Winter 2018-19 SoCalGas Conditions and Operations Report

BY STAFF OF THE CALIFORNIA PUBLIC UTILITIES COMMISSION

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Executive Summary

This Winter 2018-19 SoCalGas Conditions and Operations Report presents a summary and analyses of natural gas operations in Southern California from November 2018 through March 2019 (the winter) by the California Public Utilities Commission's (CPUC) Energy Division (ED) staff. The purpose of the report is to provide a summary of weather and system occurrences, operational actions taken, and lessons learned for future system operations and policymaking, with a focus on usage of Southern California Gas Company's (SoCalGas) Aliso Canyon natural gas storage facility (Aliso Canyon).[1]

Operating conditions remained largely similar to the 2017-18 winter due to ongoing pipeline maintenance and reduced capacity at Aliso Canyon. Prior to the start of the winter, technical experts concluded that the SoCalGas system could face potential energy reliability challenges. Additionally, the Aliso Canyon Withdrawal Protocol (Withdrawal Protocol), which prohibits SoCalGas from using Aliso Canyon except as an "asset of last resort," remained in effect.[2]

Price volatility was also a concern. Limited gas supply caused by the constraints on the SoCalGas system had caused both gas and electricity prices to spike on high demand, hot days in summer 2018, leading to concerns that similar spikes would occur on high demand, cold days in the winter.[3] However, the early winter was relatively warm, and SoCalGas was initially able to meet demand with flowing supplies from the pipelines and withdrawals from its non-Aliso gas storage fields: Honor Rancho, Playa del Rey, and La Goleta.

In contrast, the latter half of the winter brought variable conditions then a prolonged stretch of cold weather, culminating in a February that the National Weather Service declared the coldest since 1962. Complicating gas supply concerns was the fact that weather forecasts repeatedly failed to accurately predict the weather. Uncertainty and cold weather contributed to gas price spikes across the country, including in the SoCal Border and SoCal Citygate markets. As a result, electricity prices in California experienced major price hikes as well. The continuous wave of cold weather strained the SoCalGas system as demand for natural gas grew more rapidly than expected.

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[1] For more information on the Aliso Canyon well failure and a history of developments, see http://cpuc.ca.gov/aliso/

[2] Aliso Canyon Withdrawal Protocol can be found here: http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/News_Room/News_and_Updates/11.2Protocol%20PUBLIC%20UTILITIES%20COMMISSION.PDF. Energy Division's December 21, 2017, email to SoCalGas providing clarification on how the Withdrawal Protocol should be implemented can be found here: http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/News_Room/WithdrawalProtocolClarification_2017-12-21.docx.pdf. The Energy Division Director's March 3, 2018, letter to SoCalGas can be found here: http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Safety/Letter%20to%20Rodger%20Schwecke.pdf.

[3] SoCalGas' winter demand peak is driven primarily by gas heating in homes and businesses.

Over the winter, SoCalGas declared 80 low Operational Flow Orders (OFOs),[4] 14 voluntary curtailments, two curtailment watches, and two mandatory Rule 23/Rule 14 curtailments (Rule 23 curtailments) of electric generation customers.[5] SoCalGas withdrew gas from Aliso Canyon on 37 gas days,[6] with the longest, consecutive withdrawal period lasting from February 10 through February 24. SoCalGas used approximately 29 billion cubic feet (Bcf) of non-Aliso inventory throughout the winter to meet customer demand, resulting in a 61% decrease in non-Aliso inventory levels from the start of the season. In addition, SoCalGas withdrew approximately 14 Bcf of Aliso inventory to meet peak hourly and daily demand.

There were three common factors on Aliso Canyon withdrawal days—heavy withdrawals from the non-Aliso fields in the days preceding an Aliso withdrawal, the non-Aliso fields approaching their week- or month-end minimum inventories, and high hourly sendout. ED staff analyzed receipt point utilization and usage of both non-Aliso and Aliso Canyon storage at the hourly level and concludes that SoCalGas' use of storage and system operations appears to have been warranted, and the Withdrawal Protocol appears to have been followed.

In this report, ED staff also reviews SoCalGas Gas Acquisition Department's (Gas Acquisition) purchased gas for core customers and examines the impact of Operational Flow Orders. Data indicates that if Gas Acquisition had been able to schedule gas from Aliso Canyon, they could have avoided OFO penalties this winter. Furthermore, Gas Acquisition's inability to schedule gas from Aliso Canyon under the Withdrawal Protocol contributed to the thin margins between overall system demand and supply this winter.

This report expands on the winter 2017-18 report to provide stakeholders and decision-makers with additional information to plan for the upcoming 2019-20 winter season.[7] For instance, comparing the two-week winter 2017-18 cold snap to this past winter's February weather highlights the significance of ample gas storage, the impact of ramping hours on system conditions, and the cascading effects of gas supply shortages on electricity prices.

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[4] More information on OFOs can be found in SoCalGas Rule 41. OFO penalties are designed to become increasingly severe to incentivize gas deliveries during shortages when gas prices may be high. Penalties are: $.25/dekatherm (Dth) in Stage 1; $1/Dth in Stage 2; $5/Dth in Stage 3; and $25/Dth in Stage 4.

[5] SoCalGas' Rule 23 and San Diego Gas & Electric's Gas Rule 14 establish governing provisions over gas service interruption and the order in which customers are curtailed. For more information, see: https://www.socalgas.com/regulatory/tariffs/tm2/pdf/23.pdf and http://regarchive.sdge.com/tm2/pdf/GAS_GAS-RULES_GRULE14.pdf

[6] A gas day is from 7:00 AM to 7:00 AM.

[7] The Winter 2017-18 SoCalGas Conditions and Operations Report can be found at: http://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/News_Room/NewsUpdates/2018/Winter2017-2018LookbackReportCleanFinal_2018-12-06%20-%20v2.pdf

November–December 2018

On October 10, 2018, the Aliso Canyon Technical Assessment Group—which is composed of technical experts and staff from the CPUC, the California Energy Commission (Energy Commission), the CAISO, and LADWP—released its Aliso Canyon Risk Assessment Technical Report Winter 2018-19 Supplement.[8] The report indicated that the SoCalGas system continued to face energy reliability challenges. Continuing outages and reduced capacity on crucial gas transmission pipelines as well as restrictions on Aliso Canyon contributed to this assessment. The report further advised that in the event of a 1-in-10-year peak cold day, SoCalGas would likely need to withdraw gas from Aliso Canyon, noting:

> The largest risk to the system is not from a single day with high gas demand. The greatest risk is from multiple high demand days that draw down storage inventories to a point where there is insufficient withdrawal capacity to meet gas demand later in the winter…[9]

The SoCalGas system entered November with its storage fields close to maximum allowed inventory levels (see Table 1). This was attributable to several factors, such as mild late-summer weather that allowed for storage injection and the CPUC-approved SoCalGas' Second Injection Enhancement Plan.[10] In addition, the CPUC increased the maximum allowable storage inventory at Aliso Canyon from 24.6 Bcf to 34 Bcf on July 2, which increased the system's overall injection capacity.[11]

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[8] The Aliso Canyon Winter 2018-19 Supplement and all other technical reports can be found here: http://cpuc.ca.gov/alisoassessments/

[9] Aliso Canyon Winter 2018-19 Supplement, pg. 3

[10] On March 13, 2018, the CPUC directed SoCalGas to submit a Tier 2 Advice Letter proposing new operational orders to increase injections at all available storage facilities. Three of the five proposed measures in the Advice Letter were approved by Resolution G-3540. Resolution G-3540: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M213/K514/213514583.PDF

[11] SB 380 added Section 715 to the California Public Utilities Code, which requires the CPUC to determine "the range of working gas necessary [in Aliso Canyon] to ensure safety and reliability for the region and just and reasonable rates in California. On July 2, 2018, the CPUC directed SoCalGas to maintain up to 34 Bcf of inventory due to "unprecedented level of outages on the SoCalGas system", among other reasons. An archive of the CPUC's 715 Reports can be found here: http://www.cpuc.ca.gov/General.aspx?id=6442457392

Table 1: Storage Inventory on 11/1/2018

Storage Field	11/1/2018	
	Maximum Inventory (Bcf)	Actual Inventory (Bcf)
Combined Non-Aliso	50.4	46.9
Aliso Canyon	34	33.6
Total System	**84.4**	**80.5**

The SoCalGas system continued to experience outages and pressure reductions on important transmission pipelines. Line 235-2, which ruptured on October 1, 2017, remained out of service and Lines 3000 and 4000 continued to operate at reduced pressures.

Weather conditions in November remained relatively warm, with a mean composite weighted average temperature of 63°F.[12] Gas demand throughout the month was met with flowing pipeline supplies and withdrawals from the non-Aliso storage facilities. On nine gas days, receipts of pipeline gas were enough to meet customer demand without the need to use underground gas storage. In December, SoCalGas continued to use flowing pipeline supplies and withdrawals from non-Aliso fields to meet customer demand. However, on December 28, 2018, SoCalGas issued a system-wide voluntary curtailment order for electric generation customers.[13] The composite weighted average temperature for that day was 51°F, the coldest day of December. Furthermore, the last week of December experienced consistently cold weather conditions that resulted in more use of gas storage.

January–March 2019

Weather conditions in January varied, with most days being warmer than average and a few days hitting average or below-average temperatures. Complicating matters was the fact that weather forecasts repeatedly failed to predict the weather. The Natural Gas Intelligence (NGI) Forward Look raised concerns in its January 4 publication that climate change is undermining weather models:

> Indeed, January will probably become the third straight month for which forecasts by nearly every weather vendor are likely to prove far off the mark. The cause is

[12] Composite weighted average temperature can be found on SoCalGas' Envoy. The calculation first takes the average daily temperature of several locations in the territory, then averages those into one number.
[13] A voluntary curtailment of electric generation is required under Condition A of the Aliso Canyon Withdrawal Protocol.

> increasingly clear, according to EBW. Climate change is wreaking havoc with the atmosphere and the ocean, the firm said. The temperature gradient between the Arctic and lower latitudes has fallen sharply, altering the flow of the jet stream, and oceans have become much warmer.[14]

In February, the same publication noted, "weather models have often been at odds throughout the winter regarding the intensity and timing of cold snaps…"[15] Uncertainty about weather forecasts exacerbated the impacts of the cold weather, making it more difficult for customers to accurately predict how much gas they would need.

There were eight days in January when the composite weighted average temperature was less than 55°F. ED staff analyzed real-time system sendout during various days with peak demand to determine hourly margins. On January 2, 2019, system demand increased from approximately 125 MMcfh to 201 MMcfh[16] (a daily equivalent of 3.0 Bcfd to 4.8 Bcfd[17]) over the course of approximately five hours due to cold temperatures. On January 14, 2019, system demand increased from 92 MMcfh to 165 MMcfh over the course of six hours. This was equivalent to an increase of 1.8 Bcfd in daily demand. In comparison, during the same hourly time period on March 31, 2019—a day that experienced relatively mild weather—system demand increased from 59 MMcfh to 96 MMcfh (equivalent to an increase of 0.9 Bcfd).

The difference between a gradual increase in peak hourly demand and a rapid and/or unexpected increase in peak hourly demand determines whether the combined non-Aliso fields can respond in time to meet hourly changes. Furthermore, the non-Aliso fields' ability to respond declines the more they are used. As inventory levels drop, storage fields have lower pressures, which results in a decline in withdrawal rates (the amount of gas that can be withdrawn in MMcf per hour). Thus, a storage field's maximum withdrawal rate determines how quickly it can respond to growing customer demand. The relationship between withdrawal rates and peak hourly and daily demand is further examined later in the report.

Figure 1 below depicts the temperature drop during the coldest part of the winter season, which occurred from February 4 to February 22, 2019 (highlighted by the blue box). The continuous stretch of cold weather did not allow the system adequate time to recover from each of the

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[14] Natural Gas Intelligence (NGI) is a provider of natural gas and shale news/market data to the energy industry. NGI Forward Look, "Natural Gas Bears Ring in Rocking New Year as February Sheds 70-Plus Cents," Jan. 4, 2019: https://contentsharing.net/actions/email_web_version.cfm?ep=Wda7dLHy7d2HDwFVFCwnDVMtWLEb5GK2GZqhp3r317FYWdWlgLYspgnA-QoHjC3UJg8U_s00m_6bNrs8fqeaRcT865DlK8bvXlI8btpLpCsSglfJA-EestNIotyEAYik

[15] NGI Forward Look, "Natural Gas Forwards Rise on Colder Weather Outlooks," Feb. 22, 2019: https://contentsharing.net/actions/email_web_version.cfm?ep=Wda7dLHy7d2HDwFVFCwnDVMtWLEb5GK2GZqhp3r317Ew8yaUgCbhawdgySO_wdqWC0ooKFRZUy04rsF_U4cKU9yUPfVFNCkVJm88HrnHq8vwFOMQ_Vetm-HSYH7EzzaZ

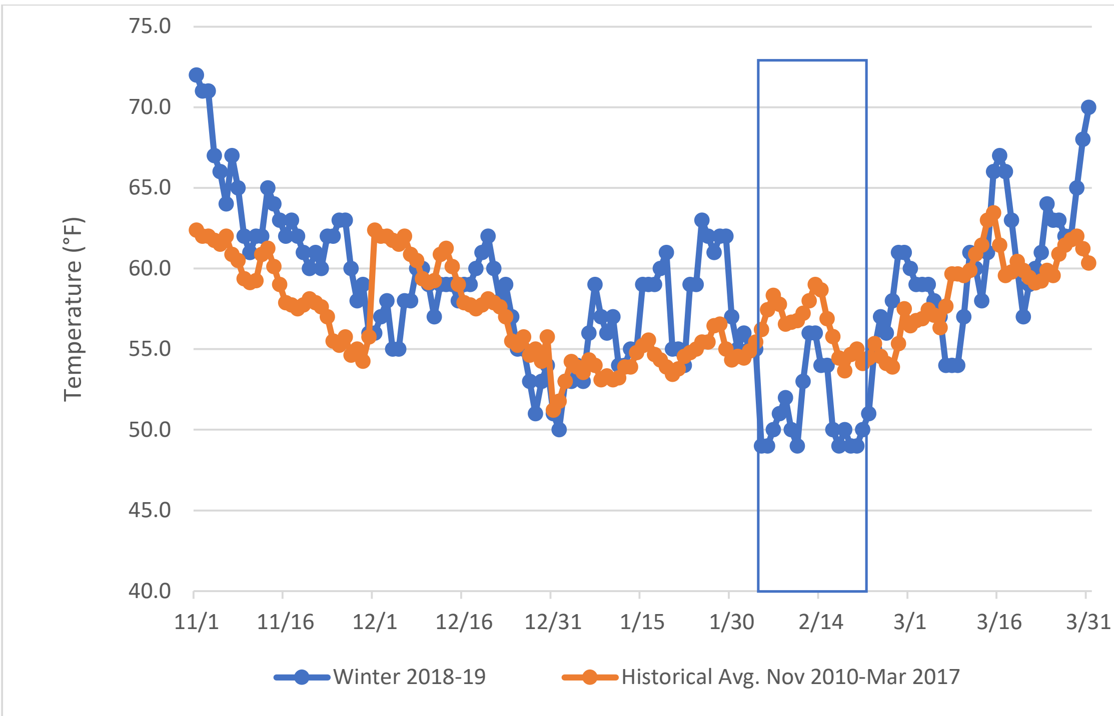
[16] Million cubic feet per hour

[17] Billion cubic feet per day

previous day's demands. In contrast, the dip in temperature on December 28, 2018, and on January 1, 2019, did not last as long.

A historical composite weighted average temperature for each date going back to 2010 is also shown in orange; by comparing winter 2018-19 to historical averages, the unique nature of winter 2018-19 can be seen.

Figure 1: Composite Weighted Average Temperature



Data source: Winter 2018-19 from SoCalGas Envoy and Historical Avg. from SoCalGas data request

February experienced a cold snap so extreme that the National Weather Service declared it the coldest February in downtown Los Angeles in nearly 60 years.[18] SoCalGas composite weighted average temperature dropped from 55°F on February 2 to 49°F the next day. Weather conditions remained in the high 40s or low 50s throughout the rest of the week. In fact, highs failed to reach 70°F for 41 consecutive days.[19] February highs never reached 70°F for the first time since records began in July 1877. Several cities experienced all-time record lows, including Woodland Hills (30°F), Burbank (35°F), and Long Beach (37°F).[20] The contrast between peak customer demand and available hourly supply compounded the problem and exhausted the system throughout much of February. SoCalGas called Stage 3 and Stage 4 low OFOs for all but one gas

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[18] "February is coldest in Los Angeles in nearly 60 years." Los Angeles Times. https://www.latimes.com/local/lanow/la-me-ln-cold-february-20190225-story.html (Feb. 25, 2019)
[19] Temperature source: National Centers for Environmental Information. http://www.noaa.gov/
[20] Ibid.

day from February 4 through 23, as shown below in Table 2.[21] In total, SoCalGas declared 80 low OFOs during winter 2018-19.

Table 2: February OFO Declarations

Low OFO Declarations for each Gas Day		
February 4	Stage 3	-5%
February 5	Stage 3	-5%
February 6	Stage 3	-5%
February 7	Stage 4	-5%
February 8	Stage 4	-5%
February 9	Stage 3	-5%
February 10	Stage 3	-5%
February 11	Stage 3	-5%
February 12	Stage 3	-5%
February 13	Stage 3	-5%
February 14	Stage 3	-5%
February 15	Stage 3	-5%
February 17	Stage 3	-5%
February 18	Stage 3	-5%
February 19	Stage 3	-5%
February 20	Stage 4	-5%
February 21	Stage 4	-5%
February 22	Stage 3	-5%
February 23	Stage 3	-5%

Data source: Aliso Canyon Withdrawal Protocol 30-Day Report Dated March 22, 2019 (Public Version)

As the Winter Technical Supplement forewarned, the greatest risk to the system was a result of multiple high demand days. Each gas day shown in the table above experienced ramping periods that lasted several hours.[22] The longest ramping period occurred the morning of February 6, lasting eight hours. System demand increased from 122 MMcfh to 238 MMcfh (a daily equivalent of 2.9 Bcfd to 5.7 Bcfd). In comparison, during the same hourly time period on March 20, 2019, system demand increased from 83 MMcfh to 127 MMcfh (a daily equivalent of 2.0 Bcfd to 3.0 Bcfd).

[21] For natural gas pipeline systems to remain physically "in balance," they must operate within a set range of pressures. If there is not enough gas in the system, the pressure falls, and gas does not flow properly. If there is too much gas, the pressure rises, posing a risk to the structural integrity of the pipelines. The SoCalGas System Operator is responsible for maintaining the system's balance, but it does not control most gas procurement. To maintain balance, the system operator calls low OFOs when gas deliveries are too low and high OFOs when deliveries are too high. When an OFO is called, all customers are required to deliver a certain percentage of their burn.

[22] A ramping period is the duration of time from "start of ramp" to "demand at peak."

Hopes for a mild March were only partially fulfilled as the weather alternated between warmer and colder than average temperatures. On the evening of March 4, system demand increased rapidly from 96 MMcfh to 162 MMcfh over the course of just four hours (a daily equivalent of 2.3 Bcfd to 3.8 Bcfd). In comparison, during the same hourly time period on March 29, 2019—well after the cold weather had abated—system demand increased from 84 MMcfh to 100 MMcfh (a daily equivalent of 2.0 Bcfd to 2.4 Bcfd).

Demand Response

On September 13, 2016, Energy Division's Director directed SoCalGas to submit a Tier 3 advice letter on gas demand response (DR) program(s) to be in place for residential customer participation by December 1, 2016. This ED directive resulted in SoCalGas' Smart Therm Program, which is a voluntary program that incentivizes reductions in gas consumption on peak days when the gas system is stressed by overriding participants' smart thermostats.[23] Demand Response events may be called during the morning peak from 5:00-9:00 AM and during the evening peak from 6:00-10:00 PM, with a customer being called for one peak event per day. Table 3 lists the 24 times the Smart Therm Program was activated over the winter season.

Winter 2018-2019 therm reductions and program results were summarized in a report by Nexant.[24] In the beginning of January 2019, approximately 10,000 participants were enrolled in Smart Therm. By the end of the recruitment effort, the number of participants increased to 40,000. Nexant performed a differences-in-differences analysis to estimate load savings resulting from DR events. The average hourly impact for a morning event was 15.1% less gas than the control group and 15.5% less gas for an evening event. However, the analysis found a "snap back" following a DR event, when participants used more gas than the non-DR control group. The increased gas use is the result of participants setting their thermostats to increase the temperature in their homes after a DR event. With the snapback considered, the average daily savings for a morning DR event was 2.2% less gas than the control group and 1.3% less for an evening DR event. Using the Nexant report and system sendout data, staff found that the maximum aggregate daily savings resulting from each DR event was about .01% of total system sendout.

[23] For more information on SoCalGas' Smart Therm Program, refer to https://www.socalgas.com/save-money-and-energy/rebates-and-incentives/smart-therm

[24] Nexant is a consulting firm contracted to perform an evaluation of the SoCalGas Smart Therm program. The 2018-2019 Winter Load Impact Evaluation of SoCalGas Smart Therm Program report by Nexant can be found here: http://www.calmac.org/publications/SoCalGas_2019_DR_Evaluation_Report_-_PUBLIC_FINAL.pdf

Table 3: Smart Therm Activation Dates and Savings

Smart Therm Activation Events								
Date	Time	OFO	OFO Stage	Curtailment	Aliso Canyon Usage	Aggregate Event Savings (MMcf)	Aggregate Daily Savings (MMcf)	Aggregate Daily Savings as a % of Total System Sendout
January 2	5am - 9am	Low	3	Voluntary EG	Yes	0.13	0.003	0.00009%
January 3	5am - 9am	Low	3	Voluntary EG	Yes	0.12	0.016	0.00049%
January 4	5am - 9am	No	N/A	Voluntary EG	Yes	0.14	0.029	0.00093%
January 7	5am - 9am	Low	3	Voluntary EG	No	0.12	0.070	0.00239%
January 15	5am - 9am	Low	2	Voluntary EG	Yes	0.13	0.065	0.00201%
January 16	5am - 9am	Low	2	Voluntary EG	Yes	0.12	0.094	0.00334%
January 17	5am - 9am	Low	2	Voluntary EG	Yes	0.11	0.134	0.00466%
January 22	5am - 9am	Low	1	Voluntary EG	Yes	0.12	0.084	0.00257%
January 23	5am - 9am	Low	2	Voluntary EG	Yes	0.20	0.142	0.00432%
January 24	5am - 9am	Low	2	Voluntary EG	Yes	0.23	0.162	0.00570%
February 4	5am - 9am	Low	3	Voluntary EG	No	0.34	0.345	0.01047%
February 5	5am - 9am	Low	3	Voluntary EG	Yes	0.37	0.334	0.00849%
February 6	5am - 9am	Low	3	Rule 23	Yes	0.33	0.159	0.00399%
February 7	5am - 9am	Low	4	Rule 23	Yes	0.32	0.138	0.00382%
February 8	5am - 9am	Low	4	Rule 23	Yes	0.34	0.178	0.00545%
February 11	5am - 9am	Low	3	Voluntary EG	Yes	0.29	0.179	0.00519%
February 11	6pm – 10pm	Low	3	Voluntary EG	Yes	0.03	0.013	N/A
February 12	5am - 9am	Low	3	Voluntary EG	Yes	0.21	0.076	0.00363%
February 12	6pm – 10pm	Low	3	Voluntary EG	Yes	0.06	0.042	N/A
February 13	5am - 9am	Low	3	Voluntary EG	Yes	0.22	0.199	0.00608%
February 13	6pm – 10pm	Low	3	Voluntary EG	Yes	0.09	0.008	N/A
February 14	5am - 9am	Low	3	Voluntary EG	Yes	0.19	0.158	0.00675%
February 14	6pm – 10pm	Low	3	Voluntary EG	Yes	0.08	0.057	N/A
February 15	5am - 9am	Low	3	Voluntary EG	Yes	0.24	0.183	0.00619%
February 15	6pm – 10pm	Low	3	Voluntary EG	Yes	0.08	0.017	N/A
February 19	5am - 9am	Low	3	Voluntary EG	Yes	0.35	0.149	0.00407%
February 20	5am - 9am	Low	4	Rule 23	Yes	0.40	0.237	0.00651%
February 21	5am - 9am	Low	4	Rule 23	Yes	0.41	0.303	0.00791%
February 22	5am - 9am	Low	3	Voluntary EG	Yes	0.42	0.165	0.00467%

Data source: SoCalGas data requested dated May 15, 2019 and 2018-2019 Winter Load Impact Evaluation of SoCalGas Smart Therm Program report by Nexant

The following section takes a closer look at gas operations, supply, and demand during the prolonged wave of cold weather.

Storage Usage

All storage fields are not created equal, and the non-Aliso fields provide varying degrees of usefulness in meeting gas demand. Honor Rancho is the most important non-Aliso field due both to its size and proximity to Los Angeles. Playa del Rey also performs an important supporting role in meeting intraday demand changes. While small, it is close to the largest demand load and has a large amount of withdrawal capacity for its size. Therefore, SoCalGas tries to keep it near full capacity whenever possible. La Goleta is the least useful field despite its relatively large inventory because it is far from the major load centers.

To sustain the withdrawal capacity needed to maintain core customer reliability, SoCalGas set month-end minimum storage inventory targets in its Winter 2018-19 Technical Assessment.[25] As the winter progressed, Honor Rancho and Playa del Rey were frequently close to their monthly and weekly minimum inventories.[26] La Goleta experienced significant withdrawals, but it was never close to dropping below its minimum inventory level. In this report, only the combined inventory of the non-Aliso fields is reported because the inventory of the individual fields is confidential. However, this requirement masks the severity of the depletion of Honor Rancho and Playa del Rey during the winter.

Table 4: Winter 2018-19 Month-End Minimum Inventory by Field (Bcf)

Storage Field	Nov.	Dec.	Jan.	Feb.	March
Honor Rancho	13.9	13.2	12.6	7.5	5
La Goleta	8	7.9	7.7	7.6	7.5
Playa del Rey	1.9	1.9	1.5	1.1	0.7
Total Non-Aliso	23.8	23	21.8	16.2	13.2
Aliso Canyon	5.7	5.1	4.4	3.8	2.1
Total	29.5	28.1	26.2	20	15.3

Data source: SoCalGas Winter 2018-19 Technical Assessment

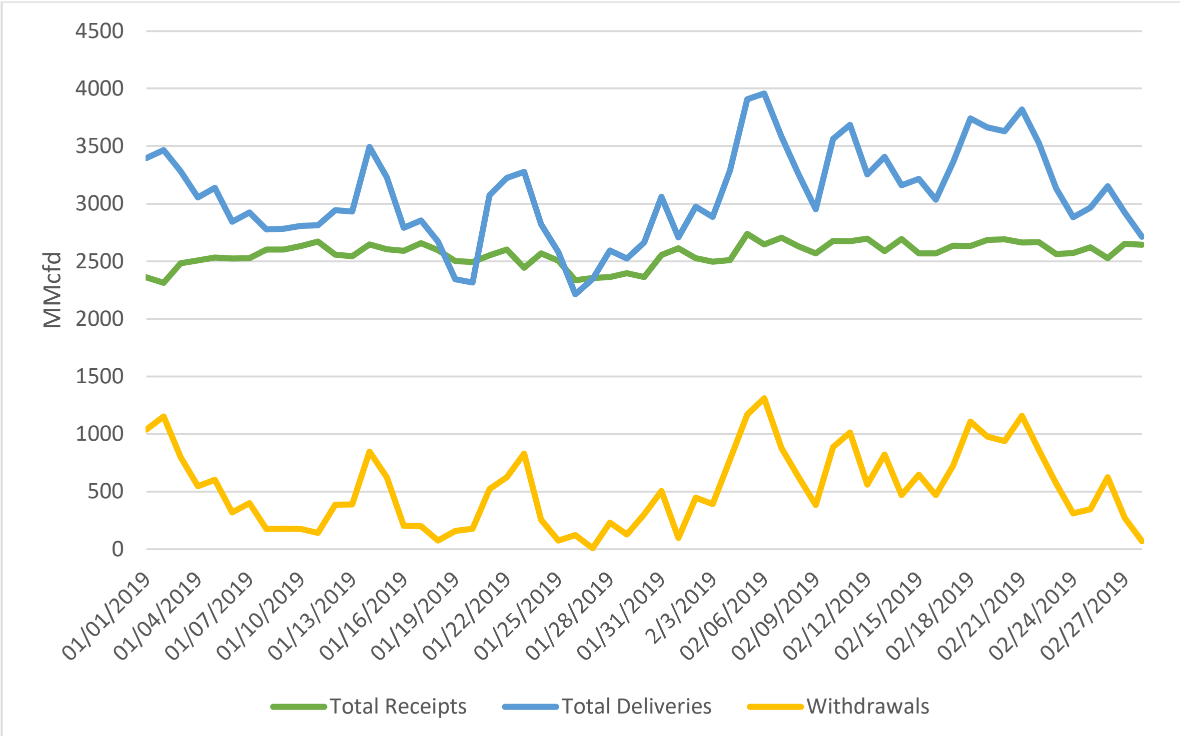
To evaluate how SoCalGas managed their storage fields during the month of January, ED staff performed an hourly analysis of receipt point utilization and storage field withdrawals. As highlighted in Figure 2, underground gas storage played a crucial role in meeting customer demand throughout January and February. The gap between the total receipts (green line) and the total delivery (blue line) illustrates demand that must be met with gas from linepack and/or storage facilities.[27] During the two-month span, gas burn exceeded gas receipts on all but four days—January 18, 20, 26, and 27. SoCalGas was compelled to withdraw gas from storage on 27 days in January and every day in February.

[25] SoCalGas Winter 2018-19 Technical Assessment, October 16, 2018, p. 7: http://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/News_Room/NewsUpdates/2018/2018%2011%2002%20SoCalGas%20(R.%20Schwecke)%20letter%20to%20CEC%20enclosing%20WINTER%202018-19%20TECHNICAL%20ASSESSMENT.PDF

[26] Weekly maximum withdrawal amounts are determined by dividing monthly targets by the number of weeks in each respective month.

[27] Linepack is gas stored in the pipelines.

Figure 2: Jan.-Feb. Daily Receipts, Deliveries, and Storage Injection



Data source: SoCalGas Envoy

On January 8, 2019, SoCalGas sent ED staff a letter stating, "we are experiencing colder weather than last winter and already have less natural gas in our non-Aliso storage fields than this time last year… withdrawals have further reduced the non-Aliso field's withdrawal deliverability to 880 MMcfd."[28] SoCalGas advised ED staff that forecasted customer demand would exceed flowing pipeline supplies frequently throughout the remainder of winter. Therefore, continued use of storage withdrawals would be needed to fill the shortfall between flowing pipeline supplies and customer demand. SoCalGas then wrote, "without greater use of Aliso Canyon to manage inventory levels at the non-Aliso fields, SoCalGas expects further reductions in inventory and withdrawal capacity at the non-Aliso storage fields." In closing, SoCalGas stated its intention to use Aliso Canyon to "(1) meet immediate high customer demands; (2) limit withdrawals at Honor Rancho to an average of 90 MMcfd per day for the remainder of the month of January; and (3) restore Playa Del Rey inventory." This letter did not alter existing regulations or restrictions in place under the Aliso Canyon Withdrawal Protocol.

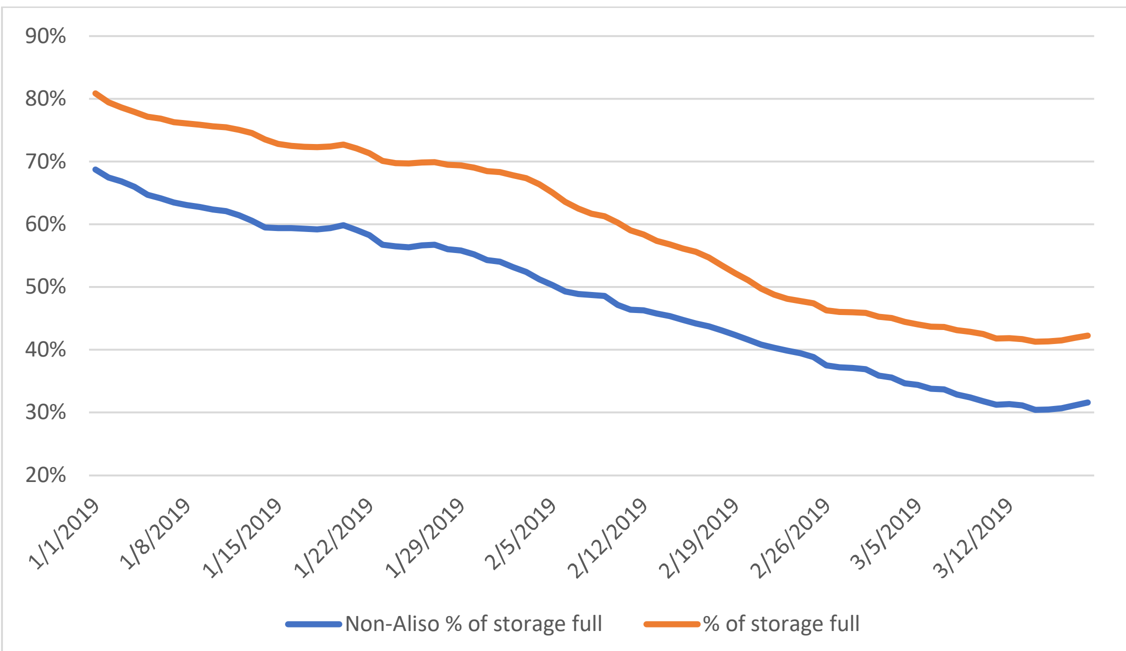
SoCalGas withdrew from storage inventory significantly during the subsequent stretch of cold weather due to daily withdrawals. Since withdrawal rates decline as inventory and pressure

[28] January 8, 2019, letter from SoCalGas, "Status of [SoCalGas] Underground Natural Gas Storage Levels and Use of Aliso Canyon":
http://cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/News_Room/NewsUpdates/2019/182019%20RSchwecke%20letter%20to%20ERandolph%20re%20Storage%20Status.pdf

levels decline, SoCalGas' capability to meet the rapid hourly increases in gas demand with the non-Aliso facilities decreased with each passing day. By February 1, combined non-Aliso withdrawal capability had declined by approximately 18% from January 1 levels.

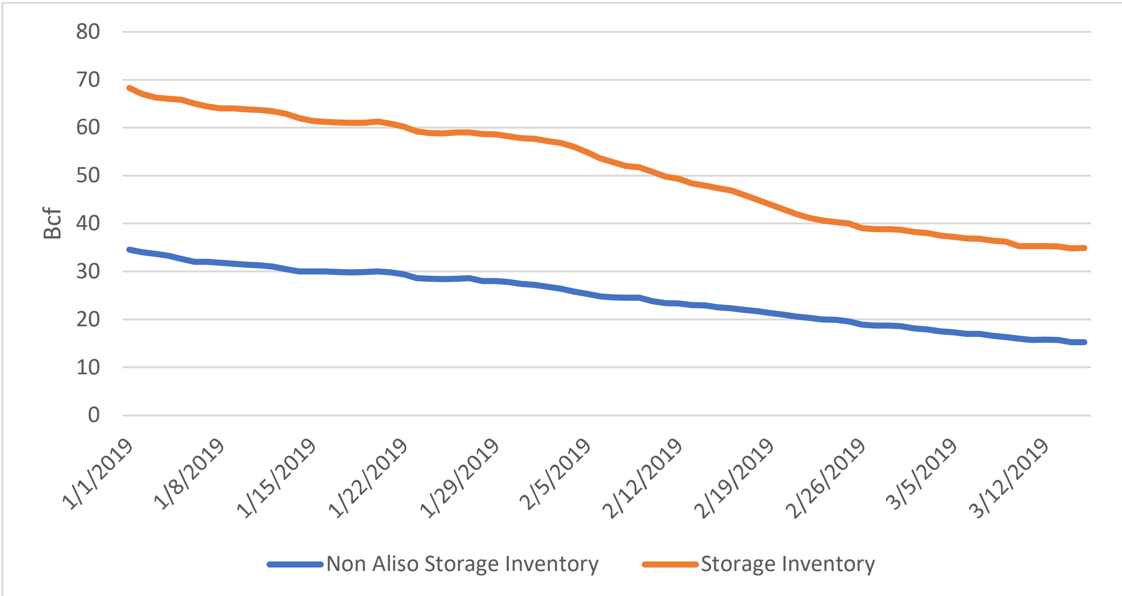
Figure 3 presents storage inventory as a percentage of storage capacity during the winter. The orange line is the result of total storage inventory divided by total storage capacity available (with Aliso Canyon restricted to 34 Bcf). The blue line takes total storage inventory at the non-Aliso fields and divides it by total storage capacity available without Aliso Canyon. At the start of 2019, the combined storage inventory was approximately 81% full, but by mid-March, the fields were approximately 42% full. Depletion of the non-Aliso storage fields is even more jarring. The percentage full of the non-Aliso fields dropped from approximately 69% to approximately 32%.

Figure 3: Storage Inventory in Percentage Full



Data source: SoCalGas Envoy and January 6, 2016, data request to provide a daily log of storage inventory by field

Figure 4: Storage Inventory in Bcf



Data source: SoCalGas Envoy and January 6, 2016, data request to provide a daily log of storage inventory by field

In Figure 4, the orange line, "Storage Inventory," reflects actual gas storage inventory as reported on Envoy.[29] The blue line, "Non-Aliso Storage Inventory," illustrates total gas storage inventory without Aliso Canyon.

As high demand conditions continued, some ongoing planned maintenance work was in progress, which reduced withdrawal capacity even further. Table 5 lists planned maintenance work listed in Envoy that affected withdrawal capacity during this period. The capacity reduction shown below is the maximum amount for the duration of the work, as the capacity reduction on a given day can vary. SoCalGas has stated that the work could not be deferred due to regulatory compliance with the Storage Integrity Management Program (SIMP).[30] In addition to the planned work, there were some unplanned incidents that impacted storage, including unplanned repairs to an aboveground pipeline at Aliso Canyon, which reduced the field's withdrawal capacity by between 220 and 470 MMcfd during the month of February. The work was completed on March 1.[31]

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[29] Envoy is SoCalGas' online bulletin board and online system for scheduling: https://scgenvoy.sempra.com/index.html

[30] Source: Energy Division Data Request 43a to SoCalGas. SoCalGas proposed SIMP as an incremental, standalone program during their 2016 general rate case to proactively identify and mitigate potential storage well safety and/or integrity issues using new inspection technologies and risk management disciplines to address well integrity. For information on SIMP, refer to D.16-06-054: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M164/K606/164606603.pdf

[31] Refer to maintenance archives on SoCalGas Envoy.

Table 5: Planned Maintenance Work

Storage Field	Start Date	End Date	Max. Withdrawal Capacity Reduction (MMcf)	Description	Reason Not Deferred
Goleta	12/1/2017	TBD	180	SIMP	Safety related: conversion to tubing-only flow
Honor Rancho	3/15/2017	TBD	215	SIMP	Safety related: conversion to tubing-only flow

Data source: Envoy

As discussed earlier, prolonged use of underground gas storage during the latter half of winter resulted in depleted inventory levels at the non-Aliso storage fields. In a letter to the Commission, SoCalGas stated, "…in both January and February, inventory levels at our Honor Rancho and Playa del Rey storage fields have neared their respective minimums for core reliability."[32] As displayed in Table 1 above, SoCalGas' combined non-Aliso storage inventory was approximately 47 Bcf at the start of the winter. By the end of the winter, it was approximately 18 Bcf. Table 6 below shows the actual month-end inventories at Aliso and the non-Aliso fields.[33] The actual non-Aliso inventory dropped by approximately 8.7 Bcf from January to February, which is more than would have been available if the non-Aliso fields had been drawn down to their month-end minimums in January. SoCalGas had an opportunity to inject gas into storage in the middle of March, which helped preserve the non-Aliso month-end inventory for that month.

Table 6: Actual Month-End Inventory (Bcf)

Storage Field	Nov.	Dec.	Jan.	Feb.	March
Non-Aliso	43.8	35.6	27.4	18.7	18.2
Aliso	33.6	33.6	30.4	20.1	20
Total	77.4	69.2	57.8	38.8	38.2

Data source: January 6, 2016, data request to provide a daily log of storage inventory by field

While storage inventory is critical and enables SoCalGas to meet its winter demand, much of the gas burned by customers flows through interstate pipelines from the receipt points at the

[32] February 26, 2019, Letter from SoCalGas, "Winter 2018-19 Lessons Learned": https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/News_Room/NewsUpdates/2019/2262019%20Letter%20to%20CPUC.pdf

[33] The actual month-end inventories cannot be shown for the individual non-Aliso fields for confidentiality reasons.

California border to the SoCalGas pipeline system. The following section analyzes how customers used the pipeline system during the continuous stretch of cold weather.

Receipt Point Utilization

Receipt point utilization is the ratio between the flow rate at a gas pipeline receipt point and the maximum operating capacity of that receipt point. Image 1 on the next page depicts receipt points with black and white circles and the maximum amount of gas that could be transported through the receipt points (assuming no maintenance or repairs). Analyzing receipt point utilization provides a supplemental perspective to storage facility usage, since demand is fulfilled by either gas in the pipelines or gas from storage facilities, or a combination of both. Gas demand changes in real-time as customer usage changes; thus, it is necessary to assess both storage withdrawal and receipt point utilization at the hourly level. It is important to highlight that gas travels at approximately 30 miles per hour, making proximity important when determining the effectiveness of incoming gas in meeting demand.

The SoCalGas System Operator department, which is charged with keeping the gas system in balance, does not have primary responsibility for procuring gas or scheduling gas deliveries. [34] With a few relatively minor exceptions, it is the customers of SoCalGas, including electric generators, industrial customers, and Gas Acquisition, who must procure and schedule delivery of gas onto the system.[35] The System Operator also calls OFOs and decides when to pull from storage for balancing and system reliability.

[34] Under certain circumstances, the System Operator can purchase gas to support demand on the Southern System, which includes San Diego. See SoCalGas Rule 41: https://www.socalgas.com/regulatory/tariffs/tm2/pdf/41.pdf

[35] SoCalGas' Gas Acquisition Department procures gas for SoCalGas and San Diego Gas & Electric (SDG&E) core customers, which are made up of residential and small business customers. There is a firewall between Gas Acquisition and the System Operator; Gas Acquisition only has access to public information about the SoCalGas system.

Image 1: Receipt Points & Transmission Zone Firm Capacities

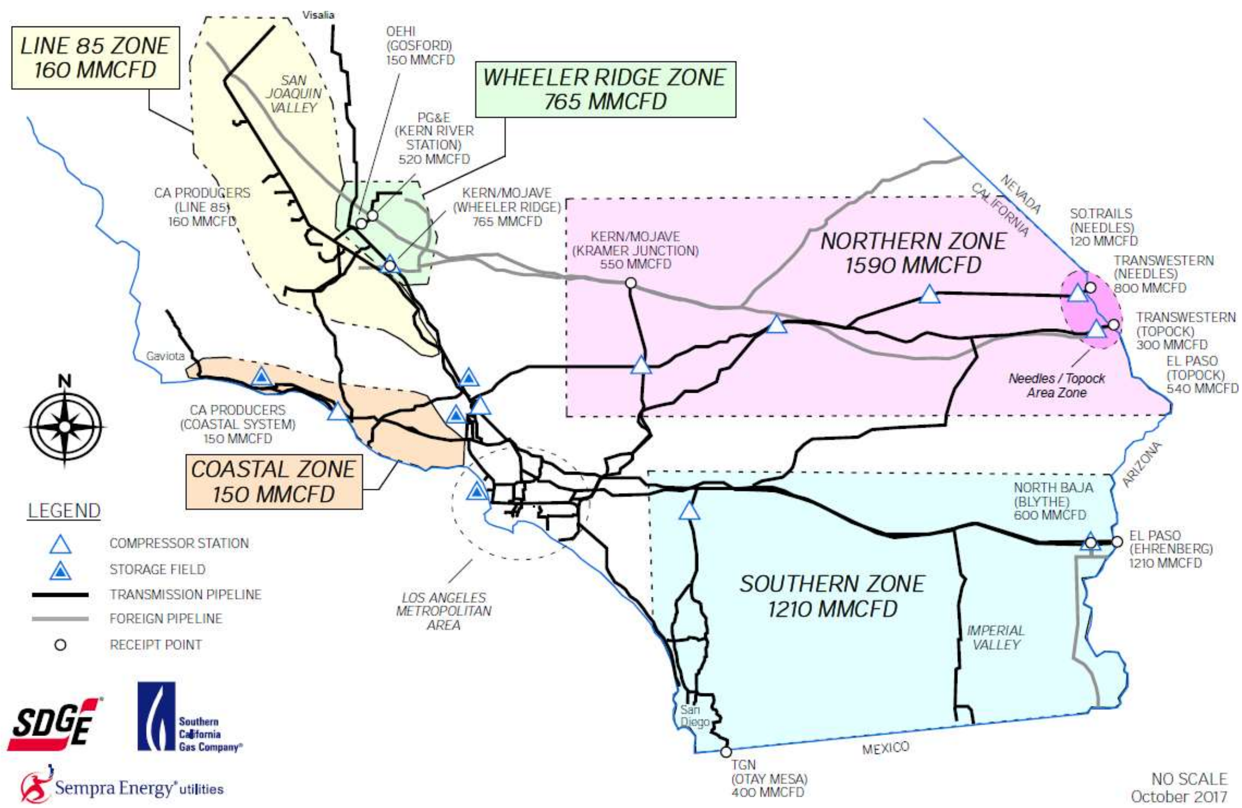

Image source: www.socalgas.com

Figures 5, 6, and 7 combine daily receipt point utilization from Ehrenberg, Otay Mesa, Blythe, Transwestern/North Needles, Kramer Junction, Kern/Mojave, Kern River, and Occidental Elk Hills for total system capacity utilization, and display corresponding weather conditions. As highlighted in Figure 5, receipt point utilization was approximately 83% on January 2 and increased to 90% on January 4. It continued to increase, reaching 97% utilization on January 11. There is a pattern of increased gas nominated and scheduled in Cycle 4 during high sendout days.[36] Receipt point utilization reached 98% on January 17, 2019—the highest capacity usage that month. Average capacity usage in January was approximately 91%. In comparison, SoCalGas has historically seen 85% receipt point utilization.[37]

As demonstrated in Figure 5, there is a soft correlation between receipt point utilization and temperatures. As temperatures dropped, system capacity utilization tended to increase. Conversely, as temperatures increased, utilization tended to decrease. Notably, storage withdrawals also increased during cold periods because receipts were not enough to meet

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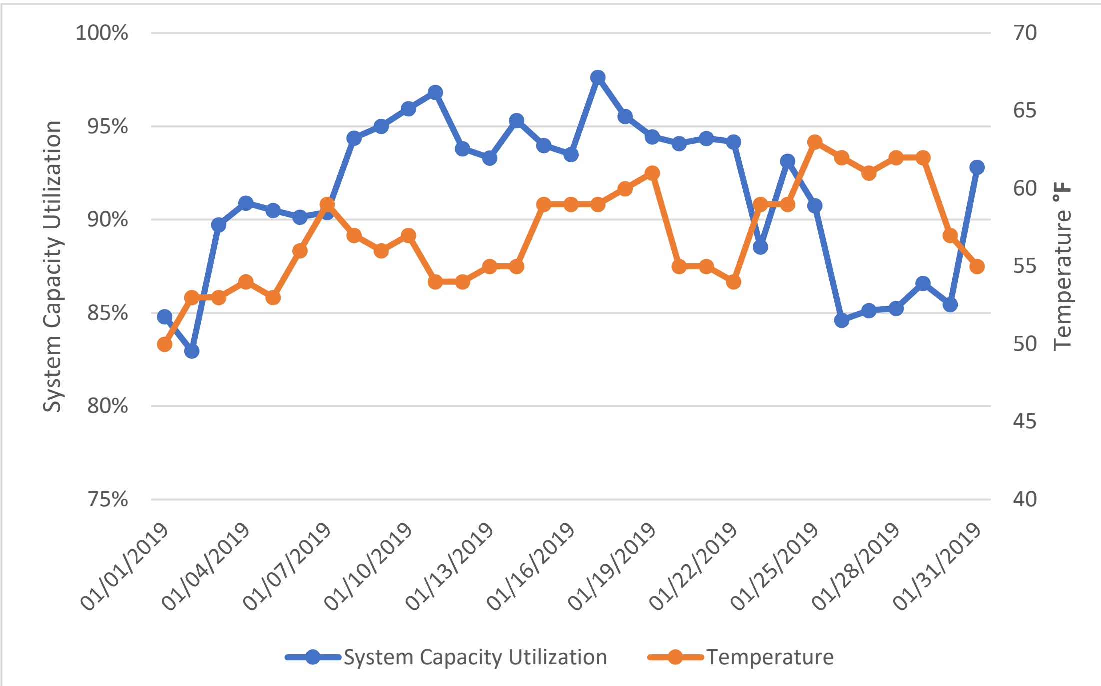
[36] There are six cycles that provide customers an opportunity to nominate and schedule gas onto the system: Timely (Cycle 1), Evening (Cycle 2), Intraday 1 (Cycle 3), Intraday 2 (Cycle 4), Intraday 3 (Cycle 5), and Intraday 4 (Cycle 6). See Page 7 of Rule 30: https://www.socalgas.com/regulatory/tariffs/tm2/pdf/30.pdf

[37] Summer 2018 Technical Assessment, pg. 18-19

customer demand. SoCalGas relied on Aliso Canyon withdrawals on three different occasions in January to meet daily and peak demand. Daily demand refers to total gas sendout per day, while peak demand refers to the highest gas demand for the day, which usually occurs in the morning or evening. In the winter, SoCalGas experiences two peak periods per day that are driven by customer behavior, once in the morning (usually around 6:00-9:00 AM) and again in the evening (usually around 6:00-9:00 PM).

Figure 5: Receipt Point Utilization in January

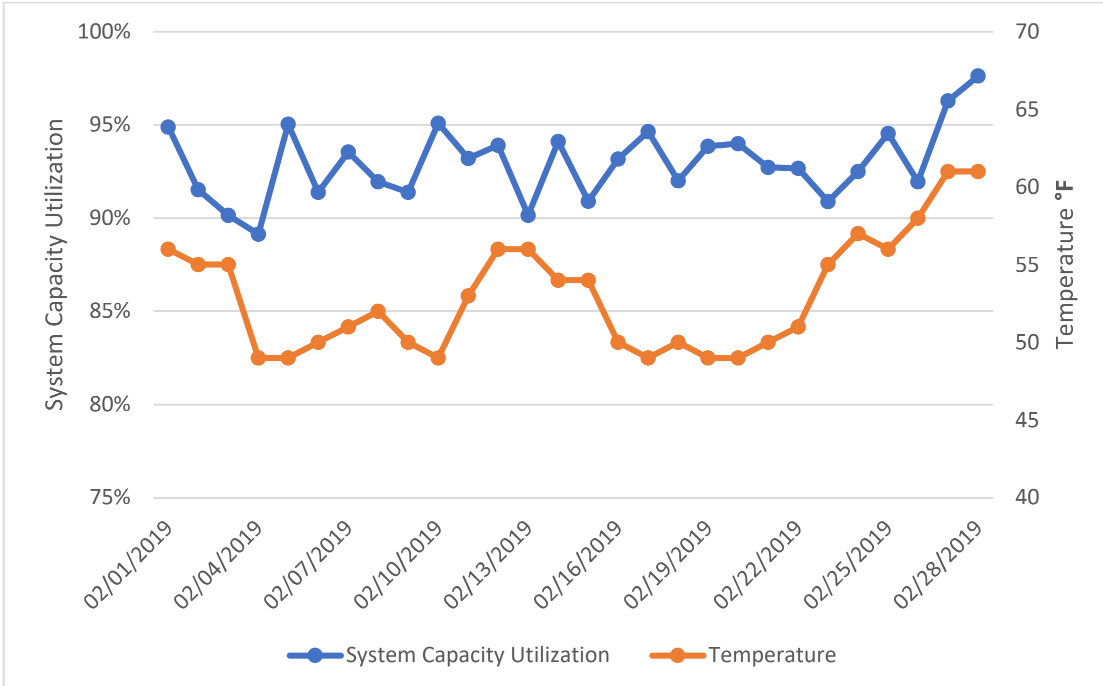


Data source: SoCalGas Envoy

As discussed earlier in the report, February saw a lengthy stretch of sustained low temperatures that impacted overall system demand. Consequently, receipt point utilization was higher in February, with an average capacity use of 94%. Even though receipt point utilization was higher this February than the historical average, customers did not schedule gas delivery to full pipeline capacity. The average available pipeline capacity in February was 2,808 MMcfd, and the average pipeline flowing quantity was 2,636 MMcfd, leaving an average of 172 MMcfd of capacity unscheduled.[38]

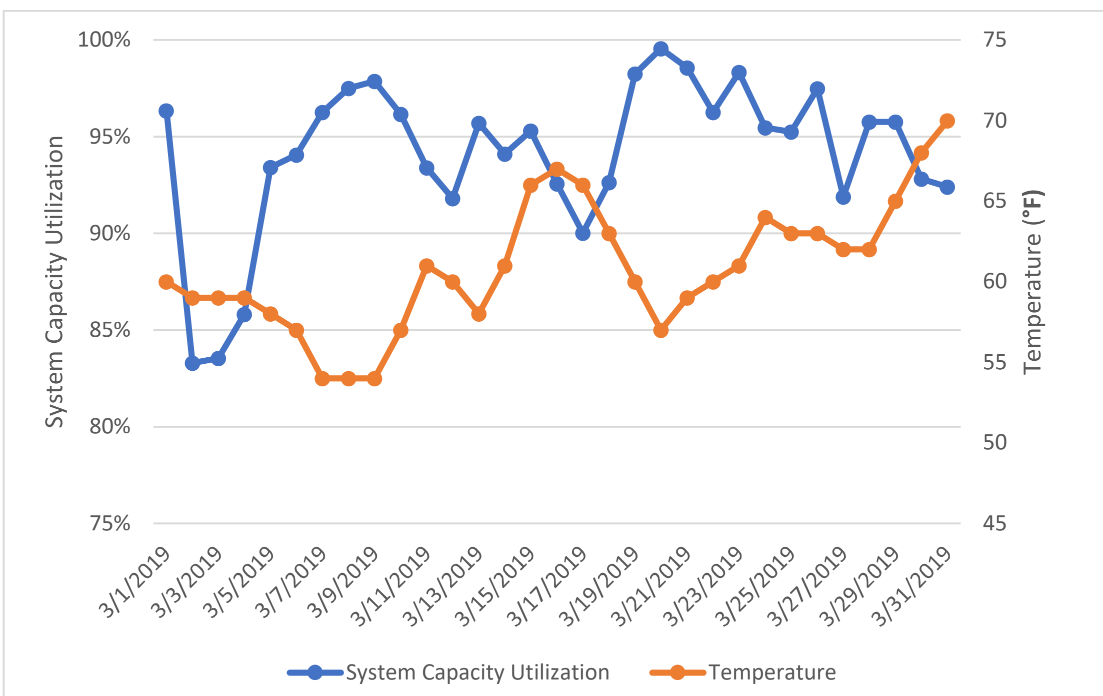
[38] 30-day Aliso Canyon Withdrawal Report, pg. 8: http://cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/News_Room/NewsUpdates/2019/AlisoWithdrawalsNotification02-04-2019c.pdf

Figure 6: Receipt Point Utilization in February



Data source: SoCalGas Envoy

Figure 7: Receipt Point Utilization in March



Data source: SoCalGas Envoy

As highlighted in Figure 7, receipt point utilization in March was not as constant as February. Average capacity utilization was approximately 94%. Capacity usage was approximately 96% on March 1 and dropped to 83% the next day. Receipt point utilization remained relatively low the next two days. It is not entirely apparent why receipt point utilization was below 90% on these days. However, lower anticipated demand may explain this dip. Notably, on gas day March 4, customers delivered 2,396 MMcfd, yet demand reached 2,963 MMcfd. Furthermore, on March 11, receipts were 2,567 MMcfd, but demand reached 3,102 MMcfd. In order to meet rapid swings in customer demand and preserve core reliability for the remainder of the winter, SoCalGas initiated withdrawals from Aliso Canyon during both March 4 and March 11.

Receipt point utilization trended upwards in the middle of March even though system sendout was lower. This can be attributed to several factors, including low market prices, an ideal amount of gas nominations by noncore and Gas Acquisition, and significant injections of gas into storage to prepare for the summer months.

ED staff analyzed receipt point utilization and determined that Aliso Canyon withdrawal was needed given the proximity of Aliso Canyon to the Los Angeles basin and the physical constraints on the SoCalGas transmission system. SoCalGas experienced rapid demand increases on all days Aliso Canyon withdrawal occurred. Use of Aliso Canyon is discussed in detail in the following section.

Aliso Canyon Usage

This winter saw the longest duration and highest volume of gas withdrawn from Aliso Canyon since the October 2015 leak. Aliso Canyon withdrawals occurred on 37 gas days this winter, resulting in approximately 14.086 Bcf withdrawn. Beginning on December 28, 2018, SoCalGas issued a system-wide (including SDG&E) voluntary curtailment of electric generators followed by a series of additional voluntary curtailments, curtailment watches, Rule 23 curtailments, and Aliso Canyon withdrawals.[39] SoCalGas did not inject gas into Aliso Canyon until March 15.[40] Figure 8 (below) displays these winter 2018-19 events and Aliso Canyon withdrawals. In total, there were eight Aliso Canyon withdrawal events (the three neighboring withdrawal events from January 21 to January 24 will be referred to as one withdrawal event, for purposes of this section).

On the first gas day Aliso Canyon was used, January 2, 2019, the total amount of gas withdrawn from Honor Rancho, La Goleta, and Playa del Rey was approximately 71% of their combined maximum withdrawal rate for that day. However, analysis at the daily level neglects the

[39] A Rule 23 curtailment is a mandatory reduction in gas use pursuant to SoCalGas' Rule No. 23 tariff (https://www.socalgas.com/regulatory/tariffs/tm2/pdf/23.pdf). A curtailment watch is a notice of a potential interruption of service or required usage reduction.

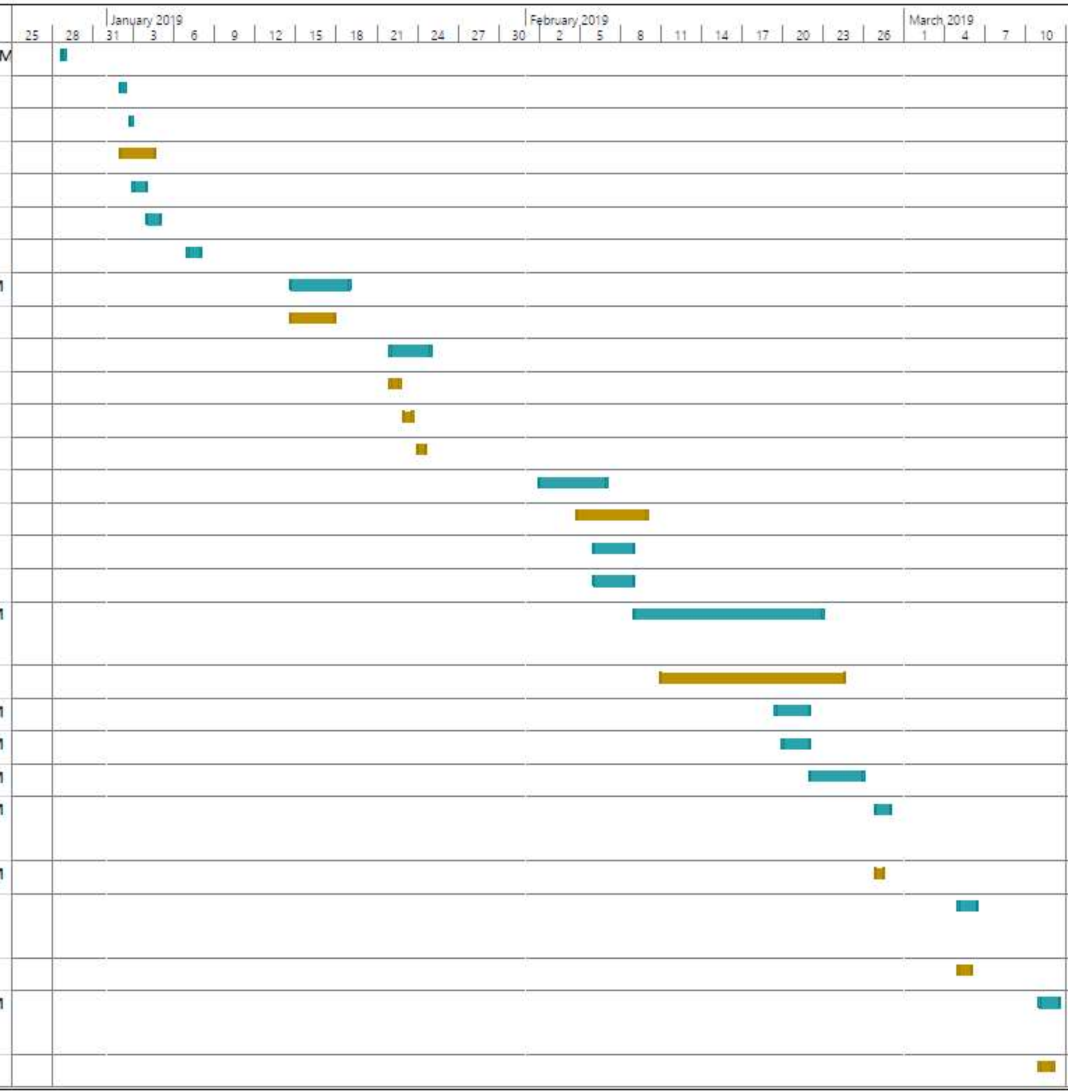
[40] From an operational standpoint, SoCalGas prioritizes injections into the non-Aliso fields first, making Aliso Canyon the last priority.

importance of peak hourly demand and supply. This section will analyze hourly operations and conditions during Aliso Canyon usage hours. First, ED staff traced back to December 28-January 1 and found that gas sendout was 30% more than receipts every day except December 30, when gas sendout was 17% more than receipts. Second, withdrawal from the non-Aliso fields from December 28 to January 1 resulted in Honor Rancho and Playa del Rey exceeding their weekly maximum withdrawal amounts. Consequently, SoCalGas ceased withdrawals from Playa del Rey on the afternoon of January 2 and began injecting into the field on January 3-4 during the period when Aliso Canyon was on withdrawals.

Furthermore, because the high correlation between temperature and core customer gas demand produces steep intraday demand changes, ED staff compared gas from all receipt points and non-Aliso fields during the peak demand hour to total sendout. Peak sendout occurred at 7:50 AM on January 2. Accordingly, ED staff analyzed the hour from 8:00-9:00 AM and determined that SoCalGas would not have met demand without withdrawal from Aliso Canyon. These three factors—heavy withdrawals from the non-Aliso fields in the days preceding an Aliso withdrawal, the non-Aliso fields approaching their week- or month-end minimum inventories, and high hourly sendout—were a recurring situation for the winter's remaining Aliso Canyon withdrawals. As mentioned in the Storage Usage section of this report, proximity of the non-Aliso fields to the gas demand center is a significant factor in determining usefulness.

Figure 8: Winter 2018-19 Events and Aliso Canyon Withdrawals

ID	Action	Start	Finish
1	Voluntary curtailment of EG	12/28/18 4:00 PM	12/28/18 11:00 PM
2	Voluntary curtailment of EG	1/2/19 5:00 AM	1/2/19 9:00 AM
3	Voluntary curtailment of EG	1/2/19 6:00 PM	1/2/19 10:00 PM
4	Aliso Withdrawal	1/2/19 6:57 AM	1/4/19 2:12 PM
5	Voluntary curtailment of EG	1/3/19 7:00 AM	1/4/19 7:00 AM
6	Voluntary curtailment of EG	1/4/19 7:00 AM	1/5/19 7:00 AM
7	Voluntary curtailment of EG	1/7/19 7:00 AM	1/8/19 7:00 AM
8	Voluntary curtailment of EG	1/14/19 2:30 PM	1/18/19 11:59 PM
9	Aliso Withdrawal	1/14/19 3:00 PM	1/17/19 9:47 PM
10	Voluntary curtailment of EG	1/22/19 7:00 AM	1/25/19 6:59 AM
11	Aliso Withdrawal	1/21/19 11:58 PM	1/22/19 4:57 PM
12	Aliso Withdrawal	1/23/19 6:49 AM	1/23/19 3:30 PM
13	Aliso Withdrawal	1/24/19 6:29 AM	1/24/19 3:07 PM
14	Voluntary curtailment of EG	2/2/19 7:00 AM	2/7/19 6:59 AM
15	Aliso Withdrawal	2/4/19 6:30 PM	2/9/19 11:37 PM
16	System-wide curtailment watch	2/6/19 12:00 AM	2/8/19 11:59 PM
17	Rule 23 curtailment	2/6/19 12:00 AM	2/8/19 11:59 PM
18	Voluntary curtailment of EG (extended on 2/17)	2/9/19 12:00 AM	2/22/19 11:59 PM
19	Aliso Withdrawal	2/10/19 11:22 PM	2/24/19 2:58 PM
20	System-wide curtailment watch	2/19/19 12:00 PM	2/21/19 11:59 PM
21	Rule 23 curtailment	2/20/19 12:00 AM	2/21/19 11:59 PM
22	Voluntary curtailment of EG	2/22/19 12:00 AM	2/25/19 11:59 PM
23	Voluntary curtailment of EG (ended early)	2/26/19 8:17 PM	2/27/19 11:59 PM
24	Aliso Withdrawal	2/26/19 8:35 PM	2/27/19 12:03 PM
25	Voluntary curtailment of EG (ended early)	3/5/19 5:14 AM	3/6/19 10:00 AM
26	Aliso Withdrawal	3/5/19 5:14 AM	3/6/19 7:04 AM
27	Voluntary curtailment of EG (extended on 3/11)	3/11/19 12:00 AM	3/12/19 12:00 PM
28	Aliso Withdrawal	3/11/19 7:55 AM	3/12/19 6:52 AM



After the first Aliso Canyon withdrawal event ended at 2:10 PM on January 4, 2019, SoCalGas did not use Aliso Canyon for about 10 days, due to slightly warmer weather. These 10 days saw continued withdrawal from Honor Rancho and La Goleta along with continued injection into Playa del Rey. Honor Rancho and La Goleta combined lost about 8% of their withdrawal capacity during this time due to reduced inventory.

Aliso Canyon withdrawals resumed at approximately 3:00 PM on gas day January 14 and continued through 9:47 PM on January 17. The highest volume of gas withdrawn from Aliso Canyon in January occurred during this event, with 586 MMcf withdrawn on gas day January 15. Envoy shows flowing pipeline receipts of about 2.6 Bcf on January 15. According to a data request response, peak demand that day was 180 MMcfh at 7:00 PM while total pipeline receipts and non-Aliso withdrawal per hour were about 111 MMcfh, which falls short of meeting peak demand without Aliso Canyon withdrawals.

During the week of January 14th, the combined non-Aliso fields were 8.7 Bcf away from their month-end minimum inventory levels, which translated to 2.9 Bcf of withdrawal remaining for the week. However, the majority of the 2.9 Bcf available was at La Goleta because Honor Rancho and Playa del Rey were very close to their month-end minimums. To preserve inventory at those fields, SoCalGas reduced withdrawals from Honor Rancho and Playa del Rey on gas days January 15-17. During this period, SoCalGas injected gas into Playa del Rey on all three days and injected gas into Honor Rancho during off-peak hours on January 16-17.[41] After reviewing hourly withdrawals and injections during this period, ED staff concluded that it was reasonable for SoCalGas to inject gas into Playa del Rey and Honor Rancho to preserve their month-end minimum inventory levels and withdrawal capability.

SoCalGas withdrew gas from Aliso Canyon again at 11:58 PM on gas day January 21 then continued intermittently through 3:07 PM on January 24 (see Figure 8 above for exact withdrawal events). Once again, system conditions consisted of more total sendout than receipts, non-Aliso fields near their minimum inventories, and peak hourly demand that could not be met without Aliso Canyon withdrawal. The cold weather brought about the highest peak demand of the month. From approximately 7:00-8:00 AM on January 23 sendout was 225 MMcfh—the equivalent of a 5.4 Bcf day. Unlike the prior withdrawal event, total daily withdrawals at the non-Aliso fields were high during ramping and peak periods and were only reduced during off-peak hours. By the end of the withdrawal event, Playa del Rey was below its month-end minimum inventory, Honor Rancho was just slightly above, and La Goleta had a healthy reserve. No further Aliso Canyon withdrawals occurred until February 4.

The cold morning of February 4 produced a peak sendout of 168 MMcfh between 8:00-9:00 AM (the equivalent of a 4.03 Bcfd), which was met with pipeline supplies, non-Aliso withdrawal, and linepack. Hourly data analysis shows that the System Operator could meet demand for the

[41] Withdrawals from Aliso Canyon had ceased by the time SoCalGas began Honor Rancho injections on January 17.

rest of the morning and afternoon, until the forecasted second peak in the evening. Because SoCalGas had withdrawn from the non-Aliso fields from gas days January 24 to February 4, Honor Rancho's withdrawal rate had dropped by more than 10%, despite injection on January 24-27 and February 1-2. At 6:30 PM on February 4, SoCalGas began Aliso Canyon withdrawals to meet the approximately 7:00 PM peak of 183 MMcfh, which would not have been met without gas from Aliso Canyon.[42] The cessation of withdrawals occurred 20 days later on February 24 after the longest period of gas withdrawal from Aliso Canyon since the October 2015 leak.

Figures 9 and 10 below depict total system sendout compared to receipts and withdrawals at the hourly level for the duration of the February withdrawals. Hourly sendout exceeded the amount of gas that customers and shippers brought onto the system for the majority of the February 4-24 period. There were limited instances of receipts exceeding sendout and allowing for injection, such as on February 7. The yellow line is derived from hourly sendout information and shows the volatility of intraday demand and steep ramping periods. ED staff also found instances of peak hourly sendout that pushed the SoCalGas system to its limits, as total receipts and withdrawals from all four fields alone were not enough, and the System Operator had to use linepack to meet demand. SoCalGas used linepack to meet the morning and evening peak periods on February 4-7, February 11-13, and February 18-21. Moreover, linepack was used to meet peak hourly demand on the mornings of February 8, February 22, February 23, and February 24.

Additionally, SoCalGas declared two mandatory Rule 23 curtailments of electric generation customers during this withdrawal event. The first curtailment went into effect on February 6, 2019, at 12:00 AM and lasted until February 8, 2019, at 11:59 PM and was driven by a period of extremely cold weather. On February 6, the minimum temperature in Downtown Los Angeles was 43°F, Woodland Hills was 32°F, and Long Beach was 40°F.[43] Even with the curtailments, gas day sendout was 3.9 Bcf, while flowing receipts were only 2.67 Bcf (gas sendout had also been 3.9 Bcf on February 5, and the system was drafting for several days).[44] On February 6, 521 MMcf of gas was withdrawn from the non-Aliso fields, accompanied by 772 MMcf of gas from Aliso Canyon—the largest Aliso withdrawal day of the winter. In addition to the curtailments, the System Operator called Stage 4 low OFOs on February 7 and February 8.[45]

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[42] On February 5, SoCalGas posted a critical notice on Envoy stating "unplanned repairs of an aboveground pipeline leading to Dehydration Unit 1 has further reduced Aliso Canyon's withdrawal capability by approximately 420 MMcfd. The capacity reduction was reduced to 200 MMcfd on February 7, then 250 on MMcfd on February 27. The work finished on March 1.

[43] Temperature source: National Centers for Environmental Information http://www.noaa.gov/

[44] A gas system is "drafting" when the linepack is not replenished at the end of the day, and the system starts the following day with less than normal linepack.

[45] During a Stage 4 low OFO, customers must balance their gas deliveries to within 5% of their burn or pay a penalty of $25 per dekatherm for any underdeliveries that exceed the 5% imbalance tolerance.

The second Rule 23 curtailment went into effect at midnight on February 20 and lasted until 11:59 on February 21. Minimum temperatures throughout the territory were very similar or identical to those during the previous Rule 23 curtailment: Downtown Los Angeles was 43°F, Woodland Hills was 32°F, and Long Beach was 40°F. Gas day sendout was 3.6 Bcf. Compounding the system's problems was the decline in total inventory in the non-Aliso fields, which were down 21% since the last Rule 23 curtailment to 42% full. The System Operator called Stage 4 OFOs on February 20 and 21.

Figure 9: SoCalGas Withdrawals, Receipts, and Sendout: 2/4-2/8

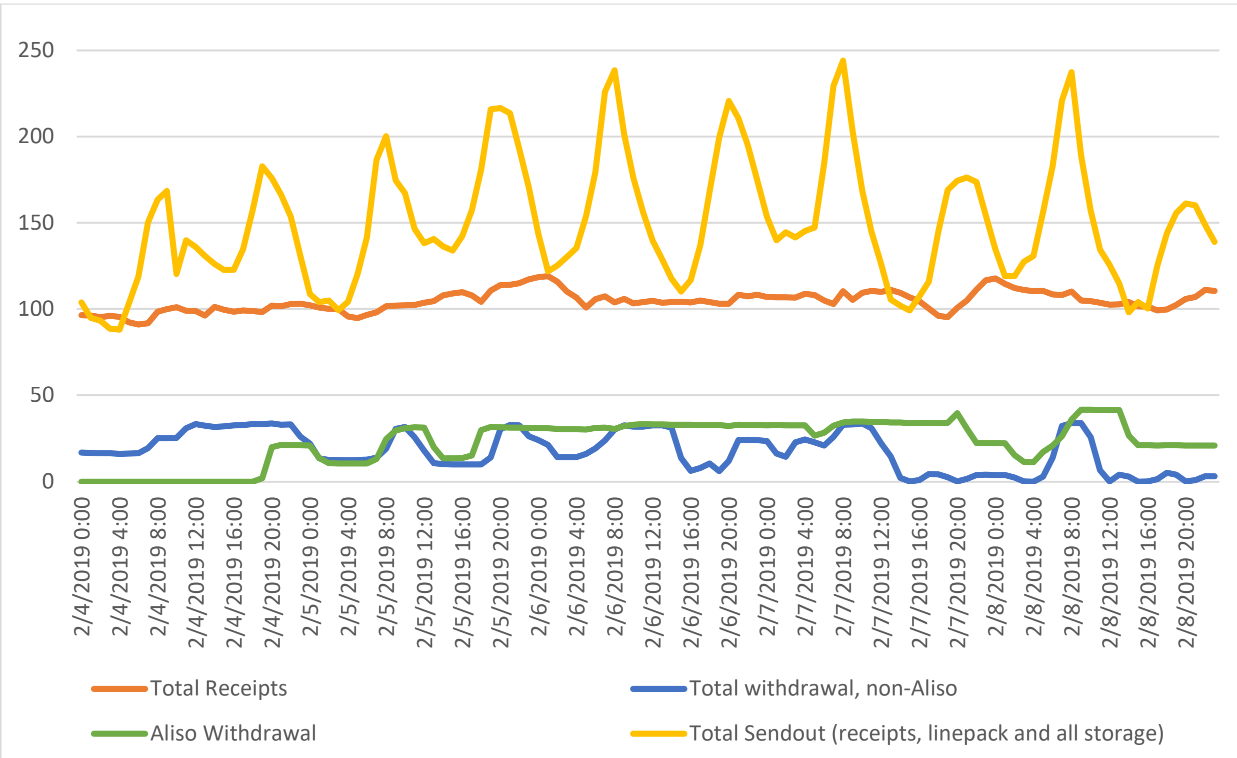
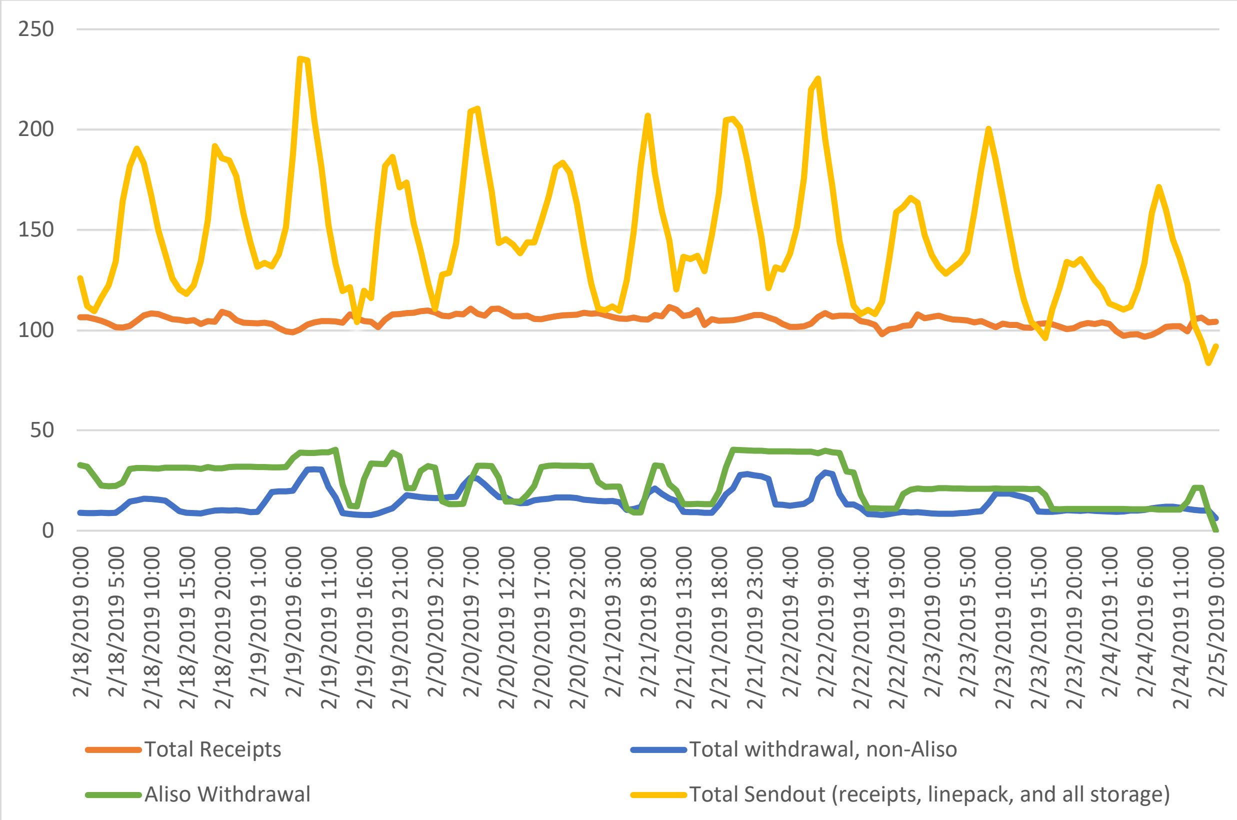


Figure 10: SoCalGas Withdrawals, Receipts, and Sendout: 2/18-2/25



Data source: SoCalGas Envoy and April 9, 2019 Data Request

February ended with one more withdrawal event, initiated on 8:17 PM on gas day February 26 and lasted until 12:03 PM on gas day February 27 (3.16 Bcf and 2.94 Bcf sendout days, respectively). SoCalGas used Aliso Canyon for approximately 17 hours, withdrawing a total of 266 MMcf of gas, and the non-Aliso fields were also used during this time. By the end of the withdrawal event, the non-Aliso fields were 37% full. SoCalGas' 30-Day Aliso Canyon Withdrawal Report on this event states that an OFO was not called because the forecasted storage withdrawal available for balancing did not exceed the withdrawal capacity needed for balancing purposes. SoCalGas did not use Aliso Canyon during the morning peak on February 26, which led to a depletion of linepack. Given the limited hourly withdrawal capacity at the non-Aliso fields, the system could not recover before the evening peak, which also saw unexpectedly high demand from gas-fired electric generators. After requesting voluntary curtailments as required under the Withdrawal Protocol, SoCalGas initiated withdrawals from Aliso Canyon to recover linepack in advance of the following morning's peak.

During this withdrawal event, total system demand was higher than what was forecasted the morning of Gas Day February 26 (3.2 Bcf vs. 3 Bcf). Restricted Maintenance Operation was not called "due to the expected short duration of this event;" and demand response was not initiated "because of (1) the warmer temperatures, (2) the risk of customer fatigue and negative response, (3) the expected short duration of the event, and (4) because some of the load was attributed to the electric generation hourly demand, which would not have been affected by the SoCalGas demand response or gas conservation programs."[46] The impact of the cold February conditions on the non-Aliso fields supports SoCalGas' operational decision not to exceed month-end minimums during the month of January, a decision which facilitated core reliability through the winter. By the end of February, Honor Rancho and Playa del Rey were alarmingly close to their month-end minimums; La Goleta was not as depleted.

There were two Aliso Canyon withdrawal events in March. The first began at 5:14 AM on gas day March 4 and continued into gas day March 5 (which began at 7:00 AM). The System Operator initiated Aliso Canyon withdrawals to meet peak hourly demand. Hourly analysis confirms that although total demand was less than 3 Bcf, March 5 intraday ramping and peak hourly demand of 188 MMcfh could not have been met without Aliso Canyon and linepack, because receipt point utilization was in the mid-90% range, and the non-Aliso fields had a reduced withdrawal rate. The non-Aliso Canyon fields plus pipeline supplies provided approximately 126 MMcfh. The next morning's peak of 140 MMcfh lasted from 6:00 to 7:00 AM, before Aliso Canyon withdrawal ceased at 7:04 AM. Honor Rancho and Playa del Rey were not used on the morning of March 6. ED staff has determined that there was sufficient linepack by then to cease Aliso withdrawals.

Aliso Canyon withdrawals began one last time at 7:55 AM on gas day March 11. This was a 3.1 Bcf demand day with a Stage 3 low OFO declared. Non-Aliso inventory started the gas day at 32% full, which makes flowing gas supplies much more significant. From 8:00-9:00 AM, peak hourly demand reached almost 203 MMcfh (99 MMcfh from pipeline supply and 22.3 MMcfh from non-Aliso) and from 7:00-8:00 PM peak hourly demand reached 162 MMcfh (103 MMcfh from pipeline supply and 10.2 MMcfh from non-Aliso). ED staff reviewed remaining capacity that could have been scheduled during Cycle 2 and Cycle 3 (the cycles flowing during March 11 peaks) to conclude 100% receipt point utilization plus maximum non-Aliso withdrawal would have still fallen short of meeting peak demand. It was unfeasible to meet both peak periods without Aliso Canyon.

Gas Acquisition

SoCalGas' Gas Acquisition Department procures gas for SoCalGas and SDG&E core customers, which are made up of residential and small business customers. Currently, Gas Acquisition is required to balance to a forecast rather than to actual burn on high or low Operational Flow Order days. Therefore, there are three data sets relevant to this section: daily core forecast,

[46] 30-day Aliso Canyon Withdrawal Report, pg. 2-3: http://cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/News_Room/NewsUpdates/2019/AlisoWithdrawalsNotification02-27-2019c.pdf

confirmed gas deliveries, and estimated actual burn.[47] ED staff analyzed Gas Acquisition's role in the winter season supply by comparing daily core forecasts to estimated actual burns, then comparing core's confirmed gas deliveries to the estimated actual burn (see Figures 11 and 12). The data in this Gas Acquisition section reflects November 2018 through March 2019.

Gas Acquisition's estimated actual burn was within +/- 5% of the forecast on about 48% of the days and +/- 10% on 82% of the days during the winter. The remaining 18% of the instances when estimated actual burn exceeded +/- 10% of the forecast primarily occurred in January through March and will receive deeper analysis in this section. There is no penalty for being out of balance on non-OFO days, so Table 7 focuses on Gas Acquisition's deliveries on days when an OFO was called. Negative percentages indicate a forecast lower than estimated actual burn.

Table 7: Number of OFO Days and Forecast Compared to Estimated Actual Burn[48]

	Number of Low OFO Days When % Difference Between Forecast and Estimated Actual Is:					
	Under -10%	Within -5%	Between -5-10%	Within +5%	Between +5-10%	Over +10%
Low OFO	8	21	19	20	8	4

	Number of High OFO Days When % Difference Between Forecast and Estimated Actual Is:					
	Under -10%	Between -5-10%	Within -5%	Within +5%	Between +5-10%	Over +10%
High OFO[49]	1	1	3	4	2	0

The 21 low OFO days when Gas Acquisition's estimated actual burn was within -5% of the forecast also saw confirmed gas deliveries within +/- 5% of estimated actual burn, with a notable exception on February 6 calendar day when a cold front hit and confirmed gas deliveries were much less than estimated actual usage. On February 18, the forecast was more than 5% below estimated actual, and confirmed gas deliveries were more than 10% less than estimated actual. This was a day of approximately 92% receipt point utilization, which leaves some remaining pipeline capacity that could have been utilized had the forecast been more accurate.

[47] The forecasts used by Gas Acquisition are created by the Demand Forecasting Group located in SoCalGas' Department of Regulatory Affairs and separated from Gas Acquisition by a firewall. In the gas scheduling process, confirmed gas is the amount of nominated gas approved for scheduled delivery into the SoCalGas system. Core's "estimated actual burn" is derived by subtracting the noncore and Core Transport Agent sendout from System Sendout.

[48] Positive imbalances on a low OFO day and negative imbalances on a high OFO day help the system.

[49] All but one high OFO days occurred in November, when injection capacity was limited due to high inventory in all four storage fields. The other high OFO occurred on March 27.

Graphs of the delta between daily core forecasts and confirmed gas deliveries cannot be provided due to confidential market information. However, it can be stated that Gas Acquisition delivered within 5% of their daily forecast approximately 69% of the time and within 10% of their daily forecast approximately 93% of the time. To provide more clarity, there were 22 low OFO days when confirmed gas deliveries were within -5% less than the forecast and one low OFO day when confirmed gas deliveries were between -5-10% less than the forecast. On February 6, confirmed gas deliveries were more than 10% below the forecast; this was a Stage 3 low OFO day. Additionally, confirmed gas deliveries were compared to estimated actual burn to analyze the extent to which daily gas deliveries fulfilled core's gas usage. These results also cannot be shared due to confidentiality, but overall themes can be shared. ED staff found that confirmed gas deliveries were within 10% of estimated actual for 70% of the winter. During the end of January, there was about one week when confirmed gas deliveries exceeded estimated actual burn by more than 15%. There were no apparent negative system impacts due to these over-deliveries, and there were no OFOs on these dates.

Confirmed gas deliveries were below estimated actual demand for almost 61% of February. Furthermore, confirmed gas deliveries were more than 10% below estimated actuals on five days in February; SoCalGas called Stage 4 OFOs on two of those days. OFO penalty data show that both noncore and Gas Acquisition's underdeliveries contributed to the Stage 4 OFO declarations. However, there was insufficient pipeline capacity available to schedule enough gas on these days, which also saw Aliso Canyon withdrawals. In addition, ED staff found a strong correlation (of almost 84%) between the daily difference of core forecast and estimated actual burn and the daily difference of confirmed gas receipts and estimated actual burn.[50] This means that when core forecasts were lower than estimated actual, it was very likely that confirmed gas receipts were also lower than estimated actual burn. Lastly, confirmed gas deliveries exceeded estimated actual usage by more than 10% on eight days in March. Two of those days, March 19 and March 20, saw the highest receipt point utilization that month. As mentioned earlier, this can be attributed to low market prices, an ideal amount of gas nominations by noncore and Gas Acquisition, and significant injections of gas into storage to prepare for the summer months.

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[50] The statistical standard of correlation higher than 50% being considered very strong correlation is used here.

Figure 11: Core Forecast vs. Estimated Actual Burn—November-December 2018

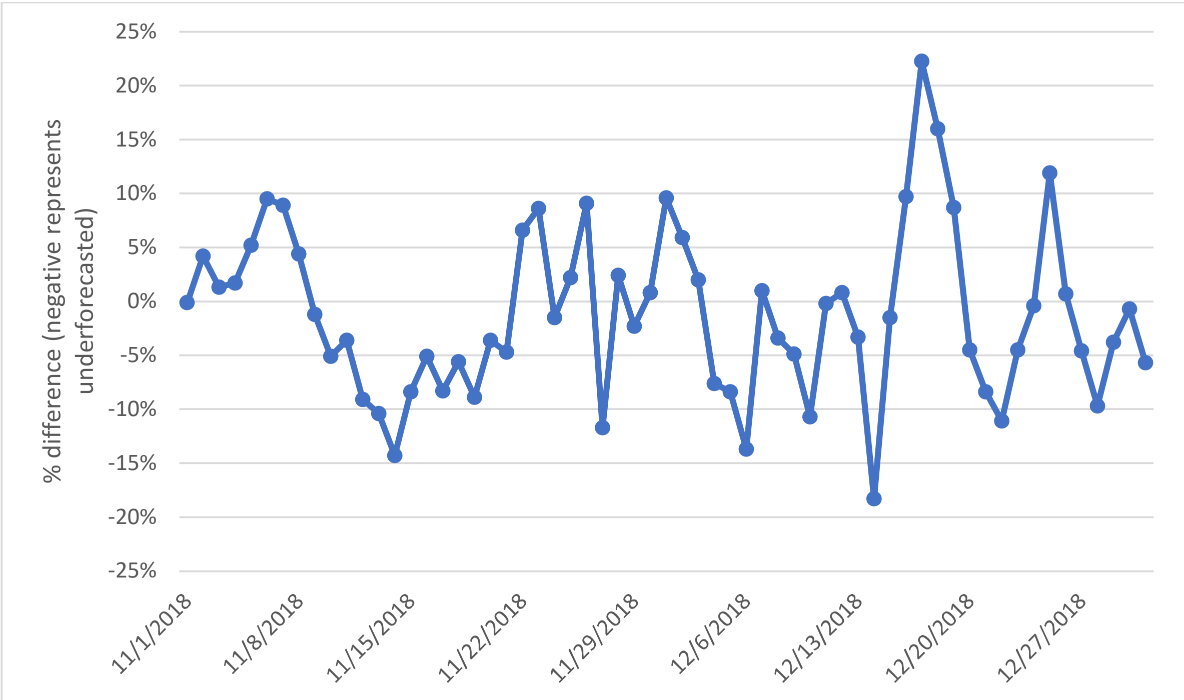
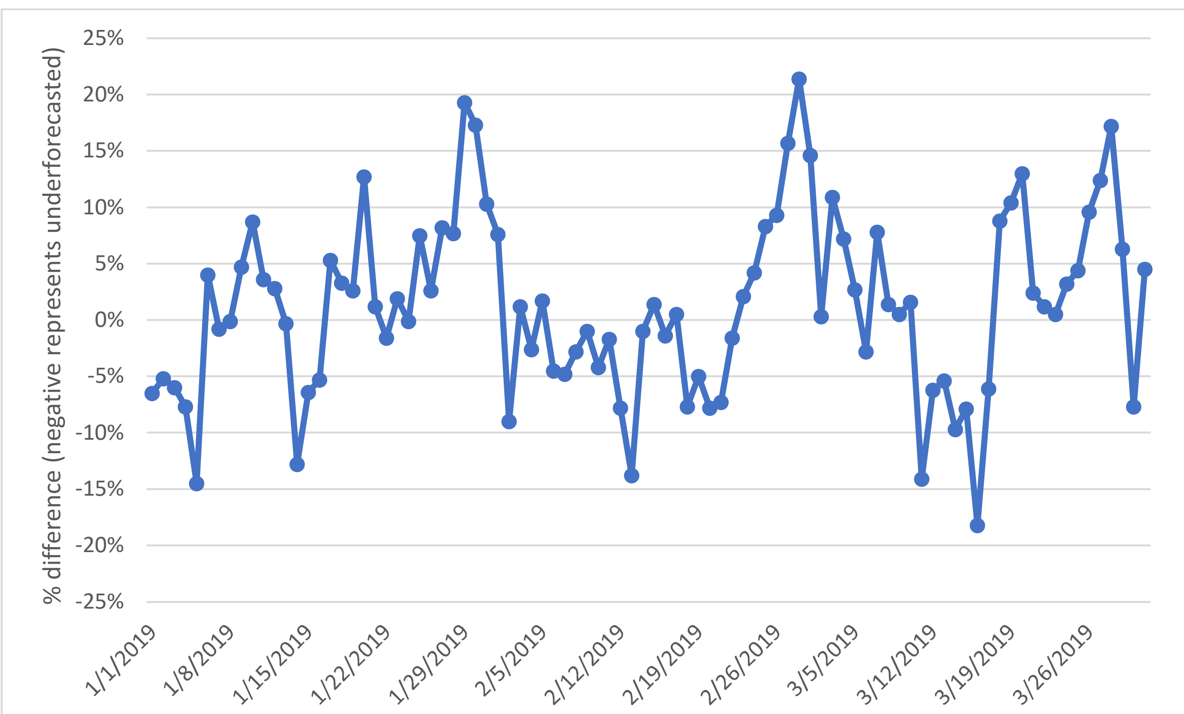


Figure 12: Core Forecast vs. Estimated Actual Burn—January-March 2019



Data source: SoCalGas data requests

ED staff analyzed Gas Acquisition' forecasts and compared them to estimated actual gas burn to determine forecast accuracy. On December 17, a Stage 1 low OFO day, core's forecasted demand was 22.2% more than estimated actual burn. The extra gas delivered by Gas Acquisition therefore benefited system balancing on that day. There were six days in January when there was more than a 10% difference between the gas forecast and estimated actual burn. On four of those days, Gas Acquisition benefited system balancing by delivering more to the system than their estimated actuals. On the remaining two days, January 5 and January 14, the forecast was lower than estimated actuals. January 5 was not a low OFO day; therefore the forecast error did not impact the system. On January 14, the gas forecast was 12.8% below estimated actual burn, a Stage 1 low OFO was declared, and OFO penalties were paid (see Table 8 below). Gas Acquisition's January 14th confirmed gas deliveries exceeded the forecasted amount and were within approximately 5% of meeting estimated actual. On that day, even if Gas Acquisition had delivered 100% of core gas burn, pipeline supplies and non-Aliso withdrawal would not have been enough to meet peak demand. However, an improved forecast on January 14 could have led to more confirmed gas deliveries and to a more balanced system.

In February, Gas Acquisition saw three instances when there was more than a 10% difference between the gas forecast and estimated actual burn. On February 13, the forecast was 13.8% lower than estimated actual burn, a Stage 3 low OFO was called, and there were Aliso Canyon withdrawals. On this day, even if Gas Acquisition had delivered 100% of core gas burn, pipeline supplies and non-Aliso withdrawal would not have been enough to meet peak demand. The second and third instances occurred on February 27-28 and were overestimates of estimated actual burn. The System Operator withdrew from Aliso Canyon on February 27 and total withdrawal capacity was especially low. Furthermore, there were 22 low OFO days in March. Gas Acquisition's forecasts were lower than estimated actual burn on nine of those days by an average of less than 10%. On the rest of the low OFO days in March, Gas Acquisition overestimated core customers' estimated actual burn.

Gas Acquisition's inability to schedule gas from Aliso Canyon under the Withdrawal Protocol, which prohibits withdrawals from the storage facility except as an asset of last resort, contributed to the thin margins between overall system demand and supply this winter. Gas Acquisition has paid to store gas in Aliso Canyon for core customers, but it is not currently allowed to schedule that gas to meet demand. The gas in core's storage account therefore subsidizes system reliability since all customers rely on it when the system is not in balance.[51] Core customers pay the carrying cost of their storage asset, which includes interest for the gas that was withdrawn for balancing purposes.[52] When gas is withdrawn for balancing, Gas

[51] On the other hand, advocates for noncore customers have pointed out in various forums that they bear the vast majority of OFO penalty charges.

[52] Carrying Costs of Storage Inventory is an interest component, carrying cost for value of the gas in storage inventory, paid by SoCalGas, and chargeable to core customers.

Acquisition must then purchase new gas, potentially on less favorable terms, to replenish what was withdrawn. Data obtained by ED staff indicates that if Gas Acquisition had been able to

Table 8: OFO Penalties Paid by Core and Noncore—January-February 2019

OFO Date	OFO Stage	SoCalGas	SDG&E	% Difference in Core Forecast to Estimated Actual Gas Burn
01/02/2019	3	$ 158,102	$ 5,768	-5.20%
01/03/2019	3	$ 93,657	$ 11,312	-6.00%
01/07/2019	3	$ -	$ 26,090	-0.80%
01/14/2019	1	$ 13,380	$ -	-12.80%
01/15/2019	2	$ 11,903	$ -	-6.40%
01/16/2019	2	$ 1,707	$ -	-5.30%
01/22/2019	1	$ 772	$ -	-1.60%
01/23/2019	2	$ 3,967	$ 3,956	1.90%
01/24/2019	2	$ 4,440	$ 1,240	-0.10%
02/01/2019	2	$ 3,055	$ -	7.60%
02/04/2019	3	$ 17,295	$ 6,104	-2.60%
02/05/2019*	3	$ 802,158	$ -	1.70%
02/06/2019*	3	$ 1,230,534	$ -	-4.50%
02/07/2019	4	$ -	$ 29,468	-4.80%
02/08/2019	4	$ 198,770	$ -	-2.80%
02/09/2019	3	$ 12,740	$ -	-1.00%
02/10/2019	3	$ 32,227	$ -	-4.20%
02/11/2019	3	$ 70,437	$ -	-1.70%
02/12/2019	3	$ 15,789	$ 6,588	-7.80%
02/13/2019	3	$ 37,570	$ -	-13.80%
02/17/2019	3	$ 21,190	$ -	0.50%
02/18/2019	3	$ 170,345	$ -	-7.70%
02/19/2019	3	$ 727,036	$ 96,907	-5.00%
02/20/2019	4	$ 108,193	$ -	-7.80%
02/21/2019*	4	$ 57,153	$ -	-7.30%
02/22/2019*	3	$ 54,930	$ -	-1.60%
02/23/2019*	3	$ 43,359	$ -	2.10%

*This table only lists dates with OFO penalties. *Indicates dates with core penalties. Data source: SoCalGas data request*

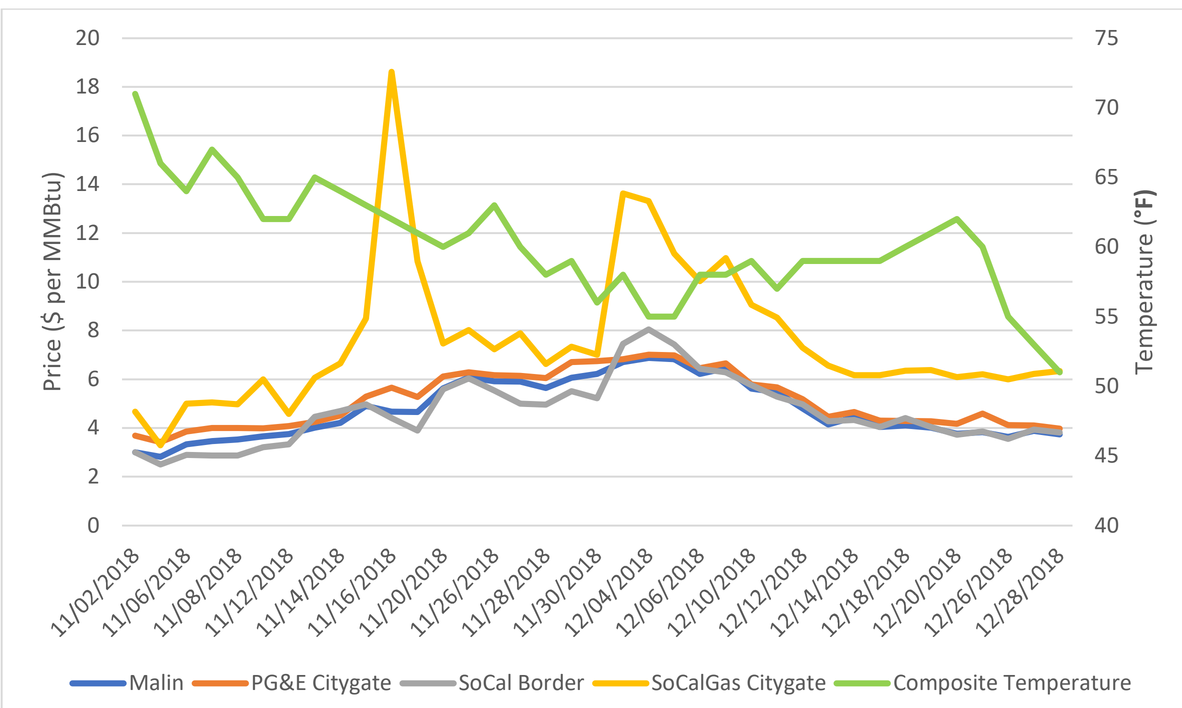
schedule gas from Aliso Canyon, they could have avoided OFO penalties this winter.

In addition to the OFO penalties incurred, this winter presented Gas Acquisition with significant costs on after-market activities. The CPUC requires Gas Acquisition to secure longterm contracts for an average of at least 90% of winter demand. Gas Acquisition procures the remaining gas during bid week or in the spot market.[53] Though minor, the remaining gap leaves Gas Acquisition exposed to gas price volatility. Gas Acquisition's after-market activities resulted in gas purchased at prices higher than the benchmark price, which had a significant impact on their Gas Cost Incentive Mechanism (GCIM) during the month of February.[54]

Natural Gas Prices

Winter 2017-18 and summer 2018 saw a pattern of price spikes during extreme weather, which continued over the winter. Inaccurate weather projections across the country impacted gas demand forecasts and contributed to price increases from coast to coast. Figures 13 and 14 graph gas prices at PG&E Malin,[55] PG&E Citygate, SoCal Border, and SoCal Citygate, then overlay the composite temperature in Southern California. SoCal Citygate prices surpassed the other price points 94% of the time over the winter. The remaining 6% of the time, the spread between the highest price and SoCalGas Citygate was less than $0.70/MMBtu.[56]

Figure 13: Gas Prices November-December 2018



[53] CPUC Decision 04-09-022, page 13

[54] Due to market confidentiality rules, the dollar amount cannot be shared in this report.

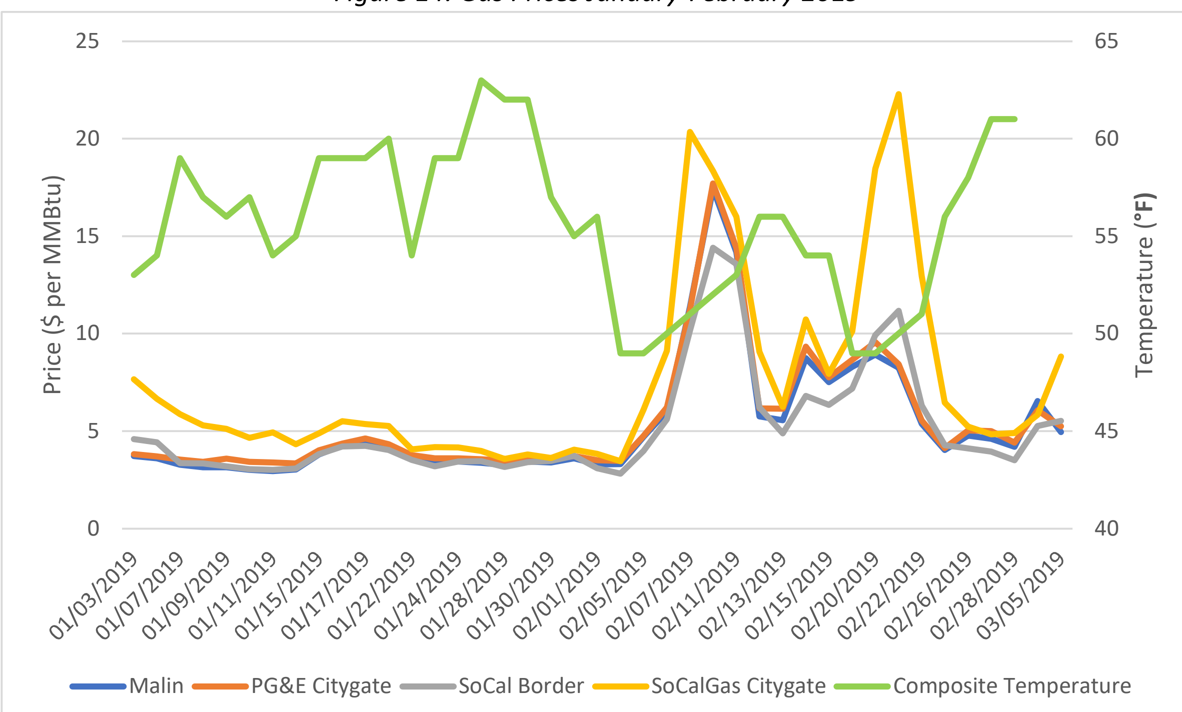
[55] Malin is a PG&E receipt point on the California border.

[56] One million British thermal units; equivalent to one dekatherm.

SoCal Citygate first spiked to approximately $18.00/MMBtu on trade date November 15 for November 16 flow, due to a maintenance-related capacity reduction of 620 MMcfd in the Wheeler Ridge Zone, which lasted from November 16-18.[57] The next two weeks saw additional volatility throughout the nation as storage inventories remained below historical norms. In Southern California, tight conditions between demand and firm receipt capacity were forecasted through November and December, contributing to higher spot and futures prices. December bidweek (the last five business days of November) recorded the highest prices to date for a December.[58]

On December 3, SoCal Citygate prices spiked again due to increased gas sendout (2.92 Bcf for gas day December 3) and capacity reductions due to maintenance at the Wheeler Ridge Transmission Zone. December 5 and 6 were 3.1 Bcf and 3.2 Bcf gas days, respectively, contributing to noticeably higher SoCal Citygate prices until mid-December.

Figure 14: Gas Prices January-February 2019



Data source: Natural Gas Intelligence and SoCalGas Envoy

Cold fronts throughout the western United States on February 6-8 increased sendout along upstream pipelines, which pushed both border and citygate prices up throughout the region. Layered on top of the Stage 4 OFOs, high receipt point utilization, Rule 23 curtailments, and Aliso maintenance work previously discussed, these national weather patterns further impacted California's gas markets. On February 6, Sumas prices at the Canada border reached

[57] Historical maintenance can be found on the SoCalGas Envoy Maintenance Schedules page.
[58] "Gas Daily." Platts. Volume 35, Issue 233. (December 2, 2018)

approximately $14/MMBtu, SoCalGas Citygate prices reached $22/MMBtu, and PG&E prices tracked closely at a high of almost $18/MMBtu.

The last major price spike of the winter occurred on February 20-21, with the highest SoCalGas Citygate prices of the season. Unlike the February 6-8 event, there was a large spread between prices in SoCalGas and PG&E territories. During this period SoCalGas Citygate prices peaked at $26/MMBtu and averaged $22.29/MMBtu.

Electricity Prices

Over the winter, SoCalGas declared 14 voluntary curtailments of electric generation customers, two systemwide curtailments watches, and two mandatory Rule 23 curtailments. During the voluntary curtailments, SoCalGas worked with the CAISO and LADWP balancing authorities to manage reliability on both the gas and electric systems. The CAISO activated their gas nomogram constraints to redispatch resources in Southern California two times in February—February 6-8 and February 20.[59] The CAISO Department of Market Monitoring issued a Q1 2019 report stating, "In the day-ahead market, these constraints were binding in about 10 percent of hours during which they were enforced and were not binding when enforced in the real-time market."[60] In brief, nomograms can be activated by the CAISO to enforce a gas constraint/limitation in a region. Gas price scalars were another tool available to CAISO, which could be activated to increase the gas price index in a region. Both nomograms and scalars make gas-fired electric generation more expensive in Southern California. On November 26, 2018, FERC accepted CAISO's proposal to temporarily extend the use of nomograms until December 31, 2019, but rejected the request to extend the use of scalars.

The voluntary curtailments had mixed results. Since electric generation demand is already low in the winter, there were several times CAISO and/or LADWP could not curtail their demand. For instance, SoCalGas asked CAISO and LADWP to curtail their demand for Gas Days January 22-23, 2019. LADWP was able to curtail load by 9 MMcfd on January 22 and by 19 MMcfd on January 23. CAISO, on the other hand, was not able to curtail on either day.[61]

Electricity prices tend to reflect natural gas price trends because natural gas generators are often the marginal resource in the CAISO market. Furthermore, "SoCal Citygate prices often impact overall system prices because 1) there are large numbers of natural gas resources in the south,

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[59] For more information on nomograms and scalars, refer to the FERC decision accepting the temporary CAISO tariff changes: https://www.ferc.gov/CalendarFiles/20160601181012-ER16-1649-000%20(2).pdf

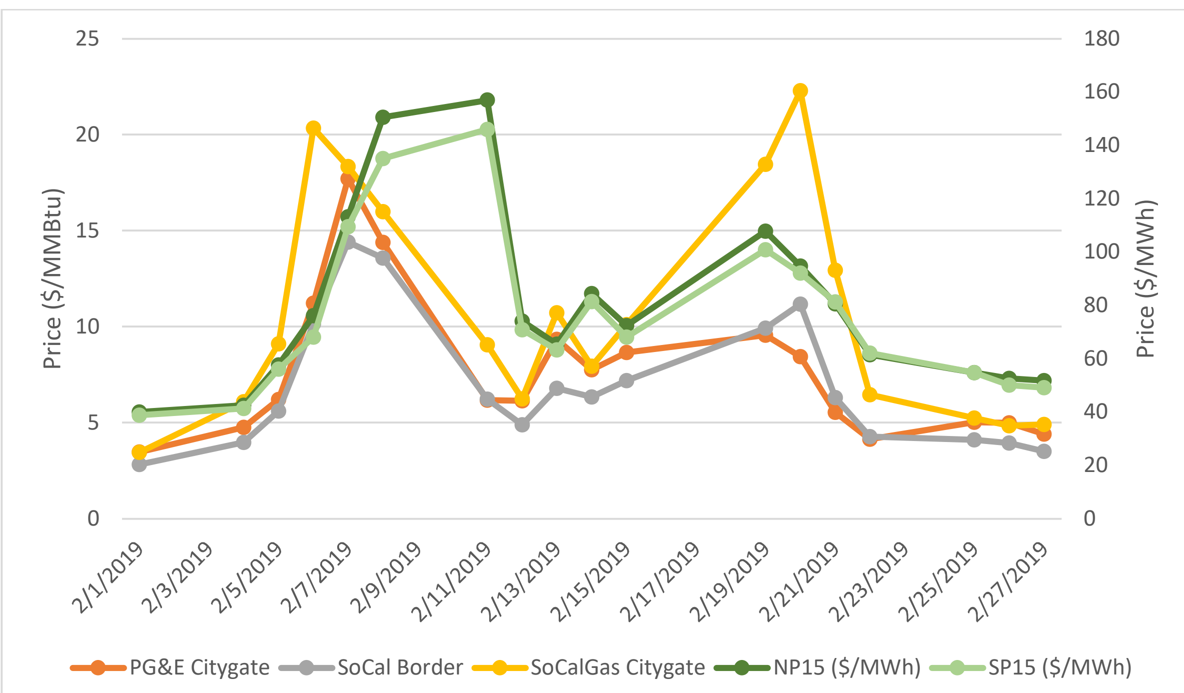
[60] *Q1 2019 Report on Market Issues and Performance*, Department of Market Monitoring — California ISO, Page 63: http://www.caiso.com/Documents/2019FirstQuarterReportOnMarketIssuesAndPerformance.pdf

[61] 30-Day Aliso Canyon Withdrawal Report (Public Version): https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/News_Room/NewsUpdates/2019/AlisoWithdrawalsNotification01-28-2019b.pdf

and 2) these resources can set system prices in the absence of congestion."[62] CAISO and LADWP both felt the impact of SoCalGas' system constraints and the cold winter. Figure 15 graphs PG&E Citygate, SoCal Border, and SoCal Citygate gas prices against CAISO NP15 and SP15 prices during February, the most volatile month of the winter. Meeting cold day sendout under gas system constraints led to Stage 3 and Stage 4 low OFOs that pushed up the price of gas. The light green and dark green lines in Figure 15 show how electricity prices were impacted.

Total wholesale cost to serve load in the CAISO market from January through March was about $2.7 billion, which is a 43% increase compared to that same period in 2018. This was largely driven by an increase in natural gas prices.[63] Moreover, bid cost recovery payments during the same time period totaled about $30 million, which is roughly $5 million higher than the first quarter of 2018. About 63% of the bid cost recovery amount was due to the real-time market. The highest bid cost recovery payments in the real-time market occurred in February when payments totaled about $8.5 million. [64] The real-time bid cost recovery payment is one parameter by which the impact of higher gas prices was realized in electricity costs.

Figure 15: Gas and Electricity Prices February 2019



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[62] *Q1 2019 Report on Market Issues and Performance*, Department of Market Monitoring — California ISO, Page 4: http://www.caiso.com/Documents/2019FirstQuarterReportOnMarketIssuesAndPerformance.pdf

[63] Ibid., Page 10.

[64] Ibid., Page 33.

Data source: Natural Gas Intelligence and CAISO OASIS

Additionally, CAISO reported “first quarter imbalance offset costs totaled $6 million, the sum of $20 million congestion offset costs less $13 million energy offset and $1 million loss offset.”[65] Unlike Q1 2018, when real-time energy imbalance offset costs contributed to the majority of the total, Q1 2019 saw real-time congestion imbalance offset costs as the main contributor (refer to footnote for CAISO details).[66]

Due to recent changes in the congestion revenue rights auction and the inability to determine what percentage of congestion costs are ultimately related to gas constraints, congestion revenue rights are not discussed in this report.

LADWP has estimated their winter costs that resulted from constraints on the SoCalGas system in Table 9 below. This is a large increase from last winter’s costs because the cold season was much lengthier this year. LADWP reported approximately $7.36 million in additional costs from November 2018 to March 2019. These costs result from several market transactions and other costs, such as: uneconomic sales/purchase to avoid OFO penalties, paying OFO penalties, uneconomic sales/purchase in response to voluntary or mandatory curtailments, and uneconomic dispatch in response to voluntary or mandatory curtailments.

Table 9: LADWP Additional Costs During Nov. 2018-March 2019

Month	Hedged Purchases	Lost Opportunity Cost	Transmission Cost	Non-economic Dispatch	Grand Total
Nov-18	$ -	$ -	$ -	$ -	$ -
Dec-18	$ -	$ -	$ -	$ 52,330.00	$ 52,330.00
Jan-19	$ 359,010.08	$ 668,682.30	$ 93,325.35	$ 603,690.06	$ 1,724,707.78
Feb-19	$ 47,273.77	$ 3,087,353.32	$ 69,201.85	$ 2,380,909.84	$ 5,584,738.78
Mar-19	$ -	$ 296,867.28	$ -	$ -	$ 296,867.28
Total	**$ 406,283.85**	**$ 4,052,902.90**	**$ 162,527.20**	**$ 3,036,929.90**	**$ 7,658,643.84**

[65] Ibid., Page 36.

[66] Ibid., Page 37

LADWP also held off on electric transmission upgrade work from February 5 to 25 due to gas curtailments and from March 5-8 due to heavy rain and gas curtailments. Due to these work stoppages, LADWP was not able to complete the work prior to summer 2019.

Closing Summary

Overall system capacity and conditions remained very similar to the winter of 2017-18. However, in winter 2018-19, weather conditions were variable in January and March and very cold in February, whereas the prior winter only saw a 15-day period of exceptionally cold weather. In the western United States, gas price volatility was experienced from Sumas, near the Canadian border, down to SoCal Citygate as weather models proved to be inaccurate. Flowing gas supplies reached near maximum capacity on several gas days. Especially notable was the consistently high receipt point utilization during the month of February. Gas storage usage was heavy, with the non-Aliso fields at approximately 32% full by mid-March. The longest duration and highest volume of gas withdrawn from Aliso Canyon since the October 2015 leak occurred this February. Aliso Canyon withdrawals occurred on 37 gas days this winter for a total withdrawal of approximately 14.086 Bcf. Despite these withdrawals, there were 80 low OFOs this winter and two mandatory Rule 23 curtailments.

From February 6 to 8, SoCal citygate prices reached $22/MMBtu, and PG&E prices tracked closely at a high of almost $18/MMBtu. CAISO and LADWP bore downstream effects of the cold weather and system constraints, with NP15 and SP15 prices reaching above $150/MWh.

In response to summer gas and electric price volatility, the CPUC held a joint workshop with the California Energy Commission on January 11, 2019.[67] Stakeholders presented potential solutions to address price volatility including: expediting pipeline work, modifying or eliminating the Aliso Canyon Withdrawal Protocol, creating a gas procurement tariff for electric generators, requiring core customers to balance to their actual burn rather than a forecast, and changing the OFO penalty structure. The CPUC has implemented most of the proposed solutions presented at the workshop.

On May 30, 2019, the CPUC approved Decision D.19-05-030 in proceeding A.14-06-021 to establish new SoCalGas OFO penalty structures aimed at providing cost relief to end-use electric customers. The decision modified Rule 30 to cap the Stage 4 OFO penalty at the Stage 3 level of $5/dth and the Stage 5 OFO penalty at $5/dth plus the G-IMB daily balancing standby rate from June 1 through September 30. The decision also adopted an eight-stage penalty structure from October 1 through May 31, which aims to maintain greater uniformity between PG&E and SoCalGas rules during peak gas season. Furthermore, on July 23, 2019, the CPUC issued a revised Aliso Canyon Withdrawal Protocol to address gas reliability challenges and

[67] For more information on the workshop, visit: https://www.energy.ca.gov/2018_energypolicy/documents/index.html#01112019

electric and gas price impacts in Southern California.[68] In addition, on August 1, 2019, the CPUC approved Decision D.19-08-002 in proceeding A.17-10-002, establishing new balancing rules that require core customers to balance their deliveries to their burn rather than a forecast, beginning April 1, 2020.

Lastly, the CPUC's Energy Division and Safety and Enforcement Division teams continued weekly—at times daily—oversight calls and meetings with SoCalGas to ensure Lines 235-2, and 4000 were remediated in a timely manner. Line 235-2 returned to service on October 15, 2019 and Line 4000 returned to service on October 24, 2019. Safety Enforcement Division also conducted unscheduled inspections to ensure that work was being performed as expected. The CPUC will continue to exercise oversight to safeguard system reliability and support just and reasonable rates.

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[68] The revised Aliso Canyon Withdrawal Protocol, CPUC letter to stakeholders, and comments can be found here: https://www.cpuc.ca.gov/aliso/