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Aliso Canyon Risk Assessment Technical Report
Summer 2018

Prepared by the staff of the California Public Utilities Commission, the California Energy Commission, the California Independent System Operator, and the Los Angeles Department of Water and Power

May 7, 2018

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EXECUTIVE SUMMARY

The Southern California Gas (SoCalGas) system continues to operate at less than full capacity due to a significant number of pipeline outages and continuing restrictions on use of the Aliso Canyon natural gas storage facility. This reduction in capacity creates a moderate threat to electric reliability this summer. The more serious threat lies ahead. With so many pipeline outages, it will be difficult for SoCalGas to fill storage to a level sufficient to ensure energy reliability throughout the coming winter.

This assessment is the fifth in a series launched because of the 2015 Aliso Canyon gas leak. It addresses the electric reliability impact of the extensive pipeline outages and of operating Aliso Canyon at less than full capacity. The report was developed by the Aliso Canyon Technical Assessment Group, which is composed of technical experts and staff from the California Public Utilities Commission (CPUC), the California Energy Commission (Energy Commission), the California Independent System Operator (California ISO), and the Los Angeles Department of Water and Power (LADWP). The assessment group has conferred with SoCalGas and relies on hydraulic modeling results prepared by the utility, but this report includes other analysis prepared independently of SoCalGas.

These reports are intended to provide short-term analysis and recommendations regarding SoCalGas system reliability. Long-term analysis and recommendations will be handled in other forums. The state Legislature has directed the CPUC to consider the feasibility of minimizing or eliminating the use of the Aliso Canyon storage facility while maintaining energy reliability. Governor Edmund G. Brown Jr. has asked for a plan to phase out use of the facility within 10 years.

The challenges this summer stem primarily from continuing outages on four key natural gas pipelines. Current available pipeline capacity of 2,655 million cubic feet per day (MMcfd) is significantly lower than the 3,185 MMcfd available last summer. As a result, the total system capacity, which is a combination of pipeline capacity and non-Aliso Canyon storage capacity, is some 200 MMcfd lower than last year. Under the assessment group's assumptions, the hydraulic model results in total system capacity for this coming summer of 3,555 MMcfd under base case assumptions and 3,425 MMcfd under sensitivity assumptions, compared to 3,638 MMcfd in summer 2017. The base case assumes current operating conditions and the sensitivity case assumes additional pipeline outages and mitigations.

Table ES-1: Comparison of System Capacity Results in Summers 2017 and 2018

	SUMMER 2017	SUMMER 2018	
	Base Case	Base Case	Sensitivity Case
	MMcfd	MMcfd	MMcfd
Pipeline	3,185	2,655	2,525
Storage	468	900	900
Total System	3,638	3,555	3,425

The summer 1-in-10-year peak day[1] forecast gas demand of 3,511 MMcfd can be met by the assessment group's base case supported demand of 3,555 MMcfd. In the assessment group's sensitivity case, however, supportable demand drops to 3,425 MMcfd. In this scenario, the 1-in-10-year peak gas demand cannot be met. This case would result in gas curtailments to electric generators. Based on the electric analysis that quantifies the minimum gas requirement for electric generation, the total gas system requirement can be reduced to 3,114 MMcfd, a level supported by the sensitivity case. In summary, electric reliability can be maintained on a 1-in-10-year electric peak day without using gas from Aliso Canyon, assuming 100 percent transmission import utilization and the availability of non-gas-fired generation in Southern California. This conclusion remains true unless electricity transmission import utilization drops below 90 percent.

The authors emphasize, however, that operating the system at these levels curtails electric generators and leads to increased costs. There is also no guarantee that the California ISO and LADWP would be able to secure the necessary electricity imports to move the system to minimum generation, especially on short notice. The availability of supply from alternative resources may be less this summer when compared to 2017 due to less-than-average hydroelectric conditions in 2018. The purpose of calculating minimum generation is not so that SoCalGas can plan to curtail the generators. Rather, it is done so that SoCalGas, the electric balancing authorities, and the regulatory agencies know how large a cut the combined electric-gas system can sustain before electric reliability is jeopardized so they can develop actions to reduce risk.

Table ES-2: 1-in-10 Demand at Forecast Versus Minimum Electric Generation Levels

Summer Demand (MMcfd)	1-in-10 Year Peak Day Forecast Electric Generation (MMcfd)	1-in-10 Year Peak Day Minimum Electric Generation, N-1 Contingency (MMcfd)
Core	770	770
Noncore, Non-Electric Generation	770	770
Noncore, Electric Generation	1,971	1,574
Total	3,511	3,114
Implied Curtailment at Minimum Generation	N/A	397

This report includes a preliminary examination of the events of winter 2017-18. Last winter, the SoCalGas system avoided serious problems primarily because of unusually warm weather. The February cold snap sharply illustrated how fast storage inventories can dwindle and how quickly storage withdrawal capacity declines. With these lessons in mind, looking beyond summer to the upcoming winter is critically important. Without sufficient storage inventory in November, Southern California could see a repetition of last winter, with energy reliability hinging on the vagaries of the weather.

1 The term *1-in-10-year* represents the warmest condition expected to occur once in 10 years and is used for planning capacity needed to serve noncore customers.

Measures to reduce the risk therefore remain necessary. Staff suggests continuing most of the current mitigation measures and exploring additional measures, including a) buying liquefied natural gas (LNG) to assure that up to 230 MMcfd can reach Otay Mesa on a firm basis,[2] b) coordinating with gas customers to ensure they are prepared to respond to both high and low operational flow orders, c) granting the SoCalGas operational hub[3] permission to buy gas to fill the receipt points to capacity when operationally and financially feasible, d) expediting any pending transmission upgrades that would further reduce the minimum generation requirement, d) monitoring the pending "Energy Infrastructure Demand Response Act of 2018" to ensure California is considered a region for any demand response pilot projects, and e) updating the Section 715 Report[4] to explore increasing the maximum target inventory at Aliso Canyon.

INTRODUCTION

This assessment assesses electricity reliability in Southern California given the operating status of the Aliso Canyon gas storage facility. Injection there resumed in July 2017 following approvals required under Senate Bill 380 (Pavley, Chapter 14, Statutes of 2016) from the Division of Oil, Gas and Geothermal Resources (DOGGR) and the CPUC. An overall cap on inventory of 24.6 billion cubic feet (Bcf) remains in place, and operations are restricted to those required to maintain reliability. Challenges to reliability remain despite the increased inventory at Aliso Canyon because of significant pipeline outages on the SoCalGas system. The outages in place during the winter remain, and new ones appear likely. Given these operating constraints, this report assesses the risk to electricity reliability over the coming summer.

Three other aspects of this assessment are worth highlighting. First, the assessment group includes a preliminary analysis on how the gas system avoided curtailments up until late this winter (well after what would normally be the coldest part of the winter). Second, it includes a first-cut analysis of the gas curtailment event that occurred from February 19 to March 6 of this year, which may be augmented later. Third, even though this is a "summer" assessment, the included gas balances run through December. This is an effort to assess how summer decisions might affect winter gas reliability and provide enough lead time for making decisions now that would affect winter.

SoCalGas released its own technical assessment on March 30, 2018, along with its Injection Enhancement Plan.[5] The assessment group has engaged in discussions with SoCalGas about its analysis.

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2 SoCalGas and SDG&E have also been urged to explore supply options at Otay Mesa through a request for offers process in a recently issued proposed decision addressing a new proposed pipeline. See http://docs.cpuc.ca.gov/SearchRes.aspx?docformat=ALL&docid=213824449.

3 SoCalGas operational hub is a group within SoCalGas who conducts activities, such as meeting any physical flowing gas supply requirements as determined by the Gas Control department.

4 For the most recent 715 Report see http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/News_Room/News_and_Updates/715_Supplement_2017-12-11_FINAL.pdf.

5 See Attachment C of SoCalGas Advice Letter 5275-A: https://www.socalgas.com/regulatory/tariffs/tm2/pdf/5275-A.pdf.

While the assessment group assessment uses somewhat different assumptions, the two assessments reach similar conclusions.

Only 2,325 MMcfd to 2,930 MMcfd of pipeline capacity (depending on the timing of certain outages versus repairs) appears to be available this summer. These numbers are based on pessimistic and optimistic outlooks of pipeline outages and mitigations. This is up to a 27 percent reduction compared to the 3,185 MMcfd available last summer. Physical mitigation measures to replace some of the lost capacity plus use of gas from non-Aliso storage result in an effective total system capacity ("supported demand") for the upcoming summer of 3,555 MMcfd in the assessment group base case and 3,425 MMcfd in the sensitivity case. This compares to 3,638 MMcfd last summer, 3,657 MMcfd at the beginning of the winter, and 4,117 MMcfd later in the winter with Line 4000 theoretically back in service.

On the electricity side, this summer's analysis still assumes that all transmission lines are in service and able to import incremental energy that would otherwise be generated inside the balancing authority area[6] with natural gas. It also assumes that there is sufficient energy available from external suppliers at the quantity and duration necessary to meet these energy import requirements.

This technical assessment first updates the status of SoCalGas' system. It then reviews how the gas system has generally avoided shortages until the gas curtailment that occurred in February/March 2018. The analysis leads to suggestions for new mitigation measures that, based on the analysis, could have reduced the magnitude of the recent curtailments. The assessment offers two hydraulic modeling cases, base and sensitivity cases. The base case assumes current operating conditions except for an incremental loss of 30 MMcfd due to the right-of-way expiration on Line 2000, and the sensitivity case assumes additional pipeline outages and mitigations. The assumptions selected by the assessment group for its hydraulic cases differ slightly from those presented by SoCalGas in its March 30 assessment. Most of the difference is because the assessment group cases do not discount receipt point capacity to assume some goes unused. Even so, the SoCalGas and assessment group analyses reach similar conclusions. The assessment group uses these hydraulic results to determine the gas system's ability to serve demand on a 1-in-10 peak electricity demand day. The assessment then presents five main gas balance cases, analyzing different combinations of pipeline outages and gas system mitigations. Among them are cases that evaluate injecting more gas at Aliso Canyon and whether that additional injection can be achieved. All scenarios provide insight into the storage inventory levels available for next winter under each set of assumptions. The assessment closes with a discussion of potential, additional mitigation measures that could be adopted to address the heightened risk forecasted for this summer and the coming winter.

6 A balancing authority is responsible for maintaining the electricity balance within its region. A balancing authority has several ways to maintain the balance of supply and demand, from turning on or of generators to importing or exporting excess electricity to or from their neighbors. (See http://www.tanc.us/chap6_picture.html.)

CURRENT OPERATING STATUS OF THE SOCALGAS SYSTEM

Under permission granted on July 19, 2017, SoCalGas may inject gas into the Aliso Canyon storage facility, up to a 24.6 Bcf inventory limit specified by the CPUC in the "Section 715" report posted by the CPUC on December 11, 2017.[7] Withdrawals are still limited by the CPUC to conditions needed to preserve reliability. The overall system is handicapped by continuing pipeline outages that may grow over the summer period (April 1 to October 31).

In SoCalGas' Southern Zone, Line 2000 has been operating at reduced pressure since 2011 and will continue to do so until the line can be made safe to operate at higher pressures. In addition, capacity on Line 2000 is reduced by 30 MMcfd due to the expiration of a right-of-way through federal lands held in trust for the Morongo Band of Mission Indians. Shippers, such as natural gas customers, marketers, and agents, can address this capacity reduction, however, by using the North Baja and Gasoducto Baja Norte pipelines to move gas from Ehrenberg, Arizona, to the southern zone receipt point at Otay Mesa.[8] Segments of transmission Line 5000 may also be removed from service between the Whitewater and Moreno Stations later the summer, when the Line 5000 right-of-way expires.[9] This can also be addressed by delivering gas at Otay Mesa.

SoCalGas' Northern Zone is experiencing multiple issues. Line 3000 remains under repair. Those repairs are scheduled to be completed in September.[10] This outage nominally reduces capacity by 540 MMcfd. Moving that 540 MMcfd to the Greater Los Angeles Area, however, requires use of Line 235-2 or Line 4000. Line 235-2 is out of service as it ruptured near the Newberry Compressor Station on October 1, 2017, and the return to service date is still undetermined. Line 4000 was out of service last fall. It returned on December 22, 2017, but has been in and out of service ever since and is operating at reduced pressure such that only an incremental 270 MMcfd is allowed into the system.[11] There is a possibility that Line 4000 could be removed from service this summer for further remediation. Anytime that all three lines from the Needles and Topock receipt points are out of service, the firm receipt point capacity into SoCalGas' Northern Zone becomes limited to the 550 MMcfd of capacity available at the Kern/Mojave (Kramer Junction) receipt point. However, according to the operator, up to 150 MMcfd of additional, interruptible daily capacity is available when the other pipelines are down.[12] The normal

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7 The latest Section 715 report can be found at http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/News_Room/News_and_Updates/715_Supplement_2017-12-11_FINAL.pdf.

8 Appendix A contains a system map so readers can identify the lines and locations discussed here.

9 Lines 2000, 5000, and 2001 make up the corridor from Ehrenberg, through the SoCalGas receipt point at Blythe, California, on into Moreno station. See SoCalGas Opening Brief in A. 16-12-011, p. 3, filed November 6, 2017. Found at http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M199/K030/199030525.PDF.

10 See *critical notice* posted to Envoy on April 18, 2018 at https://scgenvoy.sempra.com/#nav=/Public/ViewExternalEbb.getMessageLedger%3FfolderId%3D1%26rand%3D56.

11 The 2017-18 Winter Assessment originally cited the return capacity of Line 4000 as 350 MMcfd; SoCalGas informed the agencies this was a miscalculation and later revised it to 270 MMcfd.

12 Kern River Gas Transmission's FERC-certificated firm delivery capacity at Kramer Junction is 550 MMcfd. Energy Commission staff contacted Kern River Gas Transmission (Kern) on November 3, 2017, to understand how often

receipt point capacity of these Northern Zone pipelines is 1,590 MMcfd. Table 1 presents SoCalGas system pipeline capacity for summer 2017, current operating conditions as of April 10, pessimistic and optimistic cases, a combined case with additional outages and mitigations, and SoCalGas nominal system capacity (without outages).

Table 1:
SoCalGas System Pipeline Capacity

	Summer 2017	As of April 10	Summer 2018 Pessimistic	Summer 2018 Optimistic	Summer 2018 Combined	2016 CA Gas Report
	MMcfd					
Receipt Point						
North Needles	800	270[a]	0	270[a]	0	
Topock	0	0[b]	0	0[b]	0	1,590
Kramer Junction	550	550	550	625[c]	625	
Ehrenberg	1,010	980	800	980	800	1,210[d]
Otay Mesa	0	30	150	230	230	
Wheeler Ridge	765	765	765	765	765	765
CA production	60	60	60	60	60	310[e]
TOTAL Supply	**3,185**	**2,655**	**2,325**	**2,930**	**2,480**	**3,875**

a As long as Line 4000 is operating at reduced pressure, receipts at North Needles or Topock are limited to 270 MMcfd.

b The Line 3000 outage limits receipts at the Topock receipt point to zero.

c Firm deliveries at Kramer Junction are limited to 550 MMcfd; Kern River can deliver up to 700 MMcfd under certain system conditions.

d The nominal capacity of the southern zone is 1,210 MMcfd but achieving it requires 200 MMcfd be delivered via Otay Mesa. The Otay Mesa receipt point is rarely used and thus is excluded under "normal" conditions. The right-of-way expiration on Line 2000 means that 30 MMcfd must be delivered at Otay Mesa to keep the southern system total at 1,010 MMcfd.

e California production delivered to SoCalGas in recent years has run far below this nominal capacity value.

PRIOR PERIODS VERSUS WINTER 2017-18

It is fair to wonder how, despite repeated warnings about the risk of curtailment in prior technical assessments, the SoCalGas system has escaped significant curtailments — at least until the two-week cold snap beginning February 19 of this year. It largely avoided having to use gas from Aliso Canyon, again, until mid-February. The assessment group analyzed both prior periods and this past winter to

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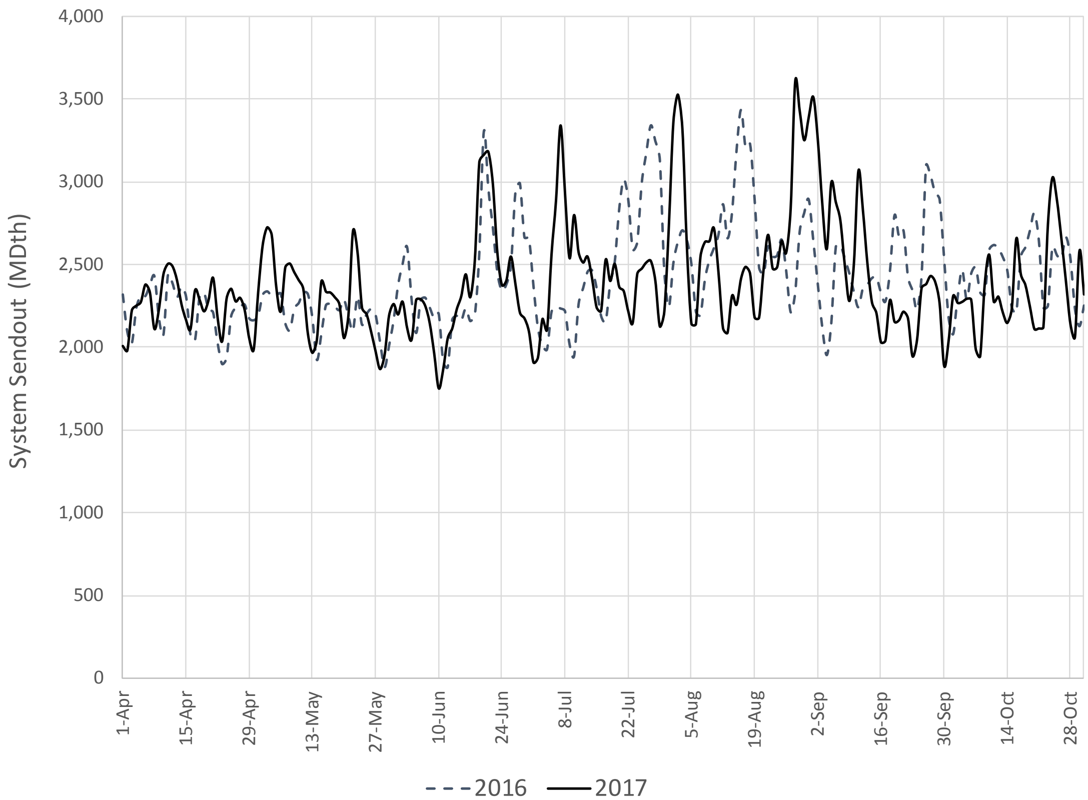
Kern can deliver the full 700 MMcfd instead of the normal 550 MMcfd. Kern indicated that it can do so daily "under current system operation conditions and gas nomination patterns." Of the 150 days between November 1 and March 31, Kern delivered more than its certificated firm delivery capability on 71 days. Of those 71 days, only on one-third of them did deliveries reach 700 MMcfd. The average delivered volume was 625 MMcfd.

compile findings. Some of the analysis for this winter is not complete and will be updated later, and additional mitigation measures may be an outcome of that assessment.

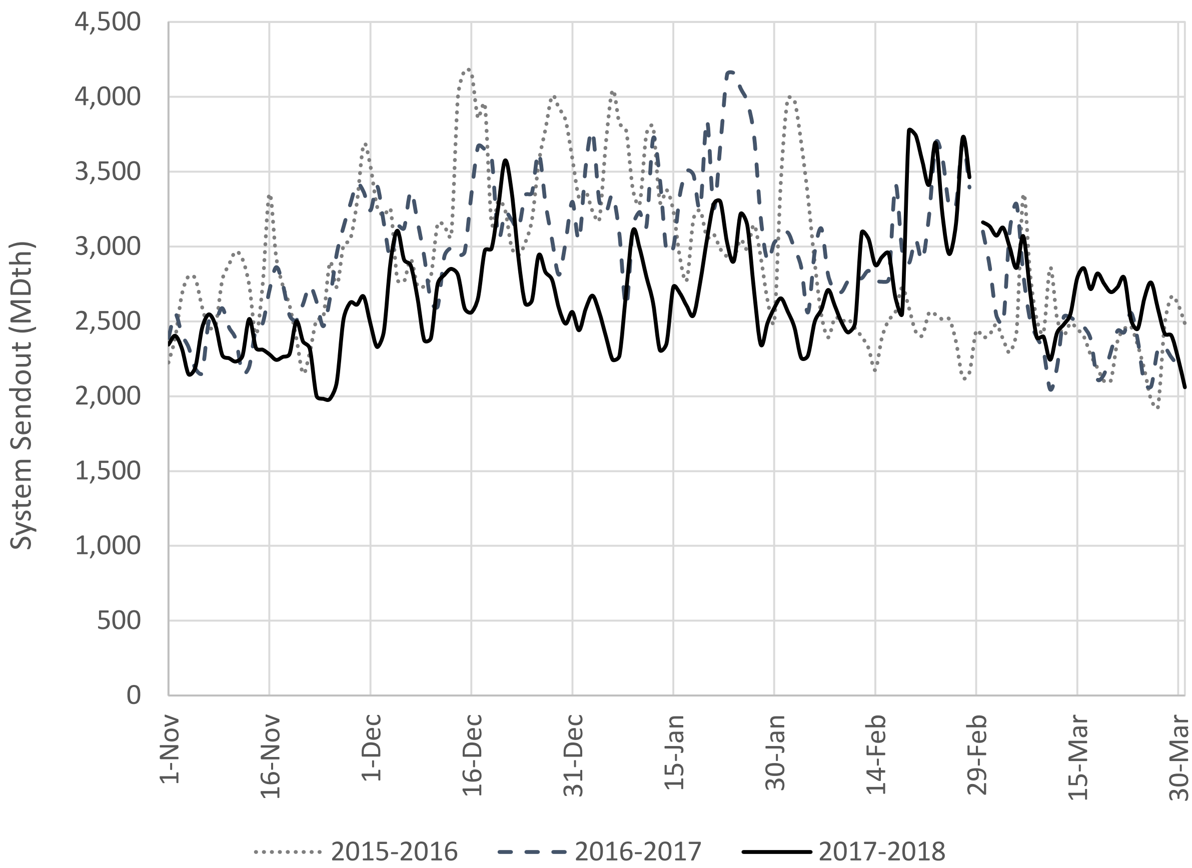
The original summer 2016 analysis pointed to demand of 3.2 Bcf per day or more, creating challenges for the gas system. Figure 1 plots gas system sendout for the past two summers. The figure demonstrates that demand was lower during most of last summer than in summer 2016. Counting the days with demand greater than 3.2 Bcf gives a sense of how frequently "stress" days occurred: Only six "stress" days occurred during summer 2016 compared to 10 in summer 2017.[13]

Figure 1: Daily Natural Gas Sendout (Demand) for Past Two Summers



13 The frequency observed in these two is different than the forecast frequency, or, the frequency at which they are expected to occur, on average, over a long period.

Figure 2: Daily Natural Gas Sendout (Demand) for Past Three Winters



Source: Staff analysis

Figure 2 plots gas system sendout for the past three winters. The figure demonstrates that Southern California, on most days, experienced lower natural gas demand last winter than in either of the prior two winters. Some care must be taken looking at these data because when a curtailment occurs, reported sendout loses value as a proxy for demand: Sendout would have been higher without the curtailment. Looking only at daily data also hides the possibility that there were specific hours where demand exceeded capacity, causing the need to use Aliso Canyon or curtail load. The other striking fact shown is that this past winter shows only 14 days with demand greater than 3.2 Bcf, compared to more than 40 days bin the prior two winters. These counts appear in Table 3 and are shown in Figures 3 and 4.

Table 3:
General Distribution of Natural Gas Demand Last Three Years by Season

Bcf per Day	2.6-2.8	2.8-3	3-3.2	3.2+
Summer 2015	23	18	11	14
Summer 2016	26	14	6	6
Summer 2017	16	9	5	10
Winter 2015	17	19	14	41
Winter 2016	17	22	22	45
Winter 2017	31	21	13	14

Source: Staff Analysis

Figure 3: Distribution of Daily Natural Gas Sendout (Demand) for Past Three Summers

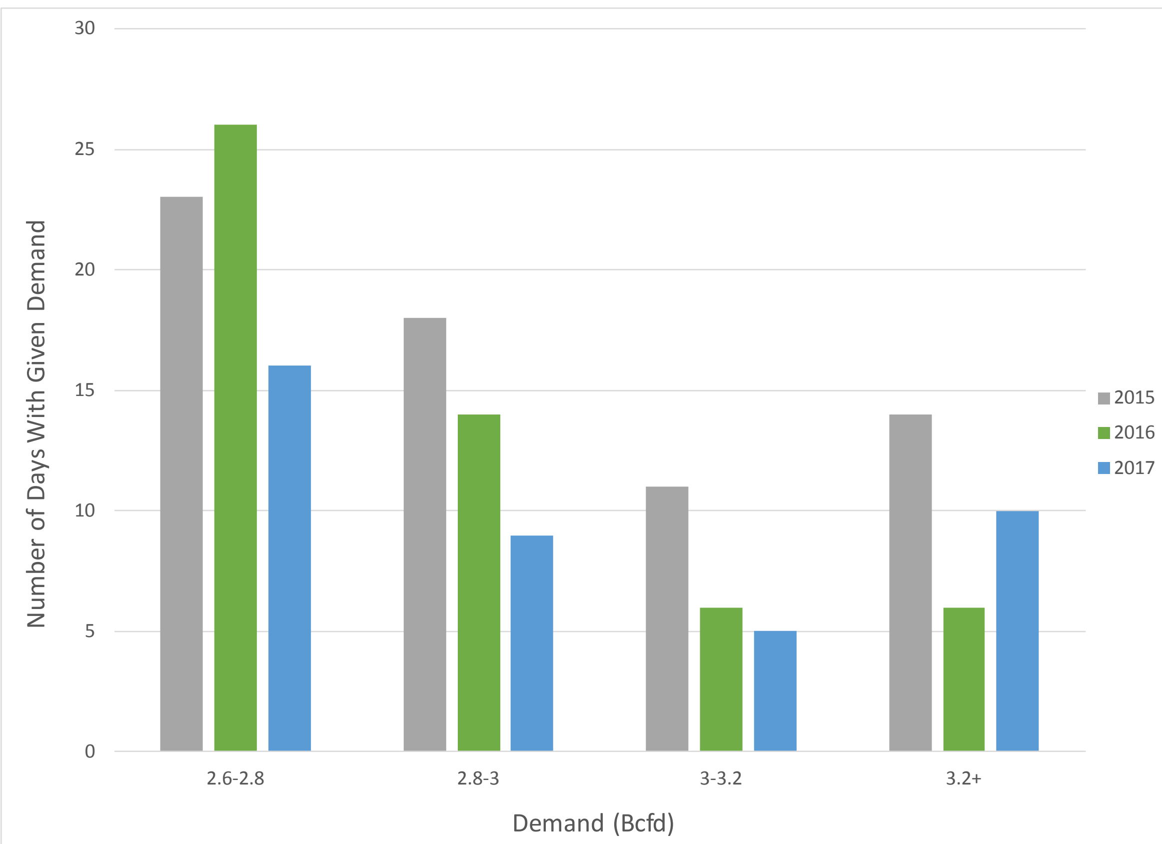
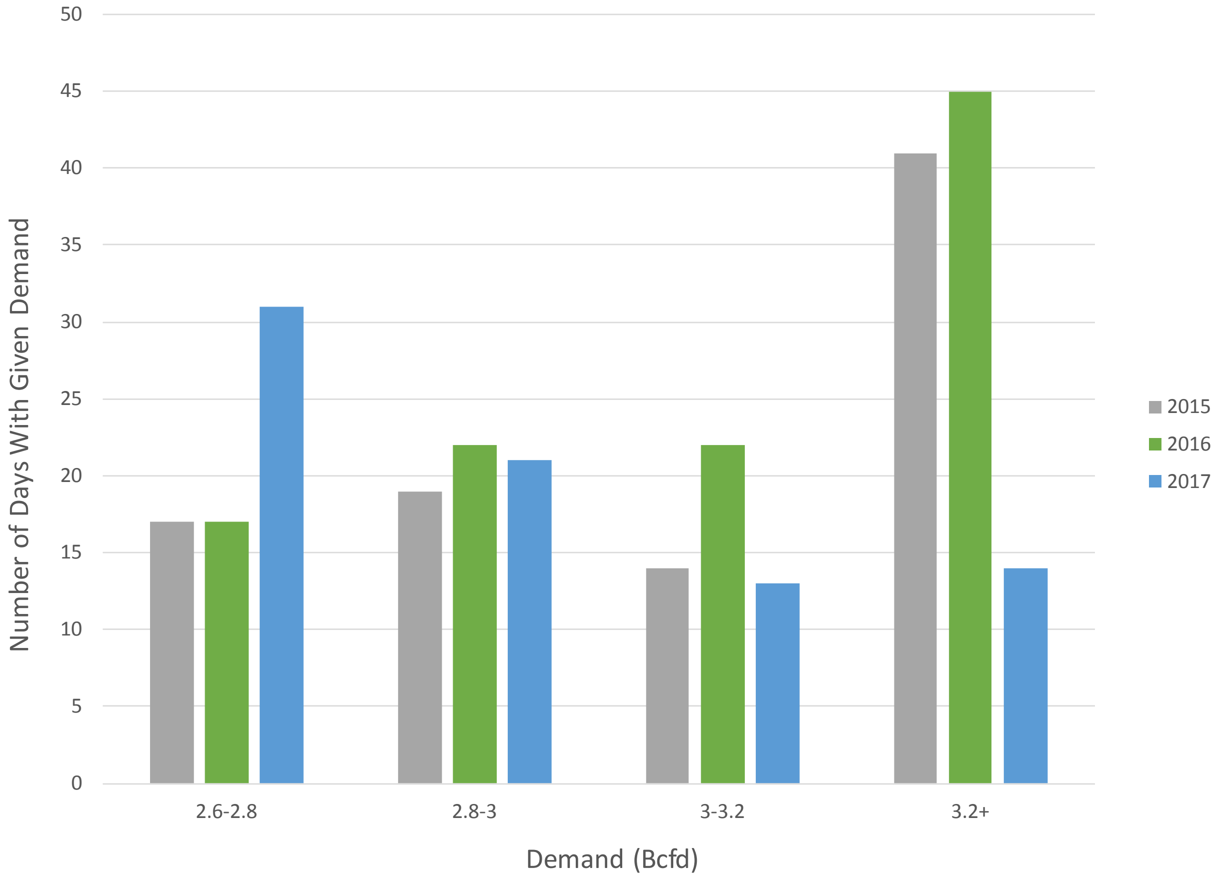


Figure 4: Distribution of Daily Natural Gas Sendout (Demand) for Past Three Winters



SoCalGas and/or the California ISO and LADWP used a combination of weather notices, curtailment watches, customer advisories, demand response, restricted maintenance, and Flex Alert days to manage demand on challenging, high-demand days.[14] Because of these efforts, only one instance of electric generators having to reduce load via informal curtailment occurred on January 24 and 25, 2017. SoCalGas also withdrew gas from Aliso Canyon to satisfy demand on those days, though not in all hours.

SoCalGas also used operational flow orders to order shippers back into balance as needed. Prior technical assessments discussed at length how large imbalances create a need to use gas from storage.[15] The ability to issue operational flow orders was identified as a key mitigation measure in the original

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14 The Energy Commission outlined use of these measures to avoid gas curtailments during the June 2017 heat wave in Appendix G of the *2017 Integrated Energy Policy Report.* Found at http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-01/TN223205_20180416T161056_Final_2017_Integrated_Energy_Policy_Report.pdf

15 Prior technical assessments are available at http://www.energy.ca.gov/2016_energypolicy/documents/index.html#04082016, http://www.energy.ca.gov/2016_energypolicy/documents/index.html#08262016, http://www.energy.ca.gov/2017_energypolicy/documents/#05222017. They can also be found at http://cpuc.ca.gov/alisoassessments/.

Summer 2016 Technical Assessment and remains a key tool for keeping the SoCalGas system from needing to use Aliso Canyon as much as it did before the well leak.

Table 4:
Use of Tools to Avoid Electricity Service Outages

	Weather Notice	Curtailment Watch	Flex Alert	SCG Request to All Customers	EG Load Reduction (Curtailment)	Low Operational Flow Orders	Delayed Work
Summer 2016		3	3			42	
Winter 2016-17	28	6		7	2	64	
Summer 2017	11	10	4			26	
Winter 2017 - 18	8	15			14	77	LADWP, California ISO[16] and SoCalGas

Source: Staff analysis

Preliminary analysis of the 2017-18 winter events, including the two-week natural gas service curtailment to electric generators during the cold snap from February 19 through March 6, leads to two key observations. First, exceptionally warm temperatures kept demand lower than expected through mid-February. The much lower-than-expected demand resulted in little gas being pulled from storage. As a result, SoCalGas still held 57.4 Bcf of storage inventory on February 18. The lower demand made the gas service curtailments anticipated for December and January in the 2017-18 Winter Technical Assessment unnecessary.

The second feature of this past winter was the cold spell that began Presidents' Day weekend. Between February 19 and March 6, colder temperatures caused a sustained rise in demand, with sendout of more than 3.5 Bcf on five days. SoCalGas asked LADWP and the California ISO to reduce their gas burn. Table 5 shows system conditions on the day before and after the start of the event, as reported on the Envoy website. In response, LADWP further delayed the transmission line upgrade work it had already deferred, given reliability concerns earlier in the winter, and the California ISO posted notices of constrained conditions so that all electric transmission line capacity would be available.

16 LADWP's delay of work it had scheduled to begin in November 2017 continued into March. California ISO, during the February cold spell issued a notice restricting maintenance and postponed some planned transmission work.

Table 5:
System Supply and Demand on Select Days in February 2018

MDth[17]	Sunday February 18, 2018		Tuesday February 20, 2018	
	Total for Day	Average Hourly	Total for Day	Average Hourly
Receipt Point				
North Needles	188	8	208	9
Topock*	0	0	0	0
Kramer Junction	641	27	617	26
Ehrenberg	1041	43	1020	43
Otay Mesa	0	0	19	1
Wheeler Ridge	740	31	698	29
CA production	95	4	97	4
TOTAL Receipts	**2705**	**113**	**2659**	**111**
System Composite Temperature[18]	**52**		**51**	
System Sendout	**2555**	**106**	**3745**	**156**
Net Injections (Withdrawals)	**149**	**6**	**-1087**	**-45**
Unused Receipt Capacity	**491**	**20**	**445**	**19**
Hours With Unused Receipt Capacity	**24**	**n/a**	**24**	**n/a**
Minimum Unused Receipt Capacity	**407**	**17**	**340**	**14**

Source: SoCalGas Envoy and nonconfidential response to data request dated March 21, 2018

The Energy Commission also analyzed hourly data obtained from SoCalGas via data request.[19] The analysis shows zero hours in which receipt capacity on the SoCalGas system was fully utilized. In other words, during all the hours and days on which the power plants were curtailed, the data show that pipeline capacity was available that seemingly could have been used to reduce curtailment. In fact, staff determined that no fewer than 6.24 MDth were available in every hour of the curtailment period, which equates to 145 MMcfd (assuming 1.03 MDth per MMcf) every day of the curtailment period. Fully using this capacity could have reduced the impact to electric generators.[20]

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17 SoCalGas reports the data in decatherms (Dth). One can translate to MMcf by simply dividing the MDth by 1.03, which implies 1.03 MDth per MMcf. Thermal content technically varies by producing field and pipeline; 1.03 is a reasonable value to assume for SoCalGas' system and the level of accuracy required here.

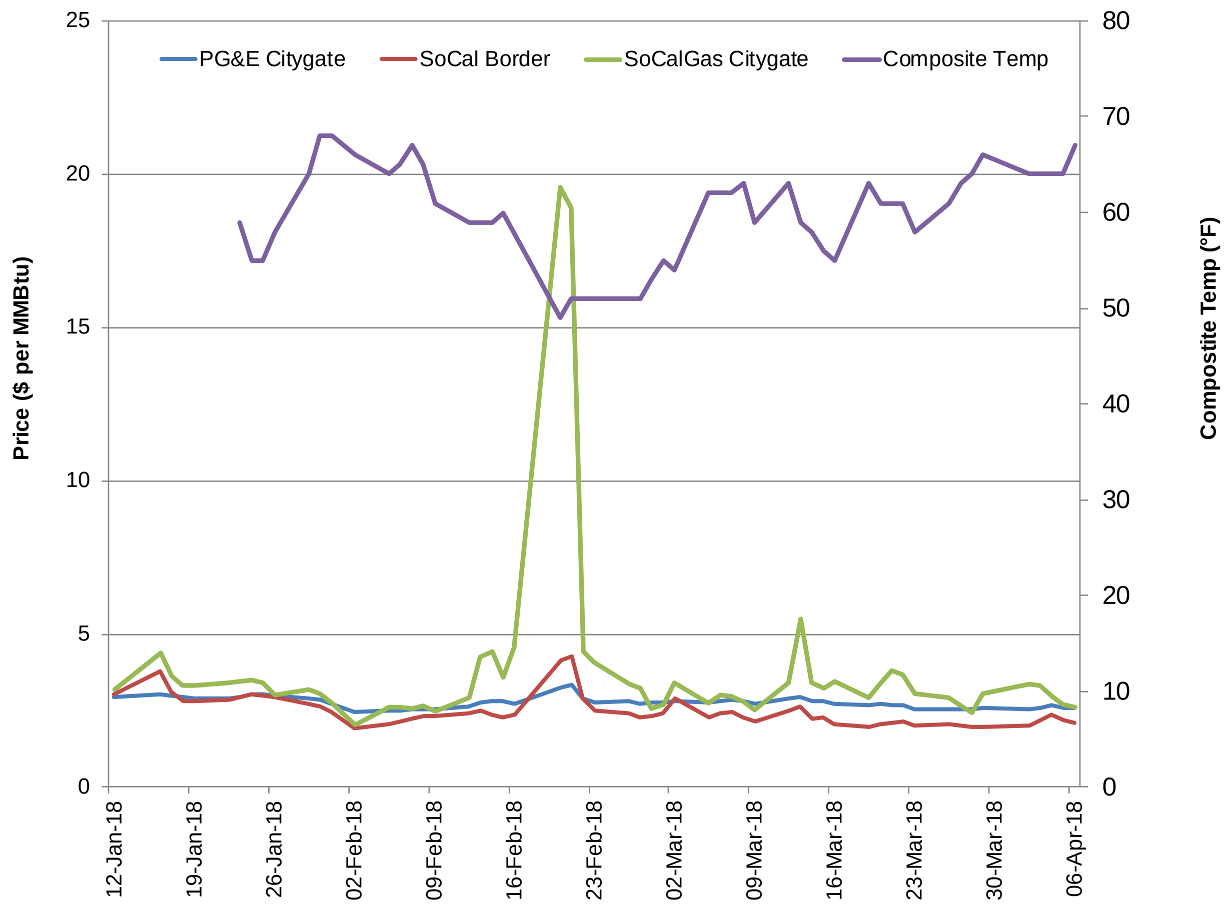
18 Data posted on Envoy show the lowest system composite temperature for the cold spell was 49 degrees on February 19. Highest posted demand (as calculated AFTER generators were curtailed) was 3.8 MDth per day on February 19.

19 Response to CPUC Data Request No. 43A, Dated March 21, 2018.

20 As an example, say that 6 MDth is the minimum quantity unused on a given day. There could be hours in which more unused capacity was available, but at least 6 were available in every hour. Six MDth times 24 hours equates to 144 MDth available for an entire day. This is less than summing the unused capacity for each hour in a given

During this period, SoCalGas withdrew roughly 10 Bcf from underground storage, including 1.14 Bcf from Aliso Canyon.[21] The Aliso Canyon withdrawals occurred in a few hours on six days during the roughly 16-day cold period. It is not clear that the curtailments or the withdrawals were due to customer imbalances. Prices for natural gas transacted at the SoCalGas Citygate temporarily increased from an average of $4.00 per MMbtu in the week before the cold snap to the $20 per MMBtu range, while those at the SoCalGas border and the PG&E Citygate did not. This is consistent with increased volatility at the SoCalGas Citygate since the rupture of Line 235-2 and the maintenance outage on Line 4000 that has been observed and noted in the Energy Commission's *2017 Integrated Energy Policy Report*.[22] The highest price increases occurred on the days that the system composite temperature was at its lowest, which coincides with the dates there were withdrawals from Aliso Canyon.

Figure 5: SoCalGas Citygate Prices During Cold Spell



Source: Energy Commission Staff Analysis

day. The latter approach would yield more precision, but the aim here is satisfied using the hour in which the unused capacity was lowest.

21 "30-Day Aliso Canyon Withdrawal Report," dated April 3, 2018, p. 8. This differs from the Aliso withdrawals reported on Envoy, however, which add to only 0.53 Bcf.

22 California Energy Commission staff. 2017. *2017 Integrated Energy Policy Report*. California Energy Commission. Publication Number: CEC-100-2017-001-CMF. p. 220.

The combination of unused capacity in all hours, price spikes, the imbalance data (which remain confidential), and the curtailments to electricity generation raise questions about whether the system, with the current rules for use of Aliso Canyon and outages on the pipeline system, could have been used more optimally and what other tools could be developed or refined that would have allowed SoCalGas to have avoided the electricity generation curtailments. SoCalGas' technical assessment suggests that permission to use Aliso Canyon more broadly would achieve this purpose. Another alternative would be to allow and require SoCalGas' operational hub to procure gas to fill and use all of its pipeline capacity before curtailing generators.[23] This and other suggestions are discussed in detail in the mitigation measures section of this report.

HYDRAULIC RESULTS

The assessment group specified two cases for hydraulic modeling runs that were performed by SoCalGas. Assumptions and results for both cases are shown in Table 6. The base assumptions assume current operating conditions as of April 10 except for the loss of 30 MMcfd due to the right-of-way expiration of Line 2000. Results for the summer 2017 case are shown, as well, for comparison. Consistent with last summer's analysis, both of the new cases assume 100 percent receipt point utilization. (As discussed shortly, SoCalGas discounts receipt point utilization by 15 percent; the assessment group cases do not). The base case has 530 MMcf per day less pipeline capacity than last summer. This is due entirely to pipeline outages on the SoCalGas system. The base case also shows greater use of gas from storage than last summer. In fact, any day that demand is greater than the base case assumed pipeline capacity of 2,655 MMcfd requires using gas from storage. The cases and results are displayed in Table 6.

The maximum supported demand on the SoCalGas system in the assessment group base case is 3,555 MMcfd. At this level of supported demand, gas-fired electricity generators can expect to be able to access 2,015 MMcfd. This is lower than the 2,201 MMcfd of generator demand the SoCalGas system could serve last summer but higher than the 1,971 MMcfd[24] forecast generator demand should a 1-in-10-year electricity system peak day occur.

The sensitivity case assumes that less pipeline capacity is available due to additional outages on Line 4000 and Line 5000 plus mitigations at Kramer Junction and Otay Mesa, compared to the base assumptions. As described in SoCalGas' March 30 assessment, Line 4000 could go back out of service. In addition, the potential for segments of Line 5000 to be removed from service is assumed to reduce capacity on the southern mainline by 200 MMcfd based on the assumption used in Table 2 of SoCalGas' 2018 Summer Technical Assessment. The sensitivity case addresses these additional outages to some degree by assuming a full 700 MMcfd is delivered at Kramer Junction (which is unlikely to occur every

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23 Recognizing that Gas Control must always retain the option of resorting to curtailment to preserve the safety and integrity of the gas system.

24 Electric generator demand of 1,971 MMcfd is based on Table 3 of SoCalGas' 2018 Summer Technical Assessment. This forecast demand is based on actual 2017 demand adjusted for planned retirements and additions of electric generation resources.

day based on recent experience) and 200 MMcfd is delivered at Otay Mesa (also unlikely to occur every day unless SoCalGas buys LNG for delivery to Otay Mesa directly via Costa Azul). The maximum supported demand on the SoCalGas system in this assessment group sensitivity case is only 3,425 MMcfd, of which electric generators can expect to receive 1,885 MMcfd.

For comparison, the results from the 2017 summer assessment found that SoCalGas maximum system sendout was 3,638 MMcfd without using gas from Aliso Canyon and assuming 100 percent receipt point capacity utilization. This figure further reflected the impact of the outage on Line 3000 and available storage withdrawal capability of 1,470 MMcfd. Recognizing this highlights another key difference between results from this summer versus last summer: Of the available storage withdrawal assumed in the cases, that capacity gets used to a greater degree this summer than last. A daily equivalent of 468 MMcfd was used in last summer's base case, while this summer's base case uses 900 MMcfd. In other words, more storage gets used, in more hours, to cope with hourly load swings during the gas day. If the storage depleted during the summer cannot be replaced before higher winter demand sets in, the system ends up being back in the same white-knuckled situation as last winter.

Table 6:
Assessment Group Base and Sensitivity Case Results

	SUMMER 2017		SUMMER 2018			
	Base Case		Base Case		Sensitivity	
	DAY MMcfd	PEAK HOUR MMcfh	DAY MMcfd	PEAK HOUR MMcfh	DAY MMcfd	PEAK HOUR MMcfh
Pipeline	**3185**	**132.7**	**2655**	**110.6**	**2525**	**105.2**
North Needles	800	33.3	270	11.3	0	0
Topock*	0	0.0	0	0	0	0
Kramer Junction	550	22.9	550	22.9	700	29.2
Ehrenberg	1010	42.1	1010[25]	42.1	800	33.3
Otay Mesa	0	0.0	0	0	200	8.3
Wheeler Ridge	765	31.9	765	31.9	765	31.9
CA production	60	2.5	60	2.5	60	2.6
Storage	**468**	**61.3**	**900**	**55**	**900**	**55**
Aliso Canyon	0	0.0	0	0	0	0
Honor Rancho	198	35.0	380	33.3	380	33.3
La Goleta	170	13.8	220	9.2	220	9.2
Playa del Rey	100	12.5	300	12.5	300	12.5
Supported Demand	**3638**	**221.5**	**3555**	**214.7**	**3425**	**205.3**
Core	808	33.7	770	32.1	770	32.1
Electric Generation	2201	153.5	2015	151.6	1885	141.9
Noncore non-EG	629	34.3	770	31.0	770	31.3
Pack(+)/Draft(-)	**15**	**-27.5**	**0**	**-49.1**	**0**	**-45.1**

*Zero receipts from the Topock receipt point due to the Line 3000 outage.

Source: SoCalGas hydraulic modeling results and staff analysis

SoCalGas presented two pipeline capacity cases in its March 30, 2018, assessment using assumptions of its own choosing, calling one a "best case" scenario with 2,905 MMcfd of pipeline supply and the other a "worst case" scenario with 2,475 MMcfd of pipeline supply. SoCalGas, however, discounts this pipeline capacity by 15 percent, to 2,478 MMcfd and 2,113 MMcfd, respectively, based on what they call a

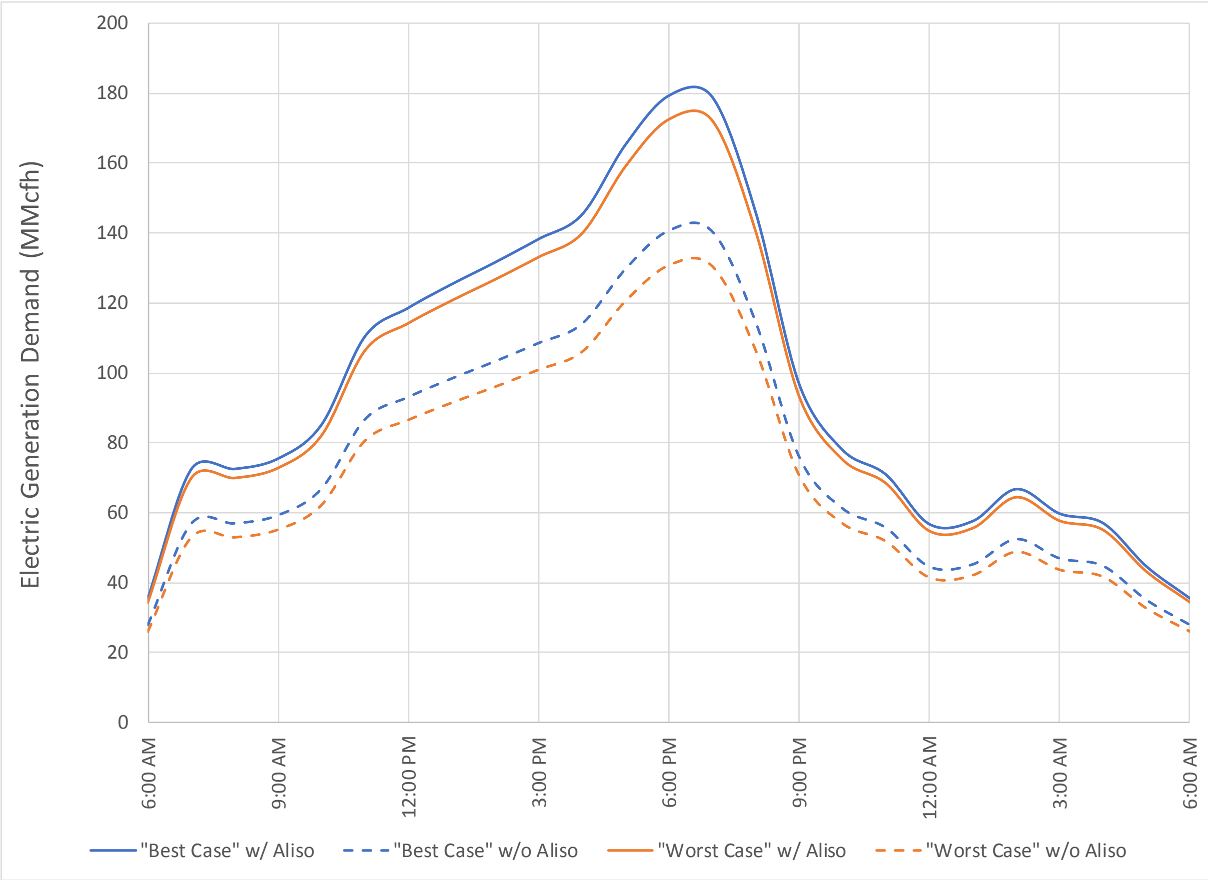
25 The assessment group defined its base case and requested that SoCalGas perform the hydraulic modeling before it knew that the Line 2000 right-of-way expiration would cause a reduction in capacity of 30 MMcfd. If the authors assume that this reduction reduces the supported demand in the hydraulic analysis on a 1:1 basis, the supported demand would not be the 3,555 MMcfd shown but instead would be 3,525 MMcfd. The assessment group has elected to show the 3,555 MMcfd because it is the factual result arising from the completed hydraulic runs using the assumptions given to SoCalGas and because sensitivity cases sufficiently capture alternate assumptions.

historic underutilization of pipeline capacity.[26] The cases specified by the assessment group, on the other hand, do not discount capacity because the authors believe it confuses the issue of behavior with true available capacity and creates the appearance of a greater need for gas from Aliso Canyon. SoCalGas' cases with the discounted capacity result in a supported demand of 3,400 MMcfd in the best case scenario and 3,271 MMcfd in the worst case scenario. Both cases require the use of gas from storage but do not use gas from Aliso Canyon. If Aliso Canyon is used, of course, the maximum supported demand increases.

SoCalGas did not publish but provided to the assessment group the supported demand for the generators by hour resulting from its scenarios. Those data demonstrate, whether looking at the "best" case or the "worst" case, how being able to use Aliso Canyon allows SoCalGas to support higher demand with steeper ramps by electric generators. These data are shown in Figure 6.[27]

26 In describing its worst-case scenario, SoCalGas notes it is likely that measures would be explored to increase receipt point utilization above 85 percent. The assessment group in fact proposes several new mitigation measures in this assessment.
27 The difference between the assessment group assumption and that of SoCalGas on the 15 percent discounting of pipeline capacity utilization would shrink the values shown below, though exactly how would require a comparative hydraulic modeling run with and without the discounting.

Figure 6: Supported Electric Generation Demand per Hour for Each SoCalGas Case



LADWP AND CALIFORNIA ISO JOINT ELECTRIC GENERATION IMPACT ANALYSIS AND RESULTS

The California ISO and LADWP, as the relevant electricity balancing authorities for generators in the Greater Los Angeles Area and Southern California, have updated their reliability analysis for the upcoming summer. This analysis determines how much natural gas the power plants must have to maintain system reliability under normal and unexpected contingency conditions.

The minimum gas burn by electricity generators calculated here is significantly lower than the electricity-generator gas burn under normal circumstances. It is the minimum that electricity generators must have to maintain electricity reliability. It is calculated not for planning to move the generators to minimum, but so that decision makers know how much gas the power plants must have to avoid electricity service outages. The implied reduction in gas use from normal to minimum levels is effectively a curtailment of gas service to electricity generators. Replacing the generation that would have occurred with this gas means the electric balancing authorities have moved generation to other, less desirable and more expensive facilities to reduce their gas requirement and the stress on the gas system. Such shifts increase the cost of electricity.

The more advance notice to the balancing authorities of such gas curtailments, the more time the electric system has to respond and reduce electric system impact. Short notice of gas curtailments reduces the options available to secure additional import energy to replace the energy lost by the gas curtailment. Because most replacement energy will have to be imported into the area, the ability to respond to short-notice gas curtailments will be limited by the electric transmission capacity and electric supply available outside the area at the time of the curtailment.

Moving electric generators to minimum generation is not easy or desirable. The generators need notice to do it. It means shifting generation to less desirable and less economic sources and, depending on notice timing and available resources, places the California ISO and LADWP into one or more levels of Energy Emergency Alerts.[28] Moving to minimum generation also assumes that gas is available at the replacement plants and that transmission and energy are available at the quantity and duration necessary to replace the generation and that no other outages occur among electric facilities. Under CPUC rules, electric generators are considered noncore service[29] in the SoCalGas/SDG&E service

28 Energy Emergency Alerts are defined at http://www.nerc.com/pa/Stand/Reliability%20Standards/EOP-011-1.pdf.

29 Noncore service is provided to large industrial and commercial customers, hospitals, power plants, and oil refineries. Core service is provided to customers at homes, small commercial operations, and small industrial enterprises.

territories and are the first gas customers called to reduce gas consumption.[30] The assessment group, therefore, does not expect SoCalGas to curtail generators to minimum generation without an emergency or implementation of system curtailments under Rule 23. To be clear, the purpose of calculating minimum generation is not so that SoCalGas can plan to curtail the generators; rather, it is so that SoCalGas, the electric balancing authorities, and the regulatory agencies know how large a cut the combined electric-gas system can sustain before electric reliability is jeopardized so they can develop actions to reduce risk.

The 2018 summer assessment focuses only on the electric reliability impact of gas constraints. There are also financial and environmental impacts of operating electric generation in non-efficient and non-economic ways to address supportable supplies and constraints on the SoCalGas/SDG&E service territories without Aliso Canyon. This assessment does not attempt to quantify those impacts.

Summary of Electric Findings

- The LADWP/California ISO joint 2018 power-flow study found that electric reliability can be met with 1.446 Bcfd (including the qualifying facilities [QFs]).[31] This study assumes 1-in-10-year summer peak electric load conditions with the required minimum generation to maintain electric reliability under normal conditions and all transmission lines in service at the assigned emergency ratings.
- The electric system is expected to be able to maintain electric reliability for summer 2018 without interruption in all scenarios assuming 100 percent electric transmission import utilization and optimistic levels of gas storage supply are available.
- To the extent electric imports are limited, meeting the 1-in-10-year summer peak load could be at risk.
- During peak summer load conditions and historic electric transmission utilization patterns, incremental gas-fired generation may be required to meet electric reliability. To the extent gas supply is insufficient to meet the increased gas demand, access to replacement energy may require emergency assistance from neighboring balancing authorities, and electric load shed in Southern California may be necessary.
- Although the electric system could operate with only minimum reliability must-run generation in gas constrained areas during the summer months, this is not commonly observed during a 1-in-10-year peak load day. Normal unconstrained, economic operation of the generation assets would require gas usage above the outcome of the reliability study. Using resources other than those that are most efficient and economic would result in increased energy dispatch costs.

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30 SoCalGas Rule 23 can be found at https://www.socalgas.com/regulatory/tariffs/tm2/pdf/23.pdf. Notably, moving the generators to minimum generation during the winter results in a curtailment of gas service that exceeds their obligation to cut 60 percent of their load under Rule 23 in the SoCalGas tariff. This is not true, however, for the summer, where the 40 percent curtailment under Rule 23 cannot be absorbed before reaching the minimum generation level. Rule 23 requires EG to curtail up to 40 percent of their load in the summer months and up to 60 percent of their load during the winter months.

31 A *qualifying facility* is a qualifying cogeneration facility or qualifying small power production facility, as defined in the Code of Federal Regulations, Title 18, Part 292.

- The summer reliability assessment focused on local transmission reliability including the contingency reserve requirement necessary to immediately meet the greater of the loss of the Most Severe Single Contingency (MSSC) or about 6 percent of the hourly peak load. The assessment also included replacement reserve capacity that will need to be sourced and procured after the first hour of a power system contingency. While the quantity and location of the generation commitment may vary depending on load level, system topology, fuel costs, and economics each day, historical experience and the summer 2018 seasonal assessment performed by the LADWP and California ISO show the need to have a minimum amount of generation commitment inside the Los Angeles, Orange County, and San Diego areas.

Assumptions

The key assumptions on the electricity side consist of a) the electricity load forecast, b) available electricity imports, and c) the impacts of an N-1 contingency, or outage, event.

A. Electricity Load Forecast. The 1-in-10-year peak summer load electricity demand forecast for Southern California totals 36,845 megawatts (MW). It breaks down as follows:
   - SCE = 24,572 MW
   - SDG&E = 4,862 MW
   - LADWP = 7,411 MW[32]

B. Imports. The analysis assumes Southern California imports of 18,818 MW of electricity. This is higher than the 15,000 MW of summer imports achieved historically and is based on available transmission capacity. The actual level of imports achievable will depend on the availability of transmission and energy on the days and hours when needed.

C. Outages. The analysis takes into account planned transmission outages. For unplanned facility outages, the analysis reflects an N-1 contingency event assumed to reduce energy available by 1,100 MW for LADWP, 2,000 MW for the California ISO, and 2,873 MW for the combined LADWP and California ISO.[33]

Results

The results below are split into a minimum gas requirement under normal conditions versus a higher gas requirement should electricity system N-1 events occur.

<u>Normal Electric Operating Conditions</u>

The gas burn required to support electric generation in Southern California is projected to total 1,446 MMcfd. This is under normal conditions and includes gas required by QFs because the QFs account for about 10 percent of the gas burn requirement. The total requirement splits into 313 MMcfd for LADWP

32 This includes LADWP itself plus the load of the utilities within its balancing area, consistent with prior technical assessments.
33 N-1 is the loss of any generator, transmission line, transformer, or shunt device without a fault or single pole block on a high–voltage, direct-current (HVDC) transmission line.

and 1,133 MMcfd for the California ISO. The two balancing authorities must be able to obtain at least this amount of gas in order to maintain electricity reliability.

To Recover From an N-1 Contingency

A contingency (outage) that would affect both LADWP and California ISO is the most severe N-1 electric outage that could occur in Southern California. Recovery from an N-1 electric contingency event increases the gas requirement because more gas-fired generation must be available and able to operate (meaning it must have access to fuel) to replace the lost electricity system component. This higher gas requirement lasts until the lost component can be restored. Both the California ISO and LADWP balancing authorities have to each carry their own operating reserve to meet their operating reserve requirement to cover their largest contingency. However, the single event in Southern California could result in a larger loss of energy as compared to the individual event. This gas quantity from an outage is assumed available in the event of an electric system contingency to meet North American Electric Reliability Corporation (NERC) reliability requirements.

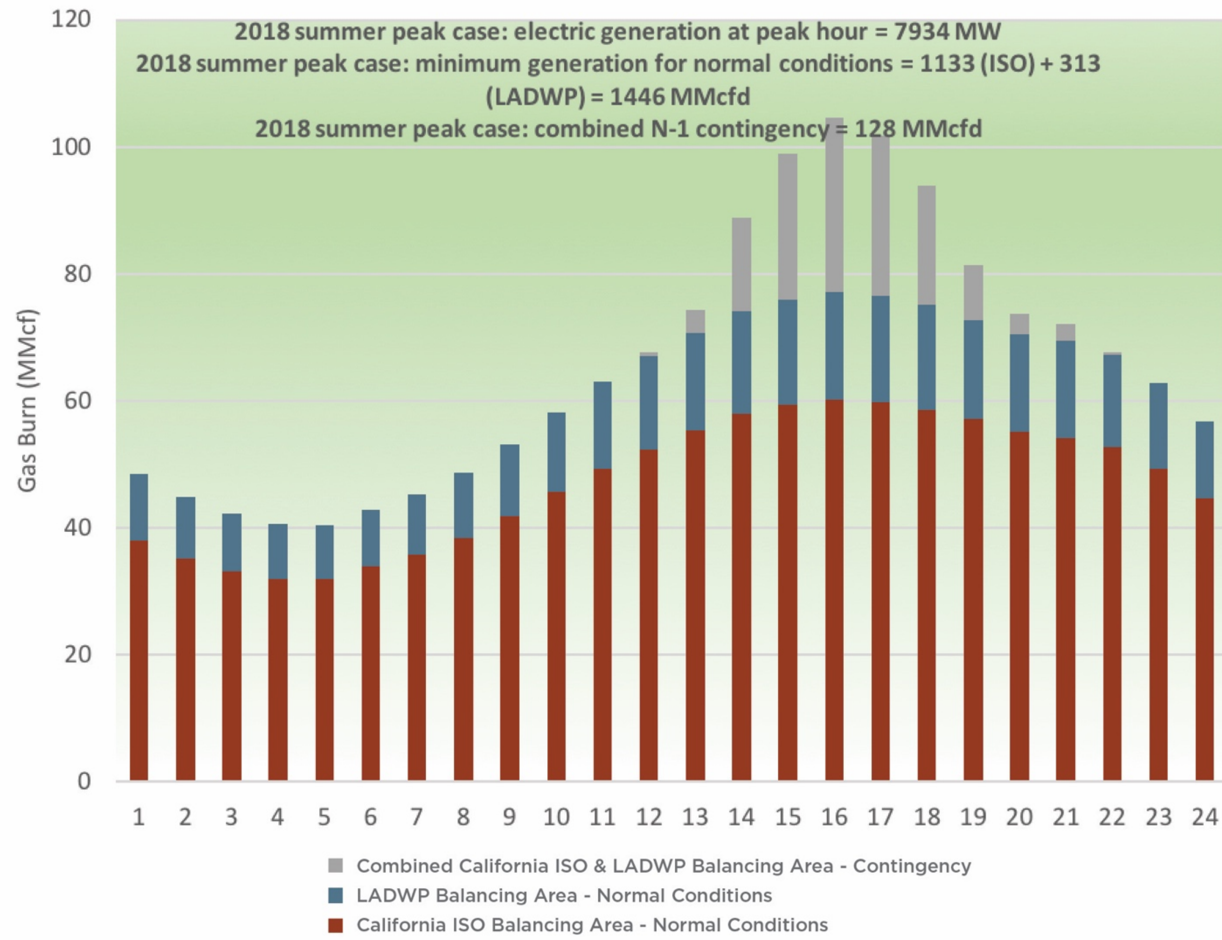
The most severe N-1 contingency equates to losses of 2,000 MW for the California ISO and 1,100 MW for LADWP. The most severe single contingency for both the California ISO and LADWP combined is a different contingency that impacts both utilities and results in a combined loss of 2,837 MW. Replacing this lost energy means the combined California ISO and LADWP will require an additional gas requirement of 128 MMcfd of natural gas. Table 7 summarizes the minimum generation gas requirements, including the QFs.

Table 7: Minimum Generation Gas Requirements Including QFs (MMcfd)

Condition	California ISO	LADWP	Total
Normal	1,133	313	1,446
N-1	128		1,446 + 128 = 1,574

Figure 6 below shows the hourly minimum daily generation needed in the LADWP and the California ISO balancing authorities to meet normal conditions and to recover from a nonsimultaneous contingency on a peak summer day. The generation need is translated into a gas requirement of 1,446 MMcfd and 1,574 MMcfd, including the QFs under normal and N-1 contingency conditions, respectively. Table 8 shows the peak hourly generation and gas burn by zone in the SoCalGas area.

Figure 6: Summer Generation in the SoCalGas Service Area Including QFs



Source: California ISO

Table 8:
1-in-10 Peak Summer Case Including QFs: Peak Hour Energy (MW) and Gas Burn (MMcf per hour) for SoCalGas Area

Zone	Gen (MW)	Gas Burn (MMcfh)
Burbank	250.00	2.43
Coastal	190.20	1.85
EOM	177.00	1.72
Glendale	46.00	0.45
Inland	1,413.50	13.72
LA Basin	2,481.00	24.09
LADWP	1,426.00	14.00
Pasadena	100.00	0.97
Riverside	195.00	1.89
SDG&E	1,299.98	12.62
SJV	355.36	3.45
Total	7,934.04	77.18

Table 9 summarizes the electric impact on the 2018 summer gas assessment. The combined California ISO and LADWP minimum generation gas burn, including the combined additional worst contingency for both balancing authorities, is 1,574 MMcfd.

Table 9:
Summary of Electric Impact on 2018 Summer Gas Assessment Including QFs

Row	Description	Formula	Gas Burn (MMcfd)
1	Actual California ISO BA SoCalGas system gas burn for 2017 Summer Peak - September 1, 2017[34] (MMcfd)		1,649
2	Actual LADWP BA SoCalGas system gas burn for 2017 Summer Peak – August 31, 2017[35] (MMcfd)		379
3	Combined actual California ISO and LADWP BAA gas burns (MMcfd)	row 1 + row 2	2,028[36]
4	California ISO SoCalGas system gas burn with minimum generation - with all transmission lines in service and no outages (MMcfd)		1,133
5	LADWP balancing area gas burn with minimum generation - with all transmission lines in service and no outages (MMcfd)		313
6	Combined California ISO and LADWP minimum generation gas burn – with all transmission lines in service and no outages (MMcfd)	row 4 + row 5	1,446
7	California ISO + LADWP Combined SoCalGas system gas burn to cover additional worst contingency (MMcfd)		128
8	Combined California ISO and LADWP minimum generation gas burn including the combined additional worst contingency from LADWP and California ISO (MMcfd)	row 6 + row 7	1,574

Difference Between 2017 Analysis and 2018 Analysis

In the 2017 summer assessment the minimum gas burn was 291 MMcfd for LADWP and 1,459 MMcfd for the California ISO under normal conditions, based on the assumption that all transmission lines were in service with import energy to meet load requirements. The assessment group anticipated that these very low gas burn requirements were sustainable only for a short period and that such a reduction would occur infrequently because they would be limited to the most extreme gas curtailment situations.

In the 2018 summer assessment, the minimum gas burn for LADWP increased to 313 MMcfd, and the California ISO's minimum burn was reduced to 1,133 MMcfd, about 300 MMcfd lower than in last summer's assessment. The power flow study assumed normal transmission system configuration with all

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34 September 1, 2017, was chosen for this analysis because it was the highest peak day in recent years for the California ISO.
35 August 31, 2017 was chosen for this analysis because it was LADWP's all-time peak.
36 The actual peak gas burn for 2017 is higher than the forecast electric generator demand for summer 2018 of 1,971 MMcfd.

lines in service at their emergency ratings. Thus, the gas burns provided in the analysis are the extreme minimums that the California ISO and LADWP could obtain due to transmission lines utilized to their emergency ratings. As per NERC Standards, in this analysis the post-contingency flow can be operated at or below the emergency rating for a finite pre-defined period. Following the contingency, the flow in the facilities should be operated below the emergency rating within no less than this pre-defined period of time. For this analysis, the pre-defined period of time for the California ISO area is 30 minutes while it is two hours for LADWP.

For LADWP, the increase in gas burn from the 2017 summer to the 2018 Summer Technical Assessment is a direct result of increased load in the LADWP balancing authority. LADWP experienced an all-time peak on August 31, 2017, and this load was used in the model and electric impact analysis for the 2018 Summer Technical Assessment. For the California ISO, several transmission upgrades located in Southern California have come online or will be online this summer, and some gas generation retirements in the SoCalGas service area contribute to the lower gas burn requirement. These transmission upgrades allow more imports into the area, reducing the minimum in-area generation requirements and corresponding gas burn. These transmission upgrades are in Table 10.

Table 10:
In-Service Dates for California ISO Board Approved Transmission Projects

	Transmission Projects	**Participating Transmission Owner Service Territory**	**Target In-Service Dates**
1	Santiago Synchronous Condensers (3x81 MVAR)	SCE	In-Service (12/8/2017)
2	San Luis Rey Synchronous Condensers (2x225 MVAR)	SDG&E	In-Service (12/29/2017)
3	Sycamore – Peñasquitos 230kV Line	SDG&E	Mid July 2018

Potential Gas Curtailment for Electric Generation

Determining the potential gas curtailment for electric generation is a two-step process. The first step is to calculate an adjusted summer peak day gas demand incorporating the minimum electric generation requirements. The next step is to compare the adjusted summer peak demand to the SoCalGas supportable demand or system sendout as shown in Table 6. The impact on electric generation, shown in Table 9, is based on the post N-1 contingency minimum generation combined gas burn of 1,574 MMcfd for the LADWP and California ISO, which is approximately 300 MMcfd less than the minimum combined gas burn in 2017. The analysis determines the amount of electric generation that can be curtailed from what the gas burn would otherwise be on a 1-in-10 year peak gas demand day.

These figures are in Table 11. The gas forecast as required by power plants on a 1-in-10 year peak day is 1,971 MMcfd. If the power plants must be taken to minimum generation, that demand would be reduced to 1,574 MMcfd, including the amount needed to support N-1 contingency conditions. The difference between those two figures is 397 MMcfd, which represents the largest cut gas-fired generators could withstand and still maintain electricity service reliability on a peak summer day, assuming 100 percent transmission utilization. It is only achievable as long as the balancing authorities have the ability to import replacement electricity from external generation resources.

Table 11:
1-in-10 Year Summer Peak Day Demand Implied Curtailment at Forecast Versus Minimum Electric Generation Levels

Summer Demand (MMcfd)	1-in-10 Year Peak Day Forecast Electric Generation[37]	1-in-10 Year Peak Day Minimum Electric Generation, N-1 Contingency,
Core	770	770
Noncore, Non-Electric Generation	770	770
Noncore, Electric Generation	1,971	1,574
Total	3,511	3,114
Implied Curtailment if Electric Generation Goes to Minimum Generation	N/A	397

Operating the electricity system this way results in increased cost to serve electric load. It is also only feasible when there is sufficient energy available from external suppliers at the quantity and duration necessary to meet the resulting energy import requirements.

Table 12 compares the SoCalGas system capability shown in Table 6 to the adjusted summer peak day demand shown in Table 11. In both the assessment group's base and sensitivity cases, the gas system's supported demand (without using Aliso Canyon) is sufficient if the power plants are cut to minimum generation levels. The base case supported demand shows 441 MMcfd still available on the gas system after moving the power plants to minimum generation on a summer peak day. The sensitivity case has lower supported demand and consequently a lower amount of gas system capacity still available after reducing the power plant load to the minimum level of 311 MMcfd. This so-called "surplus" capacity could be used to allow generators to burn more than the minimum level. Any outage or change on the gas system that reduces gas system capacity below the 3,114 MMcfd minimum generation gas demand level will result in insufficient gas being available to keep the electricity system reliable on a summer

37 The 1-in-10 year summer 2018 peak day forecast is based on Table 3 of SoCalGas' technical assessment. The assessment group acknowledges the uncertainty surrounding the forecast and that a different forecast could have been used.

peak day. Another interpretation is that there appears to be enough capacity that the generators should not need to be curtailed to minimum generation on a 1-in-10 peak day.

Table 12:
Shortfall or Surplus on a 1-in-10 Year Peak Day with Minimum Electric Generation and an N-1 Contingency, Assuming 100 Percent Gas and Electric Transmission Utilization (MMcfd)

(MMcfd)	Assessment Group Base Case	Assessment Group Sensitivity
1-in-10 Year Customer Demand with Generation Curtailed to Minimum Levels	3,114	3,114
Supported Demand without Aliso Canyon	3,555	3,425
Gas System "Surplus" After Moving Electric Generation to Minimum	441	311

SoCalGas Rule 23 Summer Curtailment

Table 13 summarizes the electric impact if there is an electric generation curtailment for gas using the SoCalGas Rule 23 curtailment order. If constrained gas system operations occur and gas curtailments are needed, application of Rule 23 would cause up to 40 percent of electric generation load in summer months to be curtailed. If additional gas load must be shed, then SoCalGas goes to other noncore customers before curtailing more electric generation gas load. The actual 2017 peak load day gas burn for California ISO and LADWP was about 1,649 MMcfd and 379 MMcfd respectively, as shown in Table 13. If curtailment arises on the peak electric generation day, then the remaining gas left for electric generation after the maximum of 40 percent electric generation curtailment is about 989 MMcfd and 227 MMcfd for California ISO and LADWP, respectively. However, the gas needed to meet the minimum generation for a 1-in-10 peak load with all the transmission lines in service and no outages is about 1,133 MMcfd and 313 MMcfd for California ISO and LADWP, respectively, which is higher than the gas left after the maximum electric generator curtailment per SoCalGas Rule 23. In addition, even more gas is needed to cover the additional worst contingency for the California ISO and LADWP combined. The results show a shortfall of 358 MMcfd including the gas needed to cover the worst contingency.

Table 13:
Summary of Electric Impact after Electric Generation Curtailment per SoCalGas Rule 23

Row	Description	Formula	ISO	LADWP
1	2017 actual peak load day gas burn (MMcfd)	*(row 1 and row 2 from table 9)*	1,649	379
2	Up to 40% of EG curtailment in summer months - Remaining gas after EG curtailment based on 2017 peak day gas burn (MMcfd)	row1*0.6	989	227
3	Gas needed for 2018 1–in-10 peak load day with minimum generation - with all transmission lines in service and no outages (MMcfd)	*(row 4 and row 5 of table 9)*	1,133	313
4	Shortfall of gas to meet the minimum generation for normal conditions after 40% EG curtailment (MMcfd)	row2 - row3	-144	-86.0
5	Gas needed to cover the additional worst contingency for combined California ISO and LADWP balancing area(MMcfd)	*(row 7 of table 9)*	-128.0	
6	Total gas needed to cover the shortfall and the additional worst contingency for combined California ISO and LADWP balancing areas (MMcfd)	*(Row 4, Columns 5 and 6 + row 5)*	-358	

Ability to Resupply Energy Based on Electric Transmission Utilization

The power flow analysis simulated maximum possible imports into Southern California of 18,818 MW. However, the highest transfer observed is 15,500 MW, which is about 82 percent of the maximum simulated. Of this amount, 4,000 MW is expected to come from Northern California, 3,100 MW is expected to come from the Northwest, and the remainder is expected to come from Utah, Arizona, and Nevada.

If energy is already being imported and flowing prior to a gas curtailment, there will be limited capacity available to transport energy to absorb the curtailment. In addition, the availability of supply from alternate resources may be less this summer when compared to 2017 due to less than average hydro conditions in 2018.

Table 14 shows the impact on the electric system and the additional gas needed at different transmission import utilizations. The analysis reviews three cases:

1) Imports of 18,818 MW: 100 percent transmission capacity utilization as reviewed in the 1-in-10 summer peak day power flow analysis.

2) Imports of 16,936 MW: 90 percent transmission capacity utilization — about 9 percent higher than observed historical transmission utilization maximum.

3) Imports of 15,995 MW: 85percent transmission capacity utilization — still about 3 percent higher than observed historical maximum transmission utilization.

The analysis starts with the forecasted 2018 1-in-10 year peak summer load for the Southern California region. It then sums up the maximum import capability, maximum non-gas-fired generation capacity, such as hydro, solar and wind, and the minimum gas-fired generation needed to meet local reliability requirements. The sum of the generation must equal the load to maintain the electric power system balance. Table 14 shows the analysis of import energy into the Southern California region for three transmission utilization cases in Row 2. The combined LADWP and California ISO minimum gas-fired generation needed to meet reliability requirements is in Row 7. If the import utilization is insufficient, the required incremental gas generation is in Row 8. The incremental gas-fired generation required following a power system contingency event impacting Southern California is in Row 10. The incremental gas demand is Row 11, which represents the additional gas needed over the day relative to the 100 percent transmission utilization scenario. The results show that as transmission utilization decreases, the need for in-basin, gas-fired resources increases. The incremental gas demand in Row 11 is then compared to the gas system surplus in Table 12 after moving electric generation to minimum generation for the base case and sensitivity. Rows 13 and 15 show the net surplus/shortfall for the base and sensitivity cases. The results show sufficient gas system capacity for the base case with a surplus of 164 MMcfd under 90 percent electric transmission utilization and a surplus of 63 MMcfd in the 85 percent utilization. The results also show sufficient gas system capacity for the sensitivity case with a smaller surplus of 34 MMcfd under 90 percent utilization. However, the results show a shortfall of 67 MMcfd under 85 percent transmission import utilization. If all re-supply options have been exhausted, additional gas will be required from other sources including Aliso Canyon or electric load shed may be required.

Table 14: Summary of Assessment of Electric Impact-Based Transmission Utilization

Row	Description	Formula	2018 (1-in-10) peak summer case with minimum California ISO SoCalGas system and LADWP generation - 100% Import Utilization	2018 (1-in-10) peak summer case with minimum California ISO SoCalGas system and LADWP generation - 90% Import Utilization	2018 (1-in-10) peak summer case with minimum California ISO SoCalGas system and LADWP generation - 85% Import Utilization
1	California ISO and LADWP combined balancing areas - Load + Losses (MW)		36,845	36,845	36,845
2	Imports into Southern California from North and East (MW)		18,818	16,936	15,995
3	Total California ISO and LADWP combined generation (MW)	row1-row2	18,027	19,909	20,850
4	California ISO and LADWP combined non-gas generation (MW)		10,093	10,093	10,093
5	California ISO gas generation served by SoCalGas (MW)		6,212	7,674	8,405
6	LADWP gas generation served by SoCalGas (MW)		1,722	2,142	2,352
7	California ISO and LADWP combined gas generation (MW)	row5 + row6	7,934	9,816	10,757
8	Additional gas generation needed if import utilization is reduced from 100%		-	1,882	2,823
9	Additional generation needed following a contingency (MW)		2,837	2,837	2,837

10	Incremental additional supply needed from gas generation to cover the contingency (MW)	row8 +row9		4,719	5,660
11	Additional gas hours, if transmission utilization is reduced from 100% and to cover the additional contingency (MMcfd)[1]			-277	-378
12	Base case gas surplus, 1-in-10 year peak demand with generation curtailed to minimum levels (MMcfd)	Table 12, Base Case		441	441
13	Base case net surplus/shortfall to cover the specified scenario (MMcfd)	Row 11 + Row 12		164	63
14	Sensitivity gas surplus, 1-in-10 year peak demand with generation curtailed to minimum levels (MMcfd)	Table 12, Sensitivity case		311	311
15	Sensitivity net surplus/shortfall to cover the specified scenario (MMcfd)	Row 11 + Row 14		34	-67

[1] 378 MMcfd of gas is equivalent to the gas needed to generate 3891.7 MW for 10 hours from a gas plant(s) with a 10,000 Btu/kWh heat rate. Gas Burn (MMcfd) = (10,000/1,030,000)*Mwh

GAS BALANCE ANALYSIS

The Energy Commission prepared gas balances in order to provide an assessment independent of SoCalGas and to test additional sensitivity cases with alternate assumptions. As explained in prior technical assessments, a gas balance allows one to assess the difference, or margin, between capacity (or supply) versus demand to determine in general whether capacity is sufficient to meet demand. It also allows one to simulate the impact to storage inventory from monthly storage injections and withdrawals.

Several caveats apply. The gas balance is not a projection of what will happen. Rather it is a tool to demonstrate what would happen if the demand, supply, and storage assumptions shown come to fruition. Also, it is important to recognize that the demand forecasts used are for average daily consumption for each month. Individual days will have higher and lower demand than the averages shown. Weekends can be expected to be lower, for example. The balance should demonstrate a positive deliverability margin, meaning more capacity than demand, so that the system retains some amount of slack to deal with unplanned outages or days with demand higher than forecast. The gas balance applies mere arithmetic to determine the daily balance between supply and demand. It does not simulate operations hydraulically to determine constraints or assess hourly operations.

Consistent with SoCalGas' hydraulic analysis, conditions for the upcoming summer are far more constrained than those seen for summer 2017 or summer 2016. Table 1 showed the nominal firm receipt point capacity of SoCalGas' pipeline system (without the current outages) totaling 3,875 MMcfd. The current pipeline outages reduce this to 2,655 MMcfd. Even assuming some system mitigation, additional outages may reduce this to 2,325 MMcfd. The gas balances that Energy Commission staff prepared consider both the current and increased outage cases. Staff differed from SoCalGas' analysis in that none of the staff balances automatically discount supply to 85 percent of pipeline capacity (the mitigation measures in this report suggests new measures to help address this).

The tables below run through to December to take account of impacts that summer decisions may have on reliability for next winter. They calculate the deliverability margin of capacity versus demand under 1-in-2-year normal temperature conditions.[38] Demand for all cases comes from the gas demand forecast published in the 2016 California Gas Report prepared by California's gas utilities with some participating oversight by staff at the CPUC and Energy Commission.[39] Each of the cases applies the storage inventory reported on Envoy on March 31, 2018. Staff calculated the Aliso Canyon inventory by applying reported withdrawals of 1.14 Bcf to the 22.8 Bcf inventory reported by SoCalGas to have been in storage at the start of the cold weather event.[40]

Each of the gas balance cases run through summer and into early winter. The expectation reflected in last winter's gas balances that Line 3000 comes back into service November 1 to increase capacity by 540 MMcfd has been removed because it needs Line 4000 running at full pressure to get past Newberry Compressor Station. Several of the cases show 30 Bcf at Aliso Canyon. This number is based on the

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38 The assessment this time does not include cases for what is known as the 1-in-10 year "cold and dry" forecast. The normal temperature case analyses are enough to demonstrate the risk to reliability and the "deliverability balance" shows the margin available to cover increased demand.
39 The 2018 California Gas Report with updated demand forecasts will not be released until July 1, 2018.
40 "30-Day Aliso Canyon Withdrawal Report" April 3, 2018, p. 2.

inventory level that SoCalGas requested in Advice Letter 5275. At this time, no determination has been made on whether or not to grant this request.[41] Rather, the analytic purpose is to assess whether a 30 Bcf inventory can be achieved and what the winter inventories at all four fields might look like by year-end given the pipeline system's outages. Changes to the inventory level will be addressed in the CPUC 715 report.

Case A (Table 15) assumes current pipeline capacity of 2,655 MMcfd. With 2,655 MMcfd available and normal temperature demand, most months show a positive deliverability balance. Storage would be full by July but no month shows a deliverability reserve margin greater than 10 percent.[42] Serving December normal demand requires pulling gas from storage such that the month-end inventory amounts to 54 Bcf total across all four storage fields.

Adding Case A.30 (Table 16) illustrates the effects of bringing the Aliso inventory up to the 30 Bcf proposed by SoCalGas in Advice Letter 5275[43] assuming the same 2,655 MMcfd available pipeline capacity. The storage inventory reaches 75 Bcf overall without violating the maximum injection limits articulated by SoCalGas at page 4 of Advice Letter 5275. The deliverability reserve margins in this case are slightly lower in May, June and July than shown in Case A. By November, when winter demand begins, the deliverability reserve margin is close to zero and in December 525 MMcfd must be withdrawn from storage, yielding a month-end inventory of 60 Bcf total.

Case B (Table 17) is the most pessimistic one analyzed here. It removes Line 4000 from service and assumes no interruptible deliveries at Kramer Junction; thus, the northern system is limited to deliveries of 550 MMcfd.[44] The southern mainline becomes limited to 800 MMcfd in September, but 150 MMcfd is delivered at Otay Mesa. These assumptions result in 2,325 MMcfd worth of deliveries into the system.

Assuming normal demand, Case B still allows storage refill to occur and even 30 Bcf at Aliso Canyon. The deliverability balance is zero. There is no flexibility for warmer days or additional problems, and the assumed injections had to be adjusted somewhat between months in order to prevent a negative balance versus the injection pattern in Case A. Beginning in September, meeting normal demand requires withdrawing gas from storage. Meeting normal December demand requires pulling 855 MMcfd from storage. As a result, the total inventory in all four storage fields at the end of December is only 30 Bcf. This case is clearly untenable. It demonstrates the importance of getting at least some gas at Otay Mesa (plus other mitigations) to provide the natural gas needed preserve electricity reliability and protect service to core customers. Again, this is with demand under normal temperature conditions.

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41 Any changes to the inventory maximum would be made in updates to the CPUC 715 Report.

42 Using that margin would be the first step to protect electric generation should a summer peak day for electricity occur. During months with injections, SoCalGas could also back down injections on higher demand days but were that to occur consistently, the winter inventory target could not be achieved.

43 Draft Resolution G-3540 for Advice Letter 5275 rejects SoCalGas' request to increase Aliso Canyon inventory to 30 Bcf because the appropriate place to consider that issue is in the CPUC 715 Report.

44 The reasons for these additional outages are described in SoCalGas' March 30 Summer 2018 Technical Assessment, attached to Advice Letter 5275.

Case C (Table 18) is the most optimistic case. It captures the outlook should Line 4000 stay in service this summer and no additional limitation occurs on the southern system. It assumes 625 MMcfd is delivered at Kramer Junction, consistent with the average achieved over the winter.[45] It cushions the system with 230 MMcfd at Otay Mesa, which likely means some LNG must come in given the limited capacity available on the North Baja and Gasoducto Baja Norte pipelines.[46] Total supply received in this optimistic scenario would be 2,930 MMcfd.

In terms of results, Case C allows storage to reach 75 Bcf (including 30 Bcf at Aliso Canyon) while providing reasonable deliverability margins (i.e., 15 percent or higher) in each month, except later in the year. September's margin of 14 percent drops to only 12 percent in November and zero for December. December would finish with a month-end inventory of 67 Bcf. This is the most optimistic case.

Case D (Table 19) assumes the allowed inventory at Aliso remains at 24.6 Bcf and represents combined outages and mitigations of 2,480 MMcfd. It assumes all of the existing outages continue, the two new ones (Line 4000 and the southern system 200) are added, but mitigation occurs at Kramer Junction and Otay Mesa. This results in receipts of 2,480 MMcfd beginning in September. Even with 230 MMcfd delivered every day at Otay Mesa and 625 MMcf at Kramer Junction, deliverability reserve margins are again zero beginning in September and are less than 15 percent in all months. This case also shows storage withdrawals in September, most of which is replenished in October. Withdrawals are required again in November and December. The month-end December inventory at all four fields ends up at 43 Bcf, which means reliability problems into the new year unless warmer-than-normal weather occurs. Assuming more favorable weather than normal would not be prudent.

Case D.30 (Table 20) uses the same pipeline capacity but brings the Aliso Canyon inventory to 30 Bcf and achieves 75 Bcf in total inventory across all four storage fields. The deliverability margins are never more than 10 percent after May. They become zero by September and remain there through year-end. The resulting December month-end inventory would sit at 48 Bcf, with 15 of that at Aliso Canyon.

Some small additional system mitigations might be feasible. For example, California gas producers have been delivering closer to 90 MMcfd into the SoCalGas system versus the 60 MMcfd witnessed previously. This assumption is used in this and prior analyses. In addition, there may be days where demand in San Diego is high enough to absorb more than 230 MMcfd at Otay Mesa. There also may be days where more than 625 MMcfd shows up at Kramer Junction. None of these events are likely to occur on a firm basis, so these possibilities should not be counted on as bailouts. That is why they are not reflected in the gas balance cases.

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45 This is instead of the 700 MMcfd assumed by SoCalGas.

46 The case assumes the 230 MMcfd is delivered at Otay Mesa deliveries beginning in May, which is likely too soon given that SoCalGas has not applied for the requisite approvals (some of which involve affiliate transactions) from the CPUC.

Table 15: Gas Balance Case A (Capacity Conditions as of April 10, 2018)

SoCalGas Monthly Gas Balance NORMAL WEATHER										
CGR Demand (MMcfd)		**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Core		1,004	751	692	630	608	628	714	1,072	1,483
Noncore including EG		1,049	1,063	1,089	1,362	1,408	1,526	1,270	1,100	1,136
Wholesale & International		401	358	377	374	374	392	391	422	521
Co. Use and LUAF		31	27	27	30	30	32	30	33	40
Subtotal Demand		2,485	2,199	2,185	2,396	2,420	2,578	2,405	2,627	3,180
Storage Injection (Other Three Fields)		100	230	220	80		0		0	0
Storage Injection (Aliso)		40	50	25	0	0	0	0	0	0
Storage Injection Total		140	280	245	80	0	0	0	0	0
System Total Throughput		2,625	2,479	2,430	2,476	2,420	2,578	2,405	2,627	3,180
Supply (MMcfd)										
California Line 85 Zone		60	60	60	60	60	60	60	60	60
Wheeler Ridge Zone		765	765	765	765	765	765	765	765	765
Blythe (Ehrenberg) into Southern Zone		980	980	980	980	980	980	980	980	980
Otay Mesa into Southern Zone		30	30	30	30	30	30	30	30	30
Kramer Junction into Northern Zone		550	550	550	550	550	550	550	550	550
North Needles into Northern Zone		270	270	270	270	270	270	270	270	270
Topock into Northern Zone		0	0	0	0	0	0	0	0	0
Sub Total Pipeline Receipts		2,655	2,655	2,655	2,655	2,655	2,655	2,655	2,655	2,655
Storage Withdrawal (Other Three Fields)		0	0	0	0	0	0	0	0	275
Storage Withdrawal (Aliso)		0	0	0	0	0	0	0	0	250
Total Supply		2,655	2,655	2,655	2,655	2,655	2,655	2,655	2,655	3,180
DELIVERABILITY BALANCE (MMcfd)		30	176	225	179	235	77	250	28	0
Reserve Margin		1%	7%	9%	7%	10%	3%	10%	1%	0%
OTF Month-End Storage Inventory (Bcf)	25.9	29	36	43	45	45	45	45	45	37
Aliso Month-End Storage Inventory (Bcf)	21.6	23	24	25	25	25	25	25	25	17
Total Storage Inventory	47.5	52	60	68	70	70	70	70	70	54

Table 16: Gas Balance Case A.30 (Capacity Conditions as of April 10, 2018)

SoCalGas Monthly Gas Balance NORMAL WEATHER										
CGR Demand (MMcfd)		**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Core		1,004	751	692	630	608	628	714	1,072	1,483
Noncore including EG		1,049	1,063	1,089	1,362	1,408	1,526	1,270	1,100	1,136
Wholesale & International		401	358	377	374	374	392	391	422	521
Co. Use and LUAF		31	27	27	30	30	32	30	33	40
Subtotal Demand		2,485	2,199	2,185	2,396	2,420	2,578	2,405	2,627	3,180
Storage Injection (Other Three Fields)		100	230	220	80		0		0	0
Storage Injection (Aliso)		40	100	100	25	0	0	0	0	0
Storage Injection Total		140	330	320	105	0	0	0	0	0
System Total Throughput		2,625	2,529	2,505	2,501	2,420	2,578	2,405	2,627	3,180
Supply (MMcfd)										
California Line 85 Zone		60	60	60	60	60	60	60	60	60
Wheeler Ridge Zone		765	765	765	765	765	765	765	765	765
Blythe (Ehrenberg) into Southern Zone		980	980	980	980	980	980	980	980	980
Otay Mesa into Southern Zone		30	30	30	30	30	30	30	30	30
Kramer Junction into Northern Zone		550	550	550	550	550	550	550	550	550
North Needles into Northern Zone		270	270	270	270	270	270	270	270	270
Topock into Northern Zone		0	0	0	0	0	0	0	0	0
Sub Total Pipeline Receipts		2,655	2,655	2,655	2,655	2,655	2,655	2,655	2,655	2,655
Storage Withdrawal (Other Three Fields)		0	0	0	0	0	0	0	0	275
Storage Withdrawal (Aliso)		0	0	0	0	0	0	0	0	250
Total Supply		2,655	2,655	2,655	2,655	2,655	2,655	2,655	2,655	3,180
DELIVERABILITY BALANCE (MMcfd)		30	126	150	154	235	77	250	28	0
Reserve Margin		1%	5%	6%	6%	10%	3%	10%	1%	0%
OTF Month-End Storage Inventory (Bcf)	25.9	29	36	43	45	45	45	45	45	37
Aliso Month-End Storage Inventory (Bcf)	21.6	23	26	29	30	30	30	30	30	22
Total Storage Inventory	47.5	52	62	72	75	75	75	75	75	59

Table 17: Gas Balance Case B (September Capacity = 2,325, Pessimistic)

SoCalGas Monthly Gas Balance NORMAL WEATHER										
CGR Demand (MMcfd)		**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Core		1,004	751	692	630	608	628	714	1,072	1,483
Noncore including EG		1,049	1,063	1,089	1,362	1,408	1,526	1,270	1,100	1,136
Wholesale & International		401	358	377	374	374	392	391	422	521
Co. Use and LUAF		31	27	27	30	30	32	30	33	40
Subtotal Demand		2,485	2,199	2,185	2,396	2,420	2,578	2,405	2,627	3,180
Storage Injection (Other Three Fields)		100	206	220	84	20	0	0	0	0
Storage Injection (Aliso)		40	100	100	25	20	0	0	0	0
Storage Injection Total		140	306	320	109	40	0	0	0	0
System Total Throughput		2,625	2,505	2,505	2,505	2,460	2,578	2,405	2,627	3,180
Supply (MMcfd)										
California Line 85 Zone		60	60	60	60	60	60	60	60	60
Wheeler Ridge Zone		765	765	765	765	765	765	765	765	765
Blythe (Ehrenberg) into Southern Zone		980	980	980	980	980	800	800	800	800
Otay Mesa into Southern Zone		30	150	150	150	150	150	150	150	150
Kramer Junction into Northern Zone		550	550	550	550	550	550	550	550	550
North Needles into Northern Zone		270	0	0	0	0	0	0	0	0
Topock into Northern Zone		0	0	0	0	0	0	0	0	0
Sub Total Pipeline Receipts		2,655	2,505	2,505	2,505	2,505	2,325	2,325	2,325	2,325
Storage Withdrawal (Other Three Fields)		0	0	0	0	0	253	80	302	400
Storage Withdrawal (Aliso)		0	0	0	0	0	0	0	0	455
Total Supply		2,655	2,505	2,505	2,505	2,505	2,578	2,405	2,627	3,180
DELIVERABILITY BALANCE (MMcfd)		30	0	0	0	45	0	0	0	0
Reserve Margin		1%	0%	0%	0%	2%	0%	0%	0%	0%
OTF Month-End Storage Inventory (Bcf)	25.9	29	35	42	44	45	38	35	26	14
Aliso Month-End Storage Inventory (Bcf)	21.6	23	26	29	30	30	30	30	30	16
Total Storage Inventory	47.5	52	61	71	74	75	68	65	56	30

Table 18: Gas Balance Case C (September Capacity = 2,930 MMcfd, Optimistic)

SoCalGas Monthly Gas Balance NORMAL WEATHER										
CGR Demand (MMcfd)		**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Core		1,004	751	692	630	608	628	714	1,072	1,483
Noncore including EG		1,049	1,063	1,089	1,362	1,408	1,526	1,270	1,100	1,136
Wholesale & International		401	358	377	374	374	392	391	422	521
Co. Use and LUAF		31	27	27	30	30	32	30	33	40
Subtotal Demand		2,485	2,199	2,185	2,396	2,420	2,578	2,405	2,627	3,180
Storage Injection (Other Three Fields)		100	230	220	80	0	0	0	0	0
Storage Injection (Aliso)		40	100	100	25	0	0	0	0	0
Storage Injection Total		140	330	320	105	0	0	0	0	0
System Total Throughput		2,625	2,529	2,505	2,501	2,420	2,578	2,405	2,627	3,180
Supply (MMcfd)										
California Line 85 Zone		60	60	60	60	60	60	60	60	60
Wheeler Ridge Zone		765	765	765	765	765	765	765	765	765
Blythe (Ehrenberg) into Southern Zone		980	980	980	980	980	980	980	980	980
Otay Mesa into Southern Zone		30	230	230	230	230	230	230	230	230
Kramer Junction into Northern Zone		550	625	625	625	625	625	625	625	625
North Needles into Northern Zone		270	270	270	270	270	270	270	270	270
Topock into Northern Zone		0	0	0	0	0	0	0	0	0
Sub Total Pipeline Receipts		2,655	2,930	2,930	2,930	2,930	2,930	2,930	2,930	2,930
Storage Withdrawal (Other Three Fields)		0	0	0	0	0	0	0	0	265
Storage Withdrawal (Aliso)		0	0	0	0	0	0	0	0	0
Total Supply		2,655	2,930	2,930	2,930	2,930	2,930	2,930	2,930	3,195
DELIVERABILITY BALANCE (MMcfd)		30	401	425	429	510	352	525	303	15
Reserve Margin		1%	16%	17%	17%	21%	14%	22%	12%	0%
OTF Month-End Storage Inventory (Bcf)	25.9	29	36	43	45	45	45	45	45	37
Aliso Month-End Storage Inventory (Bcf)	21.6	23	26	29	30	30	30	30	30	30
Total Storage Inventory	47.5	52	62	72	75	75	75	75	75	67

Table 19: Gas Balance Case D (September Capacity = 2,480 Combined))

SoCalGas Monthly Gas Balance NORMAL WEATHER										
CGR Demand (MMcfd)		**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Core		1,004	751	692	630	608	628	714	1,072	1,483
Noncore including EG		1,049	1,063	1,089	1,362	1,408	1,526	1,270	1,100	1,136
Wholesale & International		401	358	377	374	374	392	391	422	521
Co. Use and LUAF		31	27	27	30	30	32	30	33	40
Subtotal Demand		2,485	2,199	2,185	2,396	2,420	2,578	2,405	2,627	3,180
Storage Injection (Other Three Fields)		100	230	220	80	0	0	75	0	0
Storage Injection (Aliso)		40	50	25	0	0	0	0	0	0
Storage Injection Total		140	280	245	80	0	0	75	0	0
System Total Throughput		2,625	2,479	2,430	2,476	2,420	2,578	2,480	2,627	3,180
Supply (MMcfd)										
California Line 85 Zone		60	60	60	60	60	60	60	60	60
Wheeler Ridge Zone		765	765	765	765	765	765	765	765	765
Blythe (Ehrenberg) into Southern Zone		980	980	980	980	980	800	800	800	800
Otay Mesa into Southern Zone		230	230	230	230	230	230	230	230	230
Kramer Junction into Northern Zone		600	625	625	625	625	625	625	625	625
North Needles into Northern Zone		270	0	0	0	0	0	0	0	0
Topock into Northern Zone		0	0	0	0	0	0	0	0	0
Sub Total Pipeline Receipts		2,905	2,660	2,660	2,660	2,660	2,480	2,480	2,480	2,480
Storage Withdrawal (Other Three Fields)		0	0	0	0	0	98		75	400
Storage Withdrawal (Aliso)		0	0	0	0	0	0	0	75	300
Total Supply		2,905	2,660	2,660	2,660	2,660	2,578	2,480	2,630	3,180
DELIVERABILITY BALANCE (MMcfd)		280	181	230	184	240	0	0	3	0
Reserve Margin		11%	7%	9%	7%	10%	0%	0%	0%	0%
OTF Month-End Storage Inventory (Bcf)	25.9	29	36	43	45	45	42	44	42	30
Aliso Month-End Storage Inventory (Bcf)	21.6	23	24	25	25	25	25	25	23	14
Total Storage Inventory	47.5	52	60	68	70	70	67	70	65	43

Table 20: Gas Balance Case D.30 (September Capacity = 2,480 Combined))

SoCalGas Monthly Gas Balance NORMAL WEATHER										
CGR Demand (MMcfd)		**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Core		1,004	751	692	630	608	628	714	1,072	1,483
Noncore including EG		1,049	1,063	1,089	1,362	1,408	1,526	1,270	1,100	1,136
Wholesale & International		401	358	377	374	374	392	391	422	521
Co. Use and LUAF		31	27	27	30	30	32	30	33	40
Subtotal Demand		2,485	2,199	2,185	2,396	2,420	2,578	2,405	2,627	3,180
Storage Injection (Other Three Fields)		100	230	220	80	0	0	75	0	0
Storage Injection (Aliso)		40	100	100	25	0	0	0	0	0
Storage Injection Total		140	330	320	105	0	0	75	0	0
System Total Throughput		2,625	2,529	2,505	2,501	2,420	2,578	2,480	2,627	3,180
Supply (MMcfd)										
California Line 85 Zone		60	60	60	60	60	60	60	60	60
Wheeler Ridge Zone		765	765	765	765	765	765	765	765	765
Blythe (Ehrenberg) into Southern Zone		980	980	980	980	980	800	800	800	800
Otay Mesa into Southern Zone		230	230	230	230	230	230	230	230	230
Kramer Junction into Northern Zone		600	625	625	625	625	625	625	625	625
North Needles into Northern Zone		270	0	0	0	0	0	0	0	0
Topock into Northern Zone		0	0	0	0	0	0	0	0	0
Sub Total Pipeline Receipts		2,905	2,660	2,660	2,660	2,660	2,480	2,480	2,480	2,480
Storage Withdrawal (Other Three Fields)		0	0	0	0	0	98		75	300
Storage Withdrawal (Aliso)		0	0	0	0	0	0	0	75	400
Total Supply		2,905	2,660	2,660	2,660	2,660	2,578	2,480	2,630	3,180
DELIVERABILITY BALANCE (MMcfd)		280	131	155	159	240	0	0	3	0
Reserve Margin		11%	5%	6%	6%	10%	0%	0%	0%	0%
OTF Month-End Storage Inventory (Bcf)	25.9	29	36	43	45	45	42	44	42	33
Aliso Month-End Storage Inventory (Bcf)	21.6	23	26	29	30	30	30	30	27	15
Total Storage Inventory	47.5	52	62	72	75	75	72	74	70	48

SoCalGas performed and included in its March 30 assessment for summer 2018 what it calls a “mass balance.” It provides additional variation on the staff cases described above. The SoCalGas mass balance differs in that it converted the demand forecast from daily to monthly values, discounts pipeline capacity by an additional 15 percent, and runs only through October 2018. While staff’s gas balances also use different assumptions about how much gas shows up at Kramer Junction or Otay Mesa, the general finding here is similar to that reached by SoCalGas.

Energy Commission staff performed one last assessment to identify a maximum achievable inventory given the pipeline outages. Case D.Max is in Table 21. This calculation could be done for each pipeline capacity case, but doing it for one sufficiently demonstrates the point. Staff selected the 2,480 “combined” case for this exercise. It uses the same injections for the other three fields, filling them to their maximum 45 Bcf capability. It then takes the excess deliverability margin in each month, which was already less than the 15 percent desired target, and uses that available pipeline capacity to put more gas at Aliso Canyon. This gives higher injections May to August, none of which appear large enough to violate injection constraints as the inventory builds, but if it did the theoretical maximum inventory would simply be lower. If all of the assumptions were to hold true, the theoretical maximum inventory Aliso Canyon could reach is 51 Bcf.

Cases with lower pipeline capacity available would demonstrate that lower maximum inventories are achievable. For example, in Case B, with pipeline capacity of only 2,325 MMcfd, there is no deliverability reserve margin. The maximum achievable inventory at Aliso Canyon is limited to 30 Bcf and whether it can be achieved with a zero deliverability margin is questionable. Pipeline outages are likely to prevent getting much more than 30 Bcf being injected into Aliso Canyon, regardless of the approved inventory level.

Table 21: Gas Balance Case D.Max (September Capacity = 2,480 Combined))

SoCalGas Monthly Gas Balance NORMAL WEATHER										
CGR Demand (MMcfd)		**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Core		1,004	751	692	630	608	628	714	1,072	1,483
Noncore including EG		1,049	1,063	1,089	1,362	1,408	1,526	1,270	1,100	1,136
Wholesale & International		401	358	377	374	374	392	391	422	521
Co. Use and LUAF		31	27	27	30	30	32	30	33	40
Subtotal Demand		2,485	2,199	2,185	2,396	2,420	2,578	2,405	2,627	3,180
Storage Injection (Other Three Fields)		100	230	220	80	0	0	75	0	0
Storage Injection (Aliso)		40	231	255	184	240	0	0	0	0
Storage Injection Total		140	461	475	264	240	0	75	0	0
System Total Throughput		2,625	2,660	2,660	2,660	2,660	2,578	2,480	2,627	3,180
Supply (MMcfd)										
California Line 85 Zone		60	60	60	60	60	60	60	60	60
Wheeler Ridge Zone		765	765	765	765	765	765	765	765	765
Blythe (Ehrenberg) into Southern Zone		980	980	980	980	980	800	800	800	800
Otay Mesa into Southern Zone		230	230	230	230	230	230	230	230	230
Kramer Junction into Northern Zone		600	625	625	625	625	625	625	625	625
North Needles into Northern Zone		270	0	0	0	0	0	0	0	0
Topock into Northern Zone		0	0	0	0	0	0	0	0	0
Sub Total Pipeline Receipts		2,905	2,660	2,660	2,660	2,660	2,480	2,480	2,480	2,480
Storage Withdrawal (Other Three Fields)		0	0	0	0	0	98		75	300
Storage Withdrawal (Aliso)		0	0	0	0	0	0	0	75	400
Total Supply		2,905	2,660	2,660	2,660	2,660	2,578	2,480	2,630	3,180
DELIVERABILITY BALANCE (MMcfd)		280	0	0	0	0	0	0	3	0
Reserve Margin		11%	0%	0%	0%	0%	0%	0%	0%	0%
OTF Month-End Storage Inventory (Bcf)	25.9	29	36	43	45	45	42	44	42	33
Aliso Month-End Storage Inventory (Bcf)	21.6	23	30	38	43	51	51	51	49	36
Total Storage Inventory	47.5	52	66	80	88	96	93	95	91	69

MITIGATION MEASURES

With this third summer of capacity reductions on the natural gas system in Southern California causing ever increasing risk of interruptions in electricity service, the assessment group recommends continuing most of the mitigation measures implemented previously and adding several others. To the extent that any of the existing measures in place now involve tariff approvals by either the CPUC or the Federal Energy Regulatory Commission that expire and need to be extended, the assessment group's mitigation monitoring effort will identify and remind the appropriate parties to seek extension.[47] This section does not address implementation but instead describes the new mitigation measures the assessment group recommends exploring.

First, the analysis in this assessment demonstrates a need for supply at Otay Mesa on a firm basis. The way to achieve this is to contract for LNG, delivered via tanker to Costa Azul, and then to transport it after regasification through the short pipeline from Costa Azul to Otay Mesa. LNG could provide firm, certain supply at Otay Mesa and replace or augment supply that sometimes comes in via the North Baja and Gasoducto Baja Norte pipelines. LNG no longer costs multiples over the cost of supply otherwise delivered to California, as demonstrated at an Energy Commission workshop in April 2017. Implementing this measure may take some time, but it would provide needed certainty of gas supply at Otay Mesa when the system needs it, thereby reducing gas service curtailment risk to generators and supporting the summer gas storage refill.

Second, the analysis shows that storage is used more often to meet demand. Anytime demand exceeds pipeline supplies, withdrawals from storage are needed. The gap between available pipeline capacity and even average day demand is higher this year than it was last year due to the pipeline outages. Needing to use more gas from storage suggests there will be more days where we need injection capacity to be available for injection instead of system balancing. As a result, more operational flow orders may be needed. Coordinate with gas customers to ensure that they are prepared to respond to both high and low operational flow orders.

Third, the analysis also demonstrated that pipeline capacity was available that could have reduced the curtailment of gas service to electric generators on most, if not all, of the hours during the February 19 to March 6 curtailment period. The CPUC could grant SoCalGas's operational hub the authority to buy gas to fill that unused pipeline capacity, whenever required and feasible, so that generators are not curtailed when pipeline capacity is available. SoCalGas already has a mechanism in place to purchase supply in order to assure enough gas is delivered to its southern zone to cover demand in that zone. That mechanism may be a useful starting point for developing a broader mechanism, although it may need adjustment. Importantly, this is not intended as a way to bypass the tighter balancing rules implemented by the CPUC that are a key to system management while minimizing use of Aliso Canyon.

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47 See http://www.caiso.com/informed/Pages/StakeholderProcesses/AlisoCanyonGasElectricCoordination.aspx

Fourth, the minimum generation requirement for the California ISO is 326 MMcfd lower this summer than last. This appears to be a function of planned transmission upgrades completed this past year in combination with retirement of some gas generation within the SoCalGas area. Additional transmission upgrades are planned for future years. However, the CPUC and California ISO and any other relevant agencies should identify any pending or new transmission upgrades, if any, that would further reduce the minimum generation requirement and expedite their approval or implementation where possible.

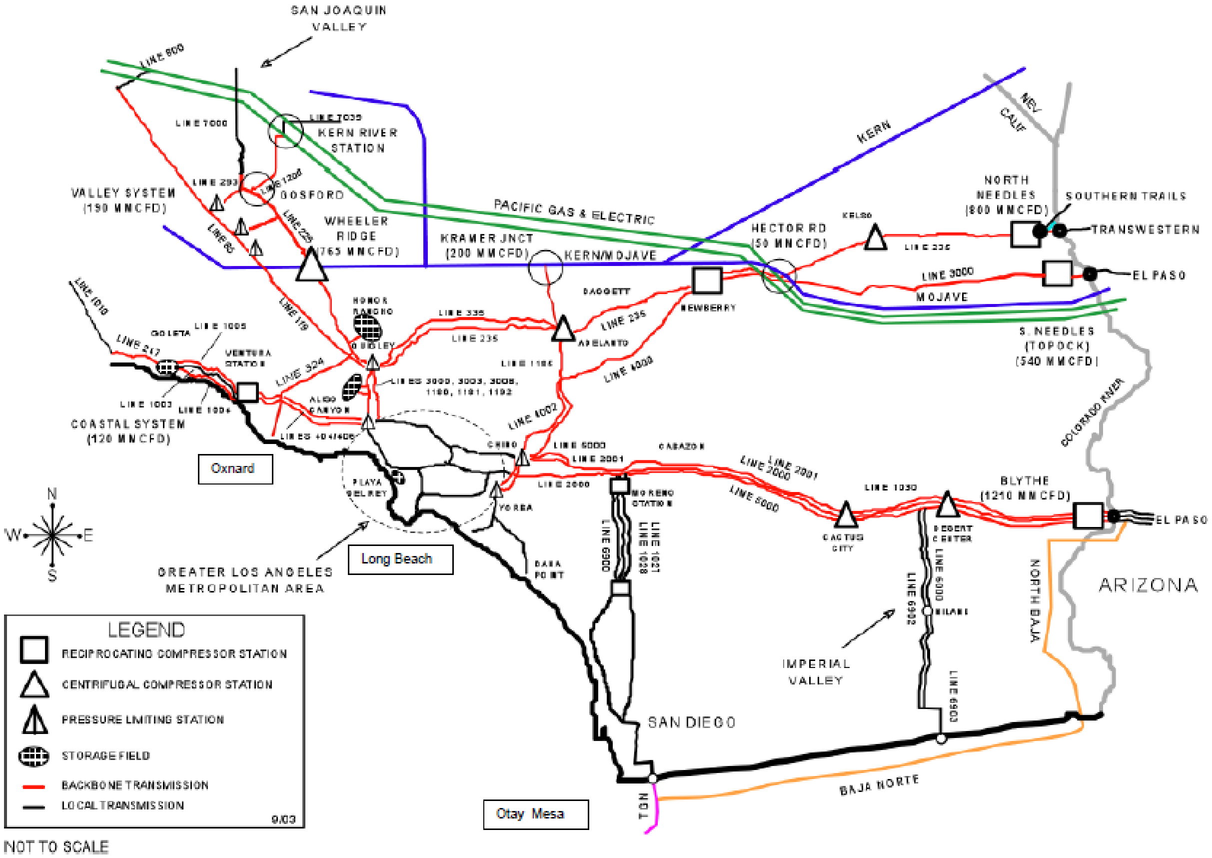
Fifth, the CPUC and CEC should monitor federal legislation (introduced by Senator Whitehouse in April 2018 and cited as the "Energy Infrastructure Demand Response Act of 2018") requiring the Department of Energy (DOE) to establish a natural gas demand response pilot program. The bill calls for the DOE to carry out the pilot program in regions experiencing fuel shortages or natural gas infrastructure constraints. The CPUC and CEC should monitor developments on this legislation to ensure California is considered as a region for any pilots.

The risk to electric generation is larger this summer than in prior summers: while the gas quantity required at minimum generation is lower, gas system conditions may make the need to cut to minimum generation more likely. The net effect of the two factors is that electric generators will need more gas this summer anytime its transmission import capability is less than 90 percent. Similar to last winter, the situation this summer will require constant monitoring and communication. For December, January and February, the assessment group posted updates noting significant changes when new information was available that changed the risk assessment. Staff will do so again this summer if warranted. In addition, all of the agency monitoring efforts will continue as will briefings to the Legislature and to other agencies such as the California Office of Emergency Services.

CONCLUSION

The SoCalGas system continues to operate at less than full capacity due to a significant number of pipeline outages and continuing restrictions on use of the Aliso Canyon gas storage facility. This reduction in capacity creates a moderate threat to electric reliability this summer. The more serious threat lies ahead. With so many pipeline outages, it will be difficult for SoCalGas to fill storage to a level sufficient to ensure energy reliability throughout the coming winter. The potential for additional outages means that the situation may be getting worse, not better. Last winter, the SoCalGas system avoided serious problems only because of unusually warm weather. The February cold snap provided a sharp illustration of how fast storage inventories can dwindle and how quickly storage withdrawal capacity declines. To avoid service interruptions this summer and next winter, the feasibility of the mitigation measures suggested in this assessment should be reviewed as quickly as possible.

APPENDIX A: SoCalGas System Map



Source: February 24, 2004 Phase I Proposal by SoCalGas and SDG&E in R. 04-01-025

APPENDIX B: Updated List of Mitigation Measures Including All Measures Proposed Since April 2016

Prudent Aliso Canyon Use	1. Make at Least 15 Bcf Stored At Aliso Canyon Available for Electric System Reliability, Including the Summer	Complete
	2. Efficiently Complete the Required Safety Review at Aliso Canyon to Allow Safe Use of the Field	Complete
Tariff Changes	3. Implement Tighter Gas Balancing Rules	Complete/Continuing until 11/30/18
	4. Modify Operational Flow Order Rule	Complete
	5. Call Operational Flow Orders Sooner in Gas Day	Closed
	6. Provide Market Information to Generators Before Cycle 1 Gas Scheduling	Complete/Continuing
	7. Consider California ISO market changes that increase gas-electric coordination	Complete/Continuing until 12/16/18
Operational Coordination	8. Increase Electric and Gas Operational Coordination	Complete/Continuing
	9. Establish More Specific Gas Allocation among Electric Generators In Advance of Curtailment	Complete
	10. Determine Whether the Reliability Benefits of Deferring Any Gas Maintenance Tasks Outweigh the Safety Risks	Complete
LADWP Operational Flexibility	11. Update Physical Gas Hedging Practice	Complete/Continuing
	12. Update Economic Dispatch Practice	Complete/Continuing
	13. Update Block Energy and Capacity Sales Practice	Complete/Continuing
	14. Explore Dual Fuel Capability	Complete/Continuing
Reduce Natural Gas and Electricity Use	15. Ask customers to Reduce Natural Gas and Electricity Energy Consumption	Complete/Continuing
	16. Expand Gas and Electric Efficiency (EE) Programs Targeted at Low Income Customers	Complete

	17. Expand Demand Response (DR) Programs	Complete
	18. Reprioritize Existing Energy Efficiency Towards Projects with Potential to Impact Usage	Complete
	19. Reprioritize Solar Thermal Program Spending to Fund Projects for Summer and by end of 2017 and add/accelerate solar PV programs	Complete
	20. Accelerate Electricity Storage	Complete
Market Monitoring	21. Protect California Ratepayers	Complete/Continuing
Gas-targeted Programs to Further Reduce Usage	22. Develop and Deploy Gas Demand Response (DR) Program	Complete/Continuing
	23. Develop and Deploy Gas Cold Weather Messaging	Complete/Continuing
Winter Operations Changes	24. Create Advance Gas Burn Operating Ceiling for Electric Generation	Complete/Continuing until 12/16/18
	25. Keep the Tighter Balancing Rules	Complete/Continuing until 11/30/18
	26. Modify Core Balancing Rules	Underway
Use of Gas from Aliso Canyon	27. Update the Aliso Canyon Withdrawal Protocol and Gas Allocation Process	Complete/Continuing
Reduce Gas Maintenance Downtime	28. Submit Reports Describing Progress on Restoring Pipeline Service	Complete/Continuing
Increase Gas Supply	29. Identify and solicit additional gas supply sources including more CA Natural Gas Production	Complete
	30. Prepare to Buy LNG	Complete (alternative agency actions will be considered under new measure)
Refineries	31. Monitor Natural Gas Use at Refineries and Gasoline Prices	Complete/Continuing

Added Summer 2017	32. Increase Gas Inventories at the Other SoCalGas Storage Facilities	Complete/Continuing
Added Winter 2017-18	33. Delay LADWP's Transmission Upgrade Work	Complete
	34. Use More Gas From Aliso Than Last Winter	Complete
	35. Turn Thermostats Down and Deploy More Smart Thermostats	Underway
	36. Use Electricity Generators' Generation Shift to Help Reduce Gas Demand/Preserve Inventory	Underway
	37. Update Section 715 Report's Aliso Canyon Inventory Target for New Circumstances	Complete/Continuing
	38. Bring LNG to Otay Mesa if Cannot Acquire Pipeline Capacity	Complete and Expired Feb. 2018
	39. Monitor and Communicate Constantly, Including to Public	Complete/Continuing
NEW for Summer 2018	**40. Buy LNG to assure that up to 230 MMcfd can reach Otay Mesa on a firm basis**	New
	41. Coordinate with gas customers to ensure they are prepared to respond to both High and Low operational flow orders	New
	42. Give the SoCalGas operational hub permission to buy gas to fill the receipt points to full capacity when capacity would otherwise go unused	New
	43. Expedite any pending transmission upgrades that would further reduce the EG minimum generation requirement	New
	44. Monitor the "Energy Infrastructure Demand Response Act of 2018" to ensure California is considered as a region for any DOE-sponsored demand response pilot programs.	New