interconnect to the utilities' pipeline systems do. It recognized that the conditioning and interconnection costs are likely to make up a large part of the overall costs of biomethane projects, but that these costs are due to the inherent composition of the gas itself. Given current low natural gas prices, the CPUC provided \$40 million in funding for incentives to help cover a portion of its interconnection costs. Projects that interconnect and successfully deliver gas for at least 30 days are entitled to an incentive of 50% of the interconnection cost up to \$1.5 million. The incentive is available to cover interconnection costs only, not conditioning or any ongoing costs for labor, odorant, or equipment. Waste Management, a participant in the proceeding, estimated capital costs to construct conditioning facilities totaling \$27.4 to \$33.1 million and \$2.5 to \$3.1 for testing and recordkeeping. The Coalition for Renewable Natural Gas cited interconnection capital cost estimates of \$1.5 to \$3 million.

SoCalGas is following the lead of German utilities and is now experimenting with Power-to-Gas (P2G) projects as a champion of “decarbonizing the pipeline (Minter, 2014).” P2G uses electricity in excess of hourly needs to produce hydrogen. The conversion is accomplished via electrolysis, which passes an electric current through water to create H₂ and O₂. (Doing so uses energy, as does any conversion back to electricity, so total efficiency is reduced.) The oxygen can be sold into existing markets for breathable oxygen gas. The hydrogen can be stored and turned back into electricity later. It can also be combined with CO₂ to create methane, although the methanization process creates additional energy loss. That methane can then be fed into the natural gas system. The hydrogen can also fuel vehicles. The German gas utilities blend hydrogen in small quantities – up to 3% by volume – into their natural gas pipeline systems (Boren, 2016). SoCalGas cites 6% in France and as much as 12% in Holland. Some suggest that the hydrogen can be injected into a natural gas pipeline to supplement natural gas demand and that existing appliances can handle it safely (Melaina, 2013).

129. The consultant appears to have been Black & Veatch. See “Challenges and Opportunities of Biomethane for Pipeline Injection in California,” slide 18, found at https://www.epa.gov/sites/production/files/2016-06/documents/21tiangco_.pdf (Accessed May 2017).

The CPUC and CEC have not gotten far in terms of analyzing the potential for renewable natural gas. The CEC, in its 2015 report pursuant to AB 1257 (Bocanegra, 2013) (which requires the CEC to produce a report looking at how to maximize the benefits of natural gas to California every three years), identified P2G, as it is often called, as a research area to explore (Bauer et al., 2015). P2G is also mentioned in the 2017 Integrated Energy Policy Report (IEPR) scoping order. The CPUC gave a cursory mention of the idea of using hydrogen production as demand response or as storage in its 2015 look moving beyond 33% renewables (CPUC, 2015c). The California Hydrogen Business Council describes P2G as “similar in scale to pumped hydroelectric and compressed air [storage] but is much more modular and flexible in siting and can utilize the vast storage capacity of the existing natural gas grid (California Hydrogen Business Council, 2015).” No analyses were found to describe exactly how this will occur.

SoCalGas, for its part in championing decarbonization, has mentioned looking at using “one of our storage facilities in terms of electric generation, carbon capture, power-to-gas hydrogen production, and methanation (VerdeXchange, 2015).” It is unclear exactly what that means, given the status of Aliso and the potential new DOGGR rules that may reduce underground gas storage capacity. SoCalGas has also encouraged the municipal utilities to look to P2G to help fulfill their SB 350 integrated resource plan requirements (Carmichael, 2017). SoCalGas currently has two P2G demonstration projects underway, one at UC Irvine and one in Colorado at National Renewable Energy Laboratory (NREL). As more renewables lower the marginal cost of production below that of natural gas, the economics of P2G will improve. Even so, the small quantity of renewable natural gas (RNG) expected to be available, and its likely flat production profile, may make both these concepts moot.

Appendix 2-7: Gas electricity coordination actions

CAISO sought stakeholder input and support for eight specific changes to its tariff. Without explaining the technical nuances of commitment bids, convergence bidding and so forth, the specific changes to CAISO’s tariff approved by FERC include:

1. provide electricity scheduling coordinators with two-day ahead advisory schedules for information purposes to help with gas procurement decisions and gas scheduling;
2. use a more timely gas price index (i.e., prices obtained from the Intercontinental Exchange between 8 and 9am PST) for calculating commitment cost caps, default energy bids, and generated bids;
3. increase by 75% the gas price used to calculate commitment cost caps and 25% to calculate default energy bids, for generating resources served by SoCalGas or SDG&E so that CAISO’s real-time market-clearing process can take into account the impact of gas system limitations and avoid further aggravating existing gas system constraints;

4. enforce a natural gas constraint in the real-time market clearing process that would limit the maximum amount of generation dispatched if dispatching more gas-fired generation would jeopardize gas and electric system reliability;
5. allow CAISO to deem certain [electricity] transmission paths non-competitive due to enforcement of the natural gas constraint;
6. make adjustments to [CAISO's] monthly congestion revenue rights auction and allocation process;
7. suspend convergence bidding [between the day-ahead and real-time markets] for purposes of market efficiency; and
8. permit scheduling coordinators to seek after-the-fact recovery of fuel costs related to commitment costs and energy bids from the Commission through an FPA section 205 filing.¹³⁰

In addition, CAISO retains its “exceptional dispatch” tariff authority without change. Exceptional dispatch allows the CAISO to dispatch generators in an order not based on economics when needed. It also had, during summer 2016, the authority to reserve internal transfer capability and to adjust its congestion revenue rights auction and allocation process. In the winter update, CAISO advised FERC it believed it did not need these two changes going forward.

In approving these tariff changes, FERC referenced the finding crafted by the inter-agency group preparing the 2016 summer and winter Action Plans that reliability challenges will continue. CAISO and the agencies considered other mitigation measures, such as moving the timeline for submitting electricity bids so they would be due before gas is nominated. See Table 20 for nominations and scheduling timeline. CAISO told FERC it did not propose such a change because the additional time gap between submitting day-ahead bids and the real-time market would increase the day-ahead forecast error. This would eliminate any benefit of shifting the bid time and potentially increase the difference between receipts and demand.

The Action Plan team also considered whether SoCalGas could call operational flow orders (OFOs) earlier in the gas day. The gas utilities get scheduled delivery quantities confirmed back from the upstream pipelines at 3pm (again, see Table 20). That information allows the

130. See ER 17-110-000, “Order Accepting Tariff Revisions, Subject to Condition,” November 28, 2016. Found at http://www.caiso.com/Documents/Nov28_2016_OrderAcceptingTariffAmendment_AlisoCanyonElectricGasCoordinationPhase2_ER17-110.pdf (Accessed May 2017). The tariff change request can be found at http://www.caiso.com/Documents/Oct14_2016_TariffAmendment_AlisoCanyonGasElectricCoordinationPhase2_ER17-110.pdf

utility to compare supply coming into its system with customer demand. If the gap between scheduled supply and expected demand is larger than the quantity the utility can address via line pack and storage, then the utility issues an OFO directing customers to more closely balance their supply and demand. Customers then go look for someone who can either use or give additional gas supply, depending on whether they need more or less gas supply delivered in order to comply. If OFOs could be called earlier in the day, electric generators would have more time to remedy their gas imbalances. This concept still appears on the mitigation measure list, held in reserve, as an idea that sounds good, but is still without an implementation approach. This is because information required for the utility to make the OFO determination is not available any earlier in the day and California cannot unilaterally require a change to the industry-wide nominations and scheduling protocols.

Calls for greater coordination between gas and electricity markets have been occurring since 2010, when American Public Power Association (APPA) published a consultant report describing, among other things, coordination issues generators would experience as they rely more on natural gas. Critically, the study pointed out the balancing problems caused by generators having to nominate and schedule gas before they know whether and to what extent their plant will be dispatched for the next electricity day. The study observed that many pipelines and states do not have gas storage, and that storage is the key to allowing the flexible balancing provisions that help make generators able to reliably provide electricity (Aspen Environmental Group, 2010).

A briefing to FERC Commissioner Moeller on the APPA gas study led him to ask parties for comments on coordination between the two markets. FERC subsequently opened a docket to discuss gas-electric coordination (FERC, 2012). FERC held five regional technical conferences to discuss 1) communications, coordination, and information sharing; 2) scheduling; 3) market structures and rules; and 4) reliability concerns. One of the concerns identified in those technical conferences was that the pipelines and electric utilities felt constrained in the information they should share without running afoul of FERC market power rules. FERC issued a rulemaking in 2013 to remove communication barriers between the two market segments (FERC, 2013).

In 2014, FERC issued an additional rulemaking to consider how to better coordinate the scheduling of natural gas and electricity markets and asked the North American Energy Standards Board (NAESB) to coordinate developing industry consensus. NAESB delivered a report containing agreement on only a narrow range of issues (FERC, 2014). CAISO, gas utilities, and merchant generators encouraged FERC not to take action. Many in the industry who asked FERC not to take action seemed to fear FERC would make things worse, not better. In the end, FERC issued Order No. 809, which adopted two small changes to the gas scheduling windows but backed away from the idea of creating an earlier start to the gas day, a single start to the gas and electricity days, or any number of other measures that would improve coordination.

Appendix 2-8: Experience with Flexible Nominations

In 2012, El Paso Natural Gas (EPNG) tested market interest in expanding its storage in eastern New Mexico's Eddy County. The market response appears to have resulted in a very small (4 Bcf) expansion of storage capacity that was scheduled to go into service in December 2015 (Kinder Morgan, 2015).¹³¹ It also sought non-binding expressions of interest for a storage-backed, no-notice, or hourly nominated transportation service to be developed collaboratively with customers:

These services could provide shippers with firm receipt to delivery point service with either greater flexibility in adjusting same day nominations or without the Shipper having to nominate for such deliveries and receipts. The service could also provide shippers with additional flexibility in the event that actual requirements vary from nominated and scheduled volumes. In order to ensure that such service is operationally viable and addresses prospective shippers' needs, EPNG is proposing to engage in a collaborative process with interested customers for the purpose of developing mutually agreeable terms and conditions for a no-notice or hourly transportation service. Additional requirements for these services may include a firm transportation path which includes the receipt and delivery point for Washington Ranch. EPNG will evaluate each request to determine if operational firm capacity exists to serve the described service. Interested parties should contact their EPNG Business Development or Marketing representatives.

We find no indication that this informal request for interest resulted in any change to EPNG's services. Since 2005, EPNG has offered a limited opportunity for shaped nominations, albeit at higher rates. Rate schedule "FT-H," which allows a three-hour peaking service in which a shipper may schedule up to 150% of its ratable hourly quantity (i.e., 1/24th of its maximum daily quantity) in three individual non-consecutive hours or 120% of the ratable hourly quantity for any twelve consecutive hours. It also allows a 12-hour and 16-hour peaking service, limited to 150% of the ratable hourly quantity for no more than 12 or 16 hours, respectively. Its 8-hour peaking service allows taking up to 300% of the ratable quantity for eight hours. These services are subject to minimum pressures being available in the pipeline, such as the 400 to 550 psig required for EPNG to provide the 8-hr and 12-hr services, compared to 250 psig for the ability to peak in only one of 3 hours in a day.¹³² The pipeline itself determines what kind of flexible services it feels its system can offer.

131. <http://passportebb.elpaso.com/ebbmasterpage/Notices/NoticesAutoTable.aspx?code=EPNG&status=Notice&name=Non-Critical%20Notices&sParam3=11966&sParam14=D&details=Y> (Accessed April 2017). If there were no underground gas storage in California, EPNG might have gotten a larger response to its open season.

132. See El Paso Natural Gas Company tariff, Third revised Volume No 1A, Part III Rate Schedules, Rate Schedule FT-H, Version 8.0.0 found at: <http://passportebb.elpaso.com/ebbmasterpage/Tariff/OrgChart.aspx?code=EPNG&status=Tariff&pdftag=cerllfsbsr> (Accessed April 2017).

EPNG also offers a firm daily balancing service for up to 10% of a daily maximum delivery quantity. These daily balancing quantities must be nominated such that EPNG will carry an imbalance for a customer, up to a maximum quantity, if the customer scheduled the imbalance (whereas California allows the imbalance essentially to be without-notice and calculates it relative to monthly demand, not daily). Shippers have 30 days to remedy the imbalance. EPNG also offers an hourly no-notice service. Such service is at EPNG's discretion, when system conditions permit, and is limited by the hourly firm service terms and quantities described above, including the availability of sufficient pressure on the El Paso system at the customer's specified delivery point.

EPNG, however, does not offer these services to customers with California delivery points (those delivery points would be the transfer points into the PG&E and SoCalGas systems at Topock and Ehrenberg). Table 21 shows the rates shippers pay for firm transportation (FT-1) versus the flexible take services. The total cost (i.e., reservation charge plus usage charge) for the flexible take services ranges from nearly 17% higher for the 12-hours of relatively small flexibility versus flat FT-1 service, to 100% higher for the 8 hours of flexibility to swing up to the 300% of daily average quantity. Using the swing services also requires the shipper to select a swing quantity, reserve it in advance, and pay the reservation portion (i.e., the much larger portion) of the rate regardless of whether it is used – every day. Violations of these quantities when critical condition notices are in place range from 1.5 to 2.5 times the normal rate for firm transportation (FT) service. Balancing and storage service for other quantities or hours of flexibility costs an additional 29.44 cents per MMBtu.

EPNG is perceived to have expanded pipeline segments, particularly to serve the Arizona shippers, to help provide these enhanced services. EPNG has also tailored the offering (i.e., the percentage and hours of allowed deviation from flat deliveries) to limits that reflect the ebb and flow around its nearly 1 Bcf per day of line pack.

Table 21. EPNG Rates for Firm and Flexible Transportation Services.

State	Component	Rate Schedule (\$/MMBtu)				
		FT-1	FTH-3	FTH-12	FTH-16	FTH-8
California	Reservation	\$0.4514	N/A	N/A	N/A	N/A
	Usage	\$0.0318	N/A	N/A	N/A	N/A
Arizona	Reservation	\$0.4514	\$0.4966	\$0.5267	\$0.5643	\$0.9028
	Usage	\$0.0318	\$0.0350	\$0.0371	\$0.0398	\$0.0637
New Mexico	Reservation	\$0.3396	\$0.3735	\$0.3962	\$0.4245	\$0.6791
	Usage	\$0.0235	\$0.0258	\$0.0274	\$0.0294	\$0.0470
Balancing & Storage		\$0.2944				

Source: EPNG Tariff Summary of Rates

Looking at who subscribes to the flexible services confirms this view. Table 22 is compiled

from the Index of Shippers posted on EPNG's Passport information system, as required by FERC. Each of the shippers identified is an integrated electric utility or a gas utility. Together, they account for about 740 MMcf (776,000 MMBtu) on total throughput that from 2009 to 2014 ranged between 3,700 and 4,700 MMcf.¹³³ These integrated gas or electric utilities are allowed by their regulators to pass these costs on to ratepayers; they are not the independent generators and they are not entities bidding into competitive electricity markets. Under current market conditions, the inability of generators to recover fixed gas costs in electricity markets is an impediment to the use of services such as firm capacity or storage.

Table 22. EPNG Shippers Holding Flexible Services.

Shipper Name	Rate Schedule	Maximum Daily Quantity (MMBtu)
Arizona Electric Power Cooperative, Inc.	FT-H12	7,424
Arizona Electric Power Cooperative, Inc.	FT-H8	8,553
Arizona Public Service Company	FT-H8	39,902
El Paso Electric Company	FT-H16	175,000
Public Service Company of New Mexico	FT-H12	23,500
Salt River Project Agricultural	FT-H12	230,000
Southwest Gas Corporation	FT-H3	75,400
Texas Gas Service, a Division of ONE	FT-H3	118,927
Tucson Electric Power Company	FT-H12	40,000
UNS Gas, Inc.	FT-H3	54,755
UNS Gas, Inc.	FT-H12	2,310
Total		775,771

Source: Aspen Compilation from Index of Shippers

133. The throughput comes from "El Paso Natural Gas Pipeline 2014-15 Winter Preparedness," Presentation to the Arizona Corporation Commission by Kevin Johnson (Director of EPNG/Mojave Western Region Gas Control)

The difficulty in implementing these types of services in California is that they cannot be provided absent some amount of gas storage or absent excess pipeline capacity that can be packed with enough extra gas to meet the contracted peaks. EPNG said as much in an Operations Description and Expansion summary it submitted in its 2005 rate case at FERC (FERC, 2007):

Washington Ranch – *Washington Ranch, El Paso’s only storage field, is operated as an auxiliary line pack facility to help dampen swings created by imbalances. Although all of El Paso’s firm transportation agreements call for ratable takes, many shippers in the EOC market area have difficulty complying with that requirement. At the sorts of relatively low loads experienced in the recent past, El Paso can accommodate more of this non-ratable flow behavior than would be possible if the system were running at full load. Washington Ranch, which is located on the east end of El Paso’s Southern Low Pressure System, is used to help dampen the impact of both non-ratable takes and daily imbalances. Because of its location on the system (i.e. relatively distant from the major south system load centers), Washington Ranch is most useful for covering daily imbalances.*

Appendix 2-9: History of Gas Storage Facility Closures in California

SoCalGas’ Montebello gas storage facility is an example of a field that has been retired. SoCalGas decided in 1997 that the Montebello Gas Storage Facility was no longer needed for operations¹³⁴ and submitted to the CPUC Application No. 00-04-031 requesting permission to recover its 23.7 Bcf of cushion gas and decommission the field. That field had been converted to gas storage in 1956.

The CPUC approved that application in 2001. In so approving, the CPUC cited its expectation that it was less worried about needing Montebello in winter than it was about summer demand constraining the ability to fill its other storage in summer (for use in winter):

“ORA, TURN, and SoCalGas agree that the potential for inadequate storage next winter is not due to insufficient storage capacity but rather to the extremely high demands on existing [gas] transmission to serve competing uses – daily consumption, including high demand by electric generation customers, versus transportation to storage fields for injection (CPUC, 2001).”

134. As cited previously, reports of leaks from Montebello abound. See, for example: http://articles.latimes.com/1985-10-03/news/hl-932_1_gas-storage and http://articles.latimes.com/1985-09-05/news/hl-24891_1_natural-gas-leak and <http://www.dailynews.com/opinion/20160421/old-gas-leak-raises-new-questions-for-socalgas> and http://www.allgov.com/usa/ca/news/controversies/puc_not_as_crazy_about_storing_natural_gas_under_cities_as_it_used_to_be?news=641689 (Accessed August 2017). See also Weatherwax, cited previously.

The decision approving Montebello's closure does not specify decommissioning costs. Rather, based on the decision and subsequent financial disclosures, it appears the removal and sale of cushion gas, sale of equipment and the land, was expected to produce a net gain for ratepayers and for the company. (Looking back at Decision 01-06-081, which approved the Montebello decommissioning, it looks like ratepayers and SoCalGas received a net gain).

SoCalGas closed another small gas storage field in Whittier in 1996. That field operated from 1952 until 1986. In 2001, SoCalGas was still recovering hazardous waste clean-up costs (SoCalGas, 2001).

Two other fields might be considered to have been retired. The first is known as the Ten Section field. Ten Section is about 10 miles from Bakersfield. It was discovered by Shell Oil in 1936. In 1953, SoCalGas, then known as Pacific Lighting Co., began a storage pilot program at the site. In 1977, PG&E and SoCalGas purchased the field from Shell for use as a gas storage facility. Storage operations continued until 1984, when PG&E and SoCalGas sold the field to McFarland Energy. At least two attempts have been made by the current owner to reestablish storage operations at the site but have not come to fruition. The latest resulted in the owner, Tricor, holding an open season seeking service subscriptions in 2009, and subsequently obtaining a CPCN from FERC to develop and operate the field.¹³⁵ Tricor intended 22.4 Bcf working inventory with a maximum injection rate of 800 MMcfd and withdrawal of 1,000 MMcfd (Wood, 2009). Tricor halted efforts to develop the project citing obstacles imposed by DOGGR (FERC, 2011). What effort SoCalGas undertook to close off the original pilot storage project is unknown. The industry rumor was that the field "leaked" and was the reason PG&E and SoCalGas sold it.

The second field was Coalinga Nose. This was a field that provided gas to PG&E until approximately 1987 or 1988. Coalinga Nose was owned jointly by Unocal, Texaco, Mobil, and Chevron. It was an operating oil field and Unocal injected natural gas to optimize the oil production. Reference is found to blowdown of the gas cap on the oil field beginning in May 1988. An old CGR would reveal how much gas PG&E received from Coalinga Nose, but as it was an oil field, it would not have been subject to approval of the CPUC to retire and abandon as a utility gas storage field (Starzer, et al., 1995).

135. The CPCN was granted in 2011 (FERC Docket No. CP-09-432-000). See presentation by Ryan Kunzi to Arizona Corporation Commission.

Appendix 2-10: Capital investments at storage facilities

PG&E and SoCalGas's FERC "Form 2" reports for each year from 1997, to 2016 show, among other things, annual capital investment and O&M expenses by asset class.¹³⁶ They do not, however, provide more descriptive information about the nature of the capital investment. Somewhat more about what the investment items included can be pieced together by reviewing rate case applications and CPUC decisions as to what regulators ultimately approved.

The Form 2 shows PG&E's O&M expense in recent years has averaged roughly \$20 million per year. The capital expenditure (CapEx) is dominated by investment in the mid-2000's to build an additional pipeline connection from McDonald Island to its Bay Area Loop and backbone transmission, which was intended to preserve reliability should one of the other lines wash out (Line 57C). The expenditures average to a 6.1% compound annual growth rate for O&M and 6.4% for capital. (See Figure 27).

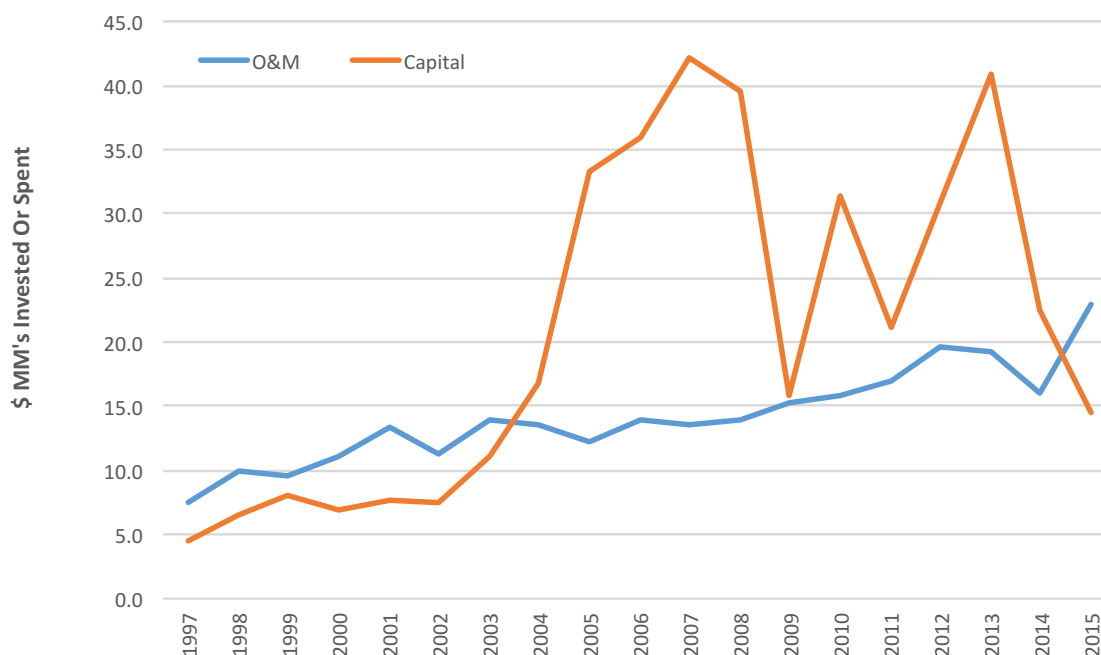


Figure 27. PG&E Reported CapEx and O&M for Storage.

Source: Aspen Environmental Group; FERC Form 2

136. The Form 2 is a standard report that FERC requires be filed by all jurisdictional pipelines. By virtue of the Hinshaw Exemption, PG&E and SoCalGas are not FERC-jurisdictional and are therefore not required to file Form 2's. They have filed the FERC Form 2 with the CPUC as a matter of practice.

Over the same years, SoCalGas spent much more in absolute terms, but its storage O&M grew at 2.3% while its capital expenditure grew at 2.9% (see Figure 28).

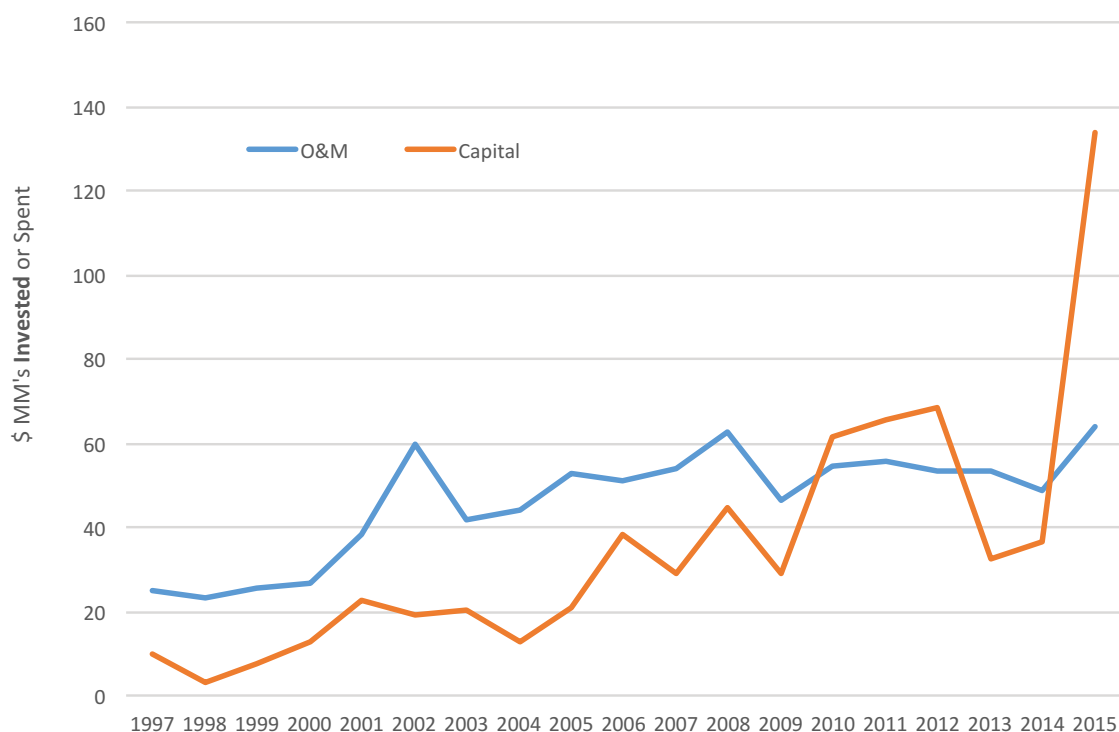


Figure 28. SoCalGas Storage Reported Capex and O&M.

Source: Aspen Environmental Group; FERC Form 2

SoCalGas's working inventory of 137 Bcf is much larger than PG&E's effective cycling capability of 40 Bcf.¹³⁷ Normalizing the O&M expense by Bcf of cycling capability, shown in Figure 29, shows the two utilities' spending on storage O&M to be generally similar.

137. PG&E began some years ago to describe its working inventory as much larger than 80 Bcf at McDonald Island, but only about half can functionally be cycled in a season. The CPUC used the smaller 40 Bcf in comparing the inventory of the two companies in Decision No. 15-06-004, p. 19. If the analysis used the larger 80 Bcf, then PG&E's per Bcf O&M would look much lower than SoCalGas'.

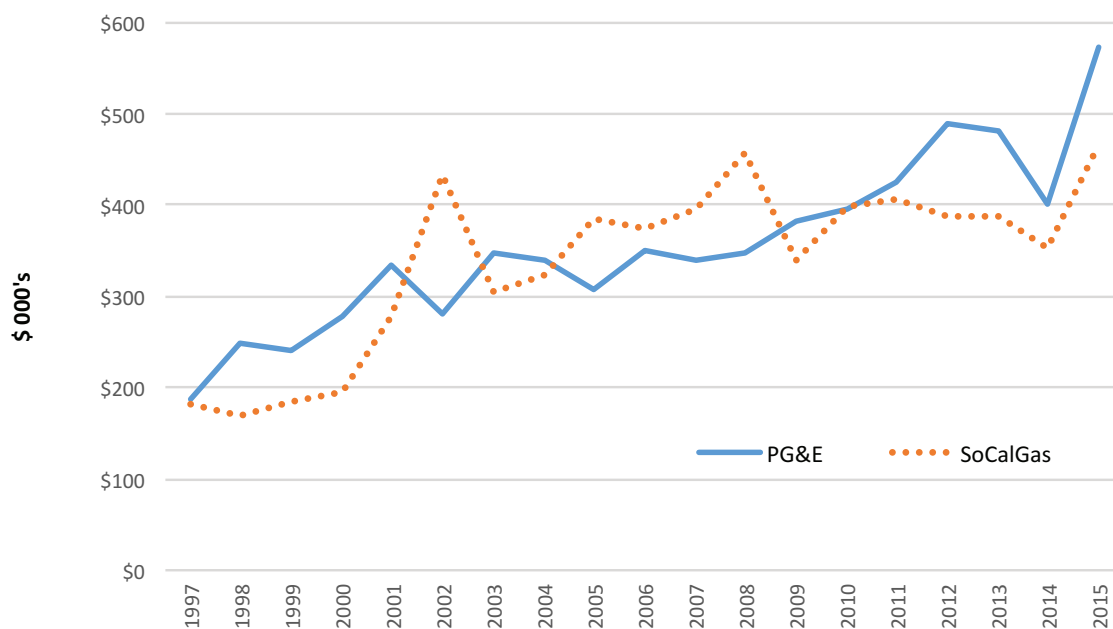


Figure 29. PG&E and SoCalGas Normalized O&M Expense for Storage.

Source: Aspen Environmental Group

While the Form 2 reports actual spending, a general rate case (GRC) is the regulatory proceeding in which a utility lays out what it proposes to spend for the next few years and obtains approval to recover those costs in rates. The CPUC uses a three-year cycle, so in 2014, SoCalGas filed its proposal to cover rates set for 2016, 2017, and 2018. PG&E's GRC is split between distribution versus transmission and storage. Its last Gas Transmission and Storage (GT&S) rate case was filed in 2013, decided in 2016, for rates effective in 2015, 2016, and 2017.¹³⁸ PG&E just filed a new GT&S case in November 2017.

In SoCalGas' last GRC (A. 14-11-002), SoCalGas described its storage department having 175 employees who operate the company's four storage fields and perform the maintenance, integrity, and engineering activities for them. It requested \$40.2 million be approved in rates to cover O&M activities. The Office of Ratepayer Advocates (ORA) came in willing to support only \$36.4 million. SoCalGas and ORA split the difference in settlement, adopted by the CPUC in Decision No. 16-06-054, which represented an increase of approximately 22%

138. Because the decision in the case came late, it authorized rates for 2018 as well. See CPUC Decision No. 16-06-056, p. 2

over 2014's recorded O&M costs (CPUC, 2016c). On capital expenditures ORA countered little on year 1 of the test period, and did not oppose the proposed spending at all for years two or three.

SoCalGas also proposed in the GRC to begin “a more proactive and in-depth approach for evaluating and managing the risks associated with the wells in [its] underground storage fields (CPUC, 2016d).” It would move away from the qualitative assessments based on operating experience in which well risk mitigation was conducted on a case-by-case basis, with actions to address problems when identified. The new approach would be a more robust and quantitative approach that would be more “proactive and in-depth” to capture “more information on the condition of our gas storage wells and develop models that will assist in prioritizing risk mitigation activities (SoCalGas, 2014b).” That prioritization would be “based on the location, age, condition and other factors.” The storage integrity improvement program would last six years, after which future inspection and mitigation costs would “be addressed through routine operations (SoCalGas, 2014b).” SoCalGas appears to have had no comprehensive, proactive, long-term view of how to manage the condition of its storage fields; instead, it was in a reactive mode asking for permission to spend more on O&M after it detected problems. Most of the new storage integrity management program will be to gather data and build a decision model so that SoCalGas can prioritize maintenance activities according to an assessment of its biggest risks rather than continue to deal with issues as they arise.

PG&E, in its last GRC, “qualitatively assessed” its facilities as in “fair to good” condition (CPUC, 2013, A 13-12-012). PG&E has not yet made public any analysis behind its decision to retire Los Medanos and Pleasant Creek. With no public information available, one cannot say if the condition issues contributed to the decision or if the decision was based solely the cost of compliance with the new DOGGR rules (estimated at roughly \$240 million per year, statewide).¹³⁹

While the PG&E and SoCalGas storage spending is public via the Form 2 and rate cases, the independent storage assets in northern California charge market-based rates. They therefore do not file rate cases at the CPUC. No known public record of their O&M or capital expenditures exists. One might expect them to more carefully maintain their facilities because not having their costs embedded in the rate base means they obtain no revenue if they cannot operate. This has limits, though, because even their rates have a large reservation charge component to it within multi-year contracts. We do know that Central Valley and Gill Ranch are essentially brand new; Wild Goose and Lodi have been recently acquired and would have gone through due diligence review, which arguably would have

139. See Standardized Regulatory Impact Assessment, p. 38 available at http://www.conservation.ca.gov/dog/general_information/Pages/UGSRules.aspx, Accessed July 2017. It does not appear that this \$238 million takes into account lost revenue potential from lower withdrawal capability although it does include \$31 million per year for new wells. Whether those are observation wells or new withdrawal wells is unclear.

included some sort of condition assessment and a taking into account of that condition in the purchase prices as part of the acquisition process. The Standardized Regulatory Impact Assessment (SRIA) also opined that the newer facilities of the independents “may not require as much remedial work” and noted that in “some cases the requirements in these proposed regulations are already in place.”¹⁴⁰

A last bit of perspective on financial viability and storage investment may be helpful. The 2015 FERC Form 2 submitted by SoCalGas showed a total value of its storage-related gas plant in service at \$833 million. Its April 2017 Form 10-K (A required annual report that provides a comprehensive overview of a company’s business and financial condition and includes audited financial statements.) with the Securities and Exchange commission cited a net book value for Aliso Canyon alone of \$531 million (which includes the \$217 spent on the new compressor turbines, which will begin service should the facility start reinjection). That Form 10-K also reported net earnings for SoCalGas in 2016 of \$349 million (and \$419 million in 2015) (Sempra, 2016). Note 15 to its statement of financial condition noted that ~\$700 million of its \$1.2 to \$1.4 billion in insurance has been spent. If they do not recover any of those costs it could have a significant impact on earnings. PG&E’s FERC Form 2 shows a value on its storage assets of \$667 million.

Financial information for the independent storage operators is again difficult to track down. We found that Lodi sold in 2014 for \$105 million, far lower than the \$440 million it had previously sold for in 2007 (Bowers, 2015). Gill Ranch’s 2010 construction value for its 20 Bcf of inventory capacity was \$225 million.¹⁴¹ (Gill Ranch is set up so that 75% is owned by an LLC held by Northwest Natural, which also owns the Mist gas storage facility near Portland, Oregon. The other 25% is owned by PG&E.) When Brookfield Infrastructure acquired Wild Goose in 2015, it acquired all of Niska Gas Storage Partners (totaling 225 Bcf of inventory capacity, including several large facilities in Alberta in addition to Wild Goose itself) for \$912 million.¹⁴² Central Valley Gas Storage was developed by AGL Resources for \$35 million (AGL Resources, 2014). With flat natural gas prices the independents may have more trouble attracting subscribers. Bloomberg cited low (and ostensibly flat) natural gas prices as causing a large decrease in the value of Niska Gas Storage, leading to a halt in distributions to shareholders and causing its owners to seek a sale.¹⁴³

140. SRIA, p. 29

141. See https://www.sec.gov/Archives/edgar/data/1359055/000110465907055631/a07-19932_4ex99d1.htm (Accessed July 2017).

142. See <https://www.pehub.com/canada/2015/6/brookfield-led-group-to-acquire-niska-gas-storage-for-912-mln/> and <https://seekingalpha.com/filing/2857264> (Accessed July 2017).

143. See <http://www.oilandgasinvestor.com/niska-gas-storage-partners-explores-sale-792161#p=full> (Accessed July 2017).

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