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California Energy Commission

STAFF PAPER

Winter 2022–2023 Southern California Gas Company Reliability Assessment

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ABSTRACT

California Energy Commission staff analyzed supply and demand conditions for the Southern California Gas Company natural gas pipeline system for winter 2022–2023 to inform policy makers and the public about the risk of service interruptions. The system remains impaired, with two key pipelines unable to operate at design capacity. Underground storage facility operations also are necessarily impaired due to inventory restrictions at Aliso Canyon and work needed to comply with California Geologic Energy Management Division safety regulations. Recognizing these restrictions, staff assesses that the risk of service interruptions is lower this winter than in recent winters. This lowered risk is largely due to forecast demand being lower than in prior years. Specifically, staff projects zero curtailment on a winter day cold enough to occur once in 10 years and curtailment of about 280 million cubic feet per day of noncore load on an extremely cold day. Staff has confirmed this finding using peak-day gas balances, a stochastic hourly gas balance, and hydraulic simulations of gas system operations. Prices this winter are likely to remain at current levels, but consumers should expect higher prices during peak demand periods. This analysis features use of a monthly average condition forecast, and cold and extreme peak day natural gas demand forecasts. In addition, this analysis uses California Energy Commission gas demand forecast for the first time instead of the utilities California Gas Report.

Keywords: Natural gas, system, peak, extreme, balance, demand, Synergi, curtailment, interruption, risk, improved, pipeline, capacity, storage, hydraulic, modeling

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EXECUTIVE SUMMARY

The California Energy Commission (CEC) presents this Southern California Gas Company (SoCalGas) Winter 2022–2023 Reliability Assessment (Winter Assessment) to help guide planning decisions and prepare the Southern California region for different fossil gas demand scenarios. The CEC's Winter Assessment shows that reliability has improved over winter 2021, and SoCalGas now appears able to meet 1-in-10 cold winter peak demand, which represents a one in ten-year likelihood of occurrence. This improved reliability is primarily due to lower forecast of demand under 1-in-10 cold conditions. Since the fossil gas leak at Aliso Canyon in 2015, SoCalGas has been unable to meet the 1-in-10 cold winter demand until this year. While SoCalGas can meet the 1-in-10 cold winter demand this year, there is no reserve margin.

Under more extreme cold conditions, the CEC projects curtailments, most likely for noncore customers on the Southern System. (SoCalGas' Southern Zone is connected to U.S. Southwest and Mexico pipeline systems at Ehrenberg in Arizona, Blythe in eastern Riverside County and Otay Mesa in southern San Diego County [to El Paso, North Baja, and TGN] respectively). Extreme peak day conditions represent 1-in-35 Core, a one in 35-year likelihood of occurrence, and 1-in-10 Noncore. Core customers are residential and small business, and noncore customers are electric generation, industrial, and all other customers. These curtailments are not related to inventory limits at Aliso Canyon natural gas storage field, which is located in the Santa Susana Mountains in Los Angeles County, California.

The National Oceanic and Atmospheric Administration (NOAA) is predicting a 75 percent chance that La Niña conditions will continue through February 2023. For California, La Niña is associated with a warm and dry winter. CEC developed a gas demand forecast for this analysis in lieu of using the gas utilities' California Gas Report (CGR) forecast, which CEC has used in the past. Staff disaggregated the annual gas demand forecast to monthly granularity and developed a 1-in-10 cold day forecast and a 1-in-35 extreme peak day forecast as shown in Table 1. The temperature associated with the 1-in-35 extreme peak day is a system average 41.4 degrees Fahrenheit (see Appendix A for methodology). The cold day forecast is about 300 million cubic feet per day (MMcfd) lower than last year's cold day forecast, and the extreme peak day demand is about 230 MMcfd lower than last year's extreme peak day forecast. Since this is the first year that CEC produced a gas demand forecast, this comparison is made to the CGR forecast that was used in last year's winter assessment. The decline in this winter's forecast is primarily due to reduced electric generation demand. Because the forecast demand is lower, the key risk to reliability is multiday cold weather events with additional infrastructure outages.

Table 1: CEC Cold Day and Extreme Peak Day Demand

	Case 1: Cold Day	Case 2: Extreme Peak Day
Peak Day Demand (MMcfd)	**Core + Noncore 1-in-10***	**Core 1-in-35 + Noncore 1-in-10****
Core	3,002	3,393
Noncore-Non-Electric Generation	744	705
Electric Generation	914	844
TOTAL Demand	4,660	4,942

***Jan Peak**

**** Dec Peak**

Source: CEC staff

The supply situation will be similar to last winter, including continued constraints on SoCalGas' Northern System and Southern System. Northern System Line 235-2 and Line 4000 both returned to service last year but at reduced operating pressure. The Southern Zone remains constrained due to the August 2021 rupture on the El Paso Natural Gas' (EPNG) southern mainline southeast of Phoenix. This mainline delivers gas to SoCalGas at Ehrenberg, Arizona. Absent an identified return to service date, the CEC assumes it will continue to be out of service this winter. While that rupture did not result in any curtailments to customers last winter, curtailment watches did occur. Last winter, the CPUC increased inventory limits at Aliso Canyon. SoCalGas reporting data show its storage facilities have inventory close to maximum levels. Table 2 presents a comparison of SoCalGas pipeline supply and storage assumptions for the previous three winters and this winter. The maximum feasible withdrawal from that inventory, however, remains unclear. Withdrawal capability depends on storage inventory, which typically declines over the winter as more gas is withdrawn. Another variable is the well maintenance and testing work required by the California Geologic Energy Management Division's (CalGEM) new safety/inspection rules, which pulls wells out of service. The average withdrawal capacity made available to customers on winter days that met the Aliso Canyon Withdrawal Protocol was 1,850 MMcfd.

The SoCalGas system was designed to meet winter demand with flowing pipeline supply and storage withdrawals. The analysis assumes 2,815 MMcfd flowing on the pipelines and 1,850 MMcfd storage withdrawal for a total of 4,665 MMcfd. The total just covers the cold day demand of 4,660 MMcfd with no reserve margin and is insufficient to cover the extreme peak day of 4,942 MMcfd, which results in about 280 MMcfd curtailment of noncore load. Any adverse event, such as a pipeline going out of service, could lead a higher curtailment. The curtailment potentially could be reduced by more supply being delivered at Ehrenberg or Otay Mesa in San Diego County, or higher storage withdrawals above 1,850 MMcfd.

In summary, the reliability outlook for this winter is improved from last winter 2021, primarily due to a lower demand forecast, but the risk of curtailments remains under adverse conditions. The key risk to reliability is multiday cold weather events with additional infrastructure outages.

Table 2: Winter Supply and Storage Comparison

	Winter 2019–2020	Winter 2020–2021	Winter 2021–2022	Winter 2022–2023
Pipeline Capacity (MMcfd)	~2,800	2,845	2,835	2,815
Total Storage Inventory (Bcf)*	~73	79	~81	~90
Percent Full (Total Storage)	87.70%	94%	96%	97%
Allowed Aliso Inventory (Bcf)	34	34	34	41

Source: CEC staff.

*Total storage inventory is as of September 30 before each winter. "Bcf" stands for "billion cubic feet."

CHAPTER 1: Introduction

The California Energy Commission (CEC) has prepared or taken a leading role in several seasonal fossil gas winter reliability assessments covering SoCalGas territory, starting in April 2016. The CEC's effort was necessitated after the well leak at the Aliso Canyon underground gas storage field owned and operated by SoCalGas severely limited use of that facility. These assessments help guide expectations about the reliability of service under normal and more extreme conditions in the winter. For reference, the gas system defines winter as November 1 to March 31. It is during these months that CEC staff expects to see the utilities withdraw gas, primarily to meet load that cannot be met solely with supplies flowing in from the interstate pipelines. A key interstate pipeline that delivers gas to the SoCalGas system remains impaired as well as certain parts of SoCalGas' pipeline or storage assets, making the winter reliability assessments even more essential.

The CEC prepared this assessment independently, using publicly available information. CEC added two new elements to the analysis, including the first CEC forecast of monthly, cold day, and extreme peak day demand, and a stochastic hourly gas balance, along with hydraulic modeling of the SoCalGas system.

CHAPTER 2: CEC Analysis

The following section provides an overview of the CEC's analysis prepared in support of the Winter Assessment. For the first time, staff developed and used CEC demand projections as inputs to this analysis instead of the utilities' demand projections from the California Gas Report. Staff also prepared monthly and peak day gas balance analysis, which assesses supply and demand for SoCalGas. An hourly stochastic analysis of the peak day was developed to understand the hourly changes to demand on the peak day and the needed storage withdrawals. Staff also analyzed the SoCalGas transmission system hydraulic model to verify the results of the peak-day gas balance. Furthermore, staff also examined market events and trends, such as gas market prices and gas system infrastructure. The following sections describe these analytical efforts.

Gas Demand Forecast

For this assessment, CEC developed a monthly gas demand forecast in lieu of using the gas utilities' forecast from the CGR. Staff disaggregated, or broke down into components, the CEC's annual gas demand forecast[1] to monthly granularity and developed a 1-in-10 cold day forecast and a 1-in-35 extreme peak day forecast.[2] Tables 3 and 4 present the findings from the monthly average, cold peak day, and extreme peak demand forecasts, and Appendix A describes the methodology. The cold day peak demand is about 300 MMcfd lower than last year's cold day peak forecast, and the extreme peak day demand is about 230 MMcfd lower than last year's extreme peak day forecast. Staff compared results to the CGR forecast used in last winter's assessment. Staff concluded that the decline in this winter's forecast is primarily due to reduced electric generation demand.

Table 3: CEC Monthly Demand

row	(MMcfd)	Oct 2022	Nov 2022	Dec 2022	Jan 2023	Feb 2023	Mar 2023
1	Average Demand (MMcfd)[3]	2,366	2,566	2,877	2,863	2,491	2,724
2	1-in-10 Demand (MMcfd)[4]	2,697	2,925	3,280	3,264	2,840	3,105

Source: CEC staff

1 *California Energy Demand Forecast 2021-2035* is available at California Energy Demand Forecast, 2021-2035.

2 1-in-10 represents a one-in-ten year likelihood of occurrence, and 1-in-35 represents a one-in-35 year likelihood of occurrence.

3 Average daily demand by month in a normal year.

4 Average daily demand by month at the 90th percentile of demand, which equates to a 1-in-10 probability of occurrence.

Table 4: CEC Cold Day and Extreme Peak Day Demand

(MMcfd)	**Case 1: Cold Day**	**Case 2: Extreme Peak Day**
Peak Day Demand (MMcfd)	**Core + Noncore 1-in-10***	**Core 1-in-35 + Noncore 1-in-10****
Core	3,002	3,393
Noncore- Non-Electric Generation	744	705
Noncore- Electric Generation	914	844
TOTAL Demand	4,660	4,942

*** January Peak**

**** December Peak**

Source: CEC staff

Pipeline Capacity and Storage Inventory

For the different analyses conducted in support of the Winter Assessment, staff made certain assumptions regarding pipeline capacity and storage inventory on the SoCalGas system. Staff observed that SoCalGas' pipeline capacity is similar to last year. SoCalGas' Envoy™ reports the capacity available to its customers for scheduling and maintenance and outage events that impact the capacity. These data are the primary source for the Winter Assessment assumptions, as follows:[5]

- The Northern Zone capacity is 1,250 MMcfd, still below the nominal capacity of 1,590 MMcfd, due to Line 235-2 and Line 4000 operating at reduced pressure.
- Wheeler Ridge can deliver 765 MMcfd.
- California production delivered to SoCalGas is assumed to be 70 MMcfd, reflecting an increase of 10 MMcfd from prior assessments due to this higher level of production.
- The Southern Zone capacity is 730 MMcfd.

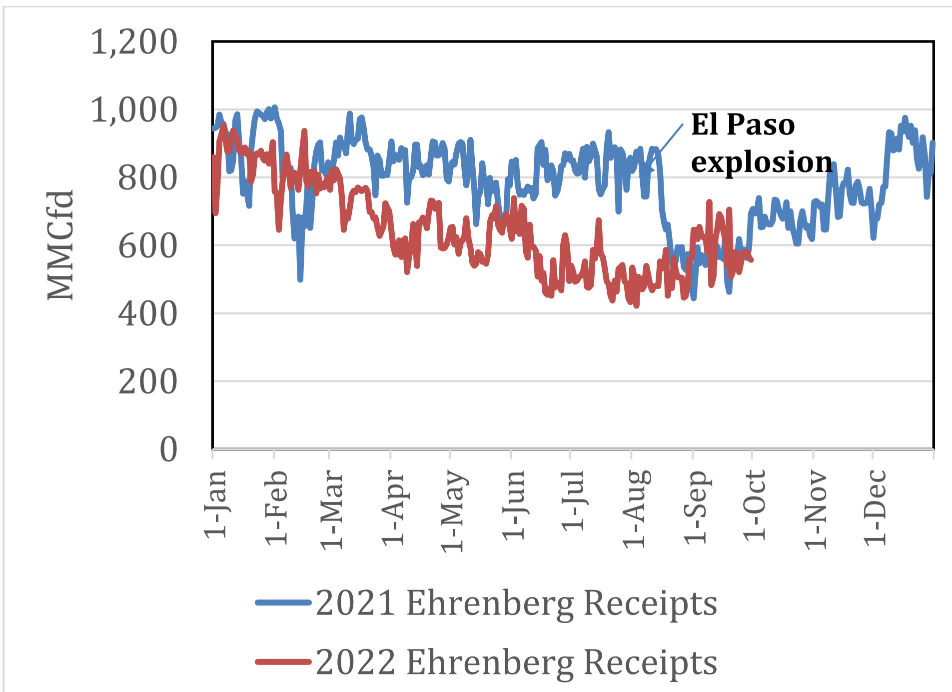
The sum of the capacities above is 2,815 MMcfd. Last winter, the increased capacity in the Northern Zone was offset by the decrease in the Southern Zone. SoCalGas' Northern and Southern Zones represent transmission zones that are connected to interstate pipelines. SoCalGas' Southern Zone is connected to U.S. Southwest and Mexico pipeline systems at Ehrenberg, Blythe in eastern Riverside County and Otay Mesa (to El Paso, North Baja, and TGN) respectively. SoCalGas' Northern Zone is connected to southwestern U.S. Southwest and Rocky Mountain pipeline systems (Transwestern, El Paso, Kern River, and Mojave) at Needles, west of Topock Arizona, and Kramer Junction in San Bernardino County.[6] As a result, the

5 Southern California Gas Company, Pacific Gas and Electric Company, San Diego Gas & Electric Company, Southwest Gas Corporation, City of Long Beach Energy Resources Department, and Southern California Edison Company, 2022. *2022 California Gas Report,* [California Gas Report | SoCalGas.]() The CEC also reviewed the *2022 California Gas Report , which* describes SoCalGas' receipt point and transmission zone firm capacities.

6 Ibid.

amount of firm capacity in the Northern Zone increased to 1,250 MMcfd[7] The decrease in the Southern Zone capacity was caused by the rupture on the El Paso pipeline near Phoenix.While the National Transportation Safety Board released its report on the August 15, 2021, rupture on the El Paso pipeline near Phoenix, EPNG has not set a date for a return to full service. In the meantime, EPNG is operating that line at reduced pressure, which decreases delivery capability in the Southern Zone. Figure 1 shows 2021 versus 2022 deliveries from El Paso into SoCalGas at Ehrenberg, demonstrating the overall impact of the El Paso rupture on deliveries; however, when demand was high last winter, there were numerous days with deliveries more than 900 MMcfd. The CEC finds this variation to be a function of demand both in California and by generators located at Phoenix, as well as willingness to pay for delivery at Ehrenberg versus other locations. As a conservative estimate, staff still assumes supply into SoCalGas at Ehrenberg is reduced by 250 MMcfd, which equates to deliveries of 730 MMcfd.

Figure 1: 2021 vs. 2022 Ehrenberg Receipts



Source: CEC Staff using SoCalGas Envoy™ daily operations data.

The only way other than Ehrenberg to deliver incremental supply into SoCalGas' Southern Zone is via Otay Mesa. There are two ways to move gas to Otay Mesa:

1. Via the El Paso pipeline connection at Ehrenberg to the North Baja system. However, with the reduced deliveries at Ehrenberg, staff expects virtually no gas to move to Otay Mesa this way.

7 Ibid., page 141.

2. Bring in liquefied natural gas (LNG) imports via Costa Azul (Baja California) LNG terminal. This is a resource of last resort, as the war in Ukraine has put upward pressure on LNG exports and global LNG prices.[8]

Staff assumes zero gas deliveries at Otay Mesa due to the reduced deliveries at Ehrenberg and LNG being a resource of last resort. In total, staff estimates total pipeline capacity of 2,815 MMcfd as described earlier. Table 5 presents the pipeline capacity and natural gas storage inventory for the prior three winters and this winter.

Table 5: Winter Supply and Storage Comparison

	Winter 2019–2020	Winter 2020–2021	Winter 2021–2022	Winter 2022–2023
Pipeline Capacity (MMcfd)	~2,800	2,845	2,835	2,815
Total Storage Inventory (Bcf)	~73	79	~81	~90
Percentage Full (Total Storage)	87.70%	94%	96%	97%
Allowed Aliso Inventory (Bcf)	34	34	34	41

Source: CEC staff

The SoCalGas system was designed to meet winter demand with flowing pipeline supply and storage withdrawals. SoCalGas Envoy™ now reports storage inventory by field and total inventory for each day. SoCalGas begins this winter season with natural gas storage inventory essentially full at 88.9 billion cubic feet (Bcf) as of September 30, 2022.

SoCalGas Winter 2022–2023 Gas Balance

Staff analyzed monthly average demand, monthly high demand, and two levels of peak day demand for this assessment.[9] Table 6 shows the monthly gas balance for the 2022–2023 winter months using the CEC's forecast for average demand. With average daily demand in December 2022 and January 2023 at around 2,900 MMcfd, staff concludes that pipeline supply plus storage withdrawals are sufficient to meet that demand. The monthly 1-in-10 high-demand case (Table 7) requires withdrawals every month throughout the winter and uses more storage inventory to meet demand, resulting in lower inventory by the end of winter. The winter ending inventory in the high-demand case is 45 Bcf compared to 86 Bcf in the average demand case. Yet, the relatively high ending inventory of 45 Bcf suggests that more storage was available and could be used to help manage the gas price charged to core customers (residential and small commercial customers), should the price of summer-injected gas be lower than winter pipeline receipts, for example.

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8 Federal Energy Regulatory Commission. September 2021. "Federal Energy Regulatory Commission Market Assessments," found at [Microsoft PowerPoint - National (ferc.gov).](ferc.gov)

9 In prior years, CEC staff used the demand projections from the *California Gas Report*. Appendix A describes the method used to develop the CEC demand projections. In the average demand case, the CEC is a little lower than the California Gas Report and a little higher in the high-demand case on average over the winter months November through March.

Table 6: Monthly Gas Balance Average Demand

Row	**Average Demand**	**Oct. 2022**	**Nov. 2022**	**Dec. 2022**	**Jan. 2023**	**Feb. 2023**	**Mar. 2023**
1	Demand (MMcfd)	2,366	2,566	2,877	2,863	2,491	2,724
2	Available Pipeline Capacity (MMcfd)	2,620	2,793	2,815	2,815	2,815	2,815
3	Injection/(Withdrawal) (MMcfd)	0	0	-62	-48	0	0
4	End-of-Month Inventory (Bcf) as of Oct. 7	89	89	87	86	86	86

Source: CEC staff

Table 7: Monthly Gas Balance 1-in-10 Demand

Row	**1-in-10 Demand**	**Oct. 2022**	**Nov. 2022**	**Dec. 2022**	**Jan. 2023**	**Feb. 2023**	**Mar. 2023**
1	Demand (MMcfd)	2,697	2,925	3,280	3,264	2,840	3,105
2	Available Pipeline Capacity (MMcfd)	2,620	2,793	2,815	2,815	2,815	2,815
3	Injection/(Withdrawal) (MMcfd)	-77	-132	-465	-449	-25	-290
4	End-of-Month Inventory (Bcf) as of Oct 7	87	83	68	54	54	45

Source: CEC staff

Peak Day Analysis

Staff evaluated two peak day cases for winter, which provided interesting insights. One case looked at a 1-in-10 peak temperature cold day for core and noncore load. The second looked at the more extreme 1-in-35 peak temperature cold day for core plus 1-in-10 peak temperature cold day for noncore.[10] As Table 7 above shows, SoCalGas' storage inventories are essentially full as the 2022-2023 winter season approaches. The maximum feasible withdrawal from that inventory, however, remains unclear. Withdrawal capability depends on storage inventory, which typically declines over the winter as more gas is withdrawn. Another variable is CalGEM's new safety/inspection rules, which require wells to be pulled from service for maintenance and testing.[11]

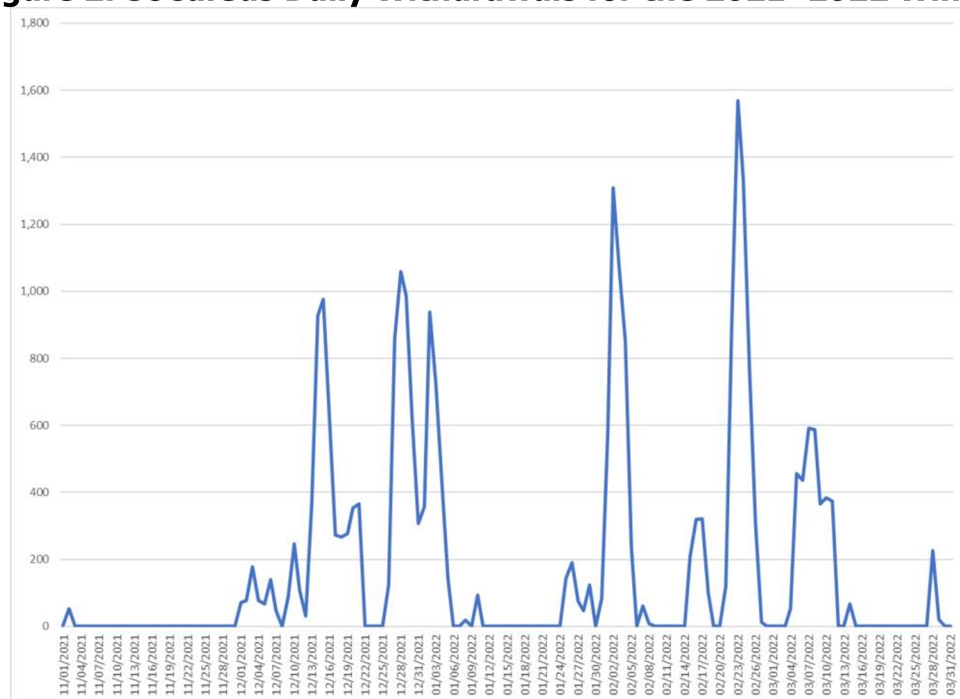
The maximum feasible withdrawal from inventory has changed over the last several years as reflected in prior analyses. SoCalGas' 2020–2021 Winter Technical Assessment reported

10 Noncore load is less temperature-sensitive, so adding its 1-in-10 probability estimate to the core 1-in-35 allows calculation of total system load that could need to be curtailed on an extreme peak day. Core load is residential and small business, and noncore load is electric generators, industrial customers, commercial, and all other noncore customers.

11 CalGEM regulations implemented in October 2018 require periodic well inspections and pressure testing, which have resulted in well maintenance occurring year-round, including the winter season. As a result, withdrawal capacity has changed over time. SoCalGas' 2020-2021 Winter Technical Assessment TN 235320: 20-IEPR-03. SoCalGas' 2021-2022 Winter Technical Assessment TN 240136: 21-IEPR-04.

maximum storage withdrawal capacity as 2,729 MMcfd.[12] Its 2021–2022 winter assessment reduced this capacity to 2,059 MMcfd in part because of maintenance required under the new CalGEM regulations.[13] The maximum observed storage withdrawal of 1,570 MMcfd last winter occurred February 23, 2022, with system demand of 4,077 MMcfd.

Figure 2: SoCalGas Daily Withdrawals for the 2021–2022 Winter



Source: CEC staff using SoCalGas Envoy™ daily operations data.

The maximum observed value of each storage field during last winter summed to 2,100 MMcfd, which is noncoincident. The CPUC Aliso Canyon Withdrawal Protocol identifies the conditions for withdrawal from that storage facility.[14] The average withdrawal capacity made available to customers on winter days that met the Aliso Canyon Withdrawal Protocol was 1,850 MMcfd.[15] Around that average, staff found SoCalGas posting on Envoy™ that 2,359 MMcfd was available December 9, 2021. This date was also the first day last winter (for example, when inventory was close to maximum) on which the Aliso Canyon Withdrawal

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12 *SoCalGas' 2020–21 Assessment* can be found at [20-IEPR-03,](https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=20-IEPR-03)
https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=20-IEPR-03.

13 Ibid.

14 The "CPUC Aliso Canyon Withdrawal Protocol" is available at Microsoft Word - UpdatedWithdrawalProtocol_2020-03-12-cleam (ca.gov).

15 The source of this information is testimony filed in SoCalGas and SDG&E 2024 Cost Allocation Proceeding A.22-09-015, Chapter_1-Manuel_Rincon_Jimmy_Yen_Storage_Overview_and_Proposal.pdf (socalgas.com), page 5, line 8. SoCalGas has demonstrated increased capacity on individual demand days higher than the 1,850 MMcfd withdrawal capacity assumption used. The cost allocation proceeding testimony cites 2,309 MMcfd of withdrawal capacity made available December 13 of last winter. Staff also found stated withdrawal capacity of 2,406 MMcfd on Envoy™ for December 14. The historical withdrawal capacities show that on an extreme peak day where CEC staff expects the withdrawal protocol to be met, SoCalGas may be able to pull more form storage than 1,850 MMcfd to meet demand.

Protocol was met. The CEC's use of the average 1,850 MMcfd from 2021–2022 accounts for the declining storage inventory over the winter.

Table 8: Peak Demand Day Gas Balances

Row	(MMcfd)	Case 1: Cold Day	Case 2: Extreme Peak Day
		Core + Noncore 1-in-10*	1-in-35 Core + Noncore 1-in-10**
1	**Demand**		
2	Core	3,002	3,393
3	Noncore-NonEG	744	705
4	EG	914	844
5	**TOTAL Demand (Sum Rows 2 to 4)**	4,660	4,942
6	Available Pipeline Capacity	2,815	2,815
7	**Needed Withdrawal (Row 5 minus Row 6)**	1,845	2,127
8	Assumed Available Withdrawal ****	1,850	1,850
9	**Net Shortfall or Curtailment (Row 7 minus 8)**	0	277

Source: CEC Staff

*Jan Peak

** Dec Peak

*** Estimated withdrawal based on maximum withdrawal observed during winter 2021-2022.

**** Estimated withdrawal based on the average withdrawal capacity made available to customers on the winter days that

Aliso Canyon protocol allows average withdrawals of 1,850 MMcfd.

Based on the above assumed conditions, staff finds that supply can meet demand in Case 1 (1-in-10 cold day demand). This is not true, however, in Case 2, which is the 1-in-35 core plus 1-in-10 noncore extreme peak day demand. Case 2 results in about 280 MMcfd net shortfall, which would require curtailment of that amount of noncore load. The shortfall potentially could be reduced by more supply being delivered at Ehrenberg or Otay Mesa, or higher storage withdrawals above 1,850 MMcfd. Following the current curtailment order approved by the

CPUC and reflected in SoCalGas Rule 30,[16] electric generators and other noncore customers would absorb those curtailments.[17]

The EPNG ruptured pipeline that is still under repair and the resulting reduced deliveries at Ehrenberg place customers located in SoCalGas' Southern Zone at higher risk this winter should an extreme cold day occur, as that system is limited to supplies received at Ehrenberg or Otay Mesa. As such, gas from storage in the L.A. Basin cannot reach customers in the Southern Zone. Most, but not all, of this load is in San Diego, with some in Imperial Valley. On such a cold day, somewhat less than 20 percent of that load would be from noncore customers. Any curtailment larger than that 20 percent puts Southern System core customer load at risk of curtailment. Still, this risk is low at the shown demand and supply conditions.

Stochastic Analysis

For the first time, staff prepared an hourly stochastic, or randomly determined, gas balance. This allows the gas balance to capture more of the uncertainty inherent in fossil gas demand, as well as hourly demand patterns that cannot be reflected in the standard peak day demand analysis shown in Table 8. The results of this stochastic assessment confirm the risk and magnitude of potential curtailments should an extreme peak day occur. Specifically, it shows zero curtailment in the 1-in-10 case and a total curtailment across the gas day of about 280 MMcfd in the more extreme 1-in-35 plus 1-in-10 case. Appendix B describes the method behind the stochastic analysis.

Hydraulic Analysis

CEC staff used the Synergi Gas hydraulic modeling platform to assess SoCalGas system operations.[18] The hydraulic model simulates operations across the entire gas day, capturing changes in line pack that the peak day gas balance cannot. It also identifies pressure violations and allows simulation testing of different operational solutions. Staff modeled the two peak demand cases (Case 1 and Case 2) as in the gas balances. Staff used pipeline supply of 2,815 MMcfd assumed in the gas balances and used ratably, meaning the same quantity every hour. Storage withdrawals, in contrast, vary hourly to meet the difference between demand and supply flowing in from the interstate pipelines. The hydraulic analysis confirms staff's gas balance results and the risk of Southern System curtailments. These curtailments are unrelated to inventory limits at Aliso Canyon. The analysis also confirms that the curtailments in Case 2 extreme demand are limited to noncore customers. Appendix C describes the method.

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16 SoCalGas Rule 30 available at GAS_G-RULES_30.pdf (socalgas.com).

17 SoCalGas conducted an in-line inspection of Line 235-1 in September 2022 and is awaiting results. Potential remediation for anomalies found could cause the line to be removed from service.

18 Synergi Gas is the long-time industry standard for hydraulic modeling of large, complex distribution and transmission systems.

Market Prices

CEC staff produces a biennial price forecast in support of the CEC's *Integrated Energy Policy Report* and updates it periodically to capture market updates. While market prices are not a specific input to this assessment, staff includes this overview to show the effects of market supply trends and events on prices.

Natural gas market prices increased over the last 12 months, with the daily spot price at Henry Hub[19] averaging $7.88/MMBtu in September 2022.[20] This increase is due to the lasting impacts of COVID-19 on production along with the war in Ukraine, despite no real impact to North American supply and demand fundamentals from the war.[21] California prices have varied higher at times during this past year, especially during high-demand periods.

The CEC concurs with the Energy Information Agency's Short-Term Energy Outlook released in October 2022 that forecasts natural gas spot prices to average $7.40/MMBtu through the end of the year and then decline below $6/MMBtu in 2023. Curves for NYMEX forward market pricing show a similar pattern. Higher prices this winter are linked to strong demand and slightly low continentwide storage inventory levels, but prices are expected to decline as production rises and the European situation stabilizes. Production only recently returned to pre-COVID levels. Higher prices on cold days are not unexpected or necessarily unreasonable. The CEC monitors these markets as part of its natural gas price forecasting and market assessment responsibility.

Conclusion

The SoCalGas system remains impaired, with two key pipelines unable to operate at design capacity. Storage is essentially full at the beginning of winter, but inventory restrictions remain at Aliso Canyon, and work at the storage fields is needed to comply with CalGEM safety regulations. The reliability outlook for this winter is improved from last winter 2021, primarily due to lower demand forecast than in prior winters, but risk remains under adverse conditions. Staff projects zero curtailment on a 1-in-10 peak day demand and curtailment of about 280 MMcfd on a more extreme cold day. Staff has confirmed this finding using peak day gas balances, a stochastic hourly gas balance and hydraulic simulations of gas system operations. The key risk to reliability is multi-day cold weather events with additional infrastructure outages. Prices this winter are likely to remain at current levels, but consumers should expect higher prices during periods of peak demand.

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19 Henry Hub is a natural gas pipeline located in Erath, Louisiana, that serves as the official delivery location for futures contracts on the New York Mercantile Exchange.

20 Prices available at Henry Hub Natural Gas Spot Price (dollars per million Btu) (eia.gov).

21 "EIA Short Term Energy Outlook." Found at https://www.eia.gov/outlooks/steo/.

Glossary

A ***billion cubic feet*** is a standard unit of measurement for natural gas supply/demand - 1,000,000 MMBtu = 1 Bcf.

A ***British thermal unit*** is the quantity of heat required to raise the temperature of one pound of water 1 degree Fahrenheit at a specified temperature (such as 39 degrees Fahrenheit).

A ***core load*** is residential and small business based in Los Angeles and Southern California.

A ***decatherm*** is the quantity of heat energy that is equivalent to 1 million British thermal units.

Federal Energy Regulatory Commission regulates natural gas transportation in interstate commerce and construction of gas pipeline, storage, and liquefied natural gas facilities.

Henry Hub is a natural gas pipeline located in Erath, Louisiana, that serves as the official delivery location for futures contracts on the New York Mercantile Exchange.

A ***liquefied natural gas*** is natural gas that has been cooled to a liquid state, at about -260° Fahrenheit, for shipping and storage.

A ***million British Thermal Unit*** is a thermal unit of measurement for Natural Gas.

A ***million cubic feet per day*** (MMcfd) is a unit of measurement used to express the amount of fluid (gas, water etc.) that is consumed, produced or traversed in a pipeline on any given day.

A ***natural gas*** is a hydrocarbon gas found in the earth, composed of methane, ethane, butane, propane and other gases.

A ***noncore load*** is electric generators, industrial customers, commercial, and all other noncore customers based in Los Angeles and Southern California.

Southern California Gas Company is a utility company and primary provider of natural gas to Los Angeles and Southern California.

Synergi Gas is the long-time industry standard for hydraulic modeling of large, complex distribution and transmission systems.

APPENDIX A: Gas Demand Forecast Methodology

This appendix presents an overview of the methodology to forecast monthly and peak day demand across the main sectors consuming gas for SoCalGas. Temperature explains most of the variation in demand for the local gas distribution company because the primary uses of gas are directly for space heating and indirectly for space cooling (for example, electric generation). Heating and cooling loads vary heavily with temperature, so gas consumption exhibits a significantly higher winter heating load and a lower, but noticeable summer cooling one, as well as multi-seasonality (for example, weekly, monthly, and yearly), and a trend over time.

The modeling of gas demand uses probabilistic programming to quantify uncertainties and estimate and forecast gas demand. Modeling relies on a combination of historical weather and gas demand representing the SoCalGas' service area. SoCalGas categorizes gas consumption by sectors such as residential, commercial, and industrial, fuel required for vehicles, electric generation (EG), and fuel for lease, pipeline, and plant operations. The Quarterly Fuel and Energy Report (QFER),[22] as reported by SoCalGas to CEC, and the 2021 California Energy Demand Forecast (CEDF),[23] as estimated by CEC, group them by residential, commercial, industrial, mining, agricultural, transportation, communication, and utilities. Sectors are subsequently classified into core and noncore customers; core customers include residential and small commercial, and noncore has electric generators, industrial customers, large commercial, and all other noncore customers.

Methodology Overview

The development of gas demand forecasts uses a combination of assessment of sector profiles and econometric modeling. There are two main models in the forecasting process. One is a model for gas demand used for electric generation. The other is a model for sector and core and noncore demand for the average year, along with estimates for peak-day demand for the average month, and abnormal peak-day demand for the extremely cold months according to a 1-in-10 and 1-in-35 planning weather standards.

Due to the uncertainty embedded in the observation of changes in historical weather and gas demand, in the main drivers of gas demand changes, and in the modeling process, econometric probabilistic models offer an advantage in inference analysis. *Probabilistic programming* is a technique that combines programming with Bayesian statistical simulation and inference methods. These analyses simultaneously employ two probabilistic programming forecasting tools, Facebook Prophet and PyMc, both open-source libraries available in Python.

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22 The CEC-1306A Sales/Deliveries Quarterly Fuel and Energy Report provides the quantity of electricity delivered monthly by utility distribution companies to end-use customers.

23 Javanbakht, Heidi, Cary Garcia, Ingrid Neumann, Anitha Rednam, Stephanie Bailey, and Quentin Gee. 2022. *Final 2021 Integrated Energy Policy Report, Volume IV: California Energy Demand Forecast*. California Energy Commission. Publication Number: CEC-1002021-001-V4.

Both create additive regression models; work well with weather and gas demand time series; support trends, seasonality, holidays, and explanatory variables; and provide comparable results.

Model Inputs

The National Weather Service of the National Oceanic and Atmospheric Administration (NOAA) provided the daily maximum and minimum temperatures (°F) from multiple relevant weather stations in the SoCalGas service area for 30 years (1991–2020). A weighted average according to population centers taken across the appropriate weather stations in SoCalGas represents the daily temperature for its service area.

Since temperature explains most of the variation in gas demand and tends to sustain the effects on demand for more than a day, one set of lag time effects is considered. It uses a weighted average of three consecutive daily temperatures, 6/10 of the current day's temperature, 3/10 of the previous day's temperature, and 1/10 of the temperature two days prior (referred to as the *631 weighted average temperature*). The 631 weighted average temperature, which is used in all the analyses, improves the model fit of temperature on demand and helps determine what a future demand would be given historical and extreme weather conditions.

In addition to temperature inputs, calendar drivers are essential for modeling gas demand and include the day of the week, the month of the year, the day of the year, the year, the day of the month, weekends and public holidays, and seasons. Additional drivers include nonholiday weekdays and COVID-19 indicator variables. Winter seasonal gas demand runs from November 1 to March 31, and summer runs from April 1 to October 31.

Modeling is defined as the relationship between the logarithm of gas demand, as thousand decatherm (MDth) or thousand decatherm per day (MDth/d), and 631 weighted average daily or average monthly temperatures. Average temperatures quantify better the impact on gas consumption and peak and abnormal peak demand than other temperature-derived variables. Modeling is partially adjusted for serial correlation. Several metrics with cross-validation, plausibility, and consistency are used to evaluate and select the most appropriate probabilistic programming forecasting model.

Monthly Demand Profiles

Monthly reference profiles for QFER sectors are calculated using monthly demand of 13 years (2008–2020) provided by SoCalGas to CEC. These monthly load profiles are applied to the annual demand forecast data from the CEDF for 28 years (2008–2025) to calibrate the monthly demands. Similarly, monthly profiles of the QFER core and noncore monthly demands are then scaled with the monthly demands of the sector to create the core and noncore monthly gas demands. These two calculations are then aggregated, or gathered, to form the final monthly demand categorized by sector, core, and noncore.

For forecast values, it is unrealistic to assume that current sector patterns will continue to hold. Instead, the changing sector profiles are better captured by applying a weighted moving average. The three-time-period weighted moving average percentage of sectors relative to the CEDF total demand is used to determine trend direction and generate values for the 2021–

2023 forecast horizon. The current month applies a weighting of 60 percent to the trend-based value, dropping to 30 percent the month before and 10 percent two months back.

Forecasting Monthly Gas Demand for Electricity Generation

This analysis estimates the sensitivity of monthly noncore gas demand used for EG for five years (2017–2021, sourced from QFER)[24] to monthly electricity demand of 13 years (2008–2021, provided by Southern California Edison). Electric generation gas demand in the Facebook Prophet regression model is expressed as a function of electricity monthly demand, periods, seasonality, and COVID-19. The analysis assumes that SCE is a proxy for SoCalGas, and the metrics for evaluating the performance of the model confirm the assumption. An annual growth rate is taken using a weighted moving average to obtain 2022–2023 electricity demand forecast values.

Daily Core, Noncore, and EG Gas Demand Profiles

The analysis calculates the historical daily gas demand profiles by sector over time from core, noncore, and EG daily gas demand for five years (2017–2021) sourced from SoCalGas. The profiles are expressed as a percentage of total demand and a portion of the total core demand.

Forecasting 1-in-2 Peak-Day Gas Demand

The aim is to estimate weather-corrected daily gas demand based on daily 631 weighted average weather conditions and calendar drivers using SoCalGas total daily gas demand data for 22 years (1999–2020), sourced by CEC from the SoCalGas Envoy™ website. The actual past demand is regressed against daily weather and other explanatory variables, including calendar effects such as indicator variables for the weekends, holidays, COVID-19, and yearly and monthly seasonality. The model captures the relationship between demand and demand drivers, and the coefficients are later used for simulating and normalizing demand for weather effects and estimating 1-in-10 and 1-in-35 peak-days demand.

The coefficients of the demand drivers are used to simulate and normalize demand for weather effects and other explanatory variables. The simulation process uses the coefficients of the variables and historical weather (1991–2020) to produce a normalized simulation run that estimates the demand if historical weather is repeated in the same order it initially occurred. The simulation creates synthetic weather for each day of each weather year. This step produces an average-daily demand, representing forecasted demand based on average weather conditions, and a peak-day demand forecast, representing the 1-in-2 daily probability of weather conditions. The gas demand is then converted into core, noncore, and EG forecasts by applying demand profiles derived from simulated historic demand from 2017 to 2020.

Estimating 1-in-10 and 1-in-35 Peak-Day Gas Demand

Estimating abnormal peak demand requires modeling how gas demand responds to extreme weather conditions. First, an analysis of the distribution of daily 631 weighted average minimum temperature values from historical weather (1991–2020) produces 1-in-10 and 1-in-

24 The CEC Quarterly Fuel and Energy Report QFER CEC-1304 Power Plant Owner Reporting Database contains energy data relating to electric generation, control area exchanges, and natural gas processing and deliveries, QFER CEC-1304 Power Plant Owner Reporting Database - Datasets - California Open Data.

35 cold daily average temperatures. These temperatures are significantly low enough to increase heating loads compared to average daily temperatures. Then, peak demands on these cold days are estimated by applying the coefficients determined earlier in the peak-day demand of the Facebook Prophet regression model to the day's characteristics. This produces abnormal cold peak-day demand for the 10-year and 35-year severe cold weather conditions. A growth driver based on the simulated month-on-month growth is applied to each daily demand value to grow demand in the relevant (2022–2023) forecast years.

Then, the abnormal peak-day total demands of the system must be converted into core, noncore, and EG forecasts. The approach calculates abnormal demand for core, noncore, and EG by applying demand profiles. The profiles are derived from simulated historical demand from 2017 to 2020. The shape is then applied to the results to generate core, noncore, and EG abnormal peak-day values. Noncore and EG exhibit low sensitivity to cold temperatures, whereas core exhibits high sensitivity. So, 1-in-10 minimum cold temperature values are applied to all categorized demands, but 1-in-35 values are only used for the core.

This method gives the abnormal peak day demand of the total system that aligns with the 1-in-10 winter cold days' total demand in Table 30 of the 2020 CGR, but the specific customer class demand estimates vary from the CGR forecast. Consequently, the core and the noncore split is calculated here by simulation and decided by a benchmarked difference with SoCalGas reported peaks. Applying sector profiles derived from simulated historical demand to abnormal peak-day demand was validated by quantifying the historical influence of lower average temperatures on changes to core and noncore contributions to total demand over time.

APPENDIX B:
Hourly Stochastic Gas Balance

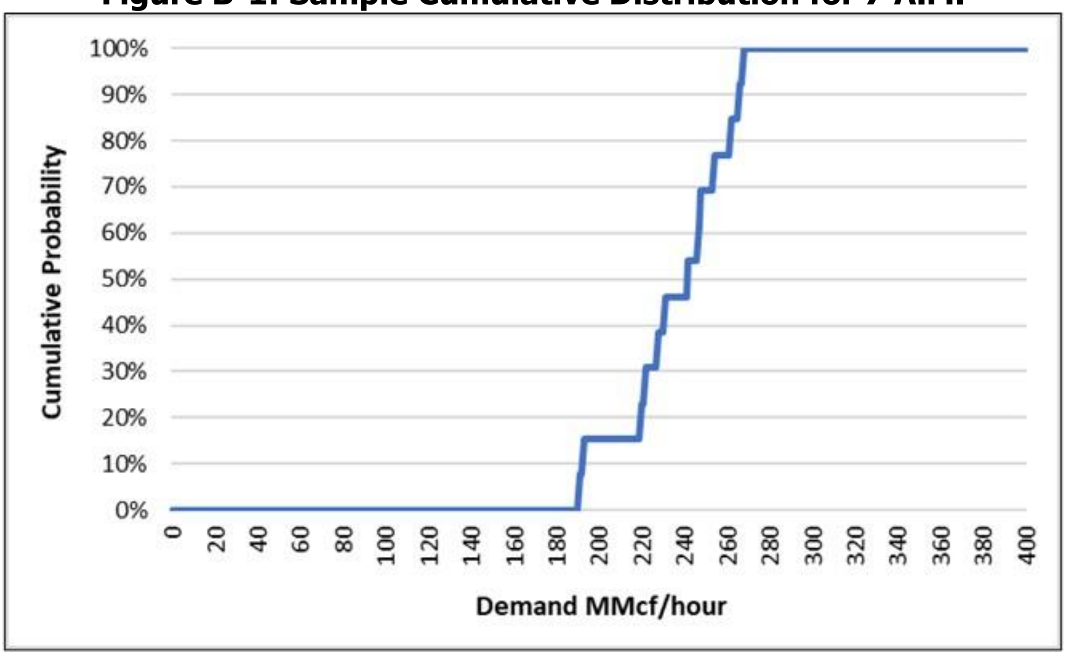
Summary

Aspen Environmental Group (Aspen) developed the CEC's hourly stochastic gas balance to capture more of the uncertainty inherent in natural gas demand and hourly demand patterns. This gas balance allows staff to assess the risk of curtailment on a more granular and probabilistic basis. For example, all days with the same demand will not necessarily have the same hourly load profile. The gas balance then assesses this probabilistically determined demand.

Method

The hourly stochastic gas balance develops a cumulative probability distribution of demand by hour using historical hourly data. This is done by counting the demand-level occurrences. Dividing that count by the total number of observations gives the probability of any given demand level for a given hour. Doing this for all hours produces a probability distribution of demand for each hour of the day. Figure B-1 gives a conceptual rendering of what the probability distribution for 7 a.m. might look like, in cumulative format, confirming that the probabilities add to 100 percent.

Figure B-1: Sample Cumulative Distribution for 7 A.M.

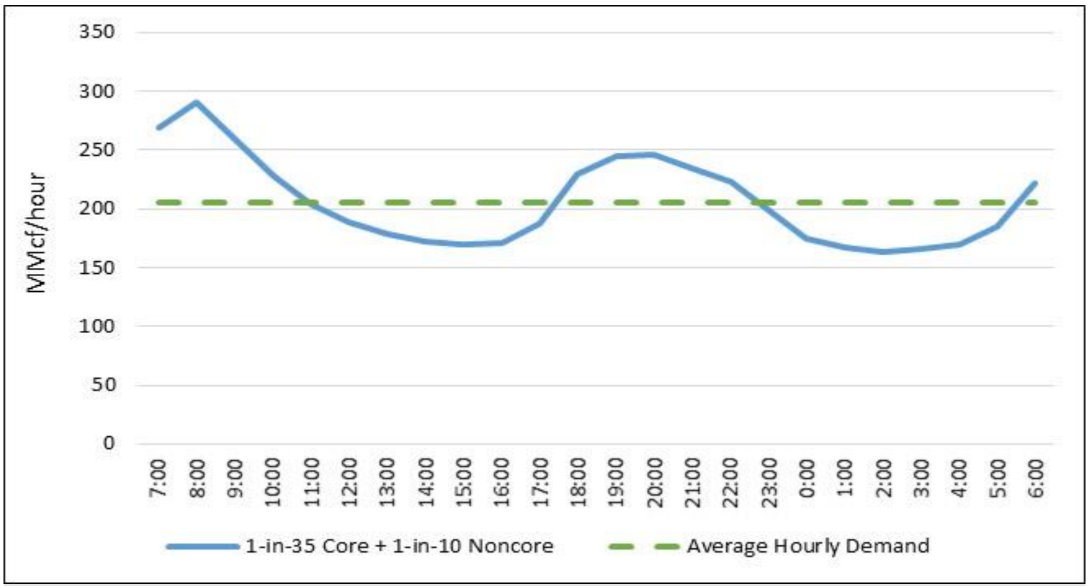


Source: Aspen Environmental Group

Conditional variables allow the ability to differentiate between month and day of week and, more specifically, whether a given day is a weekday or weekend. From the cumulative probability distribution, Aspen then takes 1,000 random draws for each hour of the day. This creates distributions, including mean and standard deviations of demand by hour. With these deviations, Aspen can estimate an average hourly load shape for natural gas demand. The standard deviations by hour allow for scaling to test various peak days. This tool can be used to simulate specific demand days or simulate a monthly load profile by hour, or even a yearly load profile by hour.

For the 2022–2023 Winter Reliability Assessment, Aspen simulated an hourly load profile based off the top 5 percent of demand days in Aspen's 12-year hourly demand dataset. Because no extreme peak days occurred within this dataset, the demand for each hour was then scaled relative to the standard deviation in each hour by a multiplier to match CEC staff's forecast of total daily demand for a 1-in-35 core plus 1-in-10 noncore demand day for 2022.[25] The hourly demand is scaled based off the relative variability in each hour.[26] The resulting load shape is shown in Figure B-2. It shows demand on the extreme peak day demand ranging from 163 MMcf per hour to 290 MMcf per hour.

Figure B-2: 1-in-35 Core + 1-in-10 Noncore Scaled Peak Day Demand Hourly Load Profile



Source: Aspen Environmental Group

Results

The stochastically determined load shape estimated above feeds into the hourly gas balance. The gas balance compares supply and demand during each hour of the day. This yields the required withdrawals for each hour of the simulated day. Consistent with expected and standard gas system operations, pipeline supply is assumed to be constant over the day,[27]

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25 The CEC's forecast of demand for a peak day with 1-in-35 core plus 1-in-10 noncore demand is 4,942 MMcfd. Its forecast of demand for all customers on a 1-in-10 cold day is 4,660 MMcfd.

26 Aspen used a goal seek method for scaling to increase demand in each hour dependent on each hour's standard deviation. This scales the load shape for a high-demand day to the CEC's forecast by setting the total daily demand to 4,942 MMcfd, for example, and adjusting the multiplier on the standard deviation. This method allows for sensitivity to peak hourly demand and does not impose a constant scaling of demand.

27 The assumed supply of 2815 MMcfd is composed of 730 at Ehrenberg, 760 at Wheeler Ridge, 1250 in the Northern Zone and 70 from local California production.

while withdrawals from storage vary as they are used to meet the hourly swings in demand.[28] A required withdrawal greater than available withdrawal implies some load will need to be curtailed.[29] The detail of the hourly analysis allows the ability to recognize ramping needs during the morning and evening peaks and demonstrates (in)adequacy to meet intraday demand swings in the system. The stochastic hourly gas balance also gives context to recognize and understand changes in the hourly profile that may occur as the electricity resource mix changes and customers electrify.

Table B-1 and Table B-2 and Figure B-3 and Figure B-4 below give the hourly gas balance results. For the extreme peak-day we assume 4,942 MMcfd of daily demand and 2,815 MMcfd of daily pipeline receipts. The stochastic gas balance estimates a cumulative needed withdrawal of 2,127 MMcfd. Key ramping periods occur in the morning around 7 a.m. to 8 a.m. and in the evening from 5 p.m. to 9 p.m. The largest ramp of the day occurs in the morning with a maximum 173 MMcf of supply required from storage at 8 a.m. to meet the peak ramp.[30] The gas balance also shows an expected feasible withdrawal curve given the withdrawal capability used in the daily gas balance analysis of 1,850 MMcfd. With expected withdrawals of 1,850 shaped over the demand day, minimum curtailment totals nearly 280 in the extreme peak day case and 0 MMcfd of curtailment in the 1-in-10 peak day case.

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28 The same total daily demand and supply scenarios were run for the hourly gas balance as the daily peak day gas balance.

29 Curtailment estimates require estimated feasible hourly withdrawals.

30The hourly gas balance cannot show the use of or change in linepack. The gas system operator routinely relies on its judgement to use some amount of difference between hourly supply and demand to be absorbed into linepack. Linepack on the SoCalGas system, however, is small, and SoCalGas has often stated that it will curtail load if necessary to restore linepack overnight before the start of the next gas day. Required withdrawals range from 46 MMcf per hour to 173 MMcf per hour.

Table B-1: Stochastic Hourly Gas Balance Results for the Core + Noncore 1-in-10 Winter Cold Day

Units in MMcf	Simulated 1-in-10- Winter Peak Day Hourly Gas Balance																								Daily
Hour	7:00 AM	8:00 AM	9:00 AM	10:00 AM	11:00 AM	12:00 PM	1:00 PM	2:00 PM	3:00 PM	4:00 PM	5:00 PM	6:00 PM	7:00 PM	8:00 PM	9:00 PM	10:00 PM	11:00 PM	12:00 AM	1:00 AM	2:00 AM	3:00 AM	4:00 AM	5:00 AM	6:00 AM	
Demand	253	272	245	215	193	179	170	163	156	161	178	214	228	232	223	211	190	167	157	154	156	159	175	208	4660
Receipts	117	117	117	117	117	117	117	117	117	117	117	117	117	117	117	117	117	117	117	117	117	117	117	117	2815
Expected Feasible Withdrawals	136	155	127	98	76	62	52	46	39	43	60	97	111	115	105	94	73	50	40	37	39	42	58	91	1845
Required withdrawal	136	155	127	98	76	62	52	46	39	43	60	97	111	115	105	94	73	50	40	37	39	42	58	91	1845
Curtailment*	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Minimum Curtailment Required in Each Hour

Source: Aspen Environmental Group

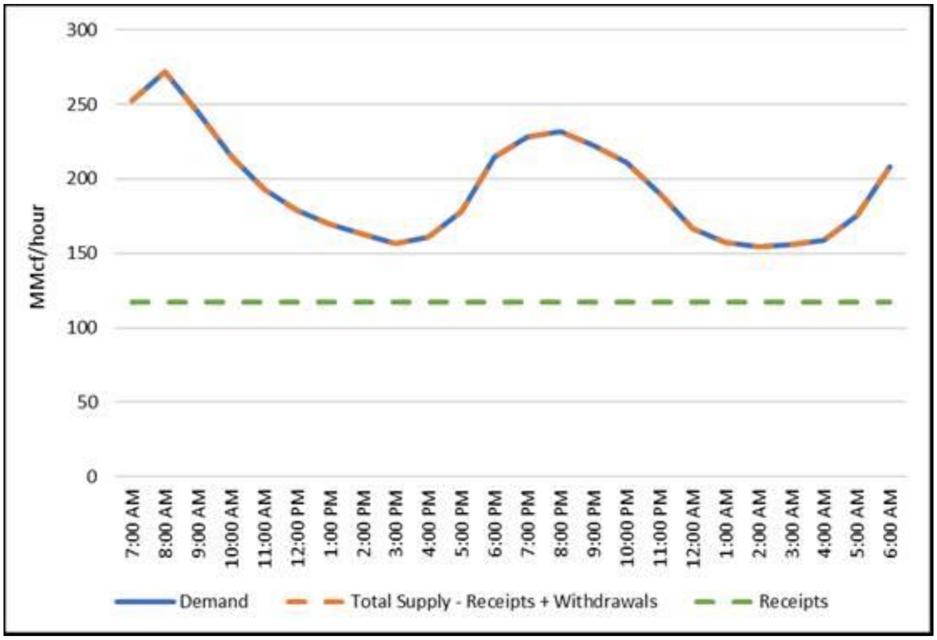
Table B-2: Stochastic Hourly Gas Balance Results for the 1-in-35 Core + 1-in-10 Noncore Extreme Peak Day

Units in MMcf	Simulated 1-in-35 Core plus 1-in-10- Noncore Winter Peak Day Hourly Gas Balance																								Daily
Hour	7:00 AM	8:00 AM	9:00 AM	10:00 AM	11:00 AM	12:00 PM	1:00 PM	2:00 PM	3:00 PM	4:00 PM	5:00 PM	6:00 PM	7:00 PM	8:00 PM	9:00 PM	10:00 PM	11:00 PM	12:00 AM	1:00 AM	2:00 AM	3:00 AM	4:00 AM	5:00 AM	6:00 AM	
Demand	269	290	259	228	204	189	179	173	170	171	188	230	245	246	234	224	198	174	167	163	166	169	185	221	4942
Receipts	117	117	117	117	117	117	117	117	117	117	117	117	117	117	117	117	117	117	117	117	117	117	117	117	2815
Expected Feasible Withdrawals	110	115	105	95	86	72	62	55	52	54	71	90	100	100	93	85	81	57	49	46	49	52	67	104	1850
Required withdrawal	152	173	142	111	86	72	62	55	52	54	71	112	127	129	117	106	81	57	49	46	49	52	67	104	2127
Curtailment*	42	58	37	16	0	0	0	0	0	0	0	22	27	29	24	21	0	0	0	0	0	0	0	0	277

Minimum Curtailment Required in Each Hour

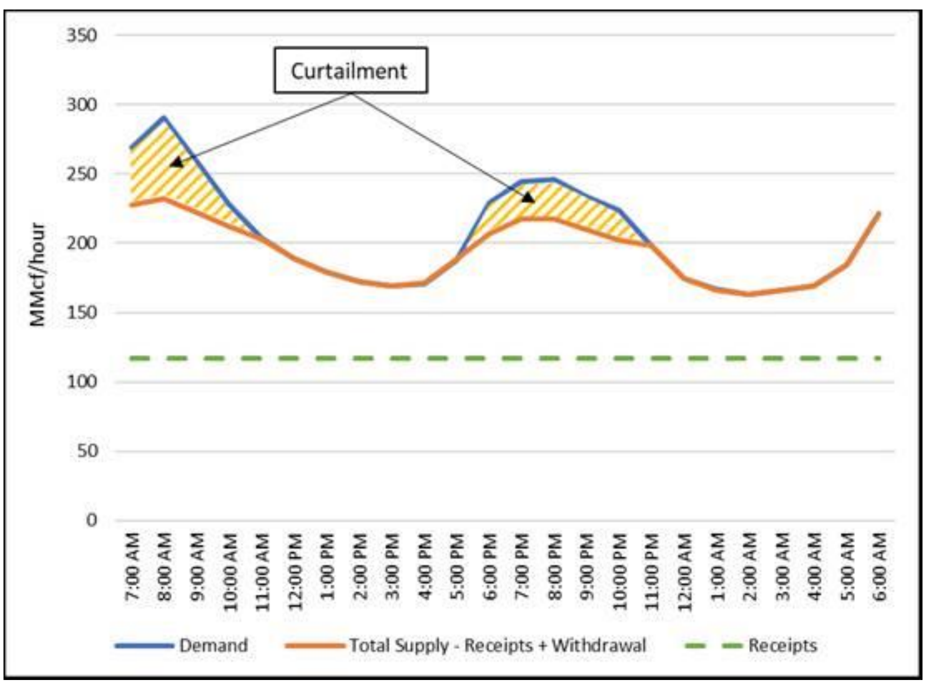
Source: Aspen Environmental Group

Figure B-3: Stochastic Hourly Gas Balance Results for the Core + Noncore 1-in-10 Winter Cold Day



Source: Aspen Environmental Group

Figure B-4: Stochastic Hourly Gas Balance Results for the 1-in-35 Core + 1-in-10 Noncore Extreme Peak Day



Source: Aspen Environmental Group

APPENDIX C: Hydraulic Modeling

In 2017, CEC staff launched a new effort to perform hydraulic modeling assessments of California's natural gas pipeline systems. Hydraulic models apply nonlinear equations that capture fluid flow dynamics for a compressible liquid to simulate the complex interactions between gas supply entering a system, gas supply leaving the system as it is consumed by end users, and the detailed physical configuration of the system. The utilities routinely use hydraulic assessments to simulate system operations and evaluate the ability to serve load under various demand, supply, and capacity conditions. They also explore when the utility should add new capacity to serve load and to establish what diameter of pipeline, for how many miles, and how much compression might be needed. The CEC independently conducts hydraulic assessments to confirm results obtained from the gas utilities and crafts and runs scenarios and cases for consideration by policy makers.

The CEC uses DNV-GL's Synergi Gas™ hydraulic modeling platform. The DNV-GL Synergi Gas™ hydraulic modeling platform is the software used by most large gas utilities in the United States, including PG&E and SoCalGas. New data regulations require the utilities to provide to the CEC with copies of their hydraulic models. In addition to copies of their hydraulic models, gas utilities provide the CEC with information on system minimum and maximum allowable pressures, demand scenarios, and load profiles. Staff uses these submittals to conduct its hydraulic modeling analysis. These are embodied in Title 20, Division 2, Chapter 3, Article 1 Section 1314 of the California Code of Regulations. Also, the two gas utilities brief the CEC when they update models, and CEC confers with them periodically to assure that staff properly understands the data and model parameters they deliver under the data regulation.

For this 2022–2023 winter reliability assessment staff used the most recent transmission system hydraulic model, which the utilities submitted to the CEC in March 2022. The model simulates operation of SoCalGas' system in transient mode, meaning that it simulates operations over the entire day. It uses configuration details, including pipe lengths and diameters; compressor station horsepower and pressures, regulators; valves and pipeline receipt points; and storage facilities. The model then uses the nonlinear equations to simulate the flow of gas over the system to serve demand at nodes. These nodes include power plants, industrial customers, and the myriad points on the transmission system that feed into distribution lines. SoCalGas also provided a spreadsheet that lists current minimum and maximum operating pressures on its transmission system. The CEC regulation affords confidential treatment for many of these operating details.

Staff simulated two cases as part of this assessment. Both use the same assumptions for capacity and supply receipts over that capacity as the gas balances tool (for example, 2,815 MMcfd). This is lower than the nominal firm design capacity of the transmission system, owing to two key pipelines that must operate at lower pressures pending repair and approval to operate at full design pressure. The main body of this report described the basis for the 2815 MMcfd. Consistent with gas industry real-time operations and transportation tariff specifications, staff set the model to maintain constant deliveries from interstate pipelines and

California production. (The tariffs approved by both the interstate pipelines, regulated by the Federal Energy Regulatory Commission, and the utilities, regulated by the CPUC, require deliveries to be made on a constant, ratable basis throughout the day). Using that same supply, staff incorporated the applicable demand inputs for each of the two cases. Case 1 is the 1-in-10 cold day demand of about 4.7 Bcfd. Case 2 is the more extreme peak day case that captures 1-in-35 demand for core customers plus 1-in-10 demand by noncore customers. Case 2 extreme peak day demand totals just under 5 Bfd.

Once staff incorporates the applicable demand inputs, it begins the simulation with the system in balance at hour zero. *Balance* means that all regulators and valves and meters show operating pressures within tolerance and that all demand is served. As the simulation proceeds, staff monitored system pressures. (Increases in demand while supply remains constant will begin to push pressures lower.) The simulation continues with staff modifying operations as needed to open or close valves at key points to maintain system pressures. Staff increases supply by turning on storage withdrawals using the four gas storage facilities on SoCalGas' system. This brings system pressures back up as supply begins to balance better to demand. Should pressures rise too high, staff turns some storage off.

When supply is less than the demand on the system, this is known as "drafting" mode. This mode can continue (in theory) until pressures are so low that the gas stops moving in a pipeline. When supply is greater than demand, the system is "packing." This can continue until the system is overpressured. Both over- and underpressure can become safety problems. As noted in the April 2016 Joint Agency Technical Report, the SoCalGas system is line pack poor. Thus, the model must restore system line pack to the levels seen at the beginning of the gas day and at the start of the simulation when the system was in balance to achieve usable results. Moreover, the simulation required service curtailment to maintain the line pack required for safe and continued operation.

In achieving a successful simulation, staff ran the model several times, each time changing various valve settings or storage withdrawals until the model solved across the entire gas day without violations. The result in a simulation of Case 1 conditions showed the SoCalGas system can meet all the demand for that scenario without curtailment. In the simulation of Case 2, however, staff curtailed about 280 MMcf/d to preserve acceptable operating pressures. In both cases, staff withdrew roughly 1,850 MMcfd of gas from storage during the day. The results match both the deterministic and stochastic hourly gas balance results. Staff believes this approach is consistent with what the utilities would apply and execute, and that these results present a reliable reflection of reality under the assumed conditions.