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| <b>Document Title:</b>  | Winter 2026-2027 California Gas Reliability Staff Report                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                 |
| <b>Description:</b>     | The California Energy Commission (CEC) presents this Winter 2026–2027 California Gas Reliability Assessment (Winter Assessment) that assesses the risk of gas service curtailment to customers served by Pacific Gas and Electric (PG&E) and Southern California Gas Company or San Diego Gas and Electric (collectively, “SoCalGas”). Using CEC-produced demand forecasts and estimates of available supply, the CEC finds that the risk of curtailment for core customers (mainly residential and small commercial) and noncore customers (large users including factories and power plants) is low assuming continued available estimated winter supplies and forecasted demand for winter 2026–2027. |
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California  
**ENERGY COMMISSION**



California Energy Commission

## **STAFF REPORT**

# **Winter 2026–2027 California Gas Reliability**

**August 2026 | CEC-200-2026-017**

# California Energy Commission

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# ABSTRACT

The California Energy Commission (CEC) presents this *Winter 2026–2027 California Gas Reliability Assessment* (Winter Assessment) that assesses the risk of gas service curtailment to customers served by Pacific Gas and Electric (PG&E) and Southern California Gas Company or San Diego Gas and Electric (collectively, “SoCalGas”). Using CEC-produced demand forecasts and estimates of available supply, the CEC finds that the risk of curtailment for core customers (mainly residential and small commercial) and noncore customers (large users including factories and power plants) is low assuming continued available estimated winter supplies and forecasted demand for winter 2026–2027.

The assessment finds that on extremely cold winter days, the PG&E gas system must rely on withdrawals from independently owned underground gas storage facilities to meet demand. Additional strategies for meeting extreme cold weather demands include procuring gas from independent storage providers and issuing operational flow orders.

The assessment finds that SoCalGas can meet extremely cold winter day demands without curtailment of noncore customers due to having enough pipeline supply and storage withdrawal capacity.

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

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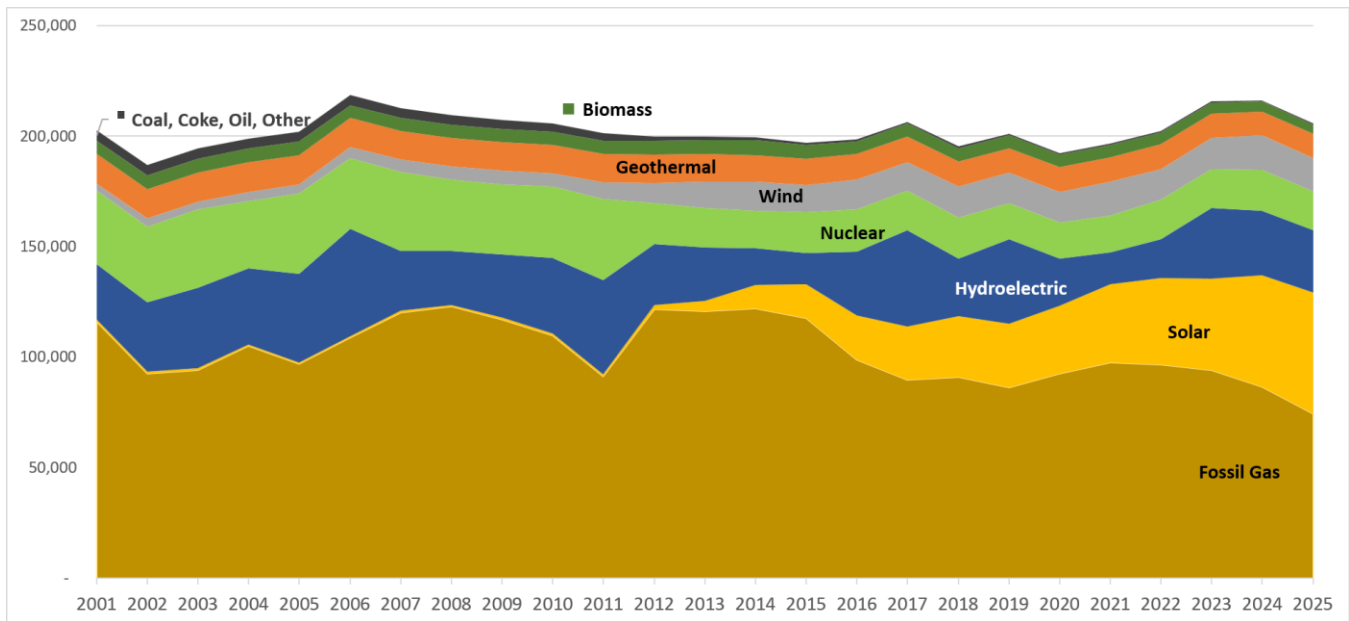
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## EXECUTIVE SUMMARY

The California Energy Commission (CEC) presents this Winter 2026–2027 California Gas Reliability Assessment (Winter Assessment) that assesses the risk of gas service curtailment to gas customers served by Pacific Gas and Electric (PG&E) and Southern California Gas Company or San Diego Gas and Electric (collectively, “SoCalGas”).

The assessment looks at the risk of curtailment to core customers (mainly residential and small commercial) and noncore customers (large users including factories and power plants). Core customers generally have a low risk of curtailment, an action that reduces the amount of energy generated to maintain the balance between supply and demand, as California Public Utility Commission (CPUC) reliability standards ensure that their service is maintained without interruption even under the most extreme cold conditions. It is also important to consider the impacts of high winter gas demand upon the electric system. While the percentage of renewable resources on the California electric grid is increasing year after year, fossil gas remains the largest source of California’s electric generation. In 2025, 36 percent of California’s electricity was produced by fossil gas. High winter gas demand can therefore also potentially jeopardize electric system reliability. This is assessed in the peak day demand cases for each utility which are scenarios of extreme demand.

**Figure E-1: EIA - California Electricity Generation by Source (GWh)**



Source: U.S. Energy Information Administration (EIA)

To assess winter reliability, CEC Staff compares forecast monthly and peak gas demands with estimated gas supply. The supply includes available pipeline capacity, storage withdrawal capability, and other available supplies.

### PG&E Analysis

CEC staff provides demand forecasts for a monthly average and a monthly cold/dry scenario on PG&E’s system. Furthermore, staff evaluates the peak demand day under two scenarios: a

1-in-10 peak day (high demand) and a 1-in-90 core demand/1-in-10 noncore demand peak day (extremely high demand). Based on projected 3.0 billion cubic feet (Bcf) PG&E pipeline capacity and a projected 857 million cubic feet (MMcf) storage withdrawal capacity, the CEC predicts a net shortfall of 135 MMcf for Case 1 — 1-in-10 peak cold day and 230 MMcf for Case 2 — 1-in-90 core/1-in-10 noncore day. For core end users, residential and small commercial customers, service would continue to be prioritized without disruption in service. The risk would first fall on lower-priority or more flexible resources, such as independent storage withdrawals, balancing measures, interruptible service, off-system deliveries, or noncore customers. If the shortfall could not be resolved through those tools, then noncore customers, including large industrial customers and electric generators, could face curtailment risk.

## **SoCalGas Analysis**

Based on the gas balance, stochastic analysis, and assessment of SoCalGas transmission system hydraulic models, SoCalGas can meet peak-day demands in both scenarios evaluated without curtailment of noncore customers. Meeting demand under these scenarios will require storage withdrawals in quantities below the assumed feasible withdrawal estimate on the SoCalGas system of 2,000 MMcfd.

The CEC estimates a 3.0 Bcf pipeline capacity for SoCalGas in winter 2026–2027. On colder days, SoCalGas is expected to rely on gas storage to meet demand. The storage required to meet this demand is below the assumed withdrawal capability of the SoCalGas system such that staff projects a limited risk of customer curtailment.

## **Market Prices**

Fossil gas prices tend to be higher and more volatile during the winter months due to increased heating demand in the residential and commercial sectors. As it is expected that California’s utility pipeline infrastructure capacity will remain roughly the same from the previous winter, staff expects prices to remain relatively consistent with last year’s prices. Overall, prices are likely to rise with increased seasonal demand. Unforeseen events, such as severe weather or unplanned pipeline outages, could significantly impact prices.



# CHAPTER 1:

## Introduction

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This assessment provides an independent analysis of the expected reliability of gas service in winter 2026–27 for the Pacific Gas and Electric (PG&E) and Southern California Gas Company/San Diego Gas & Electric (SoCalGas) systems. The winter gas season runs from November 1 through March 31.

### Gas Reliability Standards

The California Public Utilities Commission (CPUC) established gas reliability standards for PG&E and SoCalGas, as outlined in CPUC Decision 06-09-039.<sup>1</sup> The reliability standards require the utilities to use their backbone transmission and storage systems to meet peak-day standards based on each utility's local transmission planning/design, historical weather and demand, and system design practices. The *California Gas Report*,<sup>2</sup> published by the utilities, provides utility demand forecasts and planning information used to demonstrate each utility's ability to meet these standards.

The gas utilities serve two general categories of customers: core includes residential and small commercial customers, while noncore includes electric generators, large commercial and industrial customers, and others.

Gas utilities purchase gas and provide transportation and storage services for core customers. Stringent reliability standards for core customers have been designed to ensure that even under the most extremely cold conditions, gas service is maintained without interruption. Curtailing core demand is a measure of last resort, as outages to core customers take several days to weeks to restore.<sup>3</sup>

The gas utilities provide gas transportation services to noncore customers but are prohibited from purchasing gas on their behalf. Noncore customers either buy gas themselves or rely on gas suppliers or marketers for gas purchases and then schedule deliveries over the gas utilities' gas systems. Unlike core customers, noncore customers may be asked by the utility to curtail their gas usage at times where gas supply cannot meet demand. Curtailment of noncore gas service can affect industrial operations, electric system reliability, and customer

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1 CPUC. September 21, 2006. [Decision 06-09-039, Natural Gas Supply and Infrastructure Adequacy for Electric Generators, Natural Gas Quality, and Other Matters](https://docs.cpuc.ca.gov/published/Final_decision/60237.htm).  
[https://docs.cpuc.ca.gov/published/Final\\_decision/60237.htm](https://docs.cpuc.ca.gov/published/Final_decision/60237.htm).

2 Pacific Gas and Electric. [California Gas Report](https://www.pge.com/pipeline/en/reference-library/regulatory/cgr.html). <https://www.pge.com/pipeline/en/reference-library/regulatory/cgr.html>.

3 Safety requires that gas mains be brought back on-line individually and sequentially and that service to each home or building is safely restored. This restoration requires gas utility workers to go to each house or business, while someone is home, to ensure that pilot lights are properly lit. Safety concerns include the potential for explosions as pilot lights may flicker out inconsistently as line pressures drop or if restoration is improperly carried out.

costs, particularly when gas system constraints occur at the same time as cold weather, low hydroelectric generation, or high gas-fired electric generation demand.

Peak day standards are based on each utility's local transmission planning/design, historical weather-load relationships, and system design practices. PG&E's local transmission planning framework includes a core-only 1-in-90 abnormal peak-day standard, while SoCalGas/SDG&E use a core-only 1-in-35 extreme peak-day standard. These core-only standards are designed to demonstrate that protected core service can be maintained during extremely cold conditions, assuming noncore customers can be curtailed if necessary.<sup>4</sup>

## **California Energy Commission Winter Reliability Analysis**

To assess system reliability of the PG&E and SoCalGas gas systems for winter 2026–2027, CEC staff compared forecast gas demand with estimated gas supply. The supply includes available pipeline capacity, storage withdrawal capability, and other available supplies. Pipeline and storage withdrawal capacity estimates are based on historical patterns and CEC staff review of publicly available regulatory filings and maintenance outlook reports.

The comparison between demand and supply is evaluated in multiple monthly scenarios: an average temperature and average hydroelectric conditions (hereafter referred to as "average") and cold winter temperatures and dry hydroelectric conditions (hereafter referred to as "cold/dry"). The cold/dry scenario represents a higher gas demand scenario, where cold temperatures cause the need for more gas heating and where low hydro conditions reflect a higher need for gas-powered electric generation.

In addition to monthly forecasts, CEC staff develop peak-day winter demand forecasts. PG&E's peak day is evaluated under two scenarios: a 1-in-10 peak day and a combined 1-in-90 core demand day/1-in-10 noncore demand day. For SoCalGas, staff developed monthly average and cold/dry demand forecasts, as well as peak-day forecasts for a 1-in-10 cold day and an extreme peak day combining 1-in-35 core demand with 1-in-10 noncore demand. These scenarios aim to capture the impact on noncore customers, including power plants, on high-demand days driven by increased space- and water-heating demand by residential and small commercial customers. Noncore customers include electric generators and large industrial users whose curtailment can affect electric reliability, economic activity, market prices, and overall system resilience.

## **Temperature Outlook for Winter 2026–2027**

The July 2026 Seasonal Temperature Outlook for December 2026 through February 2027 favors above-normal temperatures across much of the western United States, including California. National Oceanic and Atmospheric Administration (NOAA) attributes the winter outlook in part to a strengthening El Niño, which is forecast to intensify through 2026 and continue into early 2027 (Figure 1).<sup>5</sup> While El Niño can increase the potential for periods of

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<sup>4</sup> CPUC. September 21, 2006. [Decision 06-09-039, Natural Gas Supply and Infrastructure Adequacy for Electric Generators, Natural Gas Quality, and Other Matters](#).

<sup>5</sup> National Weather Service Climate Prediction Center. August 20, 2026. "[Seasonal Temperature Outlook Nov–Dec–Jan 2026–27](#)," [https://www.cpc.ncep.noaa.gov/products/predictions/long\\_range/lead03/off03\\_temp.gif](https://www.cpc.ncep.noaa.gov/products/predictions/long_range/lead03/off03_temp.gif).

cooler conditions across parts of the southern tier, NOAA notes that above-average temperature trends may offset that effect, resulting in near-normal rather than below-normal temperature probabilities in some southern regions. Seasonal outlooks are probabilistic and do not rule out short-duration cold events that could still affect winter gas demand and reliability.

The seasonal outlook reduces the probability of a broadly colder-than-normal winter in California, but it does not eliminate the risk of short-duration cold snaps, regional demand spikes, or pipeline/storage constraints. It is useful context but not a replacement for peak-day or cold/dry reliability planning. This outlook suggests temperatures will lean above average in much of California with equal chances of above- and below-average temperatures north from the San Francisco Bay Area to the Pacific Northwest.

## **Hydro Outlook**

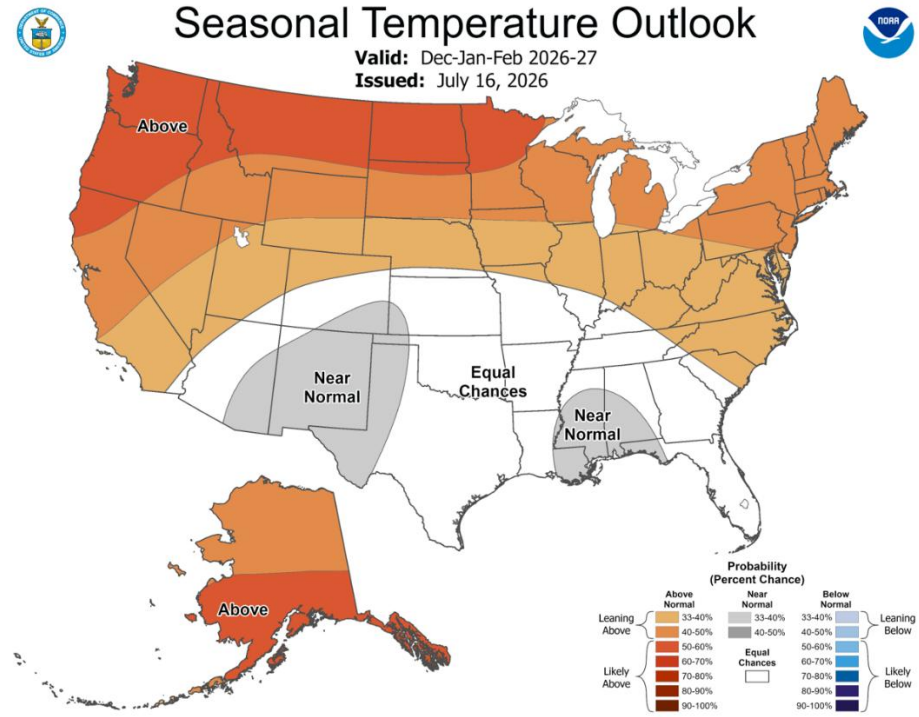
In addition to looking at temperature patterns, gas forecasters are increasingly looking at precipitation levels, snowpack, and reservoir levels to better understand expected hydropower generation levels. As hydropower and natural gas both provide important baseload electricity resources in California, it stands to reason that a “dry” hydropower year means increased natural gas usage in the electricity generation sector. EIA forecasts that hydropower generation will increase by 5% in 2026 but remain 1.8% below the 10-year average following snow drought conditions in some states.<sup>6</sup> In California, 2026 statewide accumulated precipitation was 96% of average, leading to reservoir levels<sup>7</sup> being near or above their 30-year historical average. Shasta and Orville are at 95% and 82% of their 30-year historical average, respectively.

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<sup>6</sup> EIA. April 14, 2026. [Hydropower generation expected to recover despite snow drought in the West - U.S. Energy Information Administration \(EIA\)](#)

<sup>7</sup> California Department of Water Resources. October 15, 2026. [Major Water Supply Reservoirs](#).

**Figure 1: National Weather Service Seasonal Temperature Outlook (December 2026–February 2027)**



Source: National Weather Service

## CHAPTER 2:

# CEC PG&E Gas System Analysis

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This chapter summarizes the CEC staff assessment of the ability of the PG&E gas transmission system to meet demand in winter 2026–27. Appendix A has more information about the forecasting method.

### Gas Demand Forecast

Tables 1 and 2 present CEC’s forecasts for the monthly average, cold peak-day, and abnormal peak-day demand plus forecast for the PG&E system.

**Table 1: CEC Forecast of PG&E Monthly Demand**

| Demand Scenario                            | Nov 2026 | Dec 2026 | Jan 2027 | Feb 2027 | Mar 2027 |
|--------------------------------------------|----------|----------|----------|----------|----------|
| Average Demand (MMcfd) <sup>8</sup>        | 2,552    | 3,149    | 2,996    | 2,617    | 2,274    |
| Cold/Dry Hydro Demand (MMcfd) <sup>9</sup> | 2,752    | 3,343    | 3,154    | 3,132    | 2,536    |

Source: CEC staff

**Table 2: CEC Forecast of PG&E Peak-Day Demand**

| Customer Segment                                | 1-in-10 peak day (MMcfd) | 1-in-90 core plus 1-in-10 noncore day (MMcfd) |
|-------------------------------------------------|--------------------------|-----------------------------------------------|
| Core <sup>10</sup>                              | 1,949                    | 2,044                                         |
| Noncore — Non-Electric Generation <sup>11</sup> | 838                      | 838                                           |
| Noncore — Electric Generation <sup>12</sup>     | 1,138                    | 1,197                                         |

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8 Average daily demand by month in a normal year.

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

10 Customers with average usage less than 20,800 therms per month. These are mainly residential and small commercial customers.

11 Commercial and industrial customers whose average usage exceeds 20,800 therms per month, not including power plants.

12 Power plant customers whose average usage exceeds 20,800 therms per month.

| Customer Segment         | 1-in-10 peak day (MMcfd) | 1-in-90 core plus 1-in-10 noncore day (MMcfd) |
|--------------------------|--------------------------|-----------------------------------------------|
| Off System <sup>13</sup> | 380                      | 402                                           |
| <b>Total Demand</b>      | <b>4,305</b>             | <b>4,422</b>                                  |

Source: CEC staff forecasts and estimates

## PG&E Pipeline Capacity

The PG&E gas transmission system map (Figure 2) displays the high-pressure natural gas pipeline network spanning central and northern California, stretching from Eureka and the Oregon border down to Bakersfield. PG&E's backbone transmission system<sup>14</sup> and high-diameter pipes run through much of the length of California (from Topock, Arizona, to Malin, Oregon). This system, which includes more than 1,700 miles of pipe,<sup>15</sup> provides significant pipe inventory that PG&E can draw upon to meet demand and maintain operating pressures on the gas system. These unique characteristics enable PG&E to maintain sizable linepack (the quantity of gas stored in a pipeline) even on high-demand days, which effectively offers short-term storage. To evaluate PG&E system reliability, staff estimated available pipeline capacity and storage inventory on the PG&E system (Figure 2). These pipeline capacity estimates are used for comparison in all demand scenarios.

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13 Gas deliveries to customers outside the utility's service area. For this table, this constitutes an estimate of deliveries to the SoCalGas system. Off-system deliveries include both firm (currently 80 MMcfd) and interruptible deliveries. In a peak case, only firm would be met if necessary for reliability.

14 A *natural gas backbone system* refers to the primary network of large, high-pressure pipelines that transport natural gas from production areas to major consumption centers.

15 PG&E. "[About California Gas Transmission: Welcome to CGT](https://www.pge.com/pipeline/en/about-cgt.html)," <https://www.pge.com/pipeline/en/about-cgt.html>.

**Figure 2: Map of the PG&E Gas Transmission System**



Source: PG&E

The PG&E Pipe Ranger website reports the capacity available to its customers for scheduling and maintenance and outage events that impact capacity. Monthly average capacities were generated for the Baja (southern backbone) and Redwood (northern PG&E's backbone) pipeline systems. Maintenance activities<sup>16</sup> are scheduled for the Baja and Redwood system in winter 2026–27, but an analysis of PG&E's maintenance outlook report shows that 99 percent of pipeline capacity will be available in December and January, with more than 90 percent on average available in the remaining winter months of November, February, and March.

Moreover, PG&E's pipeline system maintains significant pipe inventory to meet demand and maintain operating pressures on the gas system (Table 3).

<sup>16</sup> PG&E's Prospective Maintenance document provides a 6–12 month outlook of proposed maintenance on the CGT pipeline system. PG&E revises this a monthly basis. PG&E. "[Pipeline Maintenance](https://www.pge.com/pipeline/en/operating-data/current-pipeline-status/pipeline-maintenance/foghorn.html)," PG&E. <https://www.pge.com/pipeline/en/operating-data/current-pipeline-status/pipeline-maintenance/foghorn.html>.

**Table 3: PG&E Winter Pipeline Supply**

| <b>Supply (MMcfd)</b>           | <b>Nov<br/>2026</b> | <b>Dec<br/>2026</b> | <b>Jan<br/>2027</b> | <b>Feb<br/>2027</b> | <b>Mar<br/>2027</b> |
|---------------------------------|---------------------|---------------------|---------------------|---------------------|---------------------|
| <b>California Source Gas</b>    | 22                  | 22                  | 22                  | 22                  | 22                  |
| <b>Baja Path</b>                | 831                 | 940                 | 950                 | 829                 | 746                 |
| <b>Redwood Path</b>             | 2,046               | 2,046               | 2,046               | 2,046               | 2,046               |
| <b>Total Pipeline Receipts*</b> | <b>2,899</b>        | <b>3,008</b>        | <b>3,018</b>        | <b>2,897</b>        | <b>2,814</b>        |

**\*An average of minimum capacity available in November 2026 and March 2027 based on an analysis of PG&E's Prospective Maintenance document reported on Pipe Ranger.**

Source: CEC staff

## **PG&E and Independent Storage Providers**

PG&E owns and operates the Los Medanos and McDonald Island underground gas storage fields,<sup>17</sup> which have a combined maximum working gas capacity of about 51.1 billion cubic feet (Bcf). Neither the Pipe Ranger website nor the PG&E prospective maintenance report<sup>18</sup> identifies maintenance activities that would reduce injection or withdrawal capacities at PG&E underground gas storage facilities during winter 2026–27. PG&E received approval in D.23-11-069 to add withdrawal deliverability to its storage facilities through new and replacement wells from 2024 through 2027 in compliance with California Geologic Energy Management Division (CalGEM) safety regulations for underground gas storage facilities.

For winter 2026–2027, PG&E reported plans to add 106 MMcf/d in peak-day withdrawal capacity by building new and replacement wells at McDonald Island, Los Medanos, and Gill Ranch to offset performance losses from safety compliance. This work restores daily deliverability speeds but does not increase the physical volume (Bcf) of working gas storage. Based on CEC staff's daily tracking of storage activity and analysis of historical data on withdrawals and injections, staff estimates that the PG&E-owned gas storage facilities will be at full capacity by the beginning of winter 2026–2027.

Independent storage providers (ISPs) are owned and operated by third parties — Wild Goose, Central Valley Gas Storage, Lodi, Pleasant Creek, and Gill Ranch (partially owned by PG&E). They connect to PG&E backbone transmission pipelines and are within the PG&E service area. This analysis does not include withdrawals from ISPs and estimates of storage inventory levels. Under PG&E's Fossil Gas Storage Strategy, which was approved by the CPUC, PG&E can

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17 A third field, Pleasant Creek, is no longer in operation. In April 2025, the CPUC approved the sale of the facility by PG&E to Pleasant Creek Gas Storage Holdings, LLC, and eCorp Natural Gas Storage Holdings, LLC. In its decision approving the sale, the CPUC designates Pleasant Creek LLC as an independent storage provider authorized to charge market-based rates for natural gas storage services.

California Public Utilities Commission. [Decision Granting Joint Application](https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M565/K249/565249273.PDF). 2025. Decision Number: D.25-04-032. <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M565/K249/565249273.PDF>.

18 PG&E. "[Pipeline Maintenance](#)."

procure storage services from ISPs to meet reliability standards. But the ISPs themselves are not responsible for supporting system reliability. Noncore customers (electric generators, industrial customers, large commercial) have the option to purchase storage services from the gas utility or from ISPs, but the gas utility has no obligation to provide storage services for noncore customers. ISP transactions with customers are conducted independently of PG&E under commercial terms that are confidential. The reasoning for individual transactions — whether to withdraw gas at lower prices or to avoid curtailment — is unknown.

## PG&E Gas Balance

Staff assessed the availability of supply (Tables 4–5 and Figures 3–6) for meeting demand.

Tables 4 and 5 show the monthly gas balances for November 2026–Mar 2027 using the CEC’s forecast for average temperature demand and cold temperature/dry hydro demand, respectively. This analysis captures planned pipeline maintenance as reported by PG&E in July 2026 and is reflected in available pipeline capacity, where relevant.

Under the average temperature demand scenario, pipeline capacity is sufficient to meet demand, and on average, storage withdrawals are not needed except in December where 141 MMcfd is needed to meet demand. Under the cold temperature/dry hydro demand scenario, required monthly storage withdrawals range from 136 MMcfd to 335 MMcfd in December 2026 and January and February of 2027.

Staff demand forecasts for PG&E include estimates of off-system deliveries, particularly to the SoCalGas system at Kern River Station. Should it become necessary to preserve the higher-priority deliveries to on-system customers, PG&E can reduce or eliminate the portion of its off-system deliveries that are made on an as-available basis. For example, in the cold/dry scenario for December 2026 shown in Table 5, PG&E could reduce off-system deliveries to 80 MMcfd to meet its firm commitments and, in turn, reduce storage withdrawals from 335 MMcfd to 197 MMcfd. Typically, forecast off-system demand is met, including the lower-priority/as-available portion, when PG&E has enough flowing supply, storage withdrawals, and system capacity.

CEC staff estimates that storage field inventory at the end of winter 2026–27 in March 2027 will range from 24 Bcf to 37 Bcf.

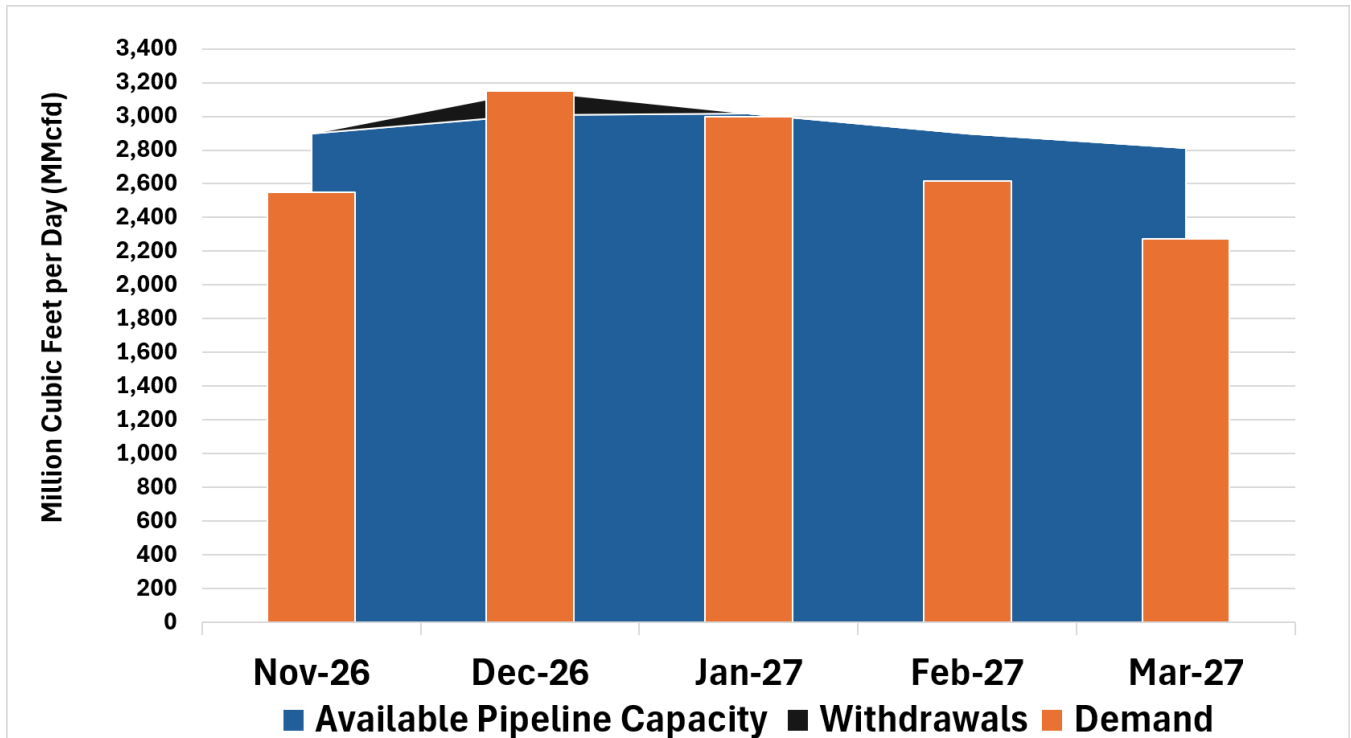
**Table 4: PG&E Monthly Gas Balance Average Demand Scenario**

| <b>PG&amp;E Gas Balances</b>                  | <b>Nov<br/>2026</b> | <b>Dec<br/>2026</b> | <b>Jan<br/>2027</b> | <b>Feb<br/>2027</b> | <b>Mar<br/>2027</b> |
|-----------------------------------------------|---------------------|---------------------|---------------------|---------------------|---------------------|
| <b>Demand (MMcfd)</b>                         | 2,552               | 3,149               | 2,996               | 2,617               | 2,274               |
| <b>Available Pipeline Capacity (MMcfd)</b>    | 2,899               | 3,008               | 3,018               | 2,897               | 2,814               |
| <b>PG&amp;E Withdrawal (MMcfd)*</b>           | 0                   | 141                 | 0                   | 0                   | 0                   |
| <b>PG&amp;E End-of-Month Inventory (MMcf)</b> | 46,000              | 42,000              | 42,000              | 42,000              | 42,000              |

**\*Uses needed withdrawals.**

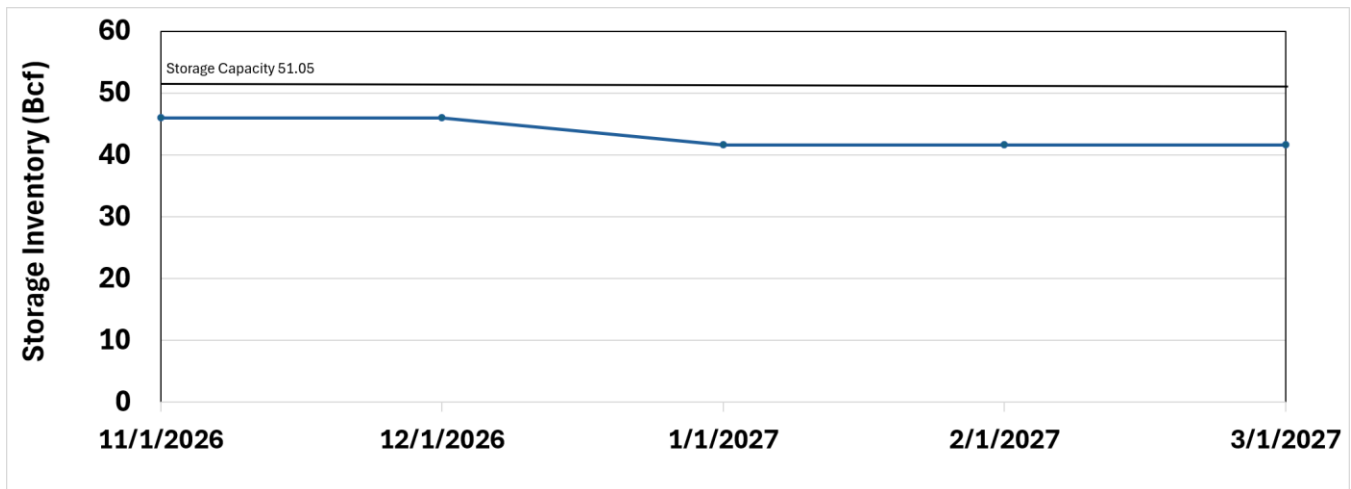
Source: CEC staff

**Figure 3: PG&E Available Pipeline Capacity, Needed Withdrawals, and Demand (Average Demand Scenario)**



Source: CEC staff

**Figure 4: PG&E Storage Inventory (Average Demand Scenario)**



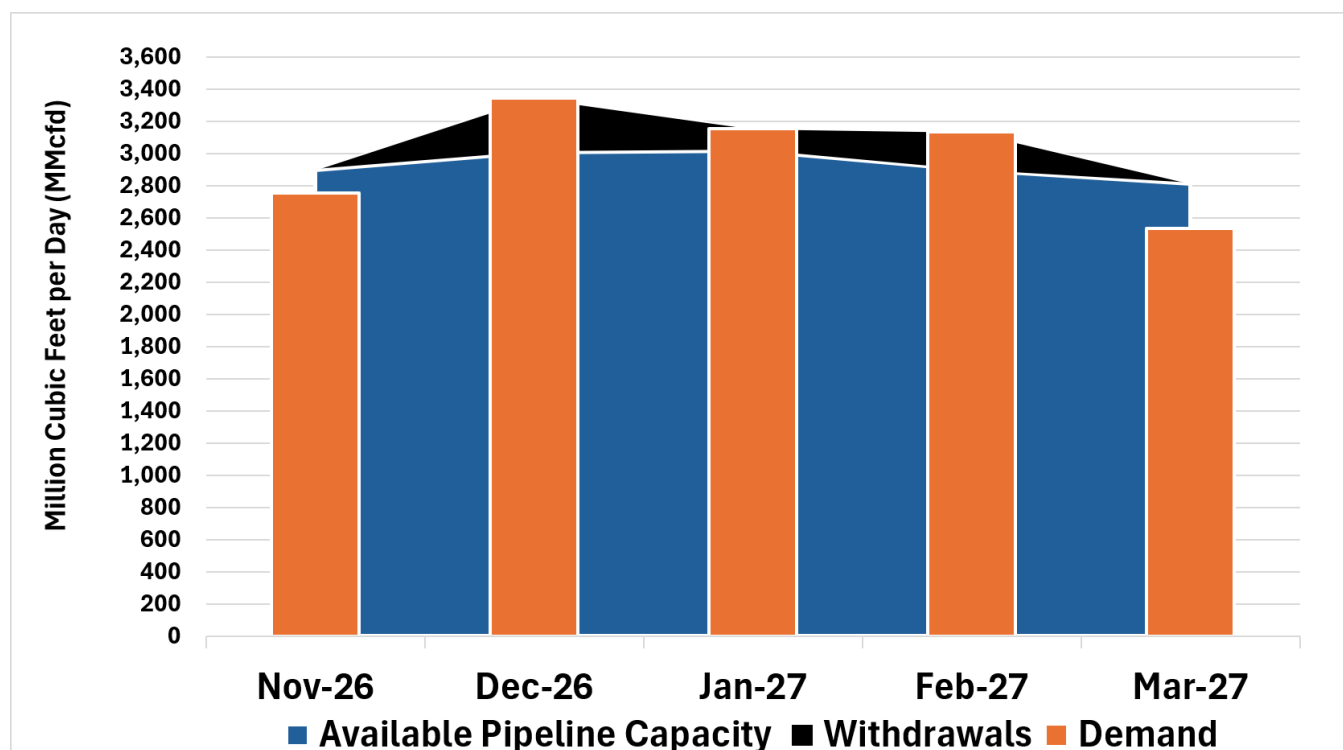
Source: CEC staff

**Table 5: PG&E Monthly Gas Balance Cold/Dry Demand Scenario**

| <b>PG&amp;E Gas Balances</b>                  | <b>Nov 2026</b> | <b>Dec 2026</b> | <b>Jan 2027</b> | <b>Feb 2027</b> | <b>Mar 2027</b> |
|-----------------------------------------------|-----------------|-----------------|-----------------|-----------------|-----------------|
| <b>Demand (MMcfd)</b>                         | 2,752           | 3,343           | 3,154           | 3,132           | 2,536           |
| <b>Available Pipeline Capacity (MMcfd)</b>    | 2,899           | 3,008           | 3,018           | 2,897           | 2,814           |
| <b>PG&amp;E Withdrawal (MMcfd)*</b>           | 0               | 335             | 136             | 235             | 0               |
| <b>PG&amp;E End-of-Month Inventory (MMcf)</b> | 46,000          | 35,000          | 31,000          | 24,000          | 24,000          |

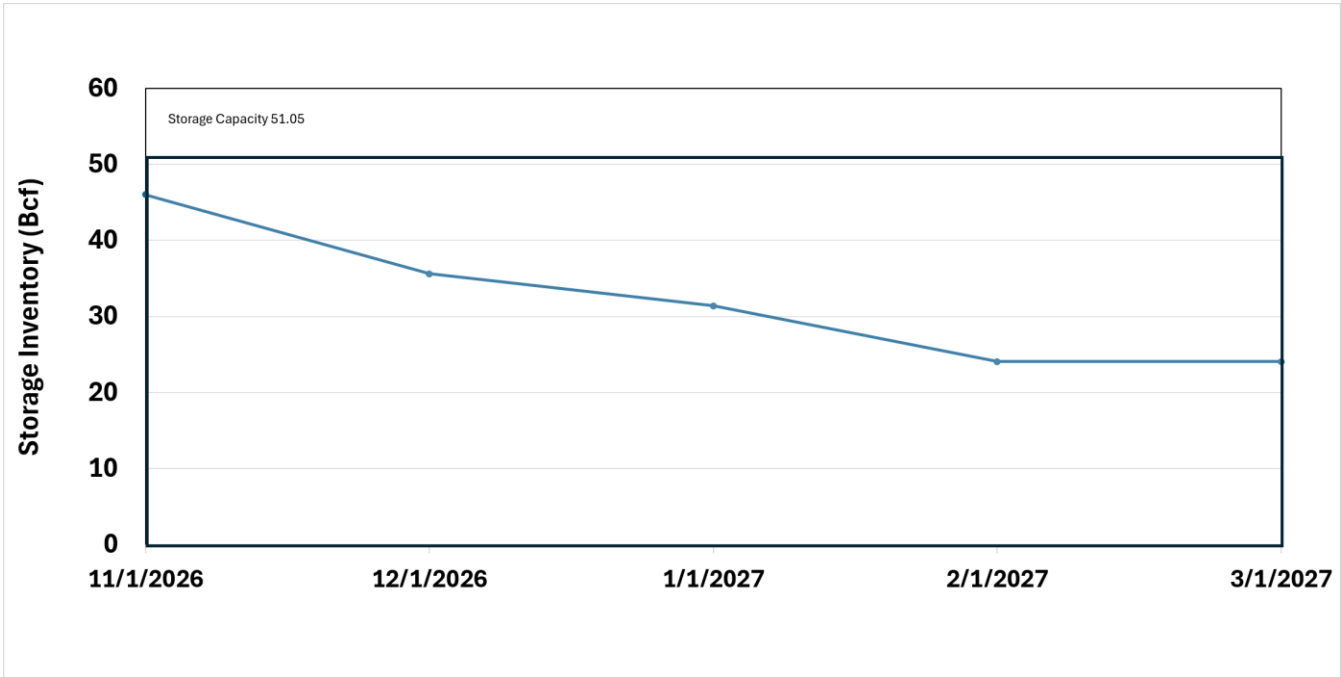
Source: CEC staff

**Figure 5: PG&E Available Pipeline Capacity, Needed Withdrawals, and Demand (Cold/Dry Hydro Demand Scenario)**



Source: CEC staff

**Figure 6: PG&E Storage Inventory (Cold/Dry Hydro Demand Scenario)**



Source: CEC staff

## PG&E Peak-Day Analysis

Staff evaluated two peak day cases for winter. Case 1 looked at a 1-in-10 peak-temperature cold day for core and noncore load. Case 2 looked at the abnormal 1-in-90 peak-temperature cold day for core plus 1-in-10 peak-temperature cold day for noncore.<sup>19</sup>

The CEC estimates a 3.0 Bcf pipeline capacity for PG&E in winter 2026–27. PG&E’s estimate of a storage withdrawal capacity of 857 MMcfd for that period. The estimated pipeline capacity, combined with PG&E’s estimate of a storage withdrawal capacity of 857 MMcfd for that period,<sup>20</sup> yields CEC’s estimated net shortfall of 135 MMcfd for Case 1 and 230 MMcfd for Case 2 (Table 6 and Figure 7).

The net shortfall estimate can be viewed as a worst-case scenario. In both cases, CEC staff assumed that off-system deliveries would be capped at the firm contractual amount of 80 MMcfd. While ISP withdrawals for noncore customers can reduce or zero out the estimates above and are hydraulically feasible, ISPs conduct these transactions independently under terms not known to the CEC or the public. These withdrawals are not used to meet reliability standards but are based on the economic needs, interests, and goals of market participants.

Furthermore, PG&E can issue operational flow orders (OFOs) or emergency flow orders (EFOs)<sup>21</sup> to noncore customers under cases of supply or capacity shortages or both.<sup>22</sup> Under PG&E’s fossil gas storage strategy, adopted by the CPUC as part of the 2019 Gas Transmission and Storage (GT&S) rate case in Decision 19-09-025, PG&E established a new reserve capacity. The reserve capacity can provide reliability against a loss of supply of up to 250 MMcfd. PG&E can use the reserve capacity to resolve significant, unplanned equipment outages, among other supply problems. The reserve capacity service is an allocated 1.0 Bcf of storage inventory, 25 MMcfd of injection capacity, and 250 MMcfd of withdrawal capacity.<sup>23</sup>

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19 Noncore load is less temperature-sensitive, so adding its 1-in-10 probability estimate to the core 1-in-90 allows calculation of total system load that could need to be curtailed on a peak day. Including the noncore load in this calculation allows staff to understand how much of the noncore load might be curtailed.

20 California Public Utilities Commission. July 31, 2024. [Application of Pacific Gas and Electric Company \(U 39 G\) for Approval of Peak Day Supply Standard Pursuant to Decision 23-11-069](https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M536/K706/536706078.PDF). Application Number: A.24-07-020, <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M536/K706/536706078.PDF>.

21 An OFO (Operational Flow Order) and an EFO (Emergency Flow Order) are official notices issued by natural gas pipeline operators to manage system stability and prevent pipeline failure. Shippers who fail to balance their volume within the allowed tolerance range face noncompliance fees. <https://www.pge.com/pipeline/en/reference-library/ofo-efo-diversions/ofo.html>

22 PG&E may issue an EFO if deliveries to end-use customers are threatened due to supply and/or capacity shortages. An EFO would normally follow an OFO but may be invoked without a preceding OFO. EFOs do not apply to oversupply (high inventory) situations. PG&E. [“Emergency Flow Order \(EFO\).” https://www.pge.com/pipeline/en/reference-library/ofo-efo-diversions/efo.html](https://www.pge.com/pipeline/en/reference-library/ofo-efo-diversions/efo.html).

23 PG&E. March 12, 2020. [“Modified Firm Storage Rights — Effective April 1, 2020,” https://www.pge.com/pipeline/en/reference-library/news-archive/20200311\\_2401\\_news.html](https://www.pge.com/pipeline/en/reference-library/news-archive/20200311_2401_news.html).

**Table 6: PG&E Peak Demand Day Gas Balances**

| <b>Demand Type, Available Pipeline Capacity, and Needed Withdrawal</b> | <b>Case 1: 1-in-10 Peak Day (MMcfd)</b> | <b>Case 2: 1-in-90 Core Plus 1-in-10 Noncore Day (MMcfd)</b> |
|------------------------------------------------------------------------|-----------------------------------------|--------------------------------------------------------------|
| <b>Core<sup>24</sup></b>                                               | 1,949                                   | 2,044                                                        |
| <b>Noncore — Nonelectric Generation<sup>25</sup></b>                   | 838                                     | 838                                                          |
| <b>Noncore — Electric Generation<sup>26</sup></b>                      | 1,138                                   | 1,138                                                        |
| <b>Off System – Interruptible</b>                                      | 300                                     | 322                                                          |
| <b>Off System – Firm</b>                                               | 80                                      | 80                                                           |
| <b>Off System Total<sup>27</sup></b>                                   | 380                                     | 402                                                          |
| <b>Total Demand</b>                                                    | <b>4,305</b>                            | <b>4,422</b>                                                 |
| <b>Total Demand Served</b>                                             | <b>4,005</b>                            | <b>4,100</b>                                                 |
| <b>Available Pipeline Capacity</b>                                     | 3,013                                   | 3,013                                                        |
| <b>Needed Withdrawal*</b>                                              | <b>(992)</b>                            | <b>(1,087)</b>                                               |
| Assumed Available Withdrawal                                           | (857)                                   | (857)                                                        |
| <b>Net Shortfall (Does Not Include ISP)</b>                            | <b>135</b>                              | <b>230</b>                                                   |

\*PG&E estimate of storage capacity for winter 2026–2027 in facilities it owns in CPUC Application 24-07-020.<sup>28</sup>

Source: CEC staff

24 Customers with average usage less than 20,800 therms per month. These are mainly residential and small commercial customers.

25 Commercial and industrial customers whose average usage exceeds 20,800 therms per month, not including power plants.

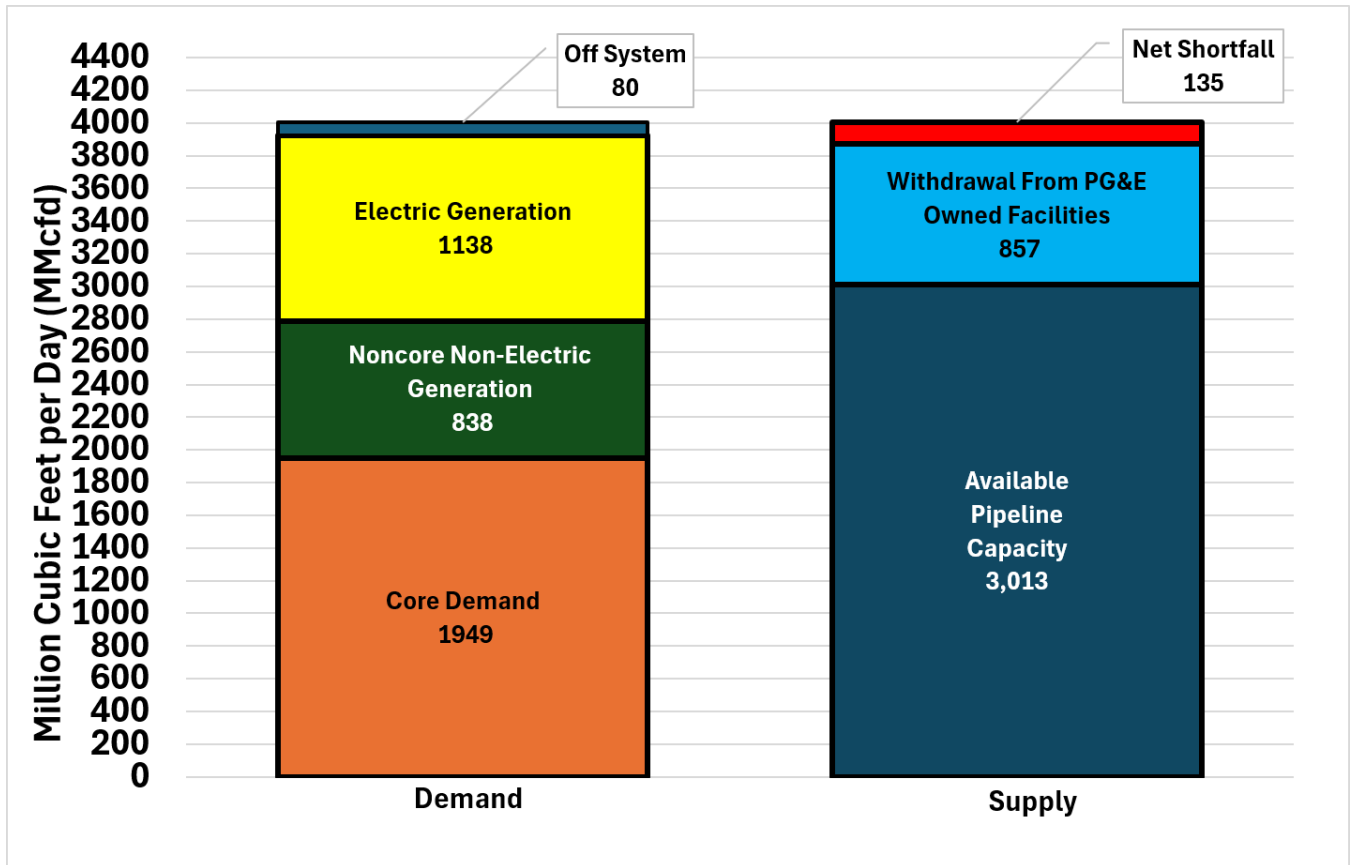
26 Power plant customers whose average usage exceeds 20,800 therms per month.

27 Gas deliveries to customers outside the utility's service area. For this table, this constitutes an estimate of deliveries to the SoCalGas system.

28 California Public Utilities Commission. [Application of Pacific Gas and Electric Company \(U39G\) for Approval of Peak Day Supply Standard Pursuant to Decision 23-11-069.](https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M604/K932/604932014.PDF)

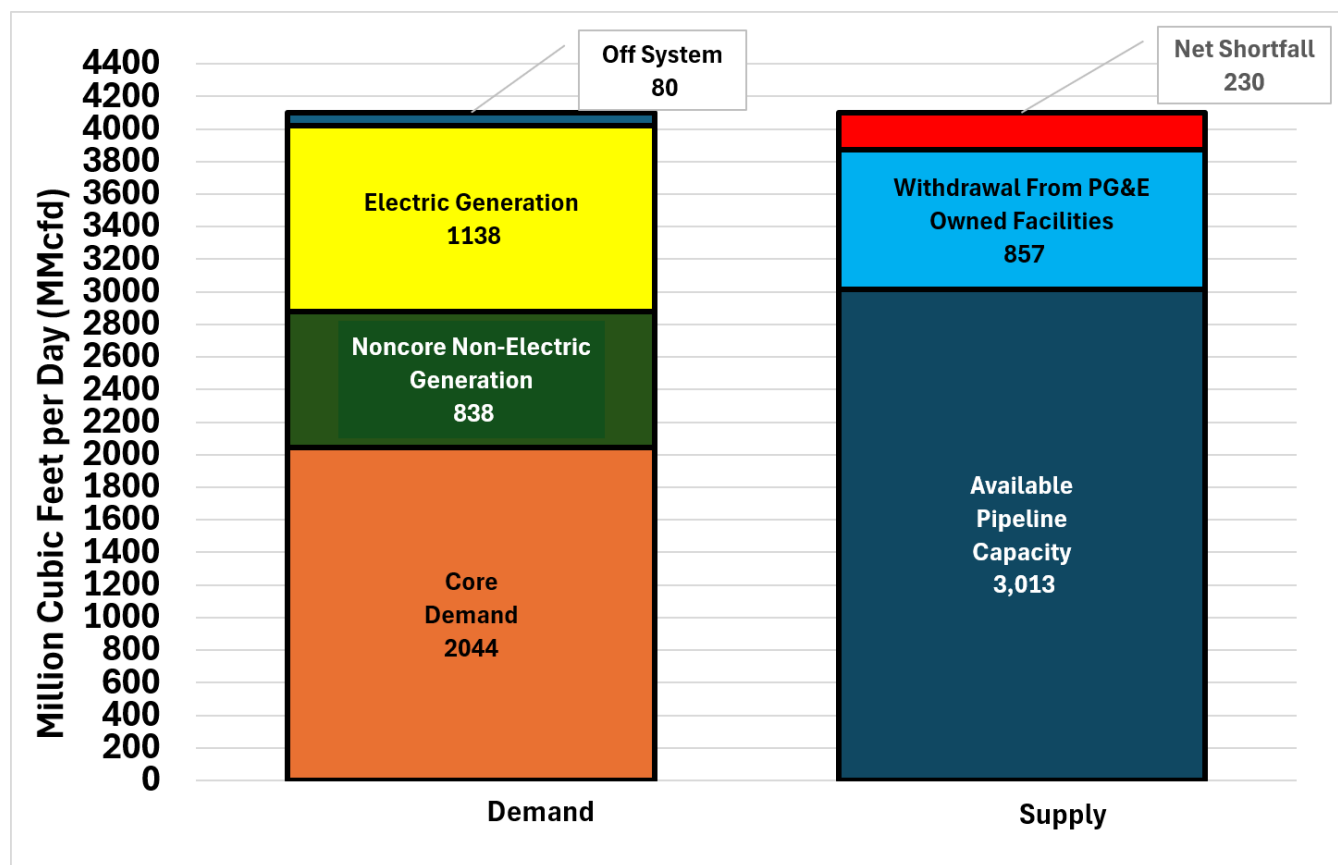
<https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M604/K932/604932014.PDF>.

**Figure 7a: PG&E Demand and Supply for Case 1: 1-in-10 Peak Day**



Source: CEC staff

**Figure 7b: PG&E Demand and Supply for Case 2: 1-in-90 Core/1-in-10 Noncore Peak Day**



Source: CEC staff

## PG&E Hydraulic Analysis

Staff used the Synergi Gas hydraulic modeling platform to assess PG&E gas system operations<sup>29</sup> for its Baja and Redwood transmission. The hydraulic analysis also identifies pressure violations and allows simulation testing of different operational solutions. Analysis of PG&E's hydraulic models shows that receipts of fossil gas from interstate pipelines combined with storage withdrawals from PG&E- and ISP-owned facilities<sup>30</sup> can eliminate the shortfalls shown in Table 6 and Figure 7.

## PG&E Conclusion

Based upon available pipeline and storage capacity, the CEC predicts a net shortfall of 135 MMcfd for Case 1 and 230 MMcfd for Case 2. (See Table 6 and Figure 7.) There are additional

<sup>29</sup> Synergi Gas is the longtime industry standard for hydraulic modeling of large, complex distribution and transmission systems.

<sup>30</sup> ISP withdrawals are hydraulically feasible based on the withdrawal capacities of the facilities that are reported to the CEC. While hydraulically feasible, CEC staff cannot estimate which facilities and how much withdrawals can be relied upon by each facility as some withdrawals are not for reliability reasons and the terms of the transactions are unknown.

tools to meet this demand before any curtailment of service to noncore customers, such that the net shortfall estimate can be viewed as a worst-case scenario.

# CHAPTER 3:

## CEC SoCalGas System Analysis

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This chapter summarizes the CEC staff assessment of the ability of the SoCalGas transmission system to meet demand in winter 2026–27. Appendix A has more information about the forecasting method.

### Gas Demand Forecast

Tables 7 presents CEC’s forecasts for the monthly average, cold-peak-day demands on the SoCalGas’ system. Table 8 presents the peak day demand under two scenarios: a 1-in-35 for core customers and 1-in-10 for noncore customers peak day.

**Table 7: CEC Forecast of SoCalGas Monthly Demand**

| <b>Demand Scenario</b>                      | <b>Nov<br/>2026</b> | <b>Dec<br/>2026</b> | <b>Jan<br/>2027</b> | <b>Feb<br/>2027</b> | <b>Mar<br/>2027</b> |
|---------------------------------------------|---------------------|---------------------|---------------------|---------------------|---------------------|
| <b>Average Demand (MMcfd)<sup>31</sup></b>  | 2,446               | 2,853               | 2,973               | 2,773               | 2,550               |
| <b>Cold/Dry Demand (MMcfd)<sup>32</sup></b> | 2,730               | 3,177               | 3,200               | 3,167               | 2,770               |

Source: CEC staff

**Table 8: CEC Forecast of SoCalGas Peak Day Demand**

| <b>Customer Segment</b>                                  | <b>1-in-10 Peak<br/>Day (MMcfd)</b> | <b>E1-in-35 Core Plus 1-in-10 Noncore<br/>Peak-Day Demand (MMcfd)</b> |
|----------------------------------------------------------|-------------------------------------|-----------------------------------------------------------------------|
| <b>Core<sup>33</sup></b>                                 | 2,595                               | 2,743                                                                 |
| <b>Noncore — Nonelectric<br/>Generation<sup>34</sup></b> | 836                                 | 836                                                                   |
| <b>Noncore — Electric<br/>Generation<sup>35</sup></b>    | 870                                 | 870                                                                   |
| <b>Total Demand</b>                                      | <b>4,302</b>                        | <b>4,449</b>                                                          |

Source: CEC staff

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31 Average daily demand by month in a normal year.

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

33 Customers with average usage less than 20,800 therms per month. These are mainly residential and commercial customers. This includes SDGE and other core customers.

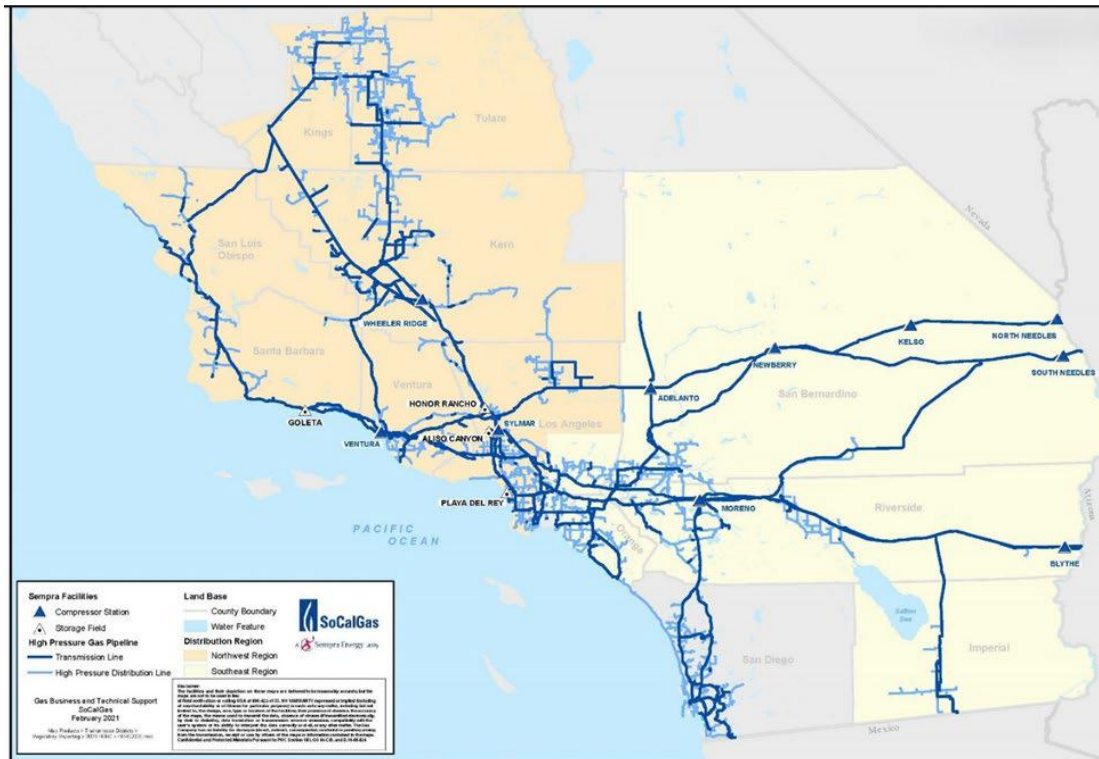
34 Commercial and industrial customers whose average usage exceeds 20,800 therms per month.

35 Power plant customers whose average usage exceeds 20,800 therms per month.

## SoCalGas Pipeline Capacity

For the winter assessment, staff estimated available pipeline capacity on the SoCalGas system (Figure 8) using maintenance outlook and scheduling information provided on the SoCalGas Envoy website.

**Figure 8: Map of SoCalGas/SDG&E Transmission System**



Source: California Energy Commission Docket 25-IEPR-03

The SoCalGas Envoy website reports pipeline and storage capacity reductions associated with scheduled maintenance, operational restrictions, and outages. CEC staff estimates SoCalGas winter 2026–2027 pipeline capacity at nearly 3.0 Bcf/d, consistent with the winter 2025–2026 estimate shown in Table 10. Earlier Northern Zone pressure reductions on Lines 4000 and 4002 were associated with Transmission Integrity Management Program work and Pipeline and Hazardous Materials Safety Administration (PHMSA)<sup>36</sup>-related compliance requirements; however, the currently posted major pipeline maintenance events are scheduled to end before the winter period. As of July 28, 2026, Envoy listed L3000 maintenance at the Topock subzone through October 30, 2026; L4002 Northern Zone maintenance through September 18, 2026; and Wheeler Ridge L225 restrictions ending August 31, 2026.<sup>37</sup> CEC staff estimates that

<sup>36</sup> The Pipeline and Hazardous Materials Safety Administration (PHMSA) is a United States Department of Transportation agency that creates and enforces safety rules for moving energy and hazardous goods. <https://www.phmsa.dot.gov/>

<sup>37</sup> SoCalGas. "SoCalGas ENVOY Maintenance Schedules," <https://www.socalgasenvoy.com/Public/ViewExternalSystemMaintenance.getMaintenanceLedger>.

pipeline capacity will not change significantly compared to the previous winter. However, on colder days, SoCalGas is expected to rely on gas storage to meet demand.

**Table 9: SoCalGas Pipeline Capacity Assumptions**

| <b>Supply (MMcfd)</b>                          | <b>Nov<br/>2026</b> | <b>Dec<br/>2026</b> | <b>Jan<br/>2027</b> | <b>Feb<br/>2027</b> | <b>Mar<br/>2027</b> |
|------------------------------------------------|---------------------|---------------------|---------------------|---------------------|---------------------|
| <b>California Line 85 Zone</b>                 | 40                  | 40                  | 40                  | 40                  | 40                  |
| <b>Wheeler Ridge Zone</b>                      | 790                 | 790                 | 790                 | 790                 | 790                 |
| <b>Blythe (Ehrenberg) Into Southern Zone</b>   | 670                 | 670                 | 670                 | 670                 | 670                 |
| <b>Otay Mesa Into Southern Zone</b>            | 0                   | 0                   | 0                   | 0                   | 0                   |
| <b>Kramer Junction Into Northern Zone</b>      | 700                 | 700                 | 700                 | 700                 | 700                 |
| <b>North Needles/Topock Into Northern Zone</b> | 890                 | 890                 | 890                 | 890                 | 890                 |
| <b>Total Supply</b>                            | <b>3,090</b>        | <b>3,090</b>        | <b>3,090</b>        | <b>3,090</b>        | <b>3,090</b>        |

Source: CEC staff

**Table 10: SoCalGas Winter Pipeline Capacity Comparison**

| <b>Season</b>                    | <b>Winter<br/>2022–2023</b> | <b>Winter<br/>2023–2024</b> | <b>Winter<br/>2024–2025</b> | <b>Winter<br/>2025–2026</b> | <b>Winter<br/>2026–2027</b> |
|----------------------------------|-----------------------------|-----------------------------|-----------------------------|-----------------------------|-----------------------------|
| <b>Pipeline Capacity (MMcfd)</b> | 2,815                       | 3,065                       | 3,035                       | 3,035                       | 3,090                       |

Source: CEC staff

## SoCalGas Storage

SoCalGas owns and operates the Aliso Canyon, Honor Rancho, La Goleta, and Playa del Rey underground gas storage fields, which have a combined maximum working gas capacity of about 120 billion cubic feet (Bcf). Based on CEC staff's daily tracking of storage activity and analysis of historical data on withdrawals and injections, staff estimates that the SoCalGas-owned gas storage facilities will be at capacity by the beginning of winter 2026–2027. The capacity includes the 68.6 Bcf working gas limit at Aliso Canyon, which the CPUC authorized in 2023 under Decision 23-08-050, which essentially removed all operating conditions at Aliso Canyon (Table 11).

**Table 11: SoCalGas Storage Inventory Comparison**

| <b>Season</b>                                   | <b>Winter<br/>2021–<br/>2022</b> | <b>Winter<br/>2022–<br/>2023</b> | <b>Winter<br/>2023–<br/>2024</b> | <b>Winter<br/>2024–<br/>2025</b> | <b>Winter<br/>2026–<br/>2027</b> |
|-------------------------------------------------|----------------------------------|----------------------------------|----------------------------------|----------------------------------|----------------------------------|
| <b>Total Storage<br/>Inventory<br/>(in Bcf)</b> | ~81                              | ~90                              | ~90                              | ~120                             | ~120                             |
| <b>Percentage<br/>Full<br/>(Total Storage)</b>  | 96%                              | 97%                              | 75%                              | 88%                              | 100%                             |
| <b>Allowed Aliso<br/>Inventory<br/>(Bcf)</b>    | 34                               | 41                               | 69                               | 69                               | 69                               |

Source: CEC staff

Storage remains a critical reliability resource for the SoCalGas/SDG&E system, particularly during cold weather and constrained market conditions. During Winter Storm Fern in January 2026, SoCalGas reported withdrawing more than 8 Bcf from storage from January 23 through January 31, with storage supplying nearly 60 percent of system demand at the peak of the storm. Aliso Canyon supplied about 30 percent of total gas delivered to the SoCalGas and SDG&E system at the peak.<sup>38</sup>

This recent winter event demonstrates the continued operational importance of storage on the SoCalGas system. In the Winter 2025–2026 Assessment, CEC staff used an assumed feasible withdrawal capability of 2,000 MMcfd, while noting that SoCalGas had previously estimated maximum withdrawal capacity at about 2.4 Bcf per day, subject to declining availability as storage inventories fall through the winter. CEC staff continues to use 2,000 MMcfd as a reasonable planning assumption for winter reliability analysis because actual withdrawal capability depends on storage inventory levels, field conditions, well availability, and ongoing maintenance.

As of July 2026, SoCalGas Envoy reported storage inventories above 100 Bcf.<sup>39</sup> In its gas balances presented below, CEC staff projects SoCalGas storage inventories will remain sufficient to support winter reliability, ending the winter at about 105 Bcf in the average case and 97 Bcf in the cold/dry case.

## **SoCalGas Gas Balance**

Staff assessed the ability of supply (Tables 9–11) for meeting monthly (Table 7) and peak-day demand.

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<sup>38</sup> SoCalGas. April 1, 2026. News release. ["Region Regional Natural Gas Storage Helped Southern Californians Avoid Over \\$120 Million in Energy Costs During Winter Storm Fern,"](https://www.socalgas.com/newsroom/press-release/Regional-Natural-Gas-Storage-Helped-Southern-Californians-Avoid-Millions) <https://www.socalgas.com/newsroom/press-release/Regional-Natural-Gas-Storage-Helped-Southern-Californians-Avoid-Millions>.

<sup>39</sup> SoCalGas. ["SoCalGas Envoy Daily Operations."](#)

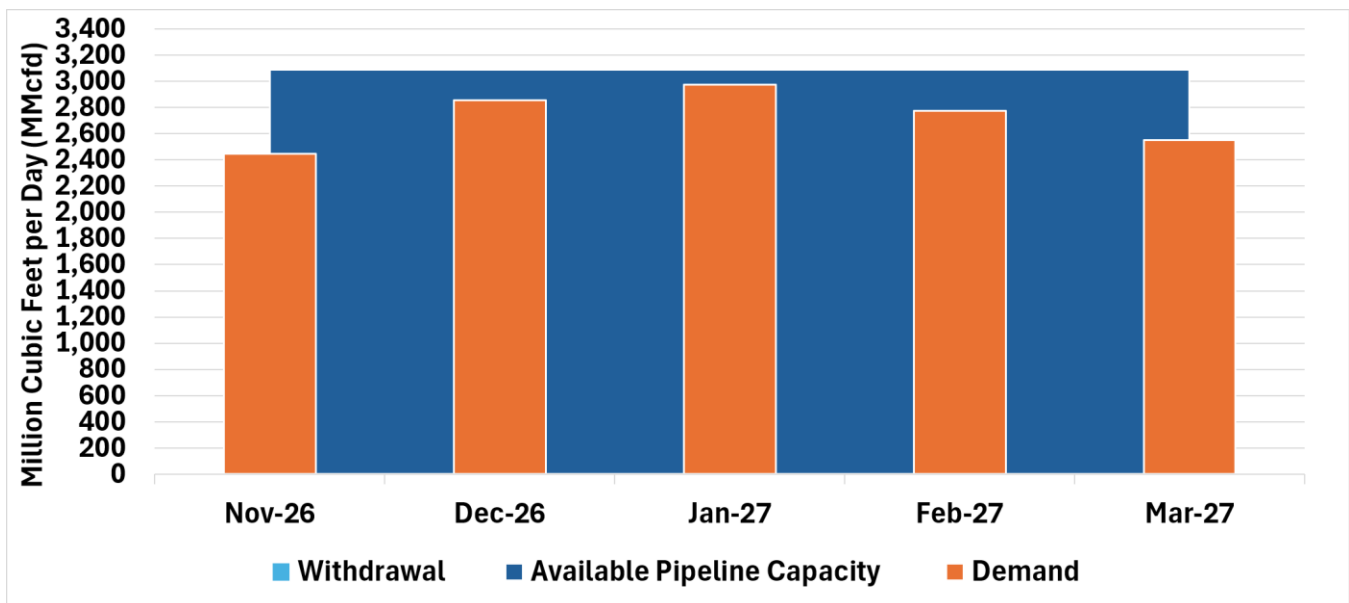
Tables 12 and 13 show the monthly gas balances for the average and cold/dry monthly demand scenarios. Required monthly storage withdrawals range from 77 MMcfd to 110 MMcfd and are only needed in the cold/dry scenario. The winter ending inventory in the winter cold case is estimated to be 112 Bcf compared to 119 Bcf in the average demand case.

**Table 12: SoCalGas Monthly Gas Balance Average Demand Scenario**

| <b>SoCalGas Gas Balances</b>                  | <b>Nov 2026</b> | <b>Dec 2026</b> | <b>Jan 2027</b> | <b>Feb 2027</b> | <b>Mar 2027</b> |
|-----------------------------------------------|-----------------|-----------------|-----------------|-----------------|-----------------|
| <b>Demand (MMcfd)</b>                         | 2,447           | 2,853           | 2,973           | 2,774           | 2,550           |
| <b>Available Pipeline Capacity (MMcfd)</b>    | 3,090           | 3,090           | 3,090           | 3,090           | 3,090           |
| <b>SoCalGas Withdrawal (MMcfd)</b>            | 0               | 0               | 0               | 0               | 0               |
| <b>SoCalGas End-of-Month Inventory (MMcf)</b> | 105,000         | 105,000         | 105,000         | 105,000         | 105,000         |

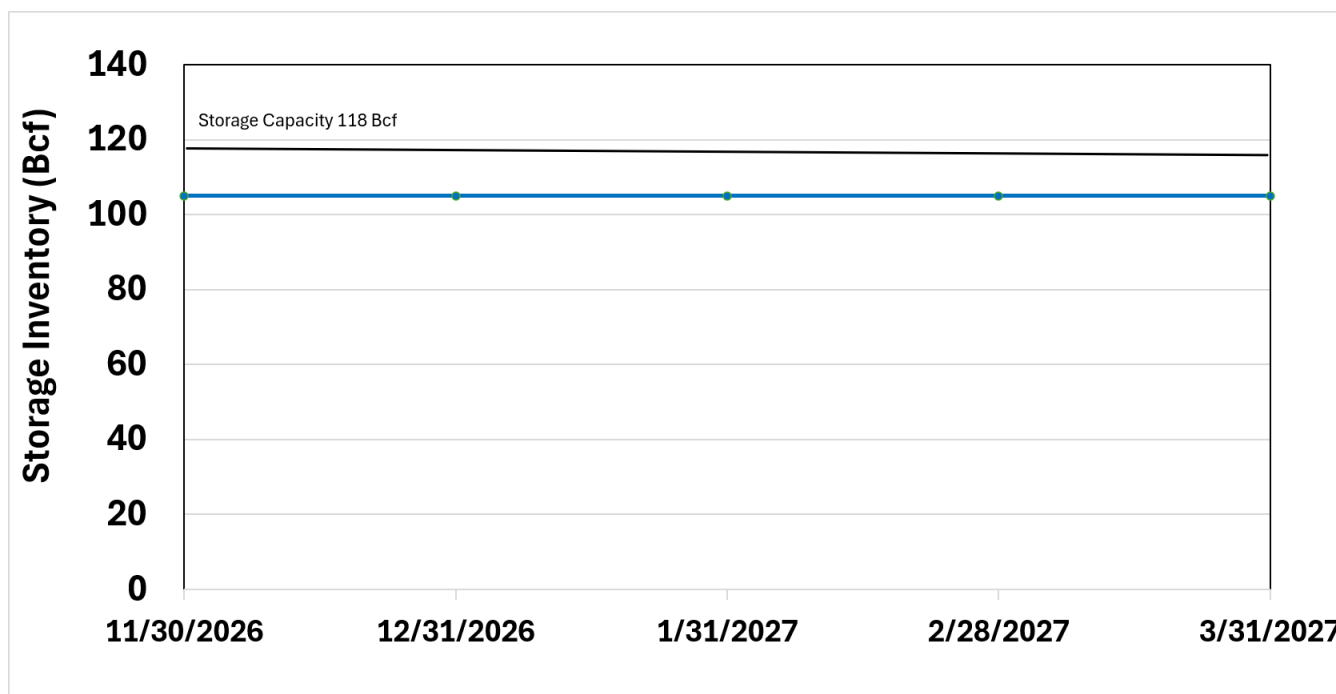
Source: CEC staff

**Figure 9: SoCalGas Available Pipeline Capacity, Needed Withdrawals, and Demand (Average Demand Scenario)**



Source: CEC staff

**Figure 10: SoCalGas Storage Inventory (Average Demand Scenario)**



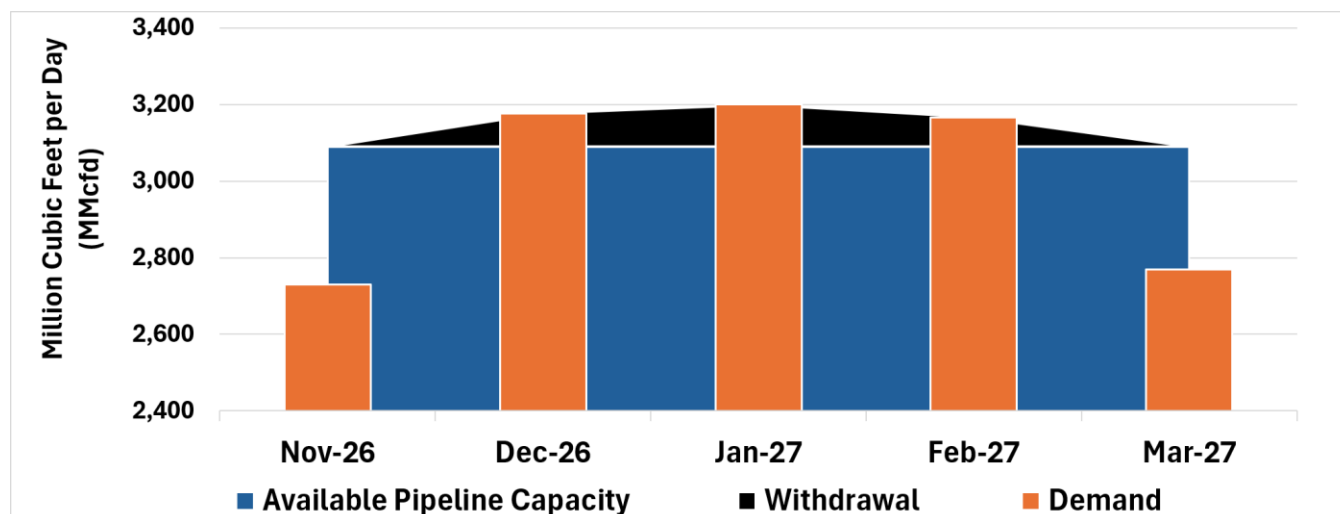
Source: CEC staff

**Table 13: SoCalGas Monthly Gas Balance Cold/Dry Demand Scenario**

| SoCalGas Gas Balances                         | Nov 2026 | Dec 2026 | Jan 2027 | Feb 2027 | Mar 2027 |
|-----------------------------------------------|----------|----------|----------|----------|----------|
| <b>Demand (MMcfd)</b>                         | 2,730    | 3,177    | 3,200    | 3,167    | 2,770    |
| <b>Available Pipeline Capacity (MMcfd)</b>    | 3,090    | 3,090    | 3,090    | 3,090    | 3,090    |
| <b>SoCalGas Withdrawal (MMcfd)</b>            | 0        | 87       | 110      | 77       | 0        |
| <b>SoCalGas End-of-Month Inventory (MMcf)</b> | 105,000  | 102,000  | 99,000   | 97,000   | 97,000   |

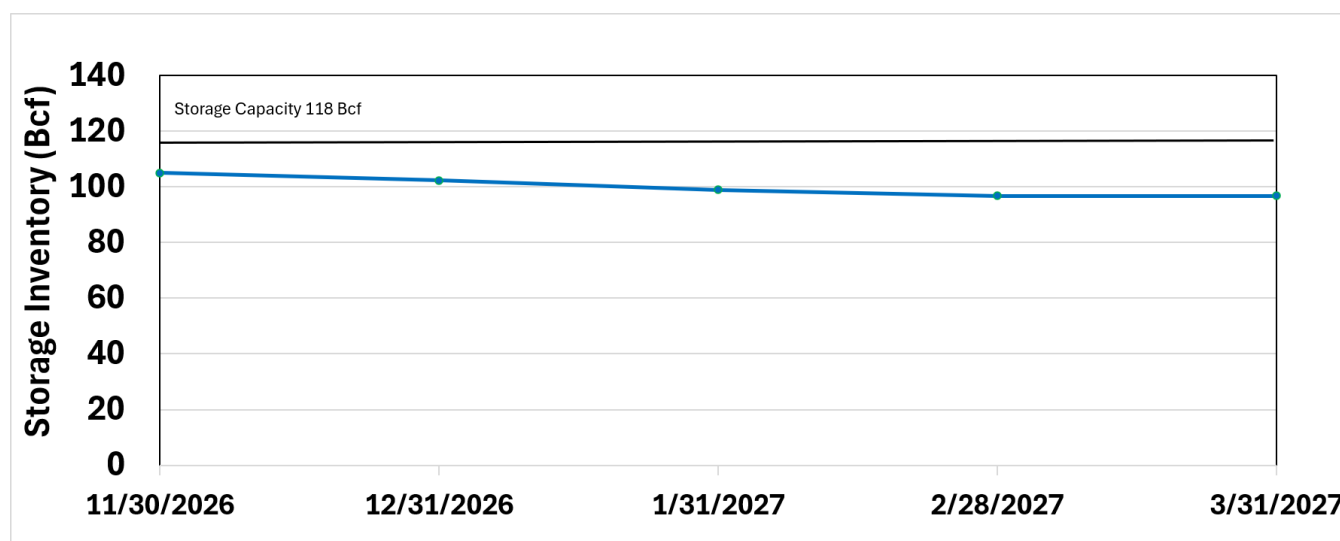
Source: CEC staff

**Figure 11: SoCalGas Available Pipeline Capacity, Needed Withdrawals, and Demand (Cold/Dry Demand Scenario)**



Source: CEC staff

**Figure 12: SoCalGas Storage Inventory (Cold/Dry Demand Scenario)**



Source: CEC staff

## SoCalGas Peak-Day Analysis

Staff evaluated two peak-day cases for winter (Table 14 and Figure 12). Case 1 looked at a 1-in-10 peak temperature cold day for core and noncore load. Case 2 looked at the more extreme 1-in-35 peak temperature cold day for core plus 1-in-10 peak temperature cold day for noncore. CEC staff projects that SoCalGas storage fields will be at full capacity by the start of the winter 2026–2027 gas season in November.

During winter 2023–2024, the maximum daily net withdrawal (accounting for injections) from these fields totaled 1.9 Bcf, which occurred January 13, 2024. When 1.9 Bcf of gas was withdrawn January 13, 2024, storage inventories were an estimated 92 Bcf, demonstrating that an assumed maximum withdrawal capacity of 2 Bcf is reasonable.

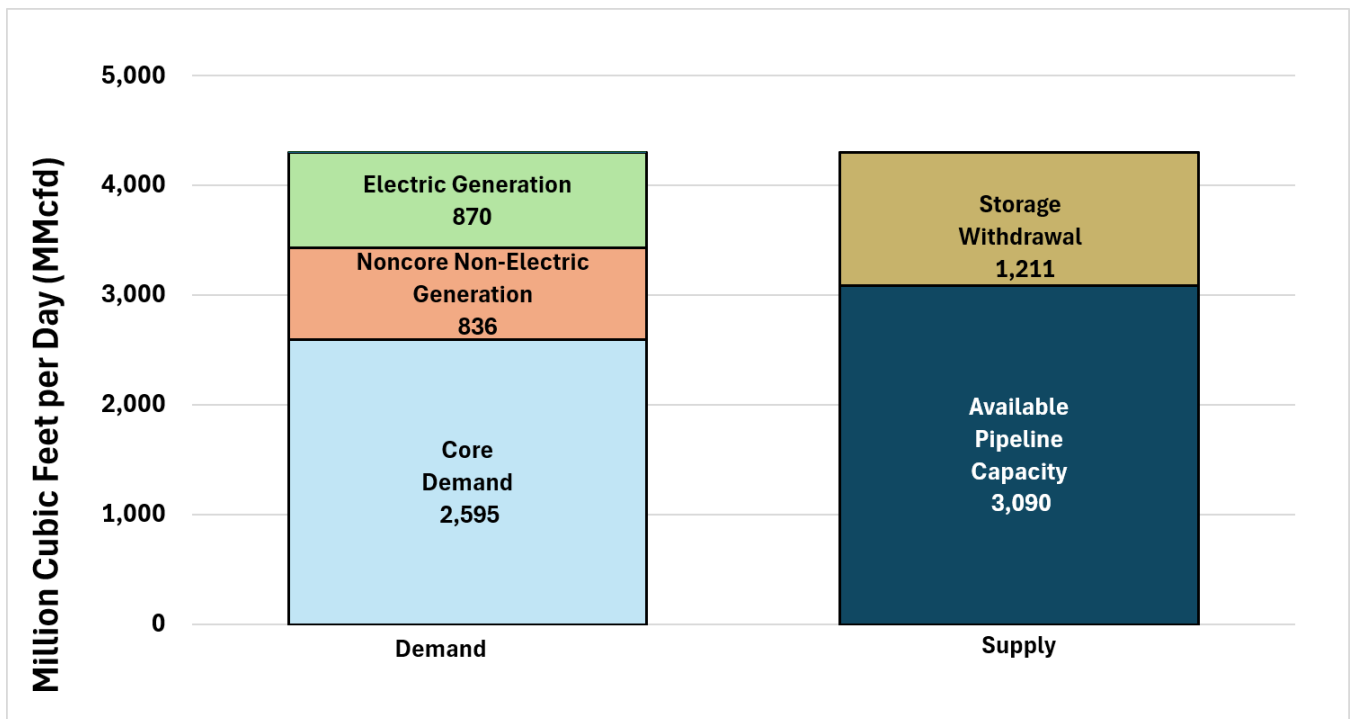
**Table 14: SoCalGas Peak-Demand-Day Gas Balances**

| <b>Demand, Withdrawal, and Net Demand Type, Available Pipeline Capacity, and Needed Withdrawal</b> | <b>Case 1: 1-in-10 Peak day (MMcfd)</b> | <b>Case 2: 1-in-35 Core /1-in10 Noncore Peak Day</b> |
|----------------------------------------------------------------------------------------------------|-----------------------------------------|------------------------------------------------------|
| Core Demand                                                                                        | 2595                                    | 2743                                                 |
| Noncore-Non-EG Demand                                                                              | 836                                     | 836                                                  |
| EG Demand                                                                                          | 870                                     | 870                                                  |
| <b>Total Demand</b>                                                                                | <b>4,302</b>                            | <b>4,449</b>                                         |
| Available Pipeline Capacity                                                                        | 3,090                                   | 3,090                                                |
| <b>Needed Withdrawal</b>                                                                           | <b>(1,211)</b>                          | <b>(1,359)</b>                                       |
| Assumed Available Withdrawal*                                                                      | 2,000                                   | 2,000                                                |
| <b>Net Shortfall</b>                                                                               | <b>0</b>                                | <b>0</b>                                             |

\*Estimated withdrawal based on CEC staff analysis of historical gas withdrawal data.

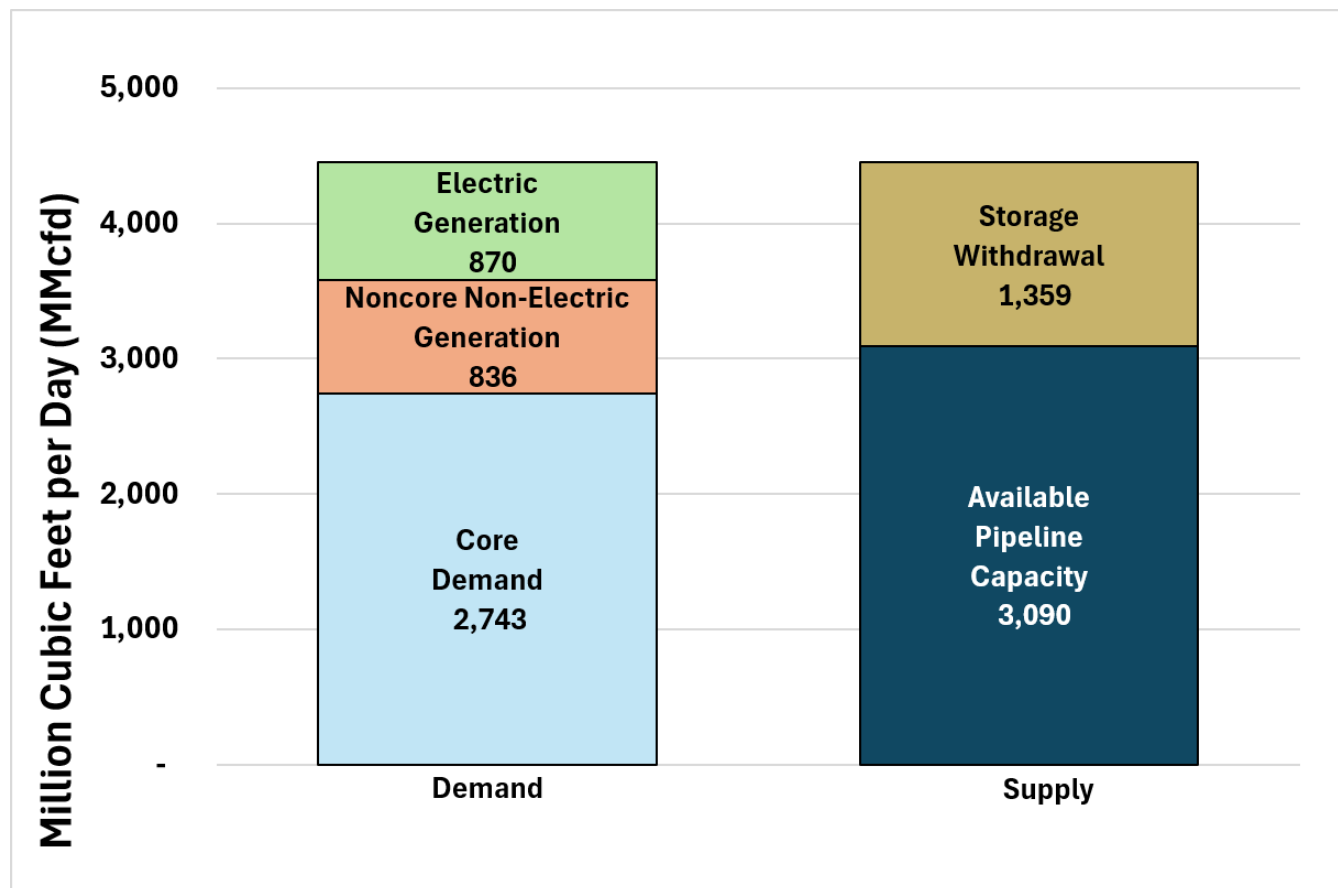
Source: CEC staff

**Figure 13a: SoCalGas Demand and Supply for Case 1 (1-in-10 Peak Day)**



Source: CEC staff

**Figure 13b: SoCalGas Demand and Supply for Case 2 (1-in-35 Core/1-in-10 Noncore Peak Day)**



Source: CEC staff

Based on the above assumed conditions, staff finds that supply can meet demand in Cases 1 and 2.

## SoCalGas Stochastic Analysis

Staff performed an additional gas balance analysis for the upcoming 2026-27 winter. It allows hourly demand to vary stochastically. This analysis simulates demand fluctuations within a historical range derived from 15 years of hourly gas demand data by day. This approach provides a more detailed picture of gas demand dynamics, capturing the hourly demand patterns that the conventional demand analysis does not.

Staff used the same method as in prior assessments to craft the hourly stochastic demand. The updated analysis reflects additional historical data, receipts, and the CEC's latest winter peak demand forecast. With these refined inputs, staff compared supply to demand in a gas balance for each hour of the day and the necessary gas withdrawals for each hour within the

simulated peak day for both the 1-in-10 cold day demand and the 1-in-35 core plus 1-in-10 noncore extreme peak day.<sup>40</sup>

Tables 15 and 16 and Figure 13 illustrate the resulting gas balances. They highlight the critical midday ramping period, the morning and afternoon peak-demand hours, and the corresponding withdrawal requirements. The variability band around the average load profile demonstrates hourly variations, with peak hours exhibiting greater fluctuation. Demand peaks at 8 a.m. in both the cold-day and extreme-peak-day cases, while supply is relatively flat hour over hour. The results show withdrawals required in all hours of the day but no estimated curtailments, even under extreme peak-day conditions.

**Table 15: Stochastic Hourly Gas Balance Results for the Cold Day**

| Hour | Demand (MMcf) | Receipts (MMcf) | Required Withdrawals (MMcf) | Curtailment* (MMcf) |
|------|---------------|-----------------|-----------------------------|---------------------|
| 7    | 227           | 129             | 98                          | 0                   |
| 8    | 246           | 129             | 117                         | 0                   |
| 9    | 224           | 128             | 96                          | 0                   |
| 10   | 199           | 129             | 71                          | 0                   |
| 11   | 182           | 128             | 54                          | 0                   |
| 12   | 165           | 128             | 37                          | 0                   |
| 13   | 157           | 128             | 29                          | 0                   |
| 14   | 148           | 127             | 21                          | 0                   |
| 15   | 141           | 128             | 13                          | 0                   |
| 16   | 146           | 128             | 18                          | 0                   |
| 17   | 161           | 128             | 33                          | 0                   |
| 18   | 194           | 128             | 66                          | 0                   |
| 19   | 210           | 128             | 81                          | 0                   |
| 20   | 213           | 129             | 84                          | 0                   |
| 21   | 210           | 128             | 82                          | 0                   |
| 22   | 196           | 129             | 67                          | 0                   |

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40 Wong, Lana, Jason Orta, and Miguel Cerrutti. 2022. [Winter 2022–2023 SoCalGas Reliability Assessment](https://www.energy.ca.gov/publications/2022/winter-2022-2023-southern-california-gas-company-reliability-assessment). California Energy Commission. Publication Number: CEC-200-2022-007, <https://www.energy.ca.gov/publications/2022/winter-2022-2023-southern-california-gas-company-reliability-assessment>.

Appendix B of this report offers detailed documentation of the stochastic gas balance method.

| Hour         | Demand (MMcf) | Receipts (MMcf) | Required Withdrawals (MMcf) | Curtailment* (MMcf) |
|--------------|---------------|-----------------|-----------------------------|---------------------|
| 23           | 178           | 129             | 49                          | 0                   |
| 0            | 157           | 130             | 27                          | 0                   |
| 1            | 148           | 129             | 19                          | 0                   |
| 2            | 149           | 130             | 19                          | 0                   |
| 3            | 146           | 130             | 16                          | 0                   |
| 4            | 149           | 130             | 19                          | 0                   |
| 5            | 165           | 130             | 35                          | 0                   |
| 6            | 190           | 130             | 60                          | 0                   |
| <b>Total</b> | <b>4302</b>   | <b>3090</b>     | <b>1212</b>                 | <b>0</b>            |

\*Minimum curtailment required in each hour

Source: Aspen Environmental Group

**Table 16: Stochastic Hourly Gas Balance Results for the Extreme Peak Day**

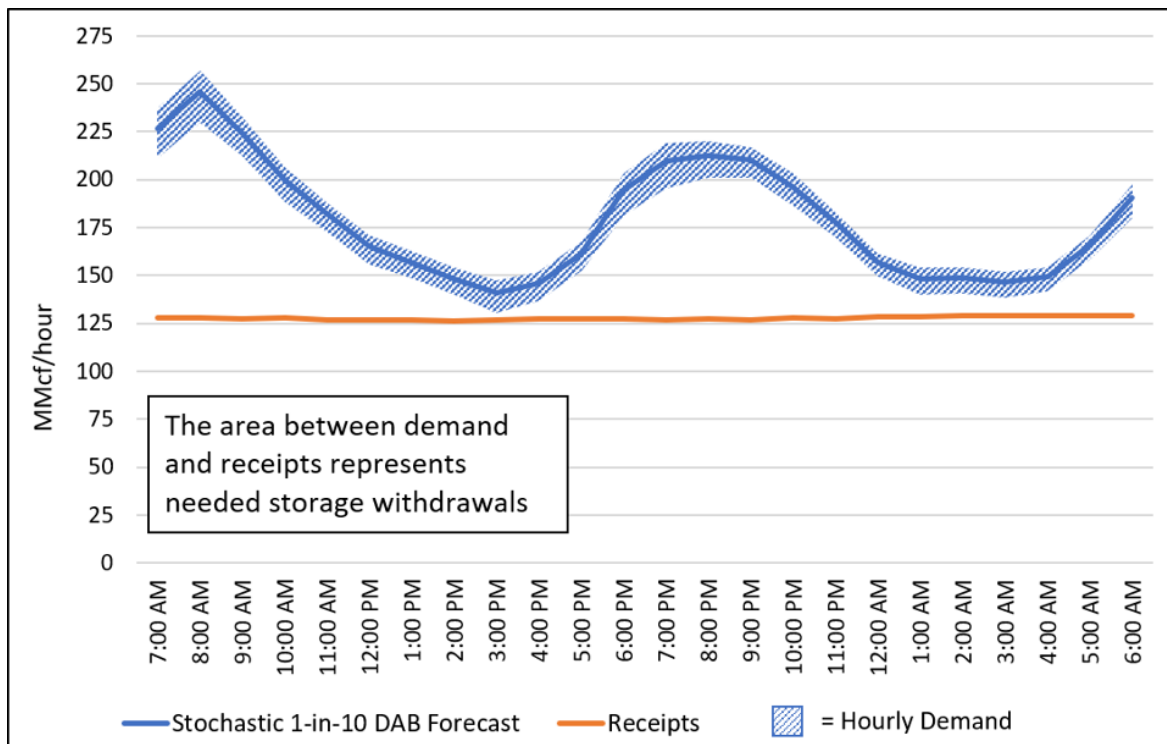
| Hour | Demand (MMcf) | Receipts (MMcf) | Required Withdrawals (MMcf) | Curtailment* (MMcf) |
|------|---------------|-----------------|-----------------------------|---------------------|
| 7    | 237           | 129             | 108                         | 0                   |
| 8    | 256           | 129             | 127                         | 0                   |
| 9    | 232           | 128             | 104                         | 0                   |
| 10   | 206           | 129             | 77                          | 0                   |
| 11   | 187           | 128             | 60                          | 0                   |
| 12   | 170           | 128             | 43                          | 0                   |
| 13   | 162           | 128             | 34                          | 0                   |
| 14   | 153           | 127             | 26                          | 0                   |
| 15   | 147           | 128             | 19                          | 0                   |
| 16   | 151           | 128             | 23                          | 0                   |
| 17   | 167           | 128             | 39                          | 0                   |
| 18   | 203           | 128             | 74                          | 0                   |
| 19   | 219           | 128             | 91                          | 0                   |
| 20   | 220           | 129             | 91                          | 0                   |

| Hour         | Demand (MMcf) | Receipts (MMcf) | Required Withdrawals (MMcf) | Curtailment* (MMcf) |
|--------------|---------------|-----------------|-----------------------------|---------------------|
| 21           | 216           | 128             | 88                          | 0                   |
| 22           | 203           | 129             | 74                          | 0                   |
| 23           | 182           | 129             | 54                          | 0                   |
| 0            | 160           | 130             | 31                          | 0                   |
| 1            | 153           | 129             | 24                          | 0                   |
| 2            | 153           | 130             | 23                          | 0                   |
| 3            | 151           | 130             | 21                          | 0                   |
| 4            | 153           | 130             | 23                          | 0                   |
| 5            | 169           | 130             | 39                          | 0                   |
| 6            | 197           | 130             | 67                          | 0                   |
| <b>Total</b> | <b>4449</b>   | <b>3090</b>     | <b>1359</b>                 | <b>0</b>            |

\*Minimum curtailment required in each hour

Source: Aspen Environmental Group

**Figure 14: Winter Peak-Day Demand Hourly Load Profile by Hour**



Source: Aspen Environmental Group

The results of this stochastic assessment confirm the adequacy of supply to meet demand and no risk of potential curtailments under winter peak-day conditions and corroborate the results of the hydraulic modeling and other gas balances.

## **SoCalGas Hydraulic Analysis**

CEC staff used the Synergi Gas hydraulic modeling platform to assess SoCalGas system operations. The hydraulic model simulates operations across the entire gas day, capturing changes in linepack 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 3,090 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 modeling analysis confirms the analysis presented in the gas balances. On peak days, the SoCalGas system can meet demand without curtailments. Appendix B describes the modeling method.

## **Conclusion**

Based on the gas balance, stochastic analysis, and assessment of SoCalGas transmission system hydraulic models, SoCalGas can meet peak-day demands (the 1-in-10 and the extreme peak day plus) without curtailment of noncore customers. Meeting demand under these scenarios will require storage withdrawals in quantities below the assumed feasible withdrawal estimate on the SoCalGas system of 2,000 MMcfd.

## CHAPTER 4:

# Qualitative Outlook of Fossil Gas Prices

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### Winter Fossil Gas Prices

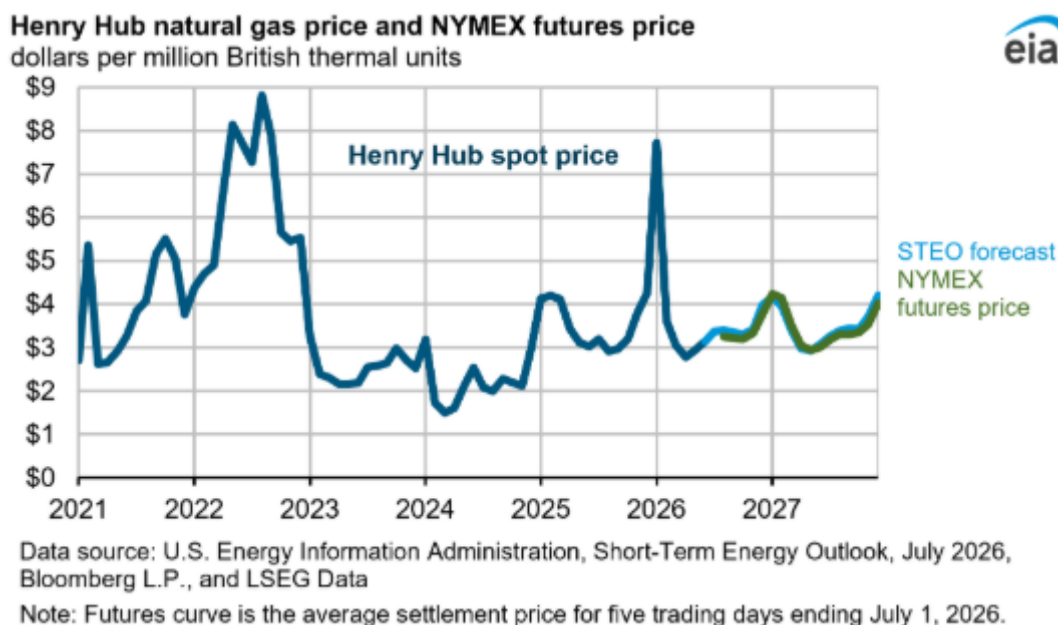
Fossil gas prices are typically higher and more volatile during the winter because residential and commercial heating demand rises, gas-fired electric generation can increase when electric demand or system conditions require it, and cold weather can reduce production or available transportation capacity in supply basins. Over the last several winters, the largest price movements have occurred when cold weather, storage concerns, pipeline constraints, and regional market stress occurred at the same time. Storage conditions are therefore a central part of the winter price outlook: high inventory and sufficient withdrawal capability can reduce exposure to same-day market purchases, while low inventory, limited deliverability, or rapid withdrawals can increase price pressure. The EIA's Short Term Energy Outlook for Henry Hub prices remain low compared to previous peaks.<sup>41</sup>

For winter 2026–2027, current market conditions appear moderate based on data available in late July 2026. California spot prices were reported as stable, no operational flow orders were declared for SoCalGas or PG&E, and California storage inventories were strong relative to working capacity. However, winter price risk remains event-driven. Severe weather, production freeze-offs, unplanned pipeline outages, storage withdrawal limitations, and broader national demand growth from LNG exports and electricity load growth can still produce short periods of significant price volatility.

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<sup>41</sup> U.S. Energy Information Administration. 2026. "[Short-Term Energy Outlook](https://www.eia.gov/outlooks/steo/index.php)," <https://www.eia.gov/outlooks/steo/index.php>.

**Figure 15: Energy Information Administration Short Term Energy Outlook**



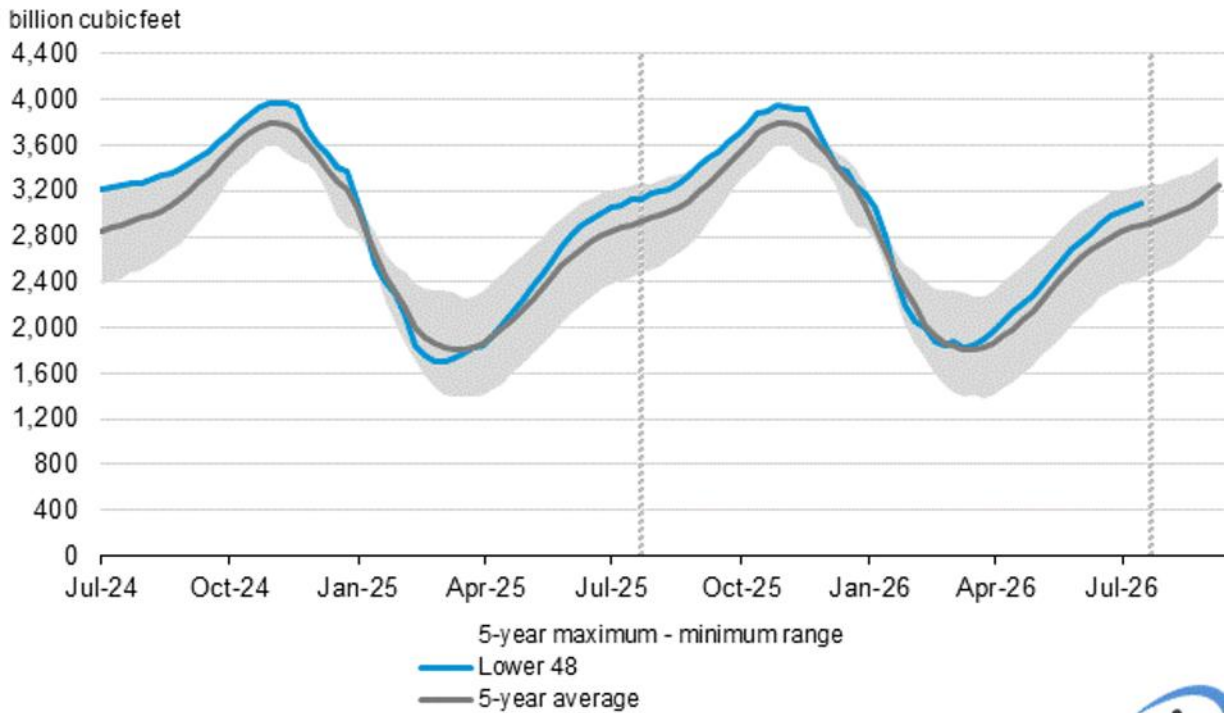
Source: U.S. Energy Information Administration

Storage inventory represents the difference in supply versus demand. Relatively small differences in storage inventories year-over-year sometimes have outsized impacts on gas commodity prices as they indicate longer-term imbalances in the market. Thus, the fossil gas market collectively pays close attention to weekly changes in storage inventory.

The EIA projects U.S. working gas in storage was 3,084 Bcf as of Friday, July 24, 2026, according to EIA estimates. This amount represents a net increase of 28 Bcf from the previous week. Stocks were 32 Bcf less than last year at this time and 185 Bcf above the five-year average of 2,899 Bcf. At 3,084 Bcf, total working gas is within the five-year historical range as seen in Figure 16.<sup>42</sup>

<sup>42</sup> U.S. Energy Information Administration. 2026. "[Short-Term Energy Outlook](#)."

**Figure 16: EIA's U.S. Fossil Gas Storage**



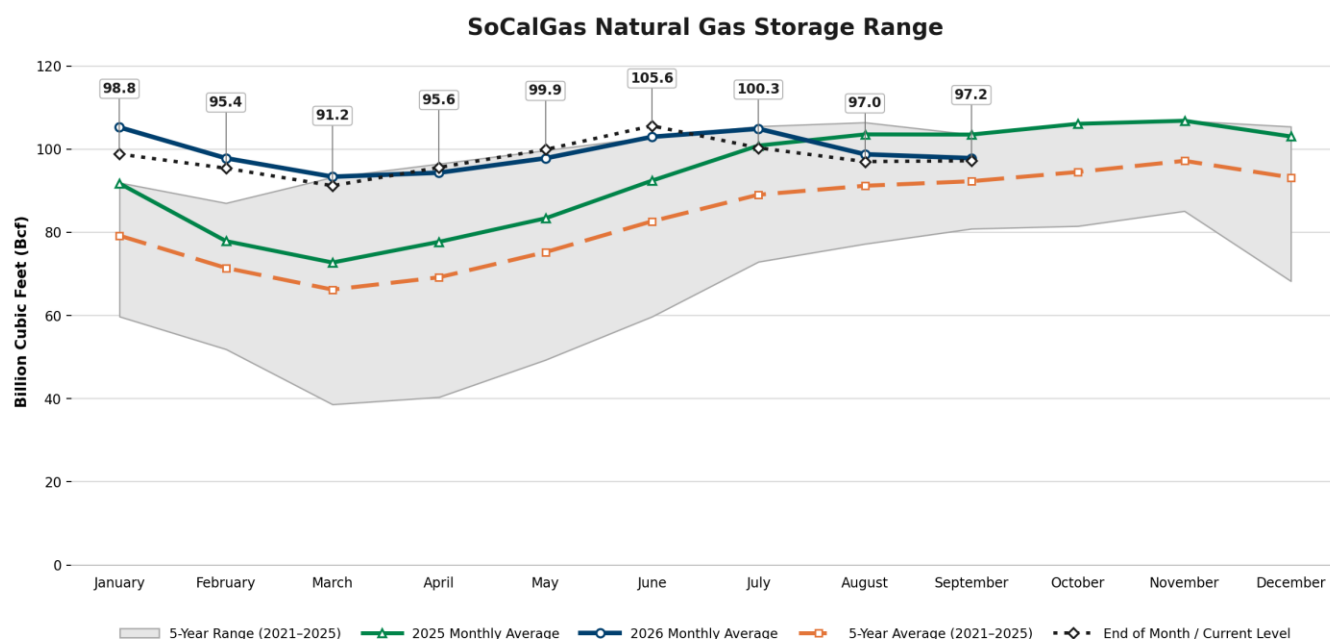
Data source: U.S. Energy Information Administration



Source: U.S. Energy Information Administration

As of July 28, 2026, SoCalGas has 101.2 Bcf of natural gas in storage. This amount is 2.8 Bcf less than the previous week and 2.6 Bcf less than this time last year. Overall, storage inventory for SoCalGas is 86 percent full.

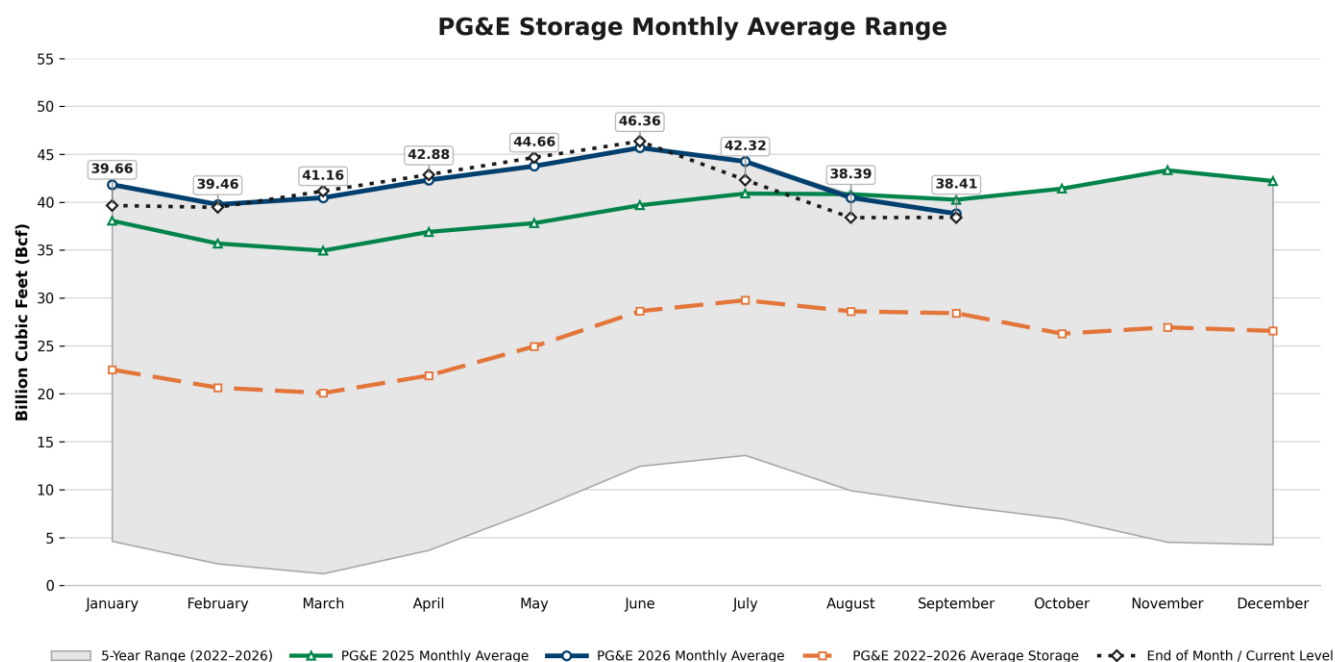
**Figure 17: SoCalGas Fossil Gas Storage Inventory**



Source: SoCalGas Envoy, CEC

As of July 28, 2026, PG&E has about 42.3 Bcf of natural gas in storage. This amount is 0.5 Bcf less than the previous week and 1 Bcf more than this time last year. The current storage inventory available is 83 percent of the total physical working gas capacity.

**Figure 18: PG&E's Fossil Gas Storage Inventory**



Source: PG&E Pipe Ranger, CEC

## **Fossil Gas Prices: Recent Winter Trends vs. Five-Year Averages (Winter 2021–2022 Through Winter 2026–2027)**

Over the past five winters from 2021–2022 through 2025–2026, California fossil gas prices continued to show strong seasonal volatility. Prices typically increase during winter because of higher residential and commercial heating demand, greater reliance on gas-fired electric generation during certain system conditions, and the risk of weather-related supply disruptions. The most significant recent California price event occurred in winter 2022–2023, when average winter prices reached \$13.63/MMBtu, including a major price spike during a January cold snap. CEC staff previously attributed that event to unusually cold weather, supply shortages, and constraints on pipeline and storage capacity.

Extreme weather outside California can also affect regional gas prices. During Winter Storm Uri in February 2021, fossil gas prices surged across much of the country because of sharp increases in heating demand, production freeze-offs, and infrastructure disruptions. Although the worst reliability impacts occurred in Texas and surrounding states, California also experienced elevated gas and electricity costs.<sup>43</sup> On February 17, 2021, the SoCal Border daily spot price peaked at \$112.90/MMBtu. While the worst effects of the storm were centered in Texas, price spikes in California underscored the importance of strong supply management and contingency plans.<sup>44</sup>

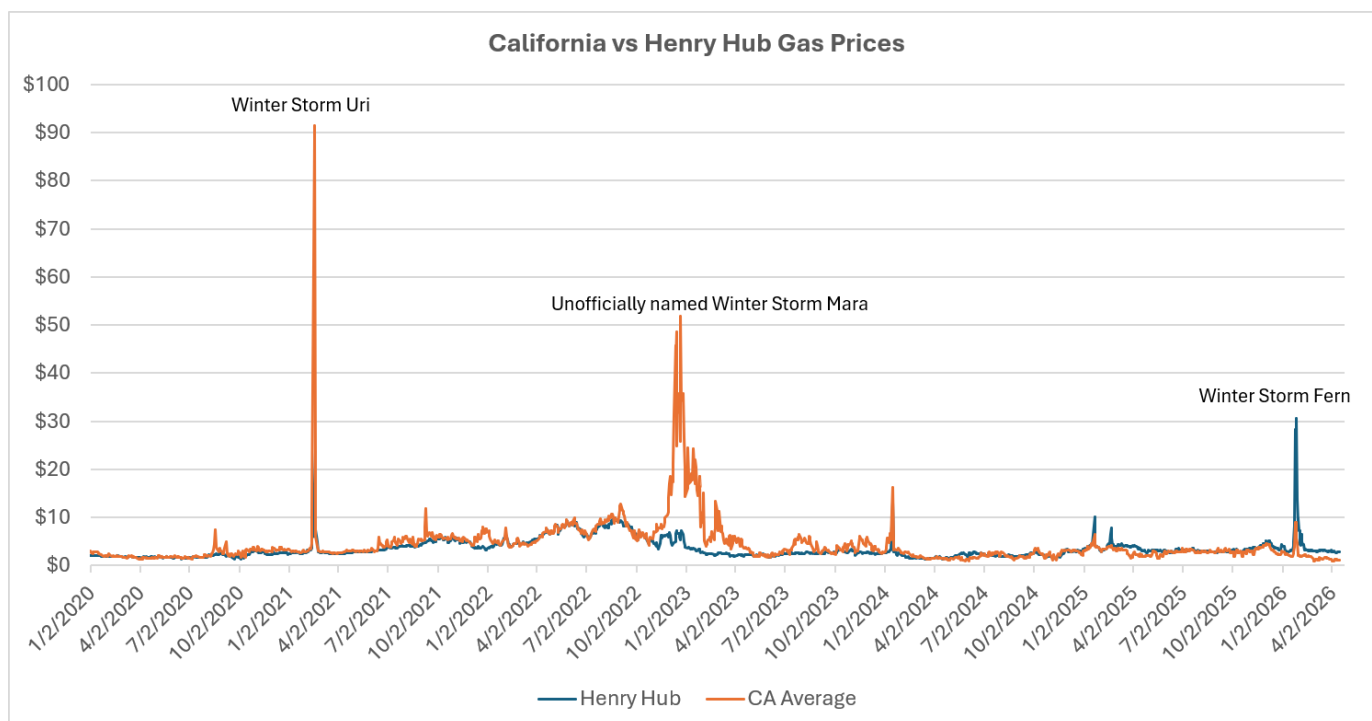
Figure 19 shows daily Henry Hub and California regional average prices from July 2020 to April 2026, highlighting spikes from Winter Storm Uri and the early cold in winter 2022–2023.

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43 California Public Utilities Commission. October 24, 2022. [Winter 2020–2021 Southern California Gas Conditions and Operations Report](https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/natural-gas/aliso-canyon/conditions-and-operations-reports/winter-2020-21-gas-report.pdf), <https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/natural-gas/aliso-canyon/conditions-and-operations-reports/winter-2020-21-gas-report.pdf>.

44 U.S. Energy Information Administration. February 5, 2026. [Record Natural Gas Stock Withdrawals During Week Ending January 30, 2026](https://www.eia.gov/todayinenergy/detail.php?id=67124&utm), <https://www.eia.gov/todayinenergy/detail.php?id=67124&utm>.

**Figure 19: Daily Fossil Gas Prices (January 2020–April 2026)**



Source: NGI, CEC

To support reliability and price stability, California has taken strategic steps, including the CPUC's decision to increase the maximum allowable inventory of Aliso Canyon from 41.16 Bcf to 68.6 Bcf.<sup>45</sup> This increase enhanced the ability of the facility to meet peak winter demand. Winter Storm Fern in January 2026 provides a more recent comparison. Like Storm Uri, Storm Fern caused broad national gas market stress with Henry Hub over \$30.00/MMBtu.<sup>46</sup> EIA reported that Lower 48 working gas stocks fell by 360 Bcf for the week ending January 30, 2026, the largest weekly net withdrawal in the history of EIA's Weekly Natural Gas Storage Report. EIA attributed the large withdrawal to increased heating demand and natural gas production curtailments caused by severe winter weather. In comparison, supported by strong regional storage and available withdrawal capability, California prices elevated moderately to a little under \$9.00/MMBtu.<sup>47</sup>

Overall, recent winter trends show that storage does not by itself determine price outcomes, but it is an important buffer. When storage inventories are high and withdrawal capability is

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45 CPUC Proposed Decision to Protect Against Natural Gas Price Spikes in Southern California (I.17-02-002), <https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/natural-gas/aliso-canyon/ac-storage-level-pd-0722823.pdf>

46 Newman, Chris. January 26, 2026. "[Henry Hub Prices Smash All-Time Records as Winter Storm Fern, LNG Tag-Team to Tighten Balances](https://naturalgasintel.com/news/henry-hub-prices-smash-all-time-records-as-winter-storm-fern-lng-tag-team-to-tighten-balances/)." Natural Gas Intelligence, <https://naturalgasintel.com/news/henry-hub-prices-smash-all-time-records-as-winter-storm-fern-lng-tag-team-to-tighten-balances/>,

47 U.S. Energy Information Administration. February 10, 2026. Press release. "[EIA Raises Natural Gas Price Forecast Following Increased Heating Demand Amid Severe Winter Weather](https://www.eia.gov/pressroom/releases/press583.php?)," <https://www.eia.gov/pressroom/releases/press583.php?>

available, California is better positioned to manage winter demand and reduce reliance on high-priced spot purchases. When storage is low or constrained, price volatility can increase sharply if cold weather, production disruptions, or pipeline limitations occur at the same time.

## **Unplanned Maintenance and Outages as a Reliability Risk**

The gas balances presented in this assessment show that PG&E and SoCalGas can generally meet forecast winter demand under assumed pipeline and storage conditions. Planned maintenance can usually be incorporated into the analysis because utilities and interstate pipelines post expected capacity reductions in advance. These planned reductions are reflected in available pipeline capacity, storage withdrawal assumptions, and gas balance scenarios where applicable.

Unplanned events are more difficult to assess because they can occur with little notice and may reduce available capacity after winter planning assumptions have already been developed. These events can include compressor station outages, pipeline pressure reductions, unplanned repairs, storage well limitations, storage field equipment outages, or force majeure events on upstream interstate pipelines.

Unplanned maintenance and outages can be caused by land movement, seismic activity, erosion, wildfire or flood damage, third-party excavation damage, equipment failure, corrosion, aging high-pressure pipe, or anomalies identified during required integrity inspections. These events may require utilities to reduce pipeline pressure, limit receipts, remove equipment from service, or restrict storage withdrawals until repairs or additional assessments are completed. While these events may not create reliability issues under normal conditions, they become more significant when they coincide with cold weather, high demand, reduced supply, or other system constraints.

This distinction is important because the California gas system relies on a combination of flowing interstate pipeline supply, in-state production, underground storage withdrawals, and linepack to meet winter demand. On cold days, demand can increase sharply, particularly for core residential and commercial heating load. At the same time, gas-fired electric generation may increase if electricity demand is high, renewable output is lower, or regional electric system conditions are tight. If an unplanned outage reduces pipeline receipts or storage withdrawal capability during these conditions, the system may need to rely more heavily on storage, operational flow orders, emergency flow orders, or curtailment of lower-priority noncore service.

This risk is difficult to fully capture in a seasonal reliability assessment because unplanned events may occur after the assessment assumptions are developed. For example, the prior winter reliability assessment could not have captured a later unplanned capacity reduction affecting the Wheeler Ridge Zone, which reduced the amount of gas supply that could enter the SoCalGas system from that receipt area.<sup>48</sup> SoCalGas Envoy identifies a force majeure on L225 in the Wheeler Ridge Zone, with staged capacity reductions during summer 2026. While the system was able to meet demand despite this reduction, the event illustrates how quickly

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<sup>48</sup> SoCalGas. July 23, 2026. "[Castaic Line Break Repair](https://www.socalgas.com/safety/pipeline-and-storage/active-projects/castaic-line-break-repair)," <https://www.socalgas.com/safety/pipeline-and-storage/active-projects/castaic-line-break-repair>.

available receipt capacity can change. This reduction should not affect reliability for winter 2026–2027, as it is scheduled to be back on-line by the end of summer.

Pipeline outages and storage limitations can also affect prices, even when customer curtailments are avoided. The EIA found that Southern California prices were lower in December 2023 than December 2022 because of milder weather, higher California storage inventories, increased hydroelectric generation, and restored pipeline capacity, including the return of El Paso Natural Gas Line 2000 and higher SoCalGas Northern Zone capacity.<sup>49</sup> These examples show that maintenance and outage conditions can affect price risk even when the physical system continues to serve demand.

For winter 2026–2027, the reliability concern is therefore best framed as a coincident-risk issue. A single maintenance event may not create a reliability problem if demand is moderate and storage is strong. The risk increases when multiple conditions occur together: cold weather, high core demand, high gas-fired electric generation, reduced hydroelectric output, lower renewable availability, upstream production freeze-offs, interstate pipeline restrictions, or reduced storage withdrawal capability.

## **Summary and Future Projects**

In summary, the recent winter period shows that favorable weather and adequate storage can support more stable fossil gas prices, while severe weather and infrastructure constraints can quickly increase price volatility. For winter 2026–2027, current conditions suggest a more moderate price outlook under average weather conditions, supported by stable California prices, no current OFOs, and strong storage inventories as of late July 2026. However, price risk remains event-driven. Severe weather, unplanned pipeline or storage outages could increase demand for gas and contribute to higher prices during constrained winter conditions. Storage remains an important buffer, but it does not guarantee protection from short-term price spikes if multiple risk factors occur at the same time.

Looking beyond winter 2026–2027, CEC staff will continue to evaluate how natural gas reliability should be assessed over a longer-term planning horizon, in addition to seasonal reliability assessments. Future work may examine how aging high-pressure pipelines, storage field limitations, recurring maintenance needs, and potential infrastructure constraints could affect long-term gas deliverability and price volatility.

CEC staff will also monitor emerging regional and national market drivers, including LNG export activity in Mexico and the associated potential effect on gas supplies available to California, data-center-related electric load growth and associated gas demand, and long-term gas reliability planning strategies used by other states and countries. Incorporating these issues into future CEC gas forecasts and reliability assessments can help identify whether additional planning, data collection, or policy coordination is needed to maintain gas and electric reliability during California’s clean energy transition.

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<sup>49</sup> U.S. Energy Information Administration. March 25, 2024. "[December Natural Gas Price in Southern California Was the Lowest Since 2015](https://www.eia.gov/todayinenergy/detail.php?id=61644)," <https://www.eia.gov/todayinenergy/detail.php?id=61644>.

## GLOSSARY

| Term                                                         | Definition                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                               |
|--------------------------------------------------------------|--------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| <b>1-in-10 peak day</b>                                      | A 1-in-10 peak day is a high-demand day expected to occur, on average, once every 10 years. It is used to test whether the gas system can meet demand under unusually cold or otherwise stressed conditions.                                                                                                                                                                                                                                                                                                                                                             |
| <b>1-in-90 core demand / 1-in-10 noncore demand peak day</b> | A 1-in-90 core demand / 1-in-10 noncore demand peak day is a combined stress case used to evaluate gas system reliability. It pairs very high core demand — mainly residential and small commercial customers — based on a rare 1-in-90 cold-weather event, with high noncore demand — including industrial customers and electric generators — based on a 1-in-10 peak-day assumption. In plain terms, it tests whether the system could serve protected core customers during an extreme cold event while also serving noncore customers under high-demand conditions. |
| <b>billion cubic feet</b>                                    | A billion cubic feet is a standard unit of measurement for fossil gas supply/demand - 1,000,000 MMBtu = 1 Bcf.                                                                                                                                                                                                                                                                                                                                                                                                                                                           |
| <b>British thermal unit</b>                                  | A British thermal unit is the quantity of heat required to raise the temperature of 1 pound of water 1 degree Fahrenheit at a specified temperature (such as 39 degrees Fahrenheit).                                                                                                                                                                                                                                                                                                                                                                                     |
| <b>PG&amp;E core customer</b>                                | A PG&E core customer are all customers with average usage less than 20,800 therms per month. These are mainly residential and small commercial customers.                                                                                                                                                                                                                                                                                                                                                                                                                |
| <b>SoCalGas/SDG&amp;E core customer</b>                      | A SoCalGas/SDG&E core customer are all residential customers; all commercial and industrial customers with average usage of less than 20,800 therms per month who typically cannot fuel switch. Also, those commercial and industrial customers (whose average usage is more than 20,800 therms per month) who elect to remain a core customer by procuring bundled service (both the fossil gas itself and the transportation services).                                                                                                                                |
| <b>decatherm</b>                                             | A decatherm is the quantity of heat energy equivalent to 1 million British thermal units.                                                                                                                                                                                                                                                                                                                                                                                                                                                                                |
| <b>end user</b>                                              | An end user means any company that consumes electricity or fossil gas for its own use and not for resale.                                                                                                                                                                                                                                                                                                                                                                                                                                                                |
| <b>energy storage system</b>                                 | An energy storage system (ESS) captures extra energy — often from renewable sources like solar or wind — and holds it in reserve. It then releases that power as electricity when demand is high or generation stops. These systems balance the power grid and provide backup energy.                                                                                                                                                                                                                                                                                    |

|                                                    |                                                                                                                                                                                                                  |
|----------------------------------------------------|------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| <b>Federal Energy Regulatory Commission</b>        | The Federal Energy Regulatory Commission regulates fossil gas transportation in interstate commerce and construction of gas pipeline, storage, and liquefied natural gas facilities.                             |
| <b>Henry Hub</b>                                   | Henry Hub is a fossil gas pipeline located in Erath, Louisiana, that serves as the official delivery location for futures contracts on the New York Mercantile Exchange.                                         |
| <b>independent storage providers</b>               | The independent storage providers are the Lodi Gas Storage, Wild Goose Storage, Central Valley Storage, and Gill Ranch Storage underground gas storage facilities, which are connected to the PG&E gas system.   |
| <b>liquefied fossil gas</b>                        | A liquefied fossil gas is fossil gas that has been cooled to a liquid state, about -260° Fahrenheit, for shipping and storage.                                                                                   |
| <b>million British thermal unit</b>                | A million British thermal unit is a thermal unit of measurement for fossil gas.                                                                                                                                  |
| <b>million cubic feet per day (MMcfd)</b>          | A million cubic feet per day (MMcfd) is a unit of measurement used to express the amount of fluid (gas, water, and so forth) that is consumed, produced or traversed in a pipeline on any given day.             |
| <b>Natural (or fossil) gas</b>                     | Natural (or fossil) gas is a hydrocarbon gas found in the earth, composed of methane, ethane, butane, propane, and other gases.                                                                                  |
| <b>noncore load</b>                                | A noncore load is electric generators, industrial customers, commercial, and all other noncore customers based in Los Angeles and Southern California.                                                           |
| <b>Pacific Gas and Electric Company (PG&amp;E)</b> | Pacific Gas and Electric Company (PG&E) is a utility company and primary provider of fossil gas to parts of Central and Northern California.                                                                     |
| <b>Peak demand day</b>                             | A Peak demand day is a day when gas use is expected to be especially high, usually because cold weather increases heating demand from homes and businesses and may also increase gas use by electric generators. |
| <b>Peak day</b>                                    | Peak day is a shortened term for “peak demand day.” In this report, it refers to a high-demand gas day used for reliability planning and analysis.                                                               |
| <b>Southern California Gas Company (SoCalGas)</b>  | Southern California Gas Company (SoCalGas) is a utility company and primary provider of fossil gas to Los Angeles, Southern California, and parts of Central California.                                         |
| <b>Synergi Gas</b>                                 | Synergi Gas is the long-time industry standard for hydraulic modeling of large, complex distribution and transmission systems.                                                                                   |

# APPENDIX A:

## Gas Demand Forecast Method

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This appendix presents a hybrid Prophet-XGBoost forecasting framework to forecast peak-day and monthly-average natural gas demand for Southern California Gas (SoCalGas) and Pacific Gas and Electric (PG&E) during the November 2026 through March 2027 winter season.

Several long-term trends have made winter natural gas demand more difficult to forecast, including greater weather variability, evolving customer consumption patterns, and climate-related shifts in winter temperature extremes. These factors have increased nonlinear behavior in natural gas demand, which conventional statistical forecasting models do not fully capture.

Traditional time-series methods effectively capture long-term trends and recurring seasonal patterns but often underperform during extreme winter weather because they cannot fully account for nonlinear temperature responses, interaction effects, or rapid changes in customer demand. Forecast errors during peak-demand events are particularly important because these periods place the greatest stress on the natural gas system.

To address these limitations, this analysis applies a hybrid Prophet-XGBoost framework that combines Prophet's time-series interpretability with the residual predictive capability of XGBoost.

The framework is designed to forecast peak-day and monthly-average natural gas demand, evaluate demand under representative winter weather scenarios, and improve forecast accuracy relative to a Prophet-only model by better capturing nonlinear weather effects and short-term demand variability.

The proposed approach substantially improved forecasting accuracy, particularly on peak-demand days. Peak-day MAPE<sup>50</sup> decreased by about 44 percent for both SoCalGas and PG&E, while monthly-average MAPE fell by 21 percent and 31 percent, respectively, demonstrating consistent performance gains across both peak and average demand conditions.

### Hybrid Prophet-XGBoost Framework

The forecasting framework consists of two sequential stages: in-sample modeling for January 2017 through March 2026 and out-of-sample forecasting for November 2026 through March 2027.

During the in-sample phase, Prophet<sup>51</sup> is fitted to the historical demand using trend, seasonal, calendar, and weather-related regressors. Trends are represented by piecewise-linear

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<sup>50</sup> Mean absolute percentage error means the average percentage by which the predictions of the model differ from the actual values.

<sup>51</sup> Taylor, Sean J., and Benjamin Letham. 2018. "[Forecasting at Scale](http://lethalletham.com/ForecastingAtScale.pdf)." *The American Statistician*, <http://lethalletham.com/ForecastingAtScale.pdf>.

functions with automatic changepoint detection, while weekly, monthly, and annual seasonality are modeled using Fourier series<sup>52</sup> under a multiplicative framework. Calendar effects, including weekdays, weekends, and holiday indicators, together with weather variables, are included as external regressors.

Residuals, defined as the differences between observed and Prophet-predicted values, are assumed to follow a normal distribution and are then modeled with XGBoost.<sup>53</sup> The XGBoost model, which uses gradient-boosted decision trees, is trained to capture nonlinear structure in the residual series using Prophet forecasts and lagged residuals as predictors.

The final in-sample forecast equals the Prophet forecast plus the XGBoost residual correction. This hybrid approach preserves the interpretability of Prophet, while the predictive accuracy of XGBoost improves forecasting performance, particularly during extreme winter conditions.

During the out-of-sample phase, Prophet first generates baseline forecasts using projected values of the external regressors. These forecasts, together with the lagged residual inputs, are then supplied to the trained XGBoost model to recursively predict future residuals.

The final out-of-sample forecasts are obtained by adding the XGBoost-predicted residuals to the corresponding Prophet baseline forecasts, thereby improving forecast accuracy by correcting errors that remain after the initial Prophet prediction.

## Data and Model Development

The analysis uses daily natural gas demand from January 2017 through March 2026 for the aggregated, core, noncore, and electric generation customer classes. Demand data for 2025 were obtained from Integrated Energy Policy Report (IEPR)<sup>54</sup> filings, while the remaining historical data were provided by the California Energy Commission (CEC).

Daily maximum and minimum temperatures for 1985 through 2026 were obtained from the National Oceanic and Atmospheric Administration (NOAA). Climate projections for 2026 through 2050 were obtained from the CEC Electric Program Investment Charge (EPIC)<sup>55</sup> program.

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52 SoCalGas. July 23, 2026. "[Castaic Line Break Repair](https://www.socalgas.com/safety/pipeline-and-storage/active-projects/castaic-line-break-repair)," <https://www.socalgas.com/safety/pipeline-and-storage/active-projects/castaic-line-break-repair>.

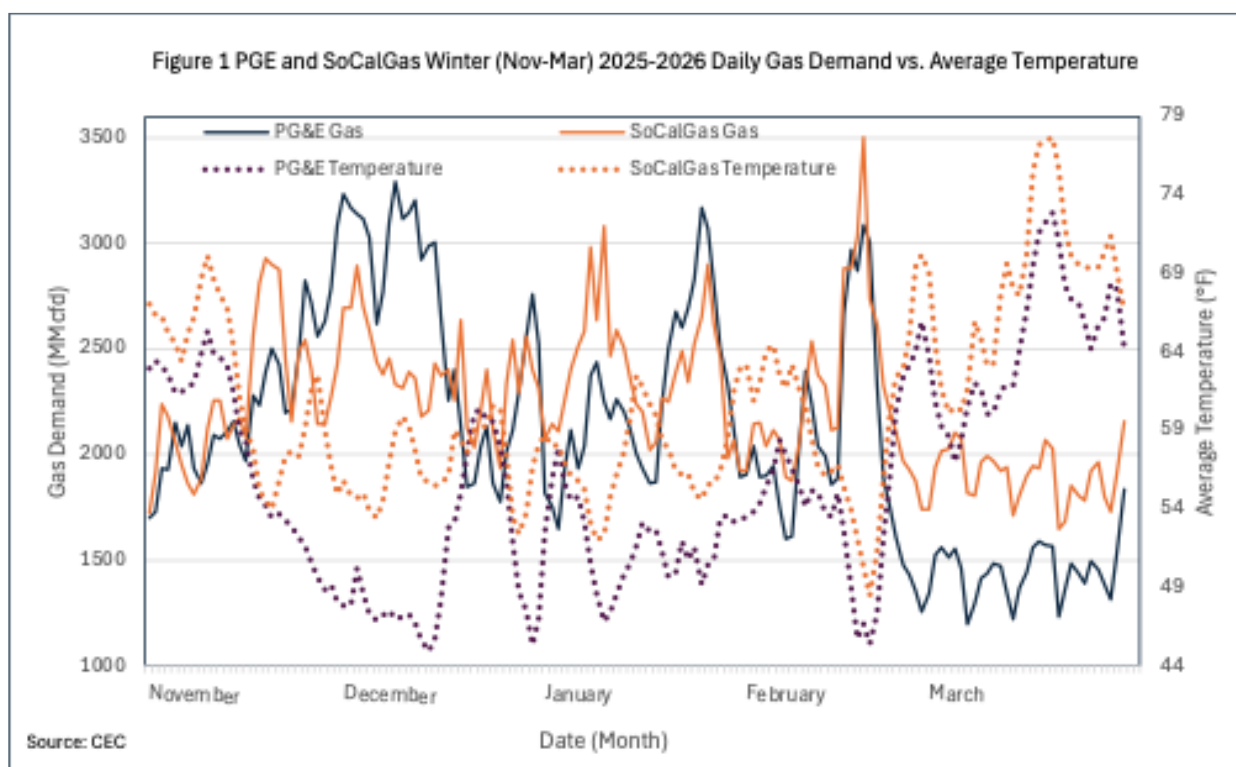
53 Chen, Tianqi, and Carlos Guestrin. 2016. "[XGBoost: A Scalable Tree Boosting System](#)," Proceedings of the 22nd ACM SIGKDD International Conference on Knowledge Discovery and Data Mining, San Francisco, 13–17 August 2016, pp. 785–794, <https://doi.org/10.1145/2939672.2939785>.

54 Kennedy, Robert and Julio Gutierrez. 2024. [Forms and Instructions for Submitting Electricity Resource Plans: Prepared in Support of the 2025 Integrated Energy Policy Report](#). California Energy Commission. Publication Number: CEC-200-2024-002, <https://efiling.energy.ca.gov/GetDocument.aspx?tn=258177&DocumentContentId=94146>.

55 Aydin, Mariko Geronimo, and Onur Aydin. December 19, 2023. "[Presentation: Key Findings in Climate Data Analyses for Demand Forecast Integration](#)," Lumen Energy Strategy, <https://efiling.energy.ca.gov/GetDocument.aspx?tn=253658>.

Figure 1 illustrates the inverse relationship between average daily temperature and natural gas demand during the 2025–2026 winter. Demand increases as temperatures decline, with PG&E exhibiting greater day-to-day variability and SoCalGas showing a smoother seasonal pattern interrupted by a pronounced February cold event. These patterns highlight the need for forecasting models that capture recurring seasonal structure and nonlinear weather sensitivity.

**Figure A-1: PGE and SoCalGas Winter (Nov-Mar) 2025-2026 Daily Gas Demand vs. Average Temperature**



Source: CEC

Weather observations were averaged within each utility service territory<sup>56</sup> and smoothed with a three-day weighted moving average.<sup>57</sup> Demand was log-transformed to reduce skewness, and daily data were aggregated into monthly averages for monthly forecasting.

The Prophet model included weekly, monthly, and annual seasonal effects; weekday, weekend, and holiday indicators; heating and cooling degree days<sup>58</sup> (HDD and CDD); daily

56 Burbank, Long Beach, Santa Barbara, Bakersfield, and Riverside in SCG's service area and Fresno, Oakland, Red Bluff, Sacramento, San Jose, San Luis Obispo, and Ukiah in PGE's service area. Station weights provided by CEC staff.

57 Weighted moving average with weights of 0.6, 0.3, and 0.1 for the most recent day, the prior day, and two days prior, respectively.

58 Cooling- and heating-degree days are based on whether the average daily temperature is above or below the thresholds of 65°F or 55°F.

changes in degree days; seasonal indicators; and extreme temperature indicators based on the historical 5th and 95th quantile temperatures. XGBoost used these variables, together with lagged Prophet residuals at 1-, 2-, 3-, 7-, 14-, and 30-day intervals.

Model hyperparameters, user-defined parameters in contrast to model-defined parameters, were optimized using Bayesian optimization<sup>59</sup>, and forecasting performance was evaluated using rolling time-series cross-validation. Prophet-optimized hyperparameters included changepoint flexibility, seasonal prior scales, and seasonal specifications, while XGBoost-optimized hyperparameters included tree depth, learning rate, number of trees, subsampling parameters, and feature selection.

**Forecast Performance Evaluation**

The hybrid Prophet-XGBoost model consistently outperformed the stand-alone Prophet model. Table 1 presents peak-day and monthly-average forecast accuracy.

**Table A-1: Comparing Utility's MAPE of Peak-Day and Monthly Average Forecasts**

| Utility  | Forecast         | Prophet MAPE | XGBoost MAPE | Percentage Reduction |
|----------|------------------|--------------|--------------|----------------------|
| SoCalGas | Peak-Day         | 4.72%        | 2.62%        | -44.49%              |
| PGE      | Peak-Day         | 6.50%        | 3.63%        | -44.15%              |
| SoCalGas | Monthly-Averages | 2.08%        | 1.64%        | -21.15%              |
| PGE      | Monthly-Averages | 4.02%        | 2.76%        | -31.34%              |

Source: CEC staff

Peak-day forecast accuracy showed the largest improvement. Peak-day MAPE declined from 4.72% to 2.62% for SoCalGas (44.49%) and from 6.50% to 3.63% for PG&E (44.15%). Monthly-average forecasts also improved, with MAPE decreasing from 2.08% to 1.64% for SoCalGas (21.15%) and from 4.02% to 2.76% for PG&E (31.34%).

Because monthly averages smooth daily variability, the baseline Prophet performed relatively well, leaving less room for improvement. By contrast, the hybrid framework substantially reduced forecast errors during weather-sensitive peak-demand periods, when accurate forecasts are most important for system reliability.

**Peak-Day and Monthly-Average Demand Alternative Scenarios**

Representative winter weather scenarios were developed using historical heating degree day (HDD) quantiles. Peak-day scenarios correspond to the 90th, 97.14th, and 98.88th HDD quantiles, while monthly-average scenarios correspond to the 50th and 90th HDD quantiles.

59 Bayesian optimization is a probabilistic, model-based optimization technique to explore and select the most promising hyperparameters.

These scenarios span normal to severe winter weather conditions and were compared with climate-adjusted projections to evaluate future winter demand.

Forecasts indicate that natural gas demand increases steadily with colder weather. Tables A-2 and A-3 illustrate the progressive increase in forecast demand under representative winter weather scenarios.

**Table A-2: Winter 2026–2027 Peak-Day Gas Demand Forecast (MMcfd) for SoCalGas and PG&E**

| Utility  | HDDs Quantile | Core  | Noncore | Electric Gen | Others | SDGE | Off System | Total |
|----------|---------------|-------|---------|--------------|--------|------|------------|-------|
| SoCalGas | 0.9000        | 2,031 | 836     | 870          | 48     | 512  | 0          | 4,302 |
| SoCalGas | 0.9714        | 2,123 | 855     | 915          | 50     | 537  | 0          | 4,481 |
| SoCalGas | 0.9888        | 2,148 | 860     | 927          | 50     | 544  | 0          | 4,530 |
| PGE      | 0.9000        | 1,949 | 838     | 1,138        | 0      | 0    | 380        | 4,305 |
| PGE      | 0.9714        | 2,032 | 845     | 1,189        | 0      | 0    | 399        | 4,466 |
| PGE      | 0.9888        | 2,044 | 846     | 1,197        | 0      | 0    | 402        | 4,489 |

Source: CEC Staff

Peak-day demand increases from 4,302 to 4,530 MMcf/d (5.3%) for SoCalGas and from 4,305 to 4,489 MMcf/d (4.3%) for PG&E between the 90th and 98.88th HDD quantiles. Core customers account for most of the increase because space-heating demand is highly temperature-sensitive. Noncore and electric generation demand increase more moderately, and demand growth begins to level off under the coldest conditions, indicating diminishing temperature sensitivity.

**Table A-3: Winter 2026–2027 Monthly-Average Gas Demand Forecast (MMcfd) for SoCalGas and PG&E**

| Utility  | Mo. | HDDs Quantile | Core  | Noncore | Electric Gen | Others | SDGE | Off System | Total |
|----------|-----|---------------|-------|---------|--------------|--------|------|------------|-------|
| SoCalGas | 11  | 0.5           | 930   | 579     | 602          | 31     | 304  | 0          | 2,446 |
| SoCalGas | 11  | 0.9           | 1,087 | 585     | 704          | 31     | 323  | 0          | 2,730 |
| SoCalGas | 12  | 0.5           | 1,329 | 603     | 568          | 32     | 321  | 0          | 2,853 |
| SoCalGas | 12  | 0.9           | 1,525 | 622     | 647          | 38     | 345  | 0          | 3,177 |
| SoCalGas | 1   | 0.5           | 1,387 | 668     | 565          | 34     | 319  | 0          | 2,973 |
| SoCalGas | 1   | 0.9           | 1,474 | 713     | 627          | 37     | 348  | 0          | 3,200 |

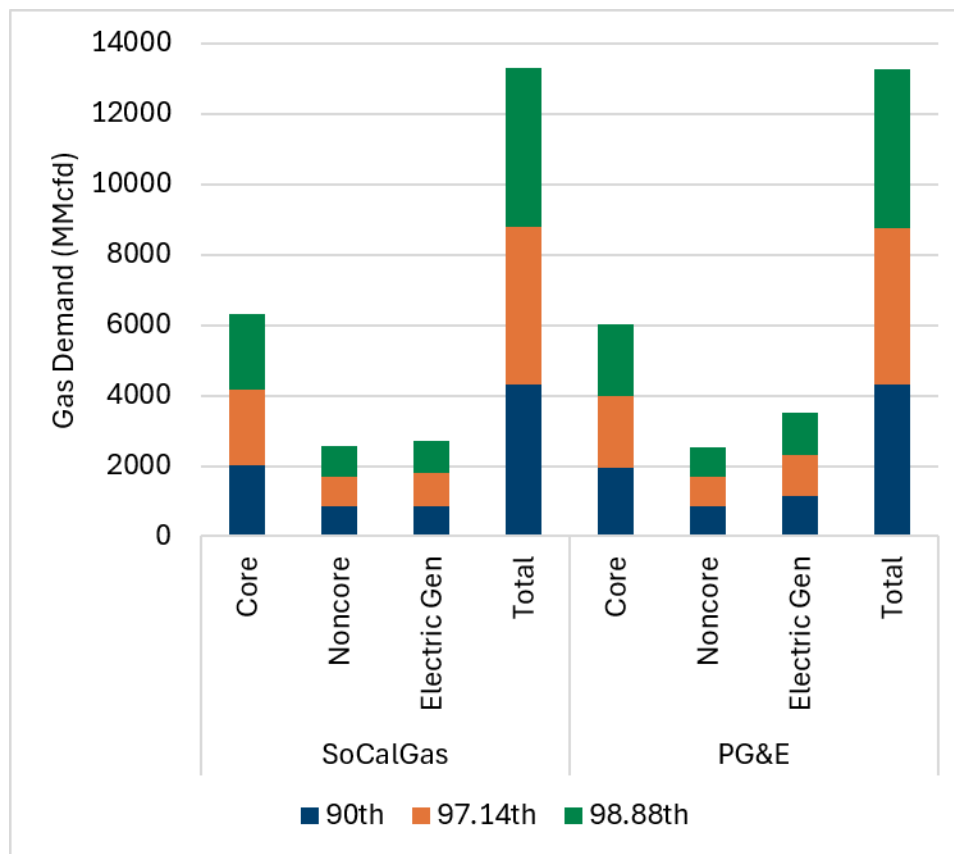
| Utility  | Mo. | HDDs Quantile | Core  | Noncore | Electric Gen | Others | SDGE | Off System | Total |
|----------|-----|---------------|-------|---------|--------------|--------|------|------------|-------|
| SoCalGas | 2   | 0.5           | 1,284 | 644     | 506          | 31     | 309  | 0          | 2,773 |
| SoCalGas | 2   | 0.9           | 1,567 | 648     | 592          | 34     | 326  | 0          | 3,167 |
| SoCalGas | 3   | 0.5           | 1,112 | 567     | 534          | 32     | 306  | 0          | 2,550 |
| SoCalGas | 3   | 0.9           | 1,234 | 592     | 574          | 36     | 334  | 0          | 2,770 |
| PGE      | 11  | 0.5           | 923   | 735     | 684          | 0      | 0    | 210        | 2,552 |
| PGE      | 11  | 0.9           | 1,034 | 742     | 737          | 0      | 0    | 239        | 2,752 |
| PGE      | 12  | 0.5           | 1,345 | 840     | 789          | 0      | 0    | 175        | 3,149 |
| PGE      | 12  | 0.9           | 1,410 | 848     | 867          | 0      | 0    | 218        | 3,343 |
| PGE      | 1   | 0.5           | 1,344 | 764     | 712          | 0      | 0    | 176        | 2,996 |
| PGE      | 1   | 0.9           | 1,428 | 774     | 784          | 0      | 0    | 168        | 3,154 |
| PGE      | 2   | 0.5           | 1,160 | 714     | 568          | 0      | 0    | 175        | 2,617 |
| PGE      | 2   | 0.9           | 1,424 | 744     | 751          | 0      | 0    | 213        | 3,132 |
| PGE      | 3   | 0.5           | 966   | 652     | 435          | 0      | 0    | 221        | 2,274 |
| PGE      | 3   | 0.9           | 1,089 | 666     | 502          | 0      | 0    | 279        | 2,536 |

Source: CEC staff

Monthly-average demand follows the expected seasonal pattern, increasing from November, peaking from December through February, and declining in March. Under the 90th-quantile HDD scenario, total demand is about 11–14% higher for SoCalGas and 6–20% higher for PG&E than under mean winter conditions. Most of the increase occurs within the core customer class, while noncore demand changes relatively little, and electric generation demand increases modestly.

Figure A-2 compares peak-day demand across customer classes under progressively colder HDD scenarios. Total demand increases steadily with weather severity, increasing from about 4,300 to 4,530 MMcf/d for SoCalGas and from 4,305 to 4,489 MMcf/d for PG&E. Core customers account for most of the incremental load, and electric generation contributes a larger share of incremental demand for PG&E than for SoCalGas.

**Figure A-2: Peak-Day Customer Class and Total Demand by Quantile and Utility**



Source: CEC

Figure A-3, located at the end of the appendix, compares monthly average demand under mean and severe winter scenarios. Demand peaks from December through February, with consistently higher levels under colder conditions. Core customers drive most of the seasonal variation, while noncore demand changes little, and electric generation represents a larger share of the total for PG&E.

The scenario analysis shows that winter weather severity is the primary driver of seasonal natural gas demand and that colder winters substantially increase system requirements.

## Conclusions

The hybrid Prophet–XGBoost framework provides a more accurate and reliable method for forecasting winter natural gas demand than a Prophet-only model.

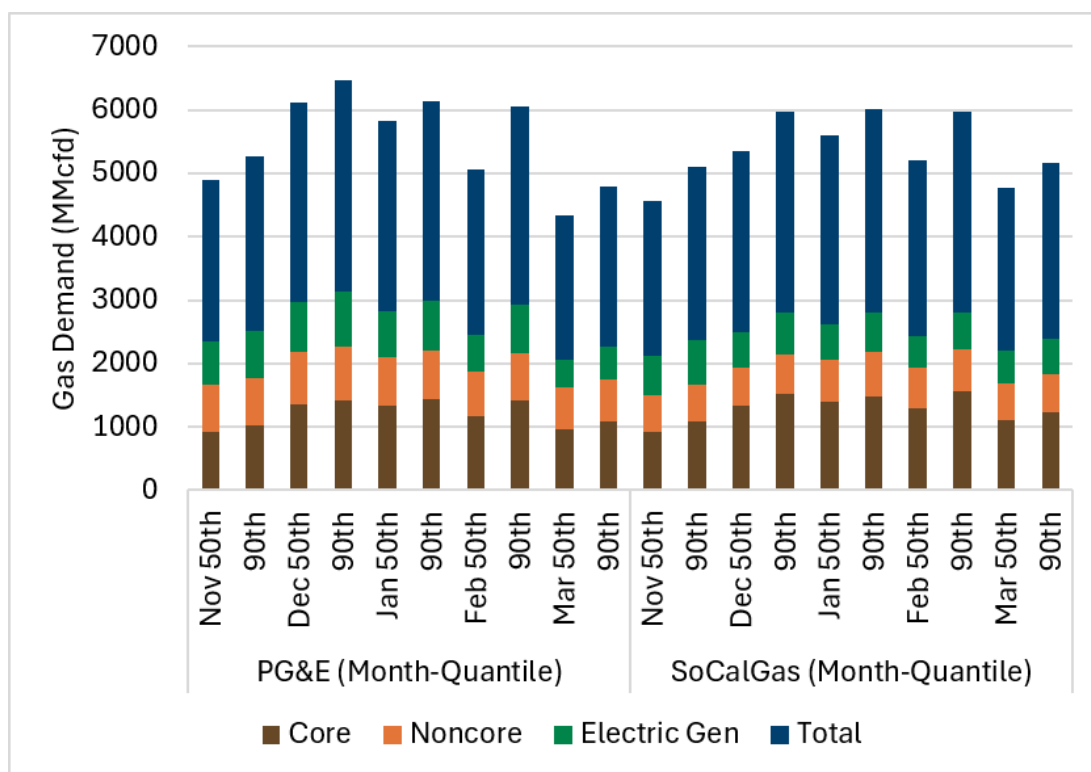
Three conclusions follow:

- The hybrid framework substantially improves forecast accuracy, particularly for peak-day demand, when forecast precision is more critical to system reliability.
- Winter natural gas demand rises with weather severity, and core customers account for most of the additional load.

- The forecasting framework provides a transparent, analytically defensible basis for winter gas reliability assessments.

Future improvements may incorporate additional demand drivers, including electrification, energy efficiency, socioeconomic trends, and alternative climate and hydrologic scenarios to enhance long-term forecasting performance.

**Figure A-3: Monthly-Average Customer Class and Total Demand by Month and Quartile**



Source: CEC

## **APPENDIX B:**

### **Hydraulic Modeling**

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In 2017, the California Energy Commission (CEC) launched an initiative to conduct independent hydraulic modeling assessments of the state's fossil gas pipeline systems. These models simulate gas-flow dynamics, incorporating complex nonlinear equations that account for the behavior of a compressible fluid. The objective is to analyze the interactions between gas supply entering the system, the consumption by end users, and the physical structure of the pipeline network.

Fossil gas utilities, such as PG&E and SoCalGas, routinely use hydraulic models to simulate operations, assess system capacity, and determine when infrastructure expansions are necessary. These assessments guide decisions on pipeline diameter, length, and compressor requirements to meet future demand. The CEC's role in this process is to verify the utilities' results, run independent simulations, and provide analysis for policy makers.

#### **Hydraulic Modeling Platform and Data Integration**

The CEC uses the DNV-GL Synergi Gas™ hydraulic modeling platform, a widely adopted tool in the United States, employed by major utilities like PG&E and SoCalGas. California's regulatory framework mandates that gas utilities submit their hydraulic models to the CEC, alongside key operational data such as minimum and maximum allowable pressures, demand scenarios, and load profiles. The CEC uses these inputs for its modeling and analysis, as outlined in Title 20, Division 2, Chapter 3, Article 1, Section 1314 of the California Code of Regulations.

Utilities are also required to brief the CEC on model updates, ensuring transparency and collaboration between both parties. This ongoing exchange helps the CEC fully understand the operational data and model parameters provided by the utilities.

#### **Winter 2026–2027 Reliability Assessment**

For the upcoming winter reliability assessment, CEC staff analyzed hydraulic models submitted by PG&E and SoCalGas. The analysis involves both steady-state and transient simulations. A steady-state analysis offers a static view of the system, illustrating gas supply, demand, and pressure levels under specific conditions. In contrast, transient analysis simulates gas flow over time, capturing the system response to changing demand throughout the day.

Both models use detailed inputs, including pipeline lengths, diameters, compressor stations, regulators, valves, and storage facilities. PG&E and SoCalGas also provide operational constraints, such as minimum and maximum pressures, which the CEC uses to ensure the models simulate realistic operating conditions.

The CEC's transient simulations assess system behavior across a full day, including how pressures fluctuate during peak-demand periods and stabilize during off-peak hours. This simulation helps identify critical moments when the system approaches capacity limits and requires adjustments to maintain balance.

## Key Scenarios and Case Studies

Two key scenarios were modeled for PG&E and SoCalGas systems as part of the 2026–2027 assessment:

- **1-in-10 Cold Day Scenario (PG&E and SoCalGas):** A high-demand scenario based on weather extremes expected once every 10 years
- **Abnormal Peak Day Plus Scenario (PG&E):** A more severe scenario combining the 1-in-90 core customer demand with 1-in-10 noncore customer demand for PG&E
- **Extreme Peak Day Plus Scenario (SoCalGas):** A 1-in-35 core customer demand plus 1-in-10 noncore customer demand for SoCalGas

In both scenarios, the models used steady-state and transient analyses to evaluate system performance under stress. Staff ensured that supply from interstate pipelines and California production was maintained at constant, ratable levels, in line with industry practices and regulatory requirements from the Federal Energy Regulatory Commission (FERC) and the California Public Utilities Commission (CPUC).

## System Balance and Intraday Operations

During the simulations, the primary goal was to maintain system balance, ensuring all pressure regulators, valves, and meters operated within tolerance and that demand was consistently met. Transient analysis offered insights into intraday operations, highlighting how peak-hour demand impacts system pressures and the adjustments needed to maintain system stability.

The concept of linepack plays a critical role in these simulations. *Linepack* refers to the amount of gas stored within the pipeline network. If supply exceeds demand, the system enters packing mode, causing pressure to rise, while drafting mode occurs when demand exceeds supply, leading to pressure drops. Managing line pack is crucial to avoid underpressure and overpressure, which can present safety risks.

The results of the 2026–2027 reliability assessment confirmed that PG&E and SoCalGas can meet demand under peak-day conditions. The findings closely aligned with each utility's gas balance projections, indicating that the CEC's independent assessments offer a reliable reflection of system behavior under the given conditions.

## Conclusion

The hydraulic modeling assessments conducted by the CEC provide critical insights into the capacity and resilience of California's fossil gas pipeline systems. By simulating real-world scenarios and verifying the utilities' models, the CEC ensures that California's gas infrastructure can reliably meet demand while maintaining safety and operational efficiency. These assessments are instrumental in guiding policy decisions and infrastructure planning, ensuring that the state remains prepared for future energy challenges.