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06/05/25
02:18 PM
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California Public
Utilities Commission

High Natural Gas Prices in Winter 2022-23: Part II

A STAFF WHITE PAPER SUPPORTING CPUC INVESTIGATION (I.) 23-03-008

Date: June 5, 2025

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Executive Summary

This Staff White Paper continues the California Public Utilities Commission's (CPUC) investigation of facts contributing to extremely high natural gas prices in winter 2022-23 through Investigation (I.) 23-03-008. It builds on findings presented in the Staff White Paper *High Natural Gas Prices in Winter 2022-23: Part I (White Paper Part I)*, issued on July 2, 2024.[1]

The focus of this expanded analysis includes the following key topics: 1) storage usage in Northern and Southern California during the winter 2022-23 price spikes; 2) independent storage provider (ISP) contracts during winter 2022-23, with comparisons to prior winters; 3) the impact of high natural gas prices on California's electric market and electricity customers; and 4) statistical analysis to determine the extent of the impact from high gas prices on electric prices.

White Paper Part I addressed two questions identified for consideration in the proceeding:

(1) What factors caused or contributed to observed gas price increases beginning on November 1, 2022? This includes market fundamentals as well as other applicable factors.
(2) Did any of the entities under the Commission's regulatory jurisdiction play a role in causing or contributing to the gas price increase in California border prices between November 1, 2022, and March 31, 2023 (gas price spikes)?

This White Paper Part II aims to further develop the record on those issues and address the following additional questions:

(5) In addition to the information currently in the record, is there any additional information that the Commission should collect or examine to further understand market dynamics that caused or contributed to the gas price spikes?
(6) What are the gas and electric market interactions that affected, during the gas price spikes, and affect, currently, costs to consumers that the Commission should examine and/or investigate?[2]

The CPUC received comments on *White Paper Part I* from seven parties. Some parties requested additional analysis that requires data that only the Federal Energy Regulatory Commission (FERC) can access and therefore will not be evaluated here.[3] Other parties requested analysis and raised questions that are included in *White Paper Part II*. For example, some parties raised questions about the utilities' use of gas storage.[4]

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[1] *High Natural Gas Prices in Winter 2022-23: Part I*: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M556/K897/556897251.PDF

[2] Assigned Commissioner's Scoping Memo and Ruling, September 5, 2023: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M519/K776/519776476.PDF

[3] For example, Small Business Utility Advocates (SBUA) recommended that the CPUC conduct a more detailed analysis of gas trading patterns and potential market manipulation at key hubs serving California. SBUA Opening Comments, pp. 1 and 8: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M537/K061/537061689.PDF.

[4] For example, Sierra Club Opening Comments, p. 4: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M537/K135/537135456.PDF>

Finally, Staff will provide a subsequent report, expected to be released in the third quarter of 2025, to respond to requests that Staff conduct additional analysis about hedging and the utilities' gas procurement incentive mechanisms.

Storage Usage During Price Spikes

As noted in *White Paper Part I,* low storage inventories in the western United States contributed to elevated natural gas prices during winter 2022-23. Gas storage plays a critical role in meeting seasonal and daily demand spikes, offering supply flexibility and a hedge against gas market volatility.[5] In comments on *White Paper Part I,* some parties raised questions about the timing of storage injections and withdrawals in winter 2022-23. *White Paper Part II* provides a detailed analysis of actual withdrawal and injection patterns throughout the winter in both Northern and Southern California.

In *White Paper Part II,* Staff analysis finds that large withdrawals from gas storage generally took place during periods of cold weather and high gas demand, such as between December 12 and December 15, 2022. In contrast, during Winter Storm Elliot (December 21-26, 2022)—when gas prices were high but weather in California was warming and demand was falling—withdrawals declined. This pattern indicates that storage usage was driven by weather and demand conditions rather than price signals alone.

Staff also find that gas storage inventories dropped significantly from the beginning to the end of the winter (68 percent for PG&E, 58 percent for SoCalGas, and roughly 74 percent for the independent storage providers, or ISPs).[6] As gas storage inventory levels fall, withdrawal capacity also declines.[7] In order to meet customer needs on high demand days late in the winter season, the utilities' core procurement departments—SoCalGas' Gas Acquisition and PG&E's Core Gas Supply—must maintain sufficient gas in storage. In winter 2022-23, high withdrawal rates were required in February and March due to cold weather and sustained demand and had to be met with the reduced withdrawal capacity that comes with lower storage inventory.

Independent Storage Provider Contracts

White Paper Part I briefly addressed the role and regulation of independent storage providers.[8] *White Paper Part II* expands Staff's analysis to ISP contracts, given the important role ISPs play in Northern California,

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[5] *White Paper Part I*, p. 3.

[6] These percentages reflect very different volumetric declines. PG&E, SoCalGas, and the independent storage providers began winter with 5.5 Bcf, 88 Bcf, and roughly 113.5 Bcf in storage respectively. ISP inventories are based on CEC estimates for the combined Wild Goose, Lodi, Central Valley, and Gill Ranch gas storage fields.

[7] This is somewhat less true for PG&E than SoCalGas. On June 11, 2021, PG&E converted 51 Bcf of working gas in its gas storage fields to base or cushion gas. The increase in cushion gas helps maintain a higher pressure in the fields and thus a higher withdrawal capacity for the remaining working gas. EIA Natural Gas Weekly Update, June 24, 2021: https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2021/06_24/.

[8] *White Paper Part I*, p. 10-11.

where they own a significant portion of the total working gas capacity. To assess whether ISP actions contributed to the price spikes or had an impact on PG&E's core customer rates,[9] Staff reviewed data request responses regarding ISP contracts for winters 2019-20 through 2022-23. While the contracts do not appear to violate tariffs, Staff's analysis raises questions about whether the ISP market remains competitive in a context in which PG&E's Core Gas Supply is required to purchase large amounts of ISP storage under the Natural Gas Storage Strategy.[10]

The ISPs operate independently from the monopoly gas distribution utilities. While they are regulated as public utilities, CPUC policy allows ISPs to offer storage services at market-based rates subject to very high price ceilings.[11] The role of the ISPs has evolved over time, and their services became more critical to gas system reliability in Northern California with the CPUC's approval of PG&E's Natural Gas Storage Strategy in 2019.

Potential areas for further analysis could include examining ISP operations and storage contracting practices, reassessing tariff structures to ensure fair pricing for core customers, considering transparency measures such as public reporting of inventory levels, and/or conducting a cost-of-service study to assess whether current market-based rates reflect competitive markets.[12]

Impact of High Gas Prices on Electricity Costs

White Paper Part I reported limited data showing the impacts of high gas prices on wholesale electric prices, which surged as gas prices spiked in the winter of 2022-23. *White Paper Part II* expands Staff's analysis of wholesale electric market costs and resulting electric bill impacts for some investor-owned utility (IOU) customers.

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[9] Gas customers are divided into two major categories: core and noncore. Core customers are made up of residential and small business and industrial customers and most receive gas service from the CPUC-regulated gas distribution public utilities, PG&E and SoCalGas. Noncore customers are large commercial and industrial customers, who either purchase the gas commodity and needed inter- and intrastate transmission pipeline transportation capacity themselves or use a third-party marketer or shipper to do it for them. Within the gas utilities, core procurement departments purchase the gas commodity, pipeline capacity, and storage capacity on behalf of core customers. These departments—Core Gas Supply at PG&E and Gas Acquisition at SoCalGas—are separated by a firewall from the rest of the company. This means that they only have access to public information about gas system operations.

[10] Detailed information about ISP contracts is not included in this report because it is market-sensitive, confidential information submitted pursuant to Pub. Util. Code Sec. 583.

[11] For example, in the Wild Goose tariff, the Withdrawal Demand Rate can be between a range of $0.00 to $200.00/Dth/month while the Injection Demand Rate can be between a range of $0.00 to $300.00/Dth/month. For perspective, gas commodity prices at the PG&E Citygate are frequently around $3/Dth and reached a high of $57/Dth in winter 2022-23. "Withdrawal Demand Rate" means rate, expressed in dollars per dekatherm per month, charged for reserving withdrawal service at the Wild Goose Storage Facility for Customer's exclusive use. "Injection Demand Rate" means the rate, expressed in dollars per dekatherm per month, charged for reserving injection service at the Wild Goose Storage Facility for Customer's exclusive use. See Microsoft Word - FINAL clean Tariff - Effective April 1, 2016 X168606 .docx.

[12] A Cost-of-Service Study helps determine how much it actually costs to provide utility service to different classes of customers.

The price of natural gas is a key component that determines market clearing prices in the California Independent System Operator (CAISO) electricity markets. Natural gas resources are often the marginal resource in the CAISO market, meaning they set the market clearing price that all electric generators receive. As a result, gas prices typically influence wholesale electricity prices. While higher wholesale electricity costs are ultimately passed through to retail electric bills, their impacts may not be felt immediately due to the way electricity rates are set by load serving entities. The investor-owned utilities and community choice aggregators (CCAs) generally update generation rates annually to ensure they recover their electric procurement costs, rather than immediately in response to market conditions.

High natural gas prices in winter 2022-23, among other factors, significantly increased the wholesale electric costs for CAISO's load. Wholesale electricity market costs were approximately $21.6 billion in 2022 compared to $12.6 billion in 2021 and $14.5 billion in 2023.[13] The extraordinary increase in wholesale electricity market costs in 2022 was driven primarily by elevated gas prices in December 2022 and to a lesser degree by high electric demand, high gas prices, and scarcity conditions during summer 2022. In December 2022, net electricity imports into California were much lower and gas-fired generation in CAISO supply was significantly higher than in previous years, due in part to the drought in the Pacific Northwest. The increase in imports contributed to elevated wholesale electricity costs in December 2022 compared to other periods. CAISO's wholesale day-ahead market costs reached $5 billion in December 2022, compared to just $1 billion in December of previous and subsequent years.

Ultimately, higher wholesale electricity costs experienced in December 2022 raised Southern California Edison's (SCE) and PG&E's customer bills. SCE bundled customers experienced a 3 percent rate increase over 12 months while PG&E bundled customers experienced an increase of approximately 6 percent over a six-month collection period.

Technical Appendix: Detailed Statistical Modeling of Electric Market and Analysis

A technical appendix to *White Paper Part II* provides an in-depth evaluation of the interactions between gas prices and electric prices. Building on the analysis of the impact of gas prices on electric prices and customers, the technical appendix drills down on pricing trends using statistical methods to isolate effects to each service area, and to evaluate correlation and volatility. One of the key takeaways from this analysis is that gas-fired power plants faced fluctuating profit margins depending on their location and the gas prices in that area. Since electricity prices are set uniformly across the state, lower natural gas costs in PG&E's service territory allowed gas-fired generators located there to gain higher profit margins compared to gas-fired generators operating in SCE's area. Similarly, non-gas generators without fuel costs benefited from the elevated electricity prices throughout CAISO as well. Staff also find that due to gas price volatility and

[13] CAISO Department of Market Monitoring. 2023 Annual Report on Market Issues and Performance, pages 4-5. https://www.caiso.com/documents/2023-annual-report-on-market-issues-and-performance.pdf

energy scarcity, electricity pricing trends diverged from historical patterns in summer 2022 and winter 2022-23.

Staff conducted extensive statistical modeling of gas-electric market interactions to better assess the extent to which high gas prices during winter 2022-23 affected California's electricity markets, using these tools:

- Implied Market Heat Rate analysis (IMHR), which is a ratio of the electricity price to the gas price and reflects the effective fuel efficiency needed to justify electricity market prices;
- Analysis of high IMHR events, which indicate scarcity, comparing scarcity events across years;
- Profitability analysis using high IMHR in excess of real heat rate levels as the indicator of times when power plants are likely earning revenue well in excess of their costs;
- Correlation analysis, which in this case measures the relationship between gas prices in the PG&E and SoCalGas service territories with the overall energy prices;
- Volatility and Risk analysis, comparing the amount of volatility in gas and electric prices from winter 2022-23 with the year before and year after, to show that winter 2022-23 was especially volatile, and that there is a cost to that volatility, expressed as Value at Risk (VaR) and Conditional Value at Risk (CVaR); and
- Other statistical tests such as T-tests, to determine if the correlations observed were not random but statistically significant.

The additional modeling demonstrated the following:

- PG&E's IMHR was higher than SCE's most of the time outside of winter 2022-23, likely due to lower gas prices in the PG&E area together with higher CAISO electricity prices, which amplified its IMHR calculation. By contrast, in winter 2022-23, IMHR in SCE area was relatively low, ranging between 8 million British thermal units (MMBtu)/MWh and 10MMBtu/MWh in the SCE service territory and 10MMBtu/MWh and 13MMBtu/MWh in the PG&E service territory indicating high gas prices in both regions. Electricity prices generally moved in line with gas prices, and the sensitivity of the electric market to gas price fluctuations increased after the winter 2022-23.
- Gas-fired power plants in PG&E's territory initially saw a drop in simulated profitability during winter 2022-23 but recovered quickly because gas prices in PG&E's area, although high, were still lower, on average, than those in the SoCalGas territory. Meanwhile, gas-fired power plants in SCE's territory struggled with low simulated profitability longer due to higher gas costs and greater price swings.
- While gas-fired power plants faced fluctuating profit margins depending on location and gas prices, non-gas generators benefited from elevated electricity prices throughout CAISO. Due to gas price volatility and energy scarcity related to weather trends, pricing trends diverged from historical patterns. This period set the stage for continued price volatility into 2023 and 2024.
- The study suggests that gas prices were the dominant driver of electricity prices, with high correlations between gas and electric prices of 0.93 for PG&E and 0.92 for SCE. That means when

gas prices increased or decreased, electric prices changed 93 and 92 percent of the same amount.[14] Gas prices in both regions experienced nearly identical movements, confirming extreme price swings and gas prices in the PG&E area and SoCalGas area become much more correlated with each other after the winter of 2022-23.

- Winter 2022-23 was the most volatile period between 2020 and 2024, with significant spikes in gas prices and higher price variability than other recent winters. These extreme increases confirmed that winter 2022-23 was an outlier in terms of pricing, however, by winter 2023-24, prices declined, with mean gas prices in the PG&E service territory returning to $4.10/MMBtu—close to 2020 levels—while gas prices at the SoCal Citygate[15] dropped to $6.00/MMBtu, still slightly above winter norms but well below the 2022-23 peak.
- Volatility in price spikes peaked in winter 2022-23, when average VaR reached as much as $7.60/MMBtu in SoCalGas prices compared to $5.80/MMBtu in winter 2021-22 during winter storm Uri and around $4.00/MMBtu in other winters. By winter 2023-24, both VaR and CVaR dropped significantly, indicating a return toward stability. PG&E's VaR fell back to $2.30/MMBtu—its 2020 level—while SoCalGas VaR dropped to $4.00/MMBtu, still slightly above pre-2022 levels.
- Similar to gas prices, winter 2022-23 was the most extreme period for electricity price spikes since the California energy crisis of 2000-01. For example, the analysis notes off-peak energy prices spiked significantly, reaching $27.90/MWh, while peak-hour prices increased to $64.40/MWh, confirming that sharp price swings were more likely and severe than before the winter 2022-23 period.

Federal Energy Regulatory Commission Analysis

As a final note, in addition to the investigations by CPUC Staff, Governor Newsom asked the Federal Energy Regulatory Commission to investigate the high gas prices in western states in winter 2022-23.[16] In FERC's *2023 Report on Enforcement,* it reported that its Department of Analytics and Surveillance (DAS) was examining winter 2022-23 western natural gas and electric market activity and had thus far referred one market participant to the Department of Investigation (DOI).[17] Since the DOI does not disclose the names of companies that it investigated with no action, it is unclear from the *2024 Report on Enforcement,* whether

[14] The correlation coefficient ranges from -1 to +1, with +1 reflecting a positive correlation.

[15] The PG&E and SoCalGas Citygates are gas commodity trading hubs inside California. In general, a citygate is any point at which the backbone transmission system connects to the distribution system. The citygate is not one specific, physical location; rather, it represents a virtual trading point on the natural gas system.

[16] 4 February 6, 2023, Governor Newsom Letter to FERC: https://www.gov.ca.gov/wp-content/uploads/2023/02/Governor-Newsom-FERC-Letter-02.06.23.pdf.

[17] FERC *2023 Report on Enforcement,* November 16, 2023, p 80: Presentation & Report | FY2023 Report on Enforcement | Federal Energy Regulatory Commission.[18] The DOI reported that it closed 10 investigations with no action in Fiscal Year 2024. Additionally, there are no relevant gas settlement agreements among the 12 the DOI negotiated during this period. FERC *2024 Report on Enforcement,* November 21, 2024, pp 17-23; 32-33: FERC Issues Fiscal 2024 Enforcement Report | Federal Energy Regulatory Commission.

that investigation is ongoing.[18] In the 2024 report, the DAS stated that it had "completed its analysis related to the Winter 2022/2023 Western Energy Price Spike without any additional referrals."[19]

[18] The DOI reported that it closed 10 investigations with no action in Fiscal Year 2024. Additionally, there are no relevant gas settlement agreements among the 12 the DOI negotiated during this period. FERC *2024 Report on Enforcement,* November 21, 2024, pp 17-23; 32-33: FERC Issues Fiscal 2024 Enforcement Report | Federal Energy Regulatory Commission.

[19] Ibid, pp 77.

Storage Usage During Price Spikes

White Paper Part I found that low storage inventories in the West contributed to the high gas prices of winter 2022-23. Gas storage plays a vital role in supplementing pipeline supply by enhancing reliability, meeting seasonal and daily demand fluctuations, and helping to mitigate price spikes.[20] In comments on *White Paper Part I,* some parties raised questions about the timing of storage injections and withdrawals. For example, Sierra Club noted that gas was injected into storage during December bidweek and other high-priced days in winter 2022-23. For this reason, Staff analyzed withdrawal and injection activity during winter 2022-23 to determine the degree to which storage was relied upon during the periods when prices peaked.

There are 12 gas storage fields in California.[21] Five of these fields are owned by independent storage providers in Northern California,[22] and the remaining seven are owned by PG&E and SoCalGas. Gas customers[23] often purchase and inject natural gas into storage fields when prices are lower in the spring and summer for withdrawal and use during the high-demand winter season. This strategy helps secure supply at a lower cost and provides a buffer against potential price spikes and supply constraints during high demand periods, which typically occur in colder months.

While the majority of gas storage injection is seasonal, customers may inject gas into storage during winter for a variety of reasons. There may be a drop in prices that incentivizes injection. Customers may also have brought in more gas than needed on a given day. Injection is a way to preserve that extra gas for future use and potentially avoid high operational flow order penalties.[24] The utility's gas system operator may also inject gas into storage to keep the system "in balance" or within the acceptable range of pipeline pressures. Both PG&E and SoCalGas have injection and withdrawal capacity as well as storage inventory set aside for

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20 California Center for Science and Technology, report *Long-Term Viability of Underground Natural Gas Storage in California*, p. 494: https://ccst.us/wp-content/uploads/Full-Technical-Report-v2_max.pdf

21 See *White Paper Part I*, p. 12, for a map showing gas storage facilities.

22 The Kirby Hills gas storage field is now integrated with Lodi Gas Storage: https://www.rockpointgs.com/Businesses/Lodi.

23 Gas customers include utilities' core procurement departments, which store gas on behalf of core customers, as well as noncore customers and shippers who purchase and store gas on behalf of noncore customers or to sell in the daily spot market. Core customers are allocated a set amount of storage inventory and injection and withdrawal capacity at the utilities' storage fields. PG&E's core procurement department must also purchase additional storage from the ISPs. In Northern California, noncore customers can purchase storage from the ISPs and can also purchase some storage from PG&E, see: Business Facts | Storage Service Program | Pipe Ranger. During winter 2022-23, noncore customers had no access to storage in Southern California due to the limitations on the Aliso Canyon gas storage field and the lack of ISPs in the region.

24 The gas pipeline system must operate within a predetermined safe pressure range, with neither too much nor too little gas on the system. Operational flow orders (OFOs) are a tool for maintaining that range by penalizing customers for bringing more or less gas onto the system than they consume. It requires shippers to balance their deliveries with their demand within a specified tolerance band, and subjects shippers to financial penalties if the difference between their deliveries and demand falls outside of the specified tolerance band. For additional information, see SoCalGas Rule 30 Current and Effective Tariffs | SoCalGas and PG&E's "Introduction to Operational Flow Orders": Introduction to Operational Flow Orders (OFO) | Pipe Ranger.

this purpose at their own storage fields [25] Hourly balancing is needed because pipeline gas is typically delivered at the same level during every hour of the day, but customer demand peaks in the morning and the evening. The system operator can inject excess gas delivered during lower demand hours and withdraw it during higher demand periods.

Injections and Withdrawals in Northern California

Staff's analysis found that in Northern California withdrawals were moderate to high during the price spikes in mid-December with consistently higher withdrawals from two independent storage providers, Wild Goose Gas Storage (Wild Goose) and Lodi Gas Storage (Lodi). Withdrawals reached their highest levels in mid-December 2022 through the end of February, aligning with colder weather and increased demand.

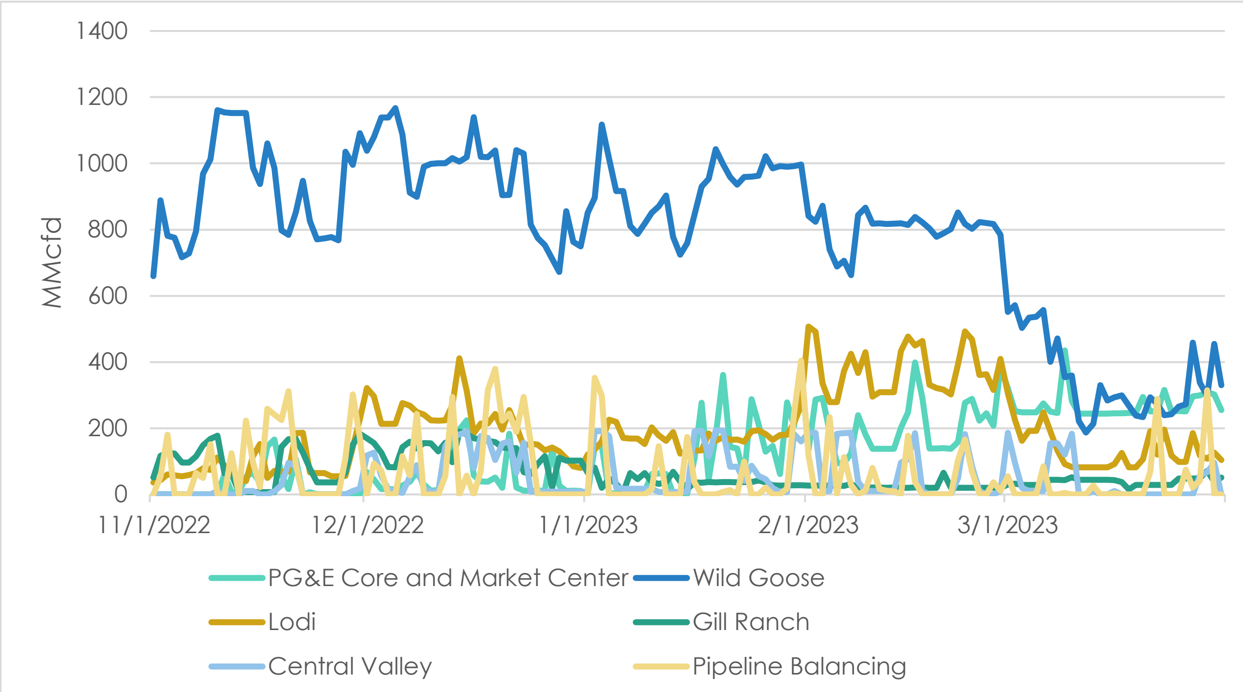
As shown in Figure 1 below, withdrawals from Northern California gas storage fields were elevated during the peak demand months of December, January, and February. Wild Goose—the largest ISP gas storage field in Northern California—saw the highest withdrawal volumes, frequently exceeding 1 billion cubic feet per day (Bcfd) before tapering off in March 2023, indicating it was an important source of supply during the price spikes. Lodi—the second largest ISP gas storage field in Northern California—also contributed significantly, with notable peaks in January and February. PG&E's Pipeline Balancing function shows repeated peaks, exceeding the 300 MMcfd set aside for Inventory Management on seven occasions. PG&E Core and Market Center,[26,27] Gill Ranch, and Central Valley, exhibited more moderate and steady withdrawal patterns. The overall trend shows a sharp increase in withdrawals beginning in November 2022, aligning with heightened winter demand, followed by a decline in mid-March as temperatures rose and market conditions stabilized.

[25] SoCalGas has 12 Bcf of inventory, 400 MMcfd of withdrawal capacity, and 345 MMcfd of injection capacity set aside for winter balancing; Settlement Agreement p. 6, D.24-09015: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M536/K556/536556034.PDF). PG&E has allocated 5 Bcf of inventory, 300 MMcfd of withdrawal capacity, and 200 MMcfd of injection capacity to Inventory Management, which is their term for balancing; PG&E also has Reserve Capacity, which is allocated 1 Bcf in inventory, 250 MMcfd in withdrawal capacity, and 25 MMcfd in injection capacity. D.19-09-025, p. 31: D1909025 Authorizing PG&E s 2019-2022 Revenue Requirement for Gas Transmission and Storage Service.pdf.

[26] The combined customer activity from PG&E's storage fields is referred to on PG&E's electronic bulletin board Pipe Ranger as "PG&E Core and Market Center": Historical Archives | Storage Search Results | Pipe Ranger. Core refers to PG&E's Core Gas Supply, which purchases gas for bundled core customers. "Market Center" refers to PG&E's product line for parking, loaning, and negotiated storage services that are sold by the Gas System Planning Products and Sales Department, which is on the other side of the firewall from PG&E's Core Gas Supply.

[27] The PG&E system operator manages injections and withdrawals from storage, either for pipeline balancing or in response to customers like PG&E's Core Gas Supply or Core Transport Agents scheduling injections or withdrawals. As noted above, there is a firewall between PGE's Core Gas Supply and the rest of the company.

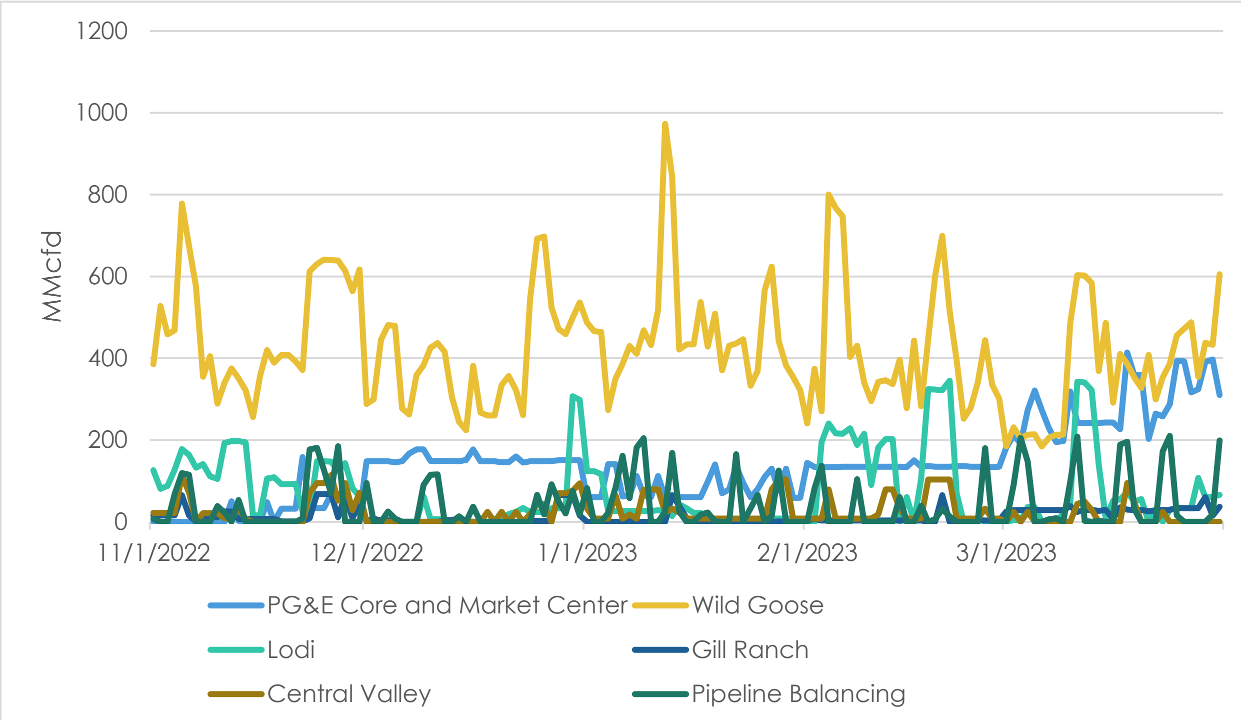
Figure 1: Winter 2022-23 Northern California Storage Withdrawals



Source: PG&E Pipe Ranger

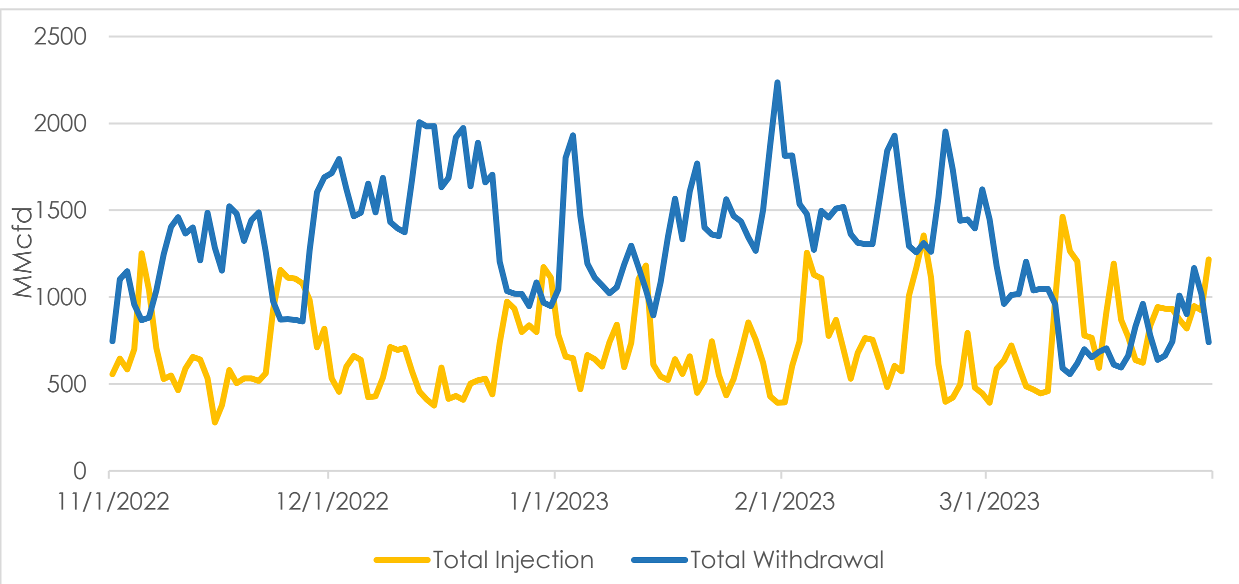
Staff also analyzed Northern California's winter 2022-23 customer injection patterns at each storage facility. Among all facilities, Wild Goose's facilities exhibited the most significant and frequent injection activity during periods of lower demand throughout the winter. Meanwhile, injections at PG&E's storage fields remained relatively consistent throughout December. In mid-December, when demand was at its peak and price spikes occurred, customer injections dipped noticeably at Wild Goose, Central Valley, and Lodi. Staff also observed a clear inverse relationship between injections and withdrawals. As shown in Figure 2 below, injections were generally lower during periods of higher withdrawals. Withdrawals reached their highest levels in mid-December 2022 through the end of February, aligning with colder weather and increased demand. However, as withdrawals declined—particularly in late January and after mid-March—injections became more pronounced.

Figure 2: Winter 2022-23 Northern California Storage Injections



Source: PG&E Pipe Ranger

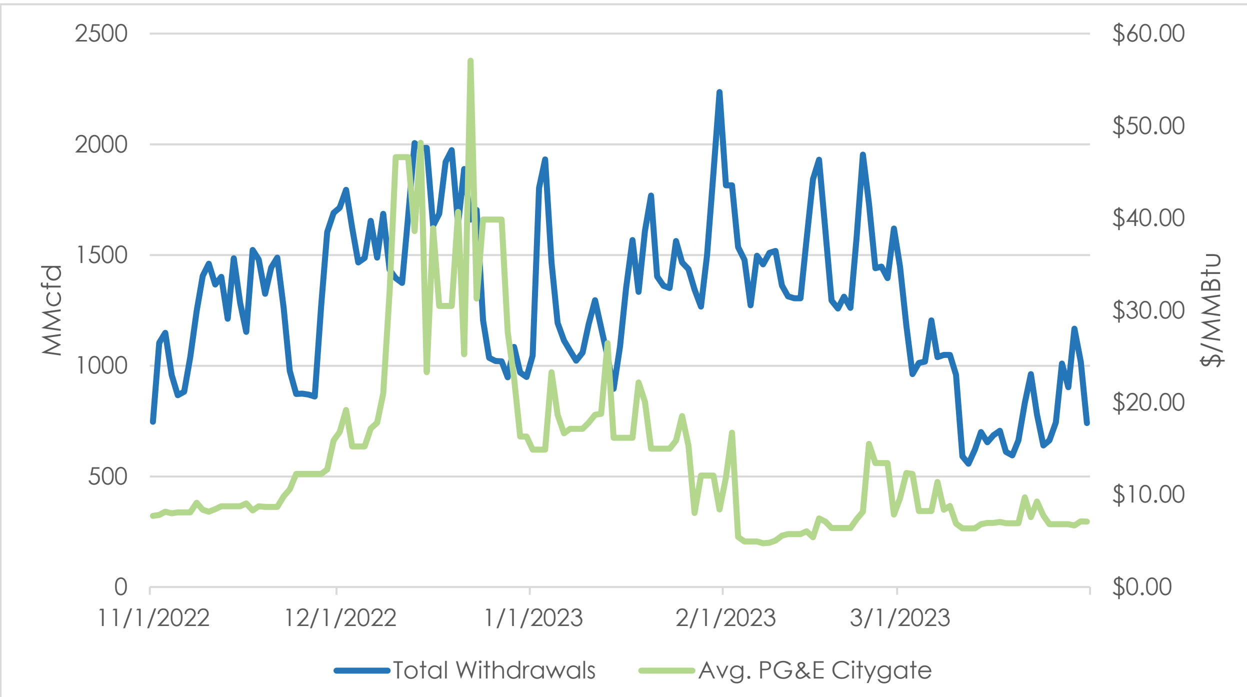
Figure 3: Winter 2022-23 Northern California Withdrawals and Injections



Source: PG&E Pipe Ranger

As illustrated in Figure 4 below, PG&E Citygate spot market prices began rising in late November and spiked December 12-14 as temperatures dropped and further pipeline outages in the West occurred, particularly on the El Paso interstate pipeline system.[28] However, withdrawals were already high before the price spike because demand and prices were rising due to colder temperatures, as can be seen in Figure 5. In mid-to-late December, prices fluctuated significantly, with some of the highest price spikes, such as the $57.07/MMBtu price on December 22, coinciding with somewhat lower withdrawal rates.

Figure 4: Winter 2022-23 Northern California Withdrawals and PG&E Citygate Prices



Source: PG&E Pipe Ranger and Natural Gas Intelligence

The fact that customer withdrawals were not consistently at peak levels in late December is likely because it was less cold in Northern California than earlier in the month, and total demand was therefore lower.[29] For example, PG&E on-system demand dropped from a peak of 3,648 MMcfd on December 19 to 2,209 MMcfd on December 25. The high prices during this period despite declines in local demand were likely

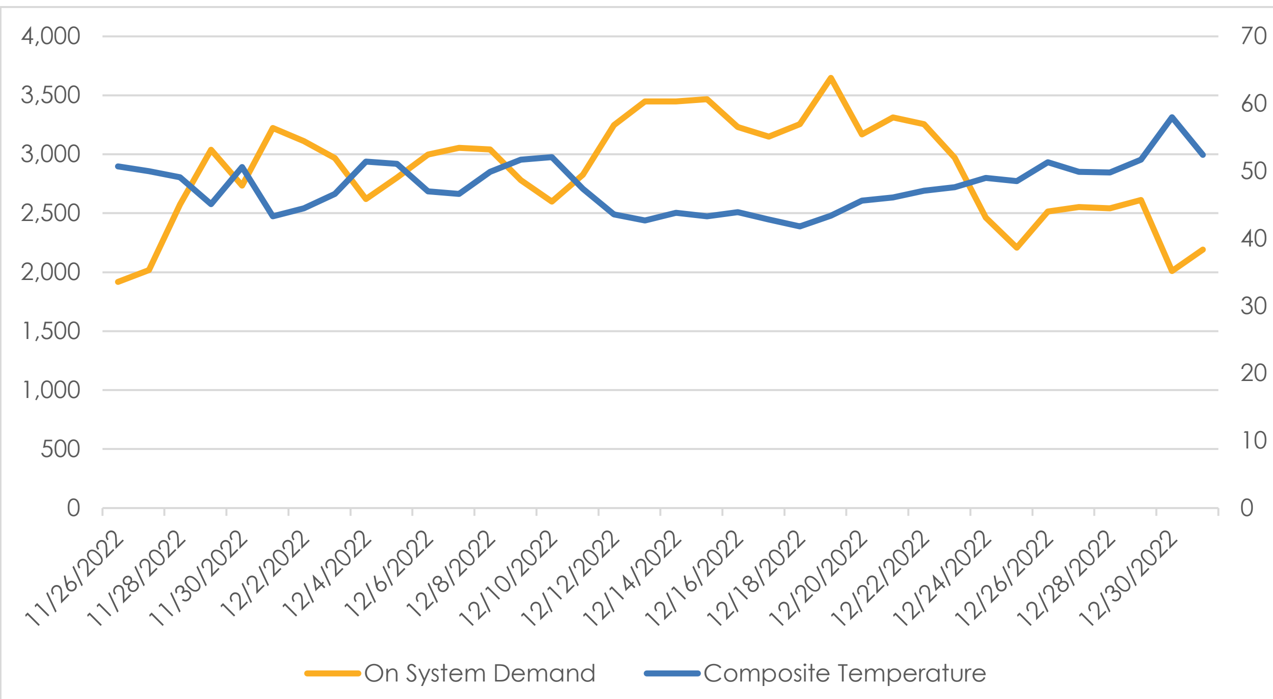
[28] White Paper Part 1, p. 34 and fn. 113, citing EIA Natural Gas Weekly Update December 22, 2022, https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2022/12_22/ and noting "pipeline constraints" as contributing to high price levels

[29] For example, the PG&E Composite Temperature on December 22 was 47.1°F compared to the monthly low of 41.8°F on December 18.

related to Winter Storm Elliot (December 21-26, 2022), which severely impacted the eastern United States,[30] reduced gas production,[31] and raised gas prices across the country.[32]

A further complicating factor was that Winter Storm Elliot coincided with the long Christmas holiday weekend. Most gas spot contracts are sold on Friday for the weekend, and these contracts typically lock in a price and an amount of gas to be delivered that remains consistent for every day of the weekend. Thus, spot market purchasing decisions made on Friday, December 23 would largely determine spot gas flows from Saturday, December 24 through Tuesday, December 27. Since demand declined over that period, customers or the system operator may have needed to inject excess gas supply.

Figure 5: PG&E On-System Demand and Composite Weighted Average Temperatures, 11/26-12/31/2022



Source: PG&E Pipe Ranger

Moving into January 2023, withdrawals remained high even as prices declined. In February, with the announcement of, and subsequent completion of, repairs on El Paso's Line 2000 on February 15, 2023[33]

[30] FERC, November 7, 2023: FERC, NERC Release Final Report on Lessons from Winter Storm Elliott | Federal Energy Regulatory Commission

[31] EIA, March 13, 2024: Winter storms have disrupted U.S. natural gas production - U.S. Energy Information Administration (EIA).

[32] Reuters, December 23, 2022: Storm cuts U.S. oil, gas, power output, sending prices higher | Reuters

[33] *White Paper Part 1*, p. 26

prices fell significantly to around $5-$8/MMBtu, yet withdrawals still showed periodic peaks, such as the 1,893 MMcfd withdrawal on February 16, which corresponded with a period of lower temperatures.

Between the beginning and end of winter, PG&E's storage inventory levels dropped from 5.5 Bcf to 1.8 Bcf, a 68.2 percent decrease.[34] In comparison, inventory declines during winters 2021-22 and 2020-21 were approximately 66 and 23 percent, respectively. However, historical comparisons are of limited utility in this case because PG&E converted 51 Bcf of storage inventory from working gas to cushion gas in June 2021.[35] Thus, the relatively modest 3.7 Bcf drop in storage inventory during winter 2022-23 resulted in a larger percentage decrease in PG&E's working gas capacity in that year than the 18.2 Bcf drop in inventory in winter 2020-21.

In contrast, the ISPs' estimated 74 percent drop in storage inventory over the course of winter 2022-23 did represent a significant volume of gas. The ISPs began winter with roughly 113.5 Bcf in inventory and ended with about 29.3 Bcf, an 84.2 Bcf decline. In comparison, during winter 2021-22, ISP storage inventories declined about 47 Bcf from an estimated 120 Bcf to roughly 73 Bcf or about 40 percent.[36] As noted in *White Paper Part I*, low storage inventories in the West contributed to high gas prices across the region.[37]

Injections and Withdrawals in Southern California

Staff's analysis found that in Southern California, SoCalGas withdrawals spiked during periods of cold weather and high-demand and to a lesser extent in response to high prices. Significant withdrawals occurred between December 12 and December 15, when SoCal Citygate prices nearly reached $50 per MMBtu, the weather was cold, and gas demand was high. However, withdrawals were lower on days with reduced demand, even when prices remained high, indicating that storage usage was driven by weather and demand conditions rather than by price signals alone.

Withdrawals were moderate early in the winter, averaging between 50 to 70 percent of available capacity. This strategy may have been driven by the need to preserve withdrawal capacity for late-winter demand, since withdrawal capacity declines with inventory in the SoCalGas storage fields. High withdrawal rates were required in February and March due to cold weather and sustained demand.

As illustrated in Figure 6 below, prices and withdrawal levels often move together, but there are times when prices are high and withdrawal levels are low and vice versa. As noted above, in mid-December, withdrawals increased significantly alongside a sharp rise in SoCal Citygate gas prices. However, later in the month,

34 PG&E Pipe Ranger Storage Activity Archives: https://www.pge.com/pipeline/en/operating-data/historical-archives/cgt-storage-search.html#

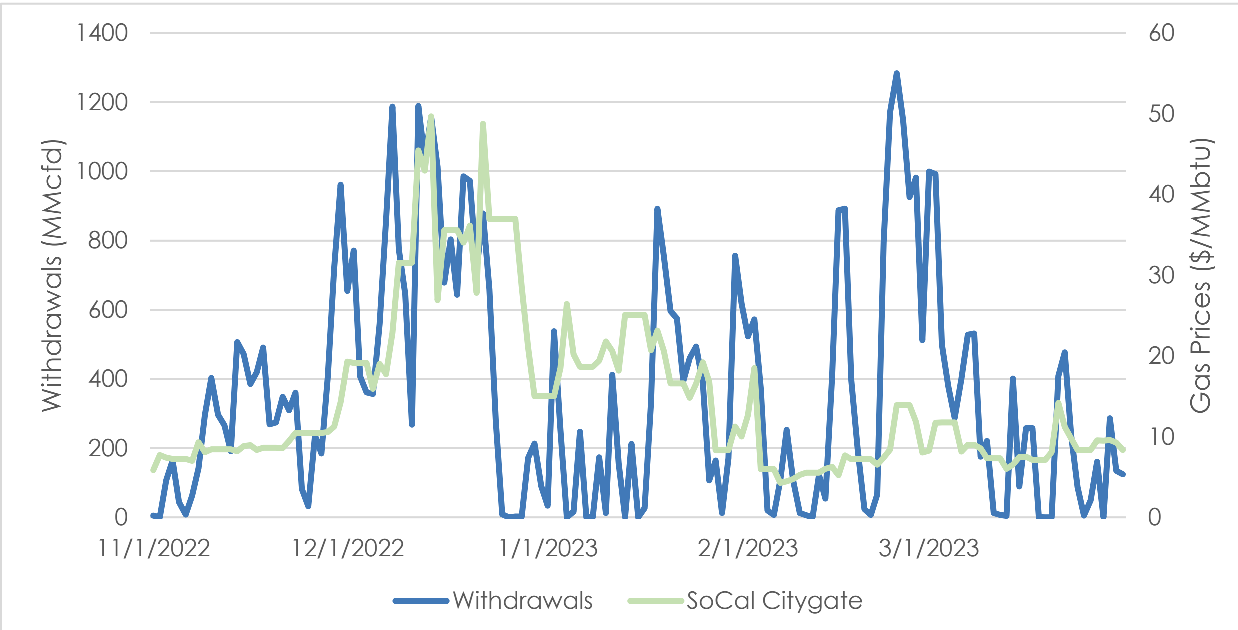
35 Energy Information Administration, June 23, 2021, Natural Gas Weekly Update: https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2021/06_24/

36 The ISPs do not make their storage inventories public. The estimates of combined ISP inventory used here are from the CEC, which did not start providing them until winter 2021-22.

37 EIA. "Natural Gas Weekly Update for week ending December 21, 2022": https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2022/12_22/.

withdrawals fell even when prices remained over $35/MMBtu. There were also high withdrawals in mid-February to early March, after prices had retreated below $15/MMBtu.

Figure 6: Winter 2022-23 SoCalGas Withdrawals and SoCal Citygate Prices



Source: SoCalGas Envoy and Natural Gas Intelligence

Between December 12 and December 15, when customer demand exceeded 3,800 MMcfd, withdrawal activity spiked, exceeding 1,000 MMcfd on all four days.[38] As shown in Figure 6 above, SoCal Citygate prices also peaked during this time. Similarly, on January 30, 2023, when demand surged to 3,742 MMcfd, withdrawals remained elevated at 890 MMcfd. A similar pattern was observed between January 18 and January 20, as demand rose above 3,500 MMcfd and SoCal Citygate prices increased, though prices were not as high as in mid-December.

As shown in Figure 7 below, there was a notable inverse correlation between system sendout and weather. For example, during the month of December the average weighted composite temperatures ranged from a low of 49°F on December 12 to a high of 65°F on December 25. System sendout moved with the temperature, hitting 3,816 MMcfd on December 12 and falling to 2,084 MMcfd on December 25.

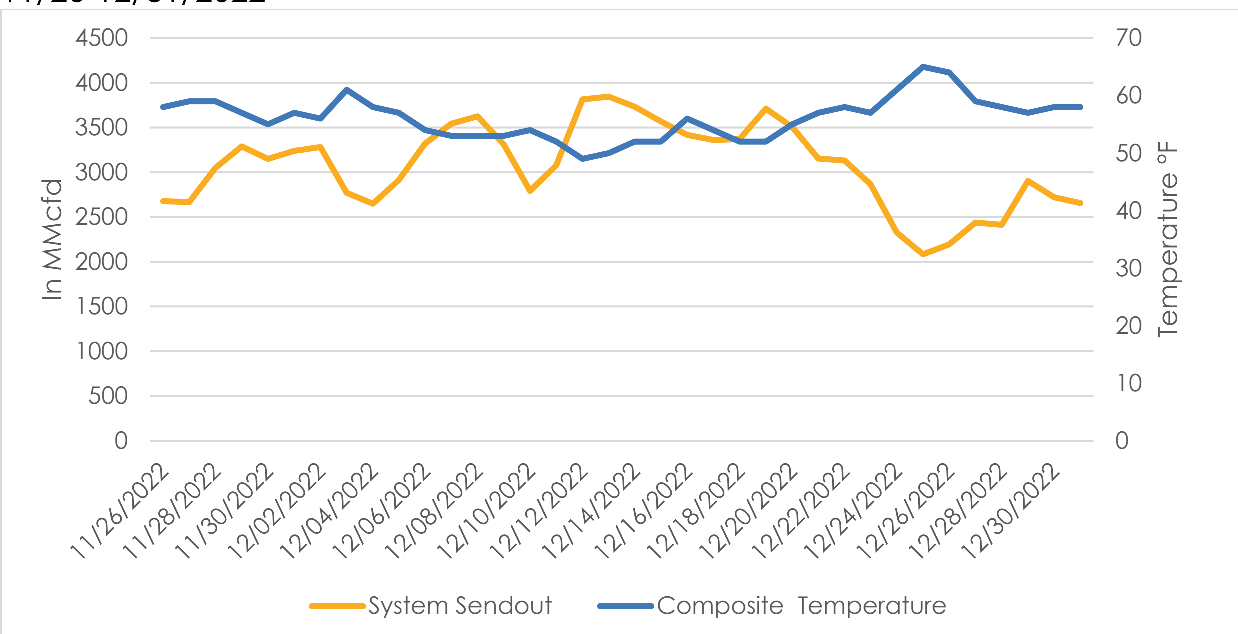
Toward the end of December, the SoCalGas service territory showed a similar pattern to that of PG&E, with demand dropping as the weather warmed. As with PG&E, this period coincided with both Winter Storm Elliot (December 21-26) and the long Christmas holiday weekend (December 24-27). As can be seen

[38] SoCalGas Envoy Daily Operations Archives: https://www.socalgas-envoy.com/index.jsp#nav=/Public/ViewExternal.showHome

in Figure 8 below, as demand declined, withdrawals dropped and injections resumed despite the fact that prices were high.

Staff reviewed SoCalGas' Gas Acquisition Department's transactions, injections, and withdrawals during the highest price periods of December and verified SoCalGas' claim that "Gas Acquisition had no scheduled storage injections during January bidweek."[39] The bidweek injections shown in Figure 8 below were thus due either to system balancing or to other core customers who held storage during this period.[40,41]

Figure 7: SoCalGas System Sendout and Composite Weighted Average Temperatures, 11/26-12/31/2022[42]



Source: SoCalGas Envoy

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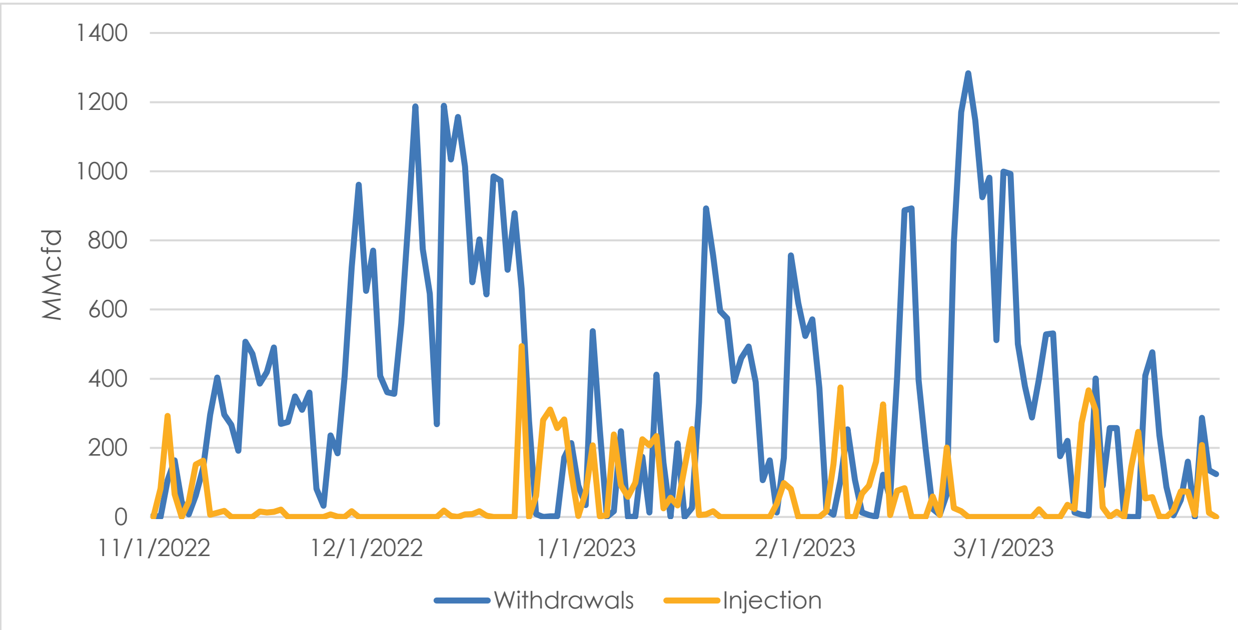
[39] SoCalGas and SDG&E, *Joint Reply Comments*, p. 7: Microsoft Word - DRAFT WGP OII - Reply Comments ALJ Ruling Admitting Staff White Paper Part 1 Seeking Comment (8.14.2024).

[40] Bidweek is discussed extensively in *White Paper Part I*. Bidweek for January 2023 took place December 23-28, 2022

[41] Southwest Gas and the City of Long Beach are wholesale core customers of SoCalGas.

[42] System sendout is how much gas was sent out on the gas system to customers. It represents gas demand.

Figure 8: Winter 2022-23 SoCalGas Withdrawal and Injections



Source: SoCalGas Envoy

As shown in Figure 9 below, while the system's total withdrawal capacity fluctuated daily—from around 870 MMcfd to over 2,000 MMcfd—actual withdrawals generally ranged between 500 and 1,100 MMcfd, peaking at about 1,189 MMcfd on December 12. On average, SoCalGas customers used approximately 50 to 70 percent of available capacity during this period. This moderated use may reflect a strategy of conserving withdrawal capacity for potential high-demand periods later in the winter. Withdrawal capacity declines with storage inventory, so a rapid depletion of storage inventory early in the winter increases the risk of being unable to meet late-winter demand.[43] Indeed, usage ramped up significantly in February and early March, when colder weather and sustained demand led to higher withdrawal rates, which at times exceeded 80 percent of available capacity.

The gradual decline in withdrawal capacity over the course of the winter can be seen in Figure 9 below. The periodic abrupt drops in withdrawal capacity observed in Figure 9 are the result of the Aliso Canyon Withdrawal Protocol in effect during the winter 2022-23. Aliso Canyon could only be used when specific conditions were met, so its capacity is not included on days the field could not be used.[44]

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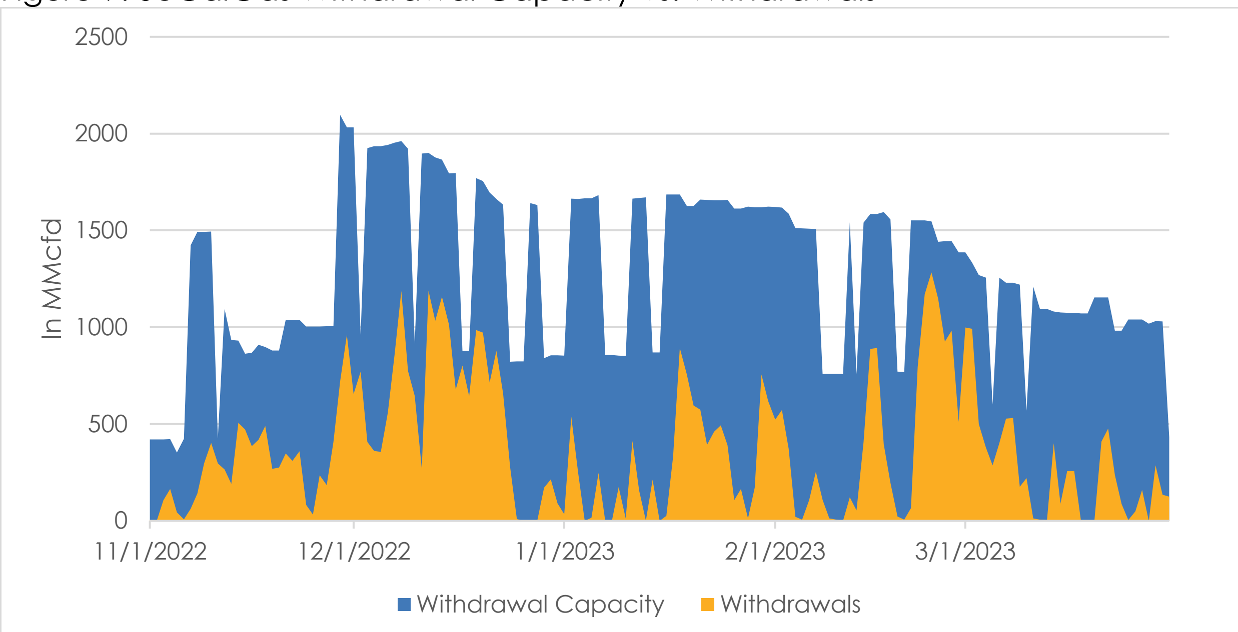
[43] The *SoCalGas Winter 2022-23 Technical Assessment* p. 8 includes the minimum inventories needed each month to serve only core customers: TN246873_20221026T152429_Greg Healy Comments - SoCalGas Winter 2022-2023 Technical Asessment.pdf as required by D.97-06-061.

[44] The July 23, 2019 version of the Aliso Canyon Withdrawal Protocol (https://www.cpuc.ca.gov/-/media/cpuc-website/files/uploadedfiles/cpucwebsite/content/news_room/newsupdates/2020/withdrawalprotocol-revised-april12020clean.pdf) was in effect until September 15, 2023 (https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/natural-gas/aliso-canyon/aliso-canyon-withdrawal-protocol-letter-2023-09-15.pdf).

Another factor that may have limited daily storage withdrawals is the CPUC requirement that the SoCalGas Gas Acquisition Department maintain firm interstate pipeline capacity equal to 100 to 120 percent of average core winter demand.[45] While firm capacity contracts do not equal actual flowing supply, the utility must plan to receive a steady flow of gas throughout the winter, and there is a relatively high quantity of pipeline gas entering the system every day under long-term and monthly contracts. Gas Acquisition typically uses storage to supplement that existing pipeline supply on above-average days but may not need all the available withdrawal capacity to meet customer demand.

Figure 9: SoCalGas Withdrawal Capacity vs. Withdrawals



Source: SoCalGas Envoy

Between November 1, 2022, and March 31, 2023, SoCalGas storage inventory declined by 51.1 Bcf from 88 Bcf to 36.9 Bcf, representing a 58.1 percent reduction.[46] While this reduction is significant compared to the inventory declines during winters 2021-22 and 2020-21 (when inventory fell by approximately 10 percent and 34 percent, respectively), it is not unprecedented.[47]

Historically, large drops in storage inventory have often been accompanied by periods of high gas prices and reliability impacts. For example, SoCalGas' lowest end-of-winter storage inventory (22.1 Bcf)[48] occurred during the 2000-01 energy crisis, which saw SoCal Border prices reach $55/MMBtu and 17 days of

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[45] *2024 California Gas Report*, p. 23: https://www.socalgas.com/sites/default/files/2024-08/2024-California-Gas-Report-Final.pdf.

[46] SoCalGas Envoy Storage Inventory Archives:https://www.socalgas-envoy.com/index.jsp#nav=/Public/ViewExternal.showHome

[47] Sierra Club, *Reply Comments*, p. 8: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M538/K617/538617449.PDF.

[48] SoCalGas Envoy: https://www.socalgasenvoy.com/index.jsp#nav=/Public/ViewExternal.showHome.

curtailments to firm, noncore customers in the SDG&E service territory.[49,50,51] SoCalGas' storage inventory ended winter 2018-19 (in the post-Aliso Canyon leak period) at a level similar to winter 2022-23 (38.3 Bcf). That winter, spot market prices spiked to $22/MMBtu,[52] electric generators were asked to voluntarily curtail their operations on 41 days,[53] and there were two mandatory curtailments of electric generators lasting a total of six days.[54] These historical examples support findings from *White Paper Part I* that low storage inventories were one factor contributing to the high gas prices in winter 2022-23.

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49 Public Policy Institute of California, *The California Electricity Crisis: Causes and Policy Options,* pp. 28-29, 32: https://www.ppic.org/wp-content/uploads/content/pubs/report/R_103CWR.pdf.

50 D.02-11-073, p. 7: https://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/21286.PDF.

51In response to the 2000-01 energy crisis, the CPUC approved a settlement agreement instituting physical gas storage inventory requirements for SoCalGas' core customers in D.02-06023- p, 18: https://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/16315.PDF.

52 Natural Gas Intelligence.

53 SoCalGas Envoy: https://www.socalgasenvoy.com/index.jsp#nav=/Public/ViewExternalEbb.getMessageLedger?ledgerType=message&Page=filter&datePosted_from=12%2F25%2F2018&datePosted_to=03%2F15%2F2019&keyword=voluntary%20curtailment&folderId=1

54 CPUC Energy Division, January 6, 2020, *Winter 2018-19 SoCalGas Systems and Operations Report*: Microsoft Word - Winter2018-19LookbackReport-Final-January2020.

Independent Storage Provider Contracts

White Paper Part I highlights the role of independent storage providers in California's natural gas market and notes that noncore customer injections into the ISP fields were low during summer 2022 due to unfavorable market conditions in the spring and summer. This behavior was in contrast to that of the utility divisions that purchase gas for core customers, PG&E's Core Gas Supply and SoCalGas's Gas Acquisition. The CPUC requires these divisions to fill their gas storage capacity to specified levels before the start of winter and to maintain gas storage capacity at specified levels as winter progresses to ensure core reliability.[55,56] For PG&E's Core Gas Supply, these requirements extend to filling the storage capacity it is required to purchase from ISPs under the Natural Gas Storage Strategy.

The role of the ISPs has evolved over time, and their services became more critical to gas system reliability in Northern California with the CPUC's approval of PG&E's Natural Gas Storage Strategy in 2019. For *White Paper Part II*, Staff conducted further analysis of ISP contracting practices to determine if they may have caused or contributed to the high gas costs PG&E incurred for core customers.

The ISPs include Wild Goose (75 Bcf), Lodi (31 Bcf), Gill Ranch (20 Bcf), and Central Valley (11 Bcf). Wild Goose and Lodi are both owned by Rockpoint Gas Storage. Together, the Rockpoint Gas Storage facilities make up over 77 percent of total ISP inventory capacity. All the ISPs are located in Northern California, so their operations do not directly impact the SoCalGas service territory.

While Staff cannot disclose confidential, market-sensitive materials, Staff's analysis raises questions about whether the ISP market remains competitive in a context in which PG&E's Core Gas Supply is required to purchase large amounts of ISP storage.

Historical Regulation of Independent Storage Providers

As California's natural gas market evolved in the 1990s, the CPUC sought to encourage competition and investment in gas storage while balancing reliability and ratepayer protection. Beginning with their initial approval in 1993, a series of decisions established a new regulatory framework for independent storage providers. The CPUC allowed ISPs to charge market-based rates and reduced regulatory oversight where the CPUC deemed competition was sufficient, while the CPUC continued to regulate safety, reliability, and

[55] For PG&E, the November 1 storage minimum is set to 90 percent of total inventory capacity and gas Schedule G-CFS, Sheet 3 identifies summer and winter storage targets. See https://www.pge.com/tariffs/assets/pdf/adviceletter/GAS_4170-G.pdf (approved February 10, 2020); https://www.pge.com/tariffs/assets/pdf/adviceletter/GAS_4271-G.pdf (approved July 29, 2020).

[56] The November 1 target for SoCalGas core customers (excluding wholesale core) is 80.025 Bcf, see SoCalGas Advice Letter 5899-G, p. 2, approved by the CPUC's Energy Division on December 20, 2021: https://tariffsprd.socalgas.com/scg/filings/content/?utilId=SCG&bookId=GAS&flngStatusCd=Approved. In D.97-06-061, OP 13, the CPUC required SoCalGas to identify January-March month-end minimums, which it does in its annual Winter Technical Assessments.

rate discrimination in the gas storage industry.[57] Market-based pricing relies on competitive markets to ensure reasonable prices, moving away from the regulated, "cost-plus" rates charged to core customers by PG&E and SoCalGas, which are based on costs plus a rate of return rather than a market rate.

The new framework reflected a shift toward a more open gas market where ISPs could meet demand for storage, facilitating access to diverse gas supplies and lowering costs through competition. The CPUC also intended to promote investment in competitive gas storage facilities and achieve other policy goals, such as ensuring adequate, reasonably priced, stable, and reliable gas supplies.[58]

In 1997, the CPUC authorized Wild Goose to be the first public utility ISP, allowing it to develop and operate an independent natural gas storage facility.[59] The decision emphasized promoting competition in the natural gas market while ensuring that ratepayers were not exposed to undue risks. Unlike utility-owned storage, Wild Goose was not subject to traditional rate regulation, as it was deemed to be operating in a competitive market. However, the CPUC acknowledged that if protecting core customers had been a concern, it could have imposed restrictions on Wild Goose's contracts to safeguard customers.[60]

Wild Goose was followed into the market by Lodi in 2000, Gill Ranch in 2009,[61] and Central Valley in 2010.[62] The CPUC's decision on Lodi concluded that the ISP lacked market power based on three factors: Lodi was new to the California gas storage market, had no initial customer base, and lacked the ability to drive other utilities out of the market.[63, 64]

PG&E's Natural Gas Storage Strategy

In its 2017 Gas Transmission and Storage Rate Case Application (A.17-11-009),[65] PG&E requested approval of its Natural Gas Storage Strategy, aiming to address increasing storage costs due to new

57 D.93-02-013, 1993 Cal. PUC LEXIS 66 at *16 ("[t]here is a need for unbundled storage service, and a 'let the market decide' policy is the best way to serve that need"),* 44, *47-*49.

58 D.93-02-013 Finding of Fact 8, 1993 Cal PUC LEXIS 66 at * 82.

59 D.97-06-091 (Wild Goose Storage CPCN), 1997 Cal PUC LEXIS 503, Finding of Fact 11 at *28 - * 29, Conclusion of Law 1 at *33- *34 (conditioned upon successful environmental review).

60 See D.97-06-091, 1997 Cal. PUC LEXIS 503 at * 11 - * 12, * 13

61 D.09-10-035: https://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/109277.PDF.

62 D.10-10-001: https://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/125051.PDF

63 D.00-05-048 Decision Granting Lodi Gas Storage, LLC a Certificate of Public Convenience and Necessity to Construct and Operate an Underground Natural Gas Storage Facility and Ancillary Pipeline, and to Provide Firm and Interruptible Storage Services at Market-Based Rates

64 D.10-10-001 (Central Valley Gas Storage CPCN), p. 28, citing D.00-05-048 at 38–39.

65 PG&E's 2019 Gas Transmission and Storage Application, A.17-11-009: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M198/K890/198890109.PDF

regulatory requirements.[66] A key element of the Natural Gas Storage Strategy was PG&E's proposal to exit the commercial storage market and transition to reliability-based operations, by: 1) selling or decommissioning two of its smaller gas storage fields, Los Medanos and Pleasant Creek, to concentrate resources on core customer needs; 2) converting the classification of 51 Bcf of gas at McDonald Island from working gas to base gas to boost withdrawal capacity; and 3) contracting with the ISPs for core storage to meet its core customer needs, thereby reducing the need for capital-intensive investments in its own infrastructure.

D.19-09-025 approved many components of the proposal, reasoning that using newer ISP storage fields could provide a cost-effective storage solution compared to investing in PG&E's own, older storage facilities. The decision found that contracting with ISPs would enable PG&E to meet its storage needs without incurring the high costs associated with upgrading and maintaining its own storage infrastructure under evolving regulatory requirements from the California Geologic Energy Management Division (CalGEM). PG&E sold the Pleasant Creek storage field in 2025[67] but withdrew its request to close Los Medanos due to evolving federal and state regulations.[68]

The decision also approved a Reliability Standard that includes the amount of gas supply sufficient to meet core demand on the coldest day in 10 years, which is currently 2,595 MMcfd.[69] Of that demand, the original Natural Gas Storage Strategy decision found that 307 MMcfd would come from PG&E's storage fields, 1,213 MMcfd would be supplied by interstate pipeline capacity, and the remaining supply would come from the PG&E Citygate and the ISPs' storage facilities.[70] While the specific amount of withdrawal capacity that Core Gas Supply must obtain from the ISPs is confidential, the ISPs agreed that they could provide up to 863 MMcfd to core in a Memorandum of Understanding approved in the proceeding.[71] Therefore, the ISPs know, within a relatively narrow range, how much storage capacity PG&E's Core Gas Supply must procure.

Analysis of Independent Storage Provider Contracts

As noted above, California ISPs—including Wild Goose, Lodi, Central Valley, and Gill Ranch—operate under CPUC-approved tariffs that allow them to charge market-based rates for storage services consistent with regulatory guidelines. The CPUC allowed ISPs to set their own tariff ceilings, reasoning at the time that

[66] The California Geologic Energy Management Division (formerly the Division of Oil, Gas, and Geothermal Resource or DOGGR) initiated a rulemaking in 2016 to increase the safety of gas storage fields in the aftermath of the Aliso Canyon gas storage leak. New storage rules were issued in 2018: California Adopts Stringent Underground Natural Gas Storage Safety Rules - King & Spalding.

[67] D.25-04-032: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M565/K249/565249273.PDF. The CPUC approved the sale to Pleasant Creek Gas Storage Holdings, LLC (Pleasant Creek, LLC) and eCORP Natural Gas Storage Holdings, LLC (eCORP Holdings) conditioned on meetings CalGEM safety regulations.

[68] D.23-11-069 at 163: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M520/K896/520896345.pdf

[69] D.23-11-069, pp. 151-155: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M520/K896/520896345.pdf.

[70] D.19-09-025 p. 41 gives these requirements in thousand dekatherms (MDth) as follows: demand: 2,580; interstate pipeline supply 1,225; PG&E storage: 318.

[71] D.19-09-025, p. 78.

customers could return to PG&E or SoCalGas storage if ISP rates were too high.[72] The ISPs set their tariff ceilings at very high levels, and market rates charged by ISPs are privately negotiated between the ISP and the contracting party. ISPs have argued against making detailed information about their inventory levels public on the grounds that the information is market sensitive and disclosing it would put them at a competitive disadvantage.[73]

Each ISP offers firm storage services with guaranteed capacity, and in some cases, interruptible or short-term storage options. Charges can generally include costs for the injection and withdrawal of gas, monthly demand charges, and additional fees like fuel charges, which are often calculated based on actual usage or fixed percentages. While generally similar in structure, the exact pricing methods and service options differ across ISPs, with some offering higher charges depending on the type of service and storage demand.

Staff requested contract information from the ISPs for winter 2022-23 as well as the previous three winters (2019-20, 2020-21, and 2021-22), including details on customer names, contract lengths, injection and withdrawal variable charges ($/Dth), inventory reservation charges ($/Dth/year), and any discounts or rate variations based on time or other factors. Staff looked at winters other than 2022-23 to confirm whether any pricing issues were limited to the price spike period or occurred at other times.

The portfolio of storage contracts held by the various ISPs during winter 2022-23 contained a mix of long-term commitments and short-term arrangements, with the shorter contracts generally being more expensive. The specific information provided by the ISPs in response to Staff's data requests regarding its contracts appeared consistent with the tariffs filed with the CPUC.

Since this investigation focuses in part on the impact of high gas prices on California ratepayers, Staff analyzed contracts held by PG&E's Core Gas Supply to assess whether bundled core ratepayers were being charged competitive rates for gas storage contracts. To do so, Staff assessed whether the ISPs charged bundled core customers more than noncore customers. While it was not always possible to make apples-to-apples comparisons, the results raised questions about whether the gas storage market remains competitive given the requirements of the Natural Gas Storage Strategy and the large proportion of ISP storage capacity owned by the Rockpoint Gas Storage facilities.

Areas for Further Investigation

Staff's analysis raises questions that the CPUC may wish to investigate further. While D.93-02-013 aimed to foster competition in gas storage and assumed a competitive and diverse market would emerge, circumstances have evolved significantly since that vision was set forth in 1993. The Natural Gas Storage Strategy, which set out reliability requirements for PG&E's Core Gas Supply that did not exist when the CPUC first undertook regulation of the ISPs, has significantly changed the storage market. In today's

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[72] See, e.g., D..97-06-091, 1997 Cal. PUC LEXIS 503 at * 13.

[73] I.23-03-008 Gas Utility and Independent Storage Provider Preparations for Winter 2023-24 Workshop Report, p. 14: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M526/K147/526147574.PDF

storage market, it is public knowledge that PG&E's Core Gas Supply must purchase ISP storage, and ISPs can estimate within a range how much storage PG&E is required to purchase from them based on the terms of the Natural Gas Storage Strategy. Such information could potentially be used to price contracts with PG&E's Core Gas Supply above competitive market prices.[74]

Areas for further inquiry could include the following:

- Review ISP's ownership of storage capacity, contract pricing, and market concentration;
- Evaluate whether current ISP tariff structures protect ratepayers from excessive pricing in light of the updated review of storage markets;
- Adopt requirements for ISPs to publicly report daily inventory levels, which could provide prospective customers with more leverage when negotiating new ISP contracts; and
- Undertake a cost-of-service study to determine if the rates charged by ISPs are justified (such as by comparing their rates to actual long-run marginal costs) and reflect a competitive market or an imbalance in market power.

[74] See D..93-02-013, 1993 Cal PUC LEXIS 66 at * 49.

Impacts of Gas Prices on Electricity Costs and Rates

White Paper Part I reported some initial data showing correlations between gas and wholesale electric prices, which surged as gas prices spiked in winter 2022-23. *White Paper Part II* expands Staff's analysis and findings on electric cost impacts from high natural gas prices.

Background on CAISO Electricity Markets

California's primary wholesale electricity market is operated by the California Independent System Operator (CAISO), which is regulated by the Federal Energy Regulatory Commission (FERC).

The CAISO market covers much of California, and in 2022, CAISO purchases supplied about 81.3 percent of California's electricity demand. However, the CAISO footprint excludes the following parts of California, representing the remaining 18.7 percent of load:

- Multi-jurisdictional utilities in the north and east (i.e., PacifiCorp., Bonneville Power Administration, and Liberty Utilities, previously owned by NV Energy);
- Los Angeles Department of Water and Power (LADWP), as well as Burbank and Glendale, which are operated as part of the LADWP Balancing Authority Area (BAA);
- Municipal utilities within the Balancing Area of Northern California (BANC), the largest of which is the Sacramento Municipal Utilities District (SMUD);
- Imperial Irrigation District (IID); and
- Turlock Irrigation District (TID).

Within CAISO, CPUC-regulated entities purchased about 88.6 percent of the energy to meet retail load.[75] CPUC-jurisdictional load serving entities participating in the CAISO market include the three major electric IOUs (PG&E, SCE, and SDG&E), energy service providers serving direct access customers, and community choice aggregators (CCAs). Non-CPUC-jurisdictional entities participating in the CAISO include various municipal utilities, such as Silicon Valley Power; Northern California Power Agency (NCPA); and the cities of Anaheim, Pasadena, Riverside, and Vernon, among others.

[75] This report focuses on energy usage to serve load in 2022 because the focus of this report is the gas and electricity market disruptions that began in late 2022.

Gas-Fired Resources in CAISO

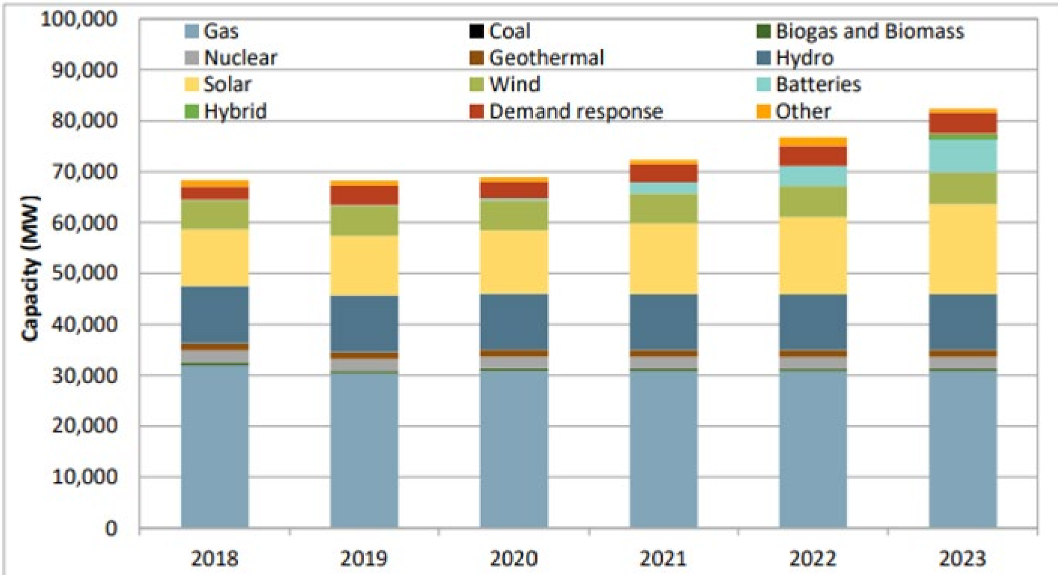
All load serving entities participating in the CAISO markets are obligated to procure sufficient electric generation capacity to meet their forecasted demand, plus a reserve margin.[76] These capacity resources are made available to CAISO through the resource adequacy program. Although they have an obligation to bid into the CAISO energy markets, they are not necessarily the resources that clear the market and are therefore dispatched to meet load. Other resources, such as imports, which are often supplied by gas-fired generation located outside the CAISO footprint, can also bid and clear in the CAISO market.

The resource adequacy resources made available to the CAISO market vary by month, but the fleet includes natural gas, hydroelectric, nuclear, geothermal, wind, solar, and imports.[77] Figure 10 below shows the maximum nameplate capacity available in the market from the resource stack on June 1 of each year. Figure 11 illustrates the average generation capacity available to meet CAISO load, by month, in 2022. Together, Figures 10 and 11 illustrate that even while the CAISO system relies on considerable amounts of renewable energy (as California has significantly expanded installed capacity from clean, non-gas fired resources) it still uses substantial quantities of gas-fired generation to meet demand. Overall, natural gas supplies the largest total capacity by fuel type.

[76] Load serving entities are entities that serve the electricity demand of their customers (i.e., their load) by making purchases of energy to meet their customers' electricity needs. In total, 38 load serving entities must meet certain CPUC resource adequacy and integrated resource planning and procurement obligations. However, the CPUC oversees electric procurement practices more broadly for only PG&E, SCE, and SDG&E.

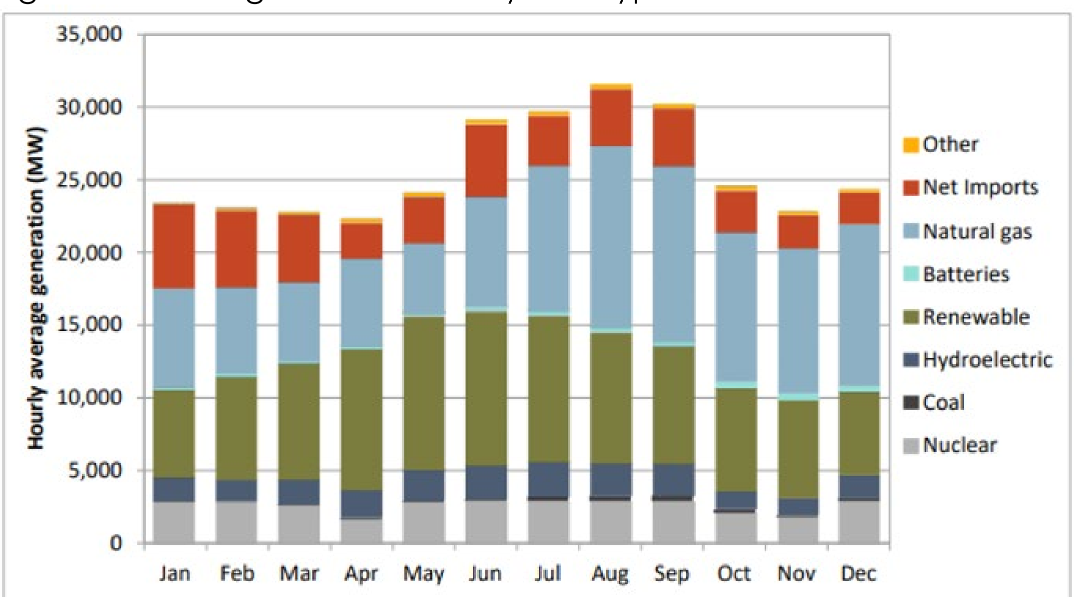
[77] Not all renewable resources are available on demand. Some generation is intermittent depending on the time of day, weather, or water supply. For example, solar and wind resource availability depends on the time of day and the weather, and hydroelectric availability depends on the time of the year for run-of-river hydroelectric resources and water storage capability and water storage levels for hydroelectric resources associated with dams.

Figure 10: Capacity By Fuel Type and Year (as of June 1 of each year)[78]



Source: CAISO Department of Market Monitoring

Figure 11: Average Generation by Fuel Type in 2022[79]



Source: CAISO Department of Market Monitoring

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[78] CAISO, 2022 Annual Report on Market Issues and Performance, available at 2022-annual-report-on-market-issues-and-performance-jul-11-2023.pdf, p. 15, Figure E-9.

[79] CAISO, 2022 Annual Report on Market Issues and Performance, available at 2022-annual-report-on-market-issues-and-performance-jul-11-2023.pdf, p. 26, Figure 1.6.

Since wind, solar, and hydro sources have intermittent availability, the CPUC and CAISO derate their nameplate capacity to get a "net qualifying capacity" (NQC) that is counted towards meeting resource adequacy requirements. The NQC represents the ability of the resource's capacity that can be relied on to meet demand during a variety of stressed system conditions, in accordance with accreditation and accounting rules applicable during a given compliance year. Table 1 below shows the fuel mix of resource adequacy resources that were available during stressed system conditions in 2022.[80] As shown in the table, gas-fired generation accounted for 58 percent of the resource adequacy capacity available. This table does not include imports, which could also be gas-fired, and takes into account the fact that variable resources like wind, solar, and hydro capacity values are derated to reflect their actual contribution to system reliability.

Table 1: Resource Adequacy Capacity by Resource Type

Resource Type	Total RA Capacity	Percent of Total
Gas Units		
Gas-fired generators (Must offer)	19,415	39%
Use-limited gas units	9,010	18%
Subtotal	28,425	58%
Imports and Non-Gas Units		
Other generators (Must offer)	1,489	3%
Imports	3,171	6%
Imports-MSS	273	1%
Hydro generators	5,335	11%
Nuclear generators	2,774	6%
Solar generators	2,036	4%
Wind generators	1,141	2%
Qualifying facilities	876	2%
Demand response (PDR)	417	1%
Storage	2,774	6%
Other non-dispatchable	679	1%
Subtotal	20,965	42%
Total	49,390	100%

Source: CAISO

[80] The resource adequacy program is meant to ensure that the CAISO has sufficient resources *under contract* for it to reliably operate its system.

Using the resource stack that is available to the CAISO at any given time, the market is cleared based on bids from available supply necessary to meet total demand. All resources that clear the CAISO markets are paid a single market clearing price, which is set by the highest priced bid taken from the last (marginal) resource dispatched to meet load.

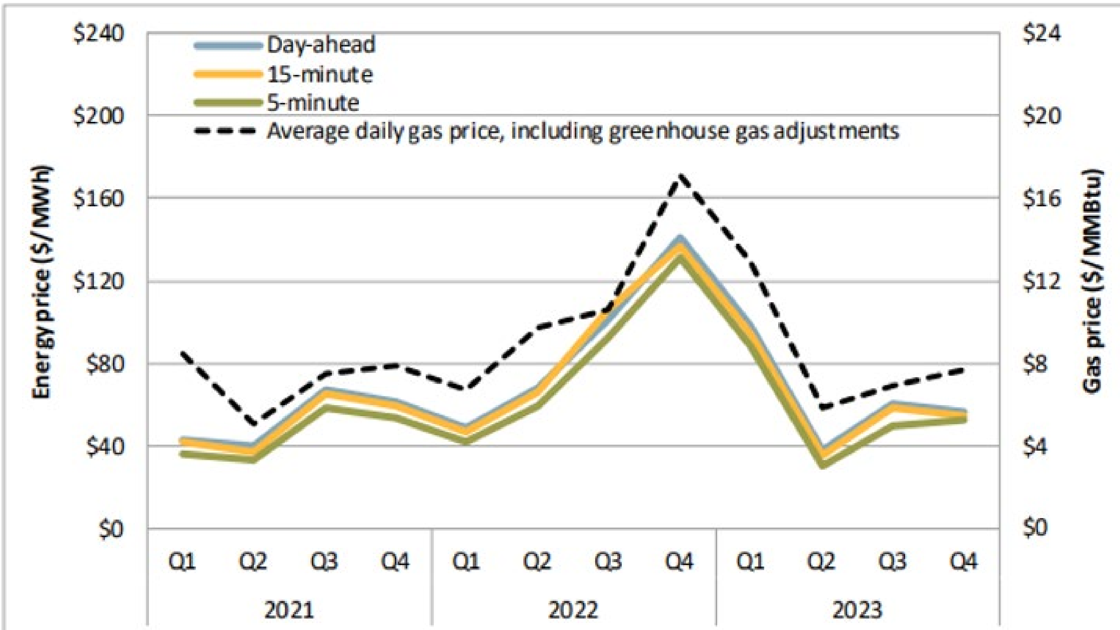
Historically, and in 2022, gas resources were often the marginal resource that set the CAISO market clearing price. In addition to gas being the largest resource by fuel-type, as illustrated in Figures 10 and 11, other reasons gas-fired generation is the marginal resource include:

- Many resources are unable to respond to price signals (e.g., nuclear) and self-schedule into the market;
- Many resources have very low marginal costs (e.g., wind or solar resources) and bid as price-takers in the market (so that they do not set the marginal bid cost);
- Many renewable resources are intermittent and not available during certain times of the day or year; and
- Hydro resources often bid to ensure dispatch during the highest price periods and, through the use of opportunity cost bidding,[81] indirectly tie themselves to the costs of running natural gas units, which are typically marginal during the high-priced periods.

As a result of the fact that the marginal unit is often a natural gas-fired generator, the price of natural gas is a critical component in the CAISO market. There is typically a clear correlation between gas prices and electricity prices, such that when natural gas prices rise, electricity prices also rise and vice versa. This correlation is illustrated in Figure 12, which shows average quarterly gas and energy prices across all three CAISO energy markets, the day-ahead, 15-minute, and five-minute markets.

[81] Opportunity costs are the potential benefits that are given up by choosing one option over another. Resource owners of hydro assets typically want to release the water and generate the power during the highest price period of the year. In the CAISO, hydro assets are allowed to use opportunity cost bidding, bidding at prices they expect to see during the high summer price period in order to ensure that the limited resource is not used during lower priced periods, such as the spring.

Figure 12: Comparison of Quarterly Gas Prices with Load-Weighted Average Energy Prices[82]



Source: CAISO

Gas Generation and Net Imports in 2022-23

In December 2022, net electricity imports to California were much lower, while in-state gas generation was much higher, than the prior year. Staff analysis of CAISO data shows that in-state gas-fired electric generators were running at 8,000–12,000 MW, on average, in December 2021. They ran at much higher levels (10,000–14,000 MW, on average) in December 2022. Staff analysis of CAISO data also shows that net imports were fairly high in 2021 (5,000–10,000 MW, on average) but substantially lower in 2022 (2,500–5,000 MW, on average).[83] The likely primary cause for low electric imports into California in winter 2022-23 was lower hydroelectric generation in the Pacific Northwest associated with drought conditions combined with high gas prices throughout the West.

Higher in-state generation led to higher demand for gas from in-state gas-fired electric generators, exacerbating pressures on the wholesale gas market and contributing to the elevated wholesale electricity costs in December 2022 compared to other periods.

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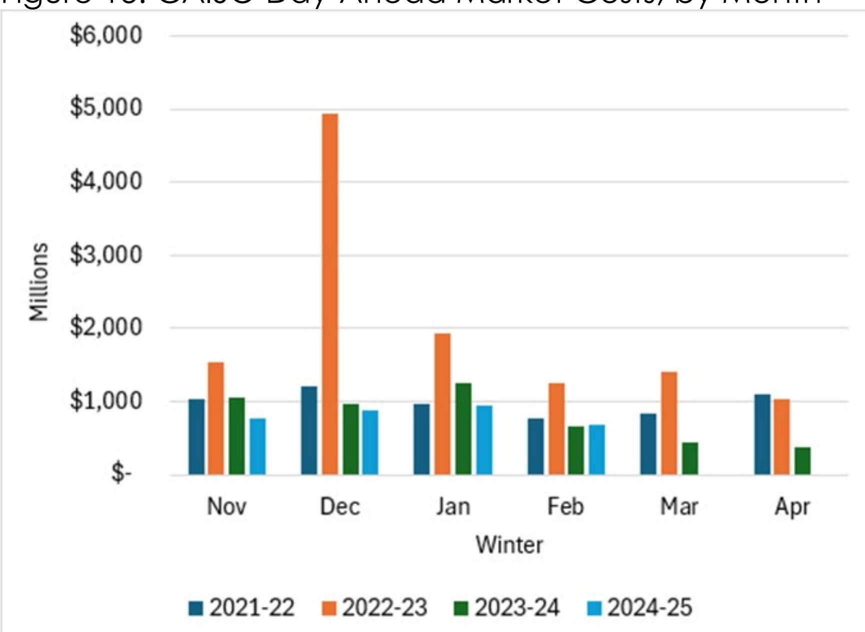
[82] CAISO, 2023 Annual Report on Market Issues and Performance, available at 2023-annual-report-on-market-issues-and-performance.pdf, p. 6, Figure E-2.

[83] CAISO, Today's Outlook, Supply Trend, available at Today's Outlook | Supply | California ISO.

Impact of Winter 2022-23 High Gas Prices on Wholesale Electric Costs

The high gas prices in winter 2022-23 increased the wholesale electric costs of serving CAISO load substantially as illustrated in the following charts and narrative. As shown in Figure 13, CAISO wholesale day-ahead market costs were $5 billion in December 2022 compared to $1 billion in December of the previous and subsequent years. Moreover, daily wholesale market costs for all months during the winter of 2022-23 were elevated compared to previous and subsequent years, as shown in Figure 13 below, due to elevated natural gas prices and their effect on the wholesale electricity market.

Figure 13: CAISO Day-Ahead Market Costs, by Month[84]

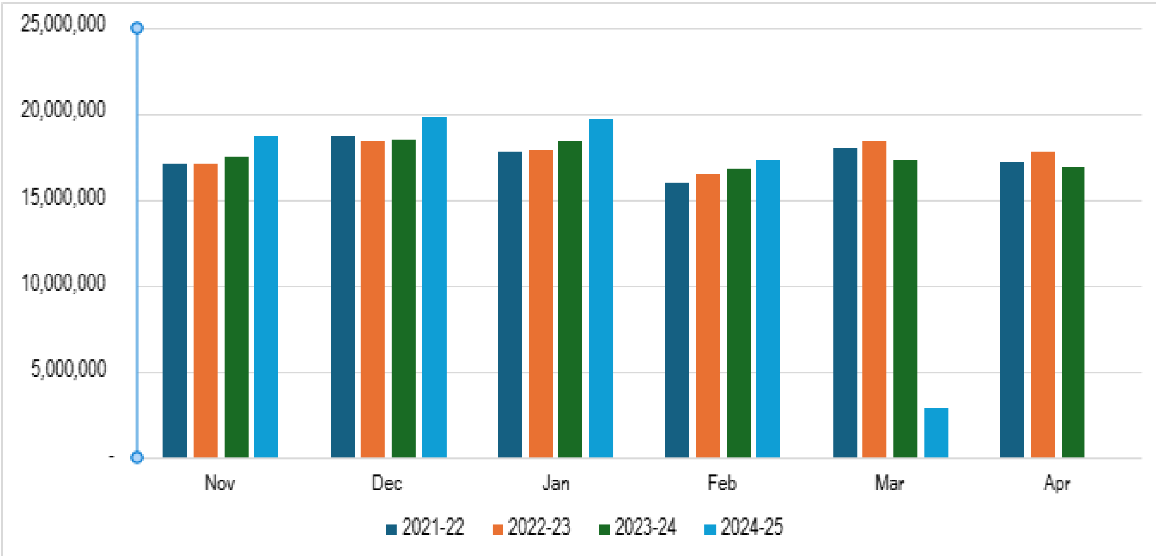


Source: CAISO OASIS

Figure 14 illustrates that wholesale market cost increases were not due to higher volumes clearing in the day-ahead market in 2022, as the total energy cleared in December 2022 was similar to previous years. Thus, winter electricity costs were high in December 2022 not because of higher-than-normal total electric usage in December but because of high electricity prices.

[84] Source: CAISO's OASIS, Energy, System, Day-Ahead Market Report, available at CAISO Demand Forecast - OASIS Prod - PUBLIC - 0.

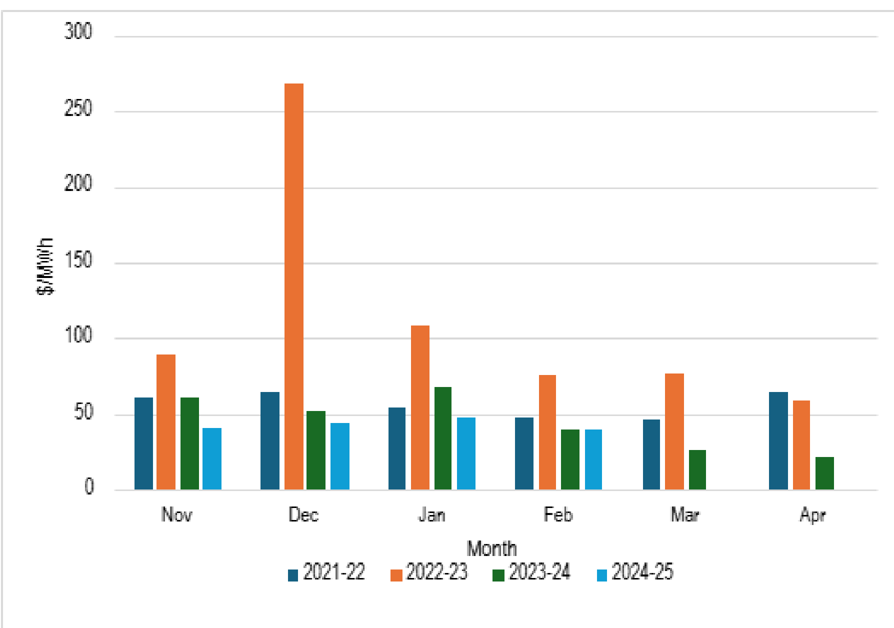
Figure 14: Total Energy Cleared in the Day-Ahead Market, by Month (in MWh)



Source: CAISO OASIS

Figure 15 shows that the monthly average of day-ahead energy prices in December 2022 (which averaged over $250/MWh) were roughly five times higher than the typical energy prices seen in prior and subsequent years ($50-60/MWh). Figure 15 also illustrates that prices in winter 2022-23 were elevated compared to previous and subsequent years in all months, not just December.

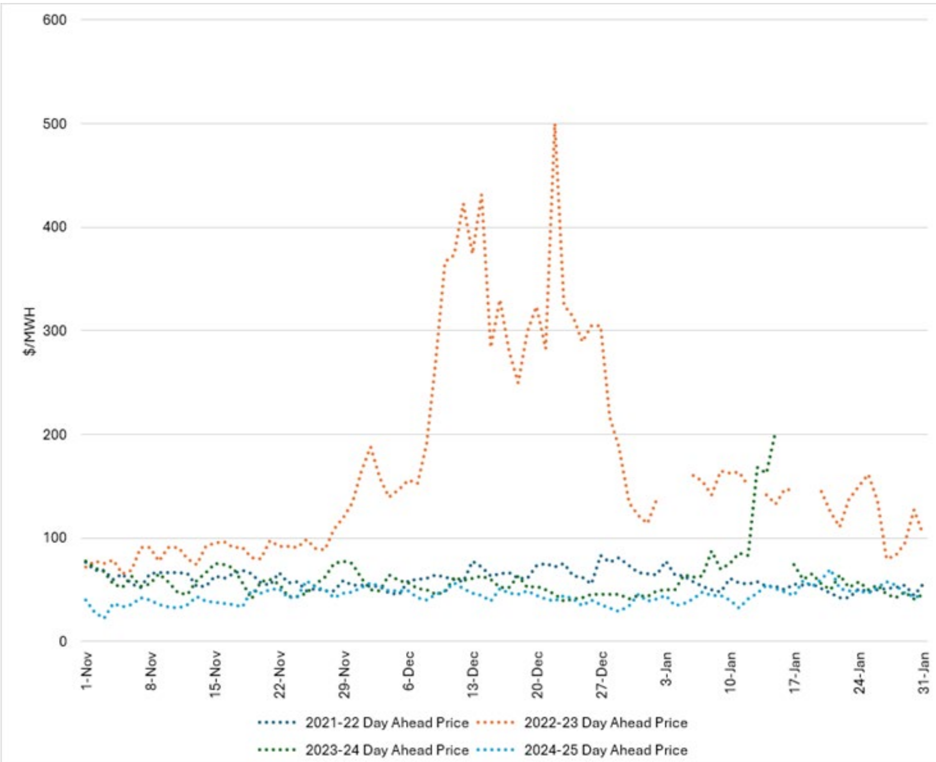
Figure 15: Average Day-Ahead Energy Prices, by Month



Source: CAISO OASIS

Figure 16 provides more granular detail of daily prices, showing average day-ahead market clearing price data. This figure illustrates the substantial and sustained increase in average daily electricity prices during the period from November 2022 through January 2023. Daily average prices peaked at $500/MWh.

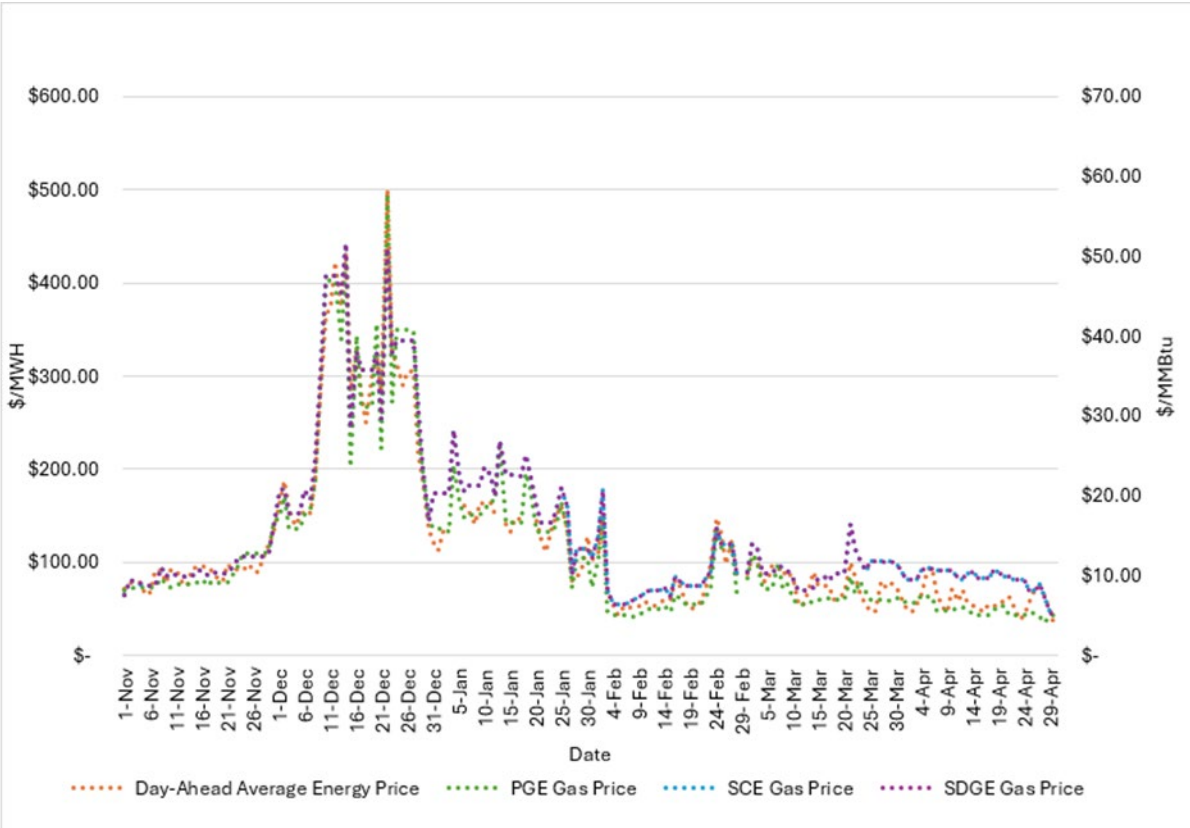
Figure 16: Day-Ahead Average Energy Prices, November–January (2021–2025)



Source: CAISO OASIS

Figure 17 shows the correlation between daily gas prices and daily energy prices during the winter of 2022-23 and demonstrates that gas prices and electricity prices and costs moved in tandem during this period.

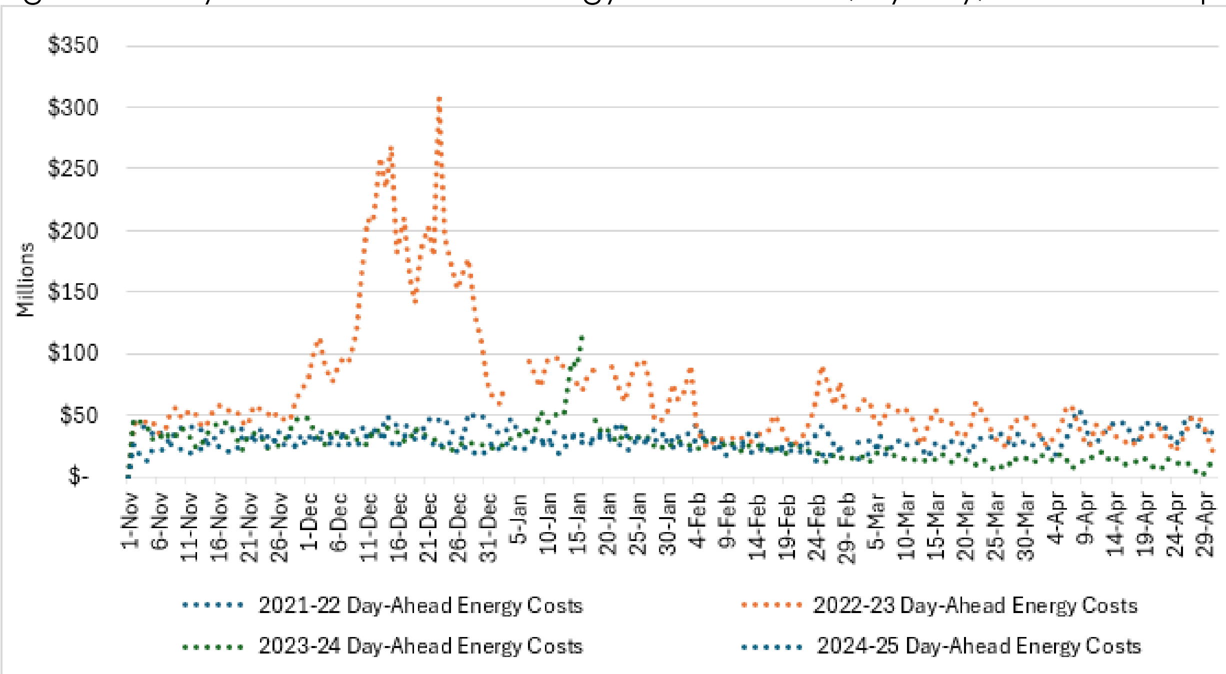
Figure 17: 2022-23 Winter Day-Ahead Market Prices and Gas Prices in Northern and Southern California



Source: CAISO OASIS

Figure 18 illustrates cost impacts of the correlation between daily gas and electricity prices, showing the increase in daily total wholesale market costs between November 2022 and April 2023 compared to historic values. Day-ahead wholesale energy costs are typically less than $50 million per day. In December 2022, these costs reached as high as $300 million per day and remained elevated through January 2023 and, to a lesser extent, in March 2023.

Figure 18: Day-Ahead Wholesale Energy Costs Cleared, by Day, November–April



Source: CAISO OASIS

The impact of the gas-electric market price correlations is illustrated by Table 3 below. Table 3 shows annual wholesale electric costs increased substantially in 2022 and 2023, from approximately $10 billion in prior years to $21.6 billion in 2022 and $14.5 billion in 2023. The extraordinary increase in 2022 was due in large part to elevated winter gas prices, although high electric demand and scarcity conditions in August and September of 2022 also had an impact. The annual wholesale electric cost to serve CAISO load in 2023 was also above longer-term trends (i.e., $14.5 billion for 2023) due to ongoing high gas and electricity prices throughout the entire winter 2022-23 as well as summer of 2023.

Table 2 Historical Wholesale Electric Costs of Serving CAISO Load (2017–2024)

Year	Wholesale Electric Market Costs ($ billions)	Annual Total Energy (GWh)	Average Wholesale Electric Prices ($/MWh)
2017	$9.3	228,191	$41
2018	$10.8	220,458	$49
2019	$8.8	214,955	$41
2020	$8.9	211,919	$42
2021	$12.6	211,020	$60
2022	$21.6	210,879	$102

Year	Wholesale Electric Market Costs ($ billions)	Annual Total Energy (GWh)	Average Wholesale Electric Prices ($/MWh)
2023	$14.5	203,268	$71

Source: CAISO

Impact of High Electricity Costs on Retail Rates

This section expands on the initial analysis presented in *White Paper Part I* to estimate residential bill impacts caused by the extraordinarily high wholesale electricity costs in the winter of 2022-23.

High electricity price events in the CAISO market (as a result of increases in natural gas prices or due to scarcity events) do not immediately increase retail residential bills. Hedging practices can mitigate the impacts to consumers of high price events. Further, the process by which electricity prices are set by the IOUs and CCAs (higher than forecasted electric procurement costs are generally collected in retail bills over the following year) can smooth the rate impacts.

Hedging

If elevated wholesale electricity prices had been fully incorporated into electricity bills in the subsequent month, electric bills would have more than quadrupled in December 2022 compared to December 2021. As it was, customers experienced increased electric bills over a longer period, rather than paying the elevated wholesale costs all at once.

Table 4 provides an illustrative example for an average residential electricity customers using 500 kWh per month, if they had been exposed to a pass-through of wholesale market prices during this time.[85]

[85] This may be a slight overestimate to the extent that customers use less energy in December and an underestimate because residential customers typically use more energy during the peak periods when prices are somewhat higher. Table 4 only shows the analysis of the effects of the CAISO electricity market and does not include costs associated with transmission, distribution, and public purpose programs or the costs associated with generation capacity. Rates remained elevated in other winter months and would have increased rates and bills in those months as well, but staff does not illustrate that effect here.

Table 3: Illustrative Bill Impact for an Average Residential Customer of Historical Wholesale Electric Costs

Year	Wholesale Electricity Rate ($/kWh)	Average Monthly Usage (kWh)	Illustrative Wholesale Electric Cost for Average Customer ($/MWh)
December 2021	$0.06	500	$30
December 2022	$0.26	500	$130
December 2023	$0.052	500	$26
December 2024	$0.04	500	$20

Source: Staff analysis based on CAISO data.

Table 3 above illustrates how high gas prices could have impacted customer costs if load-serving entities did not utilize hedging practices, such as owning generation or locking in long-term contracts at fixed prices.[86] Hedging practices by the utility can act as insurance to mitigate the impact of gas and electric market price spikes to retail customers. Therefore, the extent to which high gas prices ultimately affect customer electricity prices and rates depends on the extent to which the IOUs and CCAs are hedged for both gas and electricity.

Owning generation or contracting for power purchase agreements provides a hedge against high gas and electricity prices. IOU ownership of resources and contracting for fixed-price power purchase contracts (usually for renewables) provides "natural" hedging value because the owned or contracted generation resources receive the market-clearing price for sales into the CAISO market. For example, if a load serving entity, such as an IOU, had a power purchase agreement for solar power and agreed to pay $100/MWh, then, during the times that the solar resource generates, the IOU would bid the resource into the CAISO market and receive the market clearing price. If the market clearing price was less than $40/MWh, the IOU would pay the solar generator $100/MWh but receive $40/MWh in market revenue, a net loss for customers. On the other hand, if the market clearing price were $200/MWh, the IOU would pay the solar generator $100/MWh but receive $200/MWh in CAISO market revenues, a net gain for customers. The owner or contractor of resources receive the market prices as revenues while their power purchase costs (or operating costs in the case of resource ownership of non-gas-fired resources) remain unchanged.

IOUs that contract for natural gas resources, usually as tolling contracts[87], will sometimes buy natural gas price hedges to mitigate the impact of natural gas price spikes. Such hedges are paid for as insurance by

[86] For IOUs, electric procurement hedging practices are regulated by the CPUC in accordance AB 57 (Wright, 2022).

[87] A tolling contract allows an entity to bring the natural gas to the gas generating facility and then retain the energy output.

bundled customers. IOU procurement practices, including hedges, are subject to CPUC regulation via bundled procurement plans. CCA and ESP procurement practices, including hedges, are subject to the individual discretion of the governing bodies of each entity.

The amount and value of hedging may be limited in winter months, for several reasons. First, since high electricity prices typically occur during the summer, load serving entities generally hedge less during the winter, when lower loads are expected. Second, the value of these "natural" hedges is often lower in winter because hydroelectric generation is likely to be lower during early winter months, solar generates only during the middle of the day (when loads and prices are typically lower than peak), and total solar resources are significantly reduced over the winter. Third, utility-owned gas-fired resources provide little hedging value if gas prices or demand are higher than usual (as in the winter of 2022-23), because the increased fuel costs are passed on to ratepayers.

Energy Resource Recovery Account Forecast Process and Trigger Applications

Wholesale electricity prices are not immediately passed through and collected in retail rates, so it necessary to review their effects on retail rates over a longer period.

The IOUs generally forecast fuel and purchased power costs in the year before the forecasted costs are included in rates, through the Energy Resource Recovery Account (ERRA) proceedings. The ERRA proceeding includes all of the costs of procurement, as well as all of the revenues. The utility maintains a diverse portfolio of power purchase agreements, utility owned resources, and hedges that have a range of contract terms and prices. To set the ERRA forecast that becomes the generation rate for bundled customers, the utility compares its entire portfolio's expected costs (from contracts) against the expected revenues (from the market). To the extent that the utility's approved estimates are too low, these under-collections are generally not added to rates until the following year (i.e., the year following the year the higher costs were actually incurred). However, if the forecast deviates by a large amount, the IOUs must submit an "ERRA trigger" application to determine if the IOUs should true-up the rates sooner.[88] CCAs typically, although not always, set their generation rates in relation to the IOUs rates. Thus, the CCAs may also carry over- or under-collections to the next year.

The IOUs did not anticipate the unusually high December 2022 electricity prices when they updated their ERRA applications in November, nor did they forecast high electricity prices for 2023. Both SCE and PG&E filed ERRA trigger applications in 2023 due to the unexpectedly high prices. SDG&E did not increase its generation rates through an ERRA trigger application in 2023. It is therefore difficult to discern the retail rate effect of high wholesale electricity costs in 2022 on SDG&E's customers.

[88] IOUs submit ERRA trigger applications when the under- or over-collection balance exceeds 4 percent, the balance is forecast to exceed the 5 percent threshold, and the balance is not expected to self-correct within 120 days. The CPUC then considers whether the IOUs should begin amortizing the under- or over-collection sooner than the following year.

SCE's ERRA Trigger Application and Clean Power Alliance Rate Increases

As summarized in *White Paper Part I,* on January 31, 2023, SCE filed an ERRA trigger application with the CPUC (A.23-01-020). SCE requested authority to increase bundled service customer generation rates by $595.615 million based on its forecasted balance through April 30, 2023.[89] In its testimony, SCE explained that the ERRA trigger application and under-collections "result from significantly higher wholesale power and natural gas prices that materialized in December 2022, relative to what was forecast."[90] SCE also requested flexibility in the amount to be placed into rates "because wholesale power and natural gas prices have been exceptionally volatile in recent months."[91]

The CPUC approved SCE's request in D.23-04-012 (April 6, 2023) including a 12-month amortization period beginning June 1, 2023. On May 15, 2023, SCE filed Advice Letter 5036-E to recover $454 million over a 12-month period from its bundled service customers, and the CPUC's Energy Division approved this request consistent with D.23-04-012.

Table 4 below shows the estimated effects of the gas market disruptions on SCE bundled service residential customers of through the rate change, which resulted in a 3 percent rate increase overall. SCE bundled service residential customers experienced a 1 cent per kWh increase over 12 months, amounting to a bill increase of $5 per month (for non-CARE residential customers) or $60 over the 12-month amortization period.

Table 4: SCE Estimated Bundled Service Customer Rate and Bill Impacts (for the 12 months, beginning June 1, 2023)

Bundled Average Rates (¢/kWh)				
Customer Group	**Current Rates**	**Proposed Change**	**Proposed Rates**	**% Change**
Residential	31.4	0.96	32.4	3.1%
Lighting - Small and Medium Power	27.7	0.93	28.6	3.3%
Large Power	19.4	0.76	20.2	3.9%
Agricultural and Pumping	23.3	0.82	24.1	3.5%
Street and Area Lighting	31.6	0.55	32.2	1.7%
Standby	16.9	0.74	17.6	4.4%
Total	**26.1**	**0.88**	**27.0**	**3.4%**

Residential Bill Impact ($/Month)				
Description	**Current**	**Proposed Change**	**Proposed**	**% Change**
Non-CARE residential bill	$ 164.38	$ 5.02	$ 169.40	3.1%
CARE residential bill	$ 111.28	$ 3.40	$ 114.68	3.1%

Source: SCE Advice Letter 5036-E.

89 SCE ERRA Trigger Application, A.23-01-020, p. 2, available at Microsoft Word - 2023 ERRA Trigger Application_combs 1-27.docx.

90 SCE, Testimony in Support of Expedited Application of Southern California Edison Company (U 338-E) Regarding Energy Resource Recovery Account Trigger Mechanism," A. 23-01-020, January 31, 2023, p. 11.

91 SCE Application, A.23-01-020, p. 2.

While the CPUC does not have direct insight into when and why CCAs change rates, one of the CCAs in SCE's service territory, Clean Power Alliance, which serves 33 cities and unincorporated areas in Los Angeles and Ventura counties, increased its residential (domestic) rates by approximately 3 cents per kWh effective April 1, 2023, and again by over 1 cent per kWh effective July 1, 2023.[92]

PG&E's ERRA Trigger Application

PG&E filed an ERRA trigger application with the CPUC on July 28, 2023 (A.23-07-012). PG&E forecasted an under-collection balance of $256 million (in addition to revenue fees and uncollectibles) and requested approval to increase rates in November 2023 and to amortize the balance over six months.[93] In its application, PG&E explained that the "primary cause of PG&E's forecasted under-collection is higher than forecasted market power and natural gas prices from this past winter that resulted in increased net procurement costs for PG&E's bundled service customer load as well as lower May and June bundled customer revenues that further exacerbated the incremental ERRA and PABA [Portfolio Allocation Balancing Account] undercollection."[94] On December 14, 2023, the CPUC issued D.23-12-022, which approved PG&E's request to collect the ERRA undercollection in rates over a six-month amortization period.

PG&E indicated that the ERRA trigger request would increase system average rates by 1.95 cents per kWh, or approximately 6.3 percent above the current rates for the six-month amortization period. It thus appears higher gas and electric prices increased PG&E electric rates by 2 cents per kWh or 6 percent over the six-month amortization period, which is roughly consistent with SCE's request for a 1 cent per kWh increase over the 12-month period.

Again, while the CPUC does not have direct insight into when and why CCAs change rates, one of the largest CCAs in PG&E's service territory, now called Ava Community Energy, ties its rates to PG&E's and thus its customers may have experienced similar rate increases for this reason.

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92 Comparing Clean Power Alliance "Residential Rates as of July 2022 – October 2022 Update," to "Residential Rates as of April 2022," and "Residential Rates as of July 2023" (for communities enrolled in 2019-202), available at Residential Rates - Clean Power Alliance. See, for example, DOMESTIC rates effective as of July 1, 2022 at 10.496 cents per kWh for Lean Power, 10.804 for Clean Power, and 11.727 cents per kWh for 100 percent Green Power compared to DOMESTIC rates effective April 1, 2023 of 13.802 cents per kWh for Lean Power, 14.207 for Clean Power, and 15.421 cents per kWh for 100 percent Clean Power and DOMESTIC rates effective July 1, 2023 of 15.093 cents per kWh for Lean Power, 15.429 cents per kWh for Clean Power and 16.776 for 100 percent Green Power.

93 PG&E, "Expedited Application of Pacific Gas and Electric Company (U 39 E) Regarding Energy Resource Recovery Account Trigger Mechanism," A.23-07-012, July 28, 2023, p. 2, available at Microsoft Word - clean_A.23-07-XXX_PGE 2023 ERRA Trigger Application_7-28-23_Formatted_.docx.

94 Id. At 3.

Technical Appendix: Electric Market Modeling and Analysis

Staff performed further technical analysis to confirm our earlier findings about reasons for high electricity prices in winter 2022-23. Using statistical methods helped Staff identify gas prices in SoCalGas area as the main driver of high electricity prices, rule out other potential options, and demonstrate correlation between gas pricing in both major areas of California and electricity pricing trends in CAISO. While the preceding sections of the report supported general findings on the relationship between gas prices and electricity prices during winter 2022-23, this Technical Appendix adds context and granularity to the prior findings by using different methods and some additional data. The analysis and conclusions below are presented separately from the information covered above for clarity.

In this study, staff performed several different analyses:

1. An analysis of Implied Market Heat Rate (IMHR) in order to determine if high IMHR is caused by or points to patterns of scarcity or pricing above what would be caused by gas prices.
2. Analysis of high IMHR events, which indicate scarcity, comparing scarcity events across years
3. Profitability analysis using high IMHR in excess of real heat rate levels as the indicator of times when power plants are likely earning revenue well in excess of their costs.
4. Analysis of the correlation in energy prices and gas prices in PG&E and SoCalGas territories to further confirm if high gas prices led to high electric prices or if high electric prices can be tied to some other factor.
5. Analysis of volatility in gas and electric prices and risk of cost increases to determine the cost of this volatility for ratepayers. Staff assessed Value at Risk (VaR) and Conditional Value at Risk (CVaR) to evaluate the magnitude of risk to cost increases caused by the price volatility. Staff also show a breakdown of price distributions over the winters before and after 2022-23.
6. Other statistical tests such as T-tests, to determine if the correlations observed were not random but statistically significant.

Background

Staff performed an analysis of IMHR in PG&E and SCE areas across peak and non-peak hours. The IMHR was calculated as a ratio of electricity prices to gas prices and yielded the implied heat rate (fuel efficiency of the power plant setting the electricity price) that was implied by the market prices during the study period. For example, the IMHR exceeded the realistic heat rate of a real generator in the market (for example above 20 MMBtu/MWh) indicating electricity prices reflect scarcity and prices above costs that are supported strictly by fuel prices. It reflects the heat rate (fuel efficiency) a power plant would need to break even at current market prices.

When IMHR values are stable, it suggests that gas and electricity prices are moving in sync. But if electricity prices rise while gas prices remain flat or fall, the IMHR increases, signaling scarcity pricing or other market inefficiency. On the other hand, if gas prices rise but electricity prices do not, the IMHR drops, meaning fuel costs may not be fully reflected in electricity prices and generators may not be covering their operating costs.

In addition to simple analysis of IMHR analysis, Staff evaluated periods of scarcity when IMHR went above 20 MMBtu/MWh and assessed trends in IMHR from 2020 to 2024. Persistent values above the level needed for even older generators to break even raise questions about whether market prices are being set well above what fuel costs would justify on their own and either signal persistent scarcity in supply or bidding that is not based on costs, such as fuel costs.

Staff then used the calculated IMHR values to assess implied profitability for typical gas generators. Staff set breakeven levels for different periods of the day based on what type of power plant would generally be expected to be setting market prices at that time of day. Staff set breakeven levels—10 MMBtu/MWh for peaker units during peak hours and 7 MMBtu/MWh for combined cycle units during off-peak—to provide a rough idea of whether these generators would be earning profits or operating at a loss in a given hour.[95] These breakeven points represent typical heat rates of existing generating units operating in California, and reflect that in the peak periods in the evening, more expensive power plants like combustion turbines would set the price and in less stressed times, such as middle of the day, less expensive combined cycle plants with lower heat rates would be setting prices.

Third, Staff examined the correlation between gas and electricity prices in SCE and PG&E areas. In most periods, electricity prices are influenced by a mix of factors. But in winter 2022-23, that correlation between gas and electricity prices became much stronger, showing that gas prices were the main driver of electricity prices.

Finally, Staff assessed price volatility and risk using VaR and CVaR analysis, which measure how frequently and how severely prices spike. VaR captures the worst-case single price increases at a given confidence level (e.g., 95 percent), while CVaR reflects the average magnitude of extreme events beyond the VaR threshold. These metrics help illustrate how much risk consumers faced, especially during off-peak hours, when prices are usually stable but unexpectedly surged during the 2022-23 period.

VaR and CVaR are used to measure the potential for extreme price increases across different winters. VaR captures the expected magnitude of price spikes at the 95 percent confidence interval, while CVaR estimates the average magnitude of extreme price increases in the tail of the distribution, beyond the VaR threshold.

Using winter 2022-23 as a benchmark against other winters from 2020 to 2024, and summer 2022 as a benchmark against other summers in the same periods, Staff compared it to other recent winters to see

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[95] *Thermal Efficiency of Gas Fired Generation in California, 2015 Update*, Breakeven points are set relative to Combined Cycle and Peaker plants from Table 2, Natural Gas Fired Heat Rates 2001-2014. Published by the CEC, March 2016, linked here: https://www.energy.ca.gov/sites/default/files/2021-06/CEC-200-2016-002.pdf,

whether it stood out in terms of risk or price behavior across both PG&E and SCE gas and electricity prices.

Data Sources

This analysis relies on data from CAISO OASIS, using electricity and natural gas pricing data from CAISO to assess their relationship while isolating the impact of fuel costs on energy pricing. The study calculates the IMHR and analyzes price volatility using only the energy component of CAISO Locational Marginal Prices (LMP), excluding congestion and transmission losses. By using the energy component alone, this approach captures the relationship between gas and electricity prices without the influence of transmission and congestion components.

Data is collected for PG&E (NP-15) and SCE (SP-15) regions, recognizing that CAISO's uniform pricing structure means high gas prices in one area can influence electricity costs across the market. Natural gas price indices for PG&E and SCE, adjusted for greenhouse gas compliance costs, are used to ensure accurate assessment of fuel cost impacts on electricity prices. The PG&E Gas Price (FRPGE1GHG data from OASIS) represents PG&E Citygate, and the SCE Gas Price (FRSCE1GHG) is used to represent SoCal Citygate. Gas prices are adjusted for GHG compliance costs under California's Cap-and-Trade Program.

Summary of Key Findings from Statistical Modeling

Overall, winter 2022-23 was a pivotal period for California's energy markets, marked by high volatility, shifting generator profitability, and increasing correlation between gas and electricity prices. While gas-fired power plants faced fluctuating profit margins depending on location and gas prices, non-gas generators benefited from elevated electricity prices throughout CAISO. Due to gas price volatility and energy scarcity related to weather trends, pricing trends diverged from historical patterns. This period set the stage for continued price volatility into 2023 and 2024.

Implied Market Heat Rate (IMHR), Scarcity, Profitability and Correlation Findings

Electricity prices rose in direct response to gas price increases, especially during peak hours during summer 2022. IMHR values were consistent with expected fuel cost pass-through, particularly in the SCE area, which is generally consistent with a functional electric market. IMHR was higher in PG&E's area due to lower gas prices. This is evidence that gas generators in SCE's area became increasingly likely to set the market clearing price throughout this period and generators in PG&E's area saw enhanced profitability due to high electricity prices and lower fuel prices.

The analysis of scarcity events in summer months between 2020 and 2024 shows instances where the IMHR exceeded 20 MMBtu/MWh, which is well above the efficiency range of peaker or baseload gas generators. This shows that electricity prices were tracking fuel costs as they rose and reflecting significant scarcity pricing amid broader system stress. These elevated IMHRs helped identify hours when generators could earn profit margins well above breakeven costs. High IMHR values are consistent with tight supply conditions—driven by reduced imports, operational constraints, and high demand, and/or scarcity pricing.

In contrast, summer 2022 did not exhibit unusual scarcity pricing patterns or volatility relative to other summers in the 2020–2024 period. Although prices were extremely elevated at times, IMHR remained within the bounds of historical summer behavior, suggesting that market fundamentals including gas prices were responsible for high prices in summer 2022.

Finally, this analysis is especially relevant in the context of FERC's 2021 rule change, which increased the market bidding cap from $1,000/MWh to a hard cap of $2,000/MWh. If gas was $6 MMBtu, for example, an electricity price of $1,000/MWh implies a heat rate of 166 MMBtu/MWh which is more than 16 times higher than a combined cycle plant and 23 times higher than the heat rate of a peaker. Implemented on September 30, 2021, the rule allowed prices to exceed the original cap during scarcity events, provided cost justification was submitted. As a result, some of the price volatility observed in summer 2022 may reflect structurally permitted scarcity pricing. This pattern also supports the conclusion that the elevated prices in summer 2022 were not unusual, as they remained consistent with expectations under the new market design.

Profitability (profit margin between operating costs like gas prices and revenue from electricity prices) was especially strong in PG&E's territory, where local gas prices were lower than in Southern California. Because CAISO sets a single market-clearing price across the grid, PG&E-area generators received the high prices set by marginal units in SCE's higher priced region, resulting in higher IMHRs and greater profitability. Non-gas generators (e.g., hydro, nuclear, and renewables) also benefited, as they had no fuel costs but received the same elevated market prices.

Before 2022, PG&E gas prices had only a weak correlation with overall CAISO electricity prices—for example, just 0.27 in winter 2021–22—while SoCalGas prices showed a slightly stronger relationship, around 0.43 to 0.46. Correlation of 1 equals perfect correlation. Starting in winter 2022-23, PG&E and SoCalGas gas prices became more strongly correlated, with correlation between the two increasing to 0.98, and both showed strong correlation with electricity prices during the price spikes in winter 2022-23, with significantly higher correlation than in prior years. The increased correlation between electricity prices and gas prices confirms that gas prices were the primary driver of electricity prices in both regions. This increase in correlation reflects tight West-wide gas market conditions as discussed in *White Paper Part I*.

In summer periods, similar—though smaller—increases in correlation appeared. Gas-to-electricity correlations remained moderate (0.26 to 0.44), but PG&E and SoCalGas prices began to increase and decrease in very similar patterns. Gas prices in PG&E and SoCalGas gas prices became increasingly correlated, reaching a correlation coefficient of 0.95 by summer 2024, pointing to increasing convergence in regional gas market behavior.

Volatility and Risk Findings

Volatility in both summer 2022 and winter 2022-23 made risk management and hedging strategies more complex for utilities and increased costs for ratepayers. Analysis of VaR and CVaR confirmed that winter 2022-23 was more volatile and led to higher costs due to volatility than other recent winters.

Winter 2022-23 was the most volatile period between 2020 and 2024, with significant spikes in gas prices and higher price variability than other recent winters. These extreme increases confirmed that winter 2022-23 was an outlier in terms of pricing. However, by winter 2023-24, prices declined, with mean gas prices in the PG&E service territory returning to $4.10/MMBtu—close to 2020 levels—while gas prices at the SoCal Citygate[96] dropped to $6.00/MMBtu, still slightly above winter norms but well below the 2022-23 peak. Significantly greater volatility causes an increase in potential losses for ratepayers. VaR measures the expected value of potential losses on investments or cost increases due to commodity price within a 95 percent confidence level, while CVaR expresses the total potential losses that exceed the 95 percent threshold measured in VaR. Volatility in price spikes peaked in winter 2022-23, when average VaR reached as much as $7.60/MMBtu in SoCalGas prices compared to $5.80/MMBtu in winter 2021-22 during Winter Storm Uri and around $4.00/MMBtu in other winters. By winter 2023-24, both VaR and CVaR dropped significantly, indicating a return toward stability. PG&E's VaR fell back to $2.30/MMBtu—its 2020 level—while SoCalGas VaR dropped to $4.00/MMBtu, still slightly above pre-2022 levels.

Similar to gas prices, winter 2022-23 was the most extreme period for energy price spikes since the energy crisis of 2000-01. Off-peak energy prices spiked significantly, reaching $27.90/MWh, while peak-hour prices increased to $64.40/MWh, confirming that sharp price swings were more likely and more severe than before.

Implied Market Heat Rate and Scarcity Pricing Events Analysis

IMHR is a key measure of how electricity prices compare to natural gas prices, with a high IMHR indicating a disconnect between natural gas prices and electricity prices, often driven by factors such as transmission constraints, bidding behaviors, or scarcity conditions. A low IMHR indicates a relatively efficient market, where electricity prices closely reflect underlying fuel costs. IMHR also helps assess the profitability of gas-fired power generation and can also reveal potential market inefficiencies. Staff assess IMHR across winters and summers between 2020 to 2024 and analyzed the trends to see if gas prices electricity prices or if other factors could be determined.

During winter 2022-23, electricity prices surged across California, particularly in the PG&E and SCE service areas. PG&E's IMHR was consistently higher than SCE's, mainly because gas prices were frequently lower

[96] The PG&E and SoCalGas Citygates are gas commodity trading hubs inside California. In general, a citygate is any point at which the backbone transmission system connects to the distribution system. The citygate is not one specific, physical location; rather, it represents a virtual trading point on the natural gas system.

in PG&E's territory. Since electricity prices are set uniformly across the state, lower fuel costs in PG&E's service territory allowed generators located there to gain higher profit margins compared to generators operating in SCE's area.

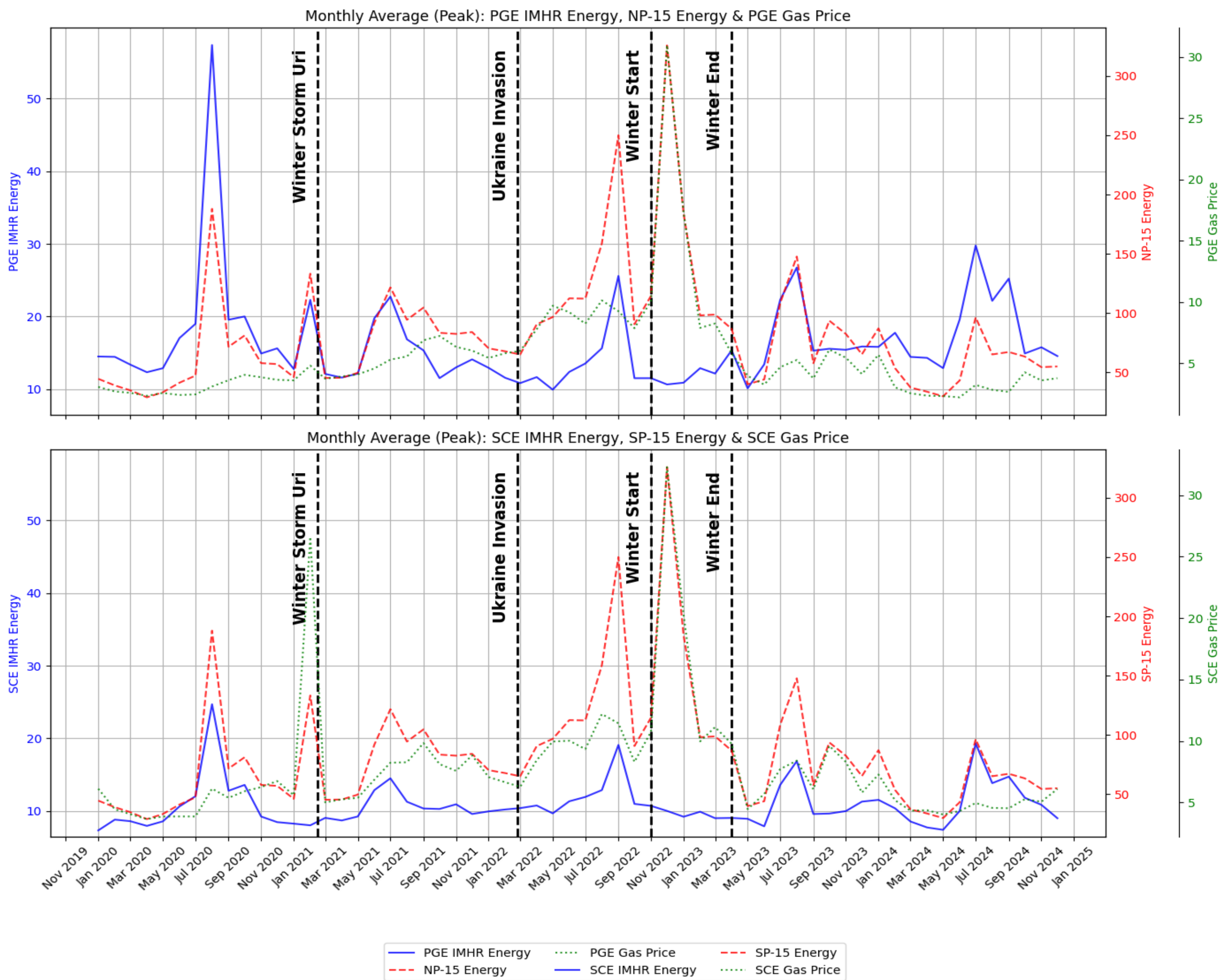
In both peak and off-peak hours, IMHR became volatile after winter 2022-23, reflecting the market's sensitivity to gas price fluctuations. Figure 19 shows monthly average energy prices during peak electric hours (Hour Ending 17:00-22:00 on weekdays) alongside natural gas prices for PG&E (top) and SCE (bottom). The blue line represents IMHR, the red dashed line shows NP-15 or SP-15 energy prices, and the green dotted line tracks gas prices either at PG&E Citygate for NP 15 or SoCal Citygate for SP-15. Key events, including Winter Storm Uri, the invasion of Ukraine (Feb 2022), and winter 2022-23 are marked with vertical black lines.

The volatility observed in this graph affected generator profitability, with PG&E plants generally faring better than SCE's due to their lower gas costs. However, non-gas power plants (such as hydro, nuclear, and renewables) also benefited during this period, as they were able to sell electricity at the same high market prices without incurring the rising fuel costs.

Staff compared IMHR and pricing trends only for PG&E and SCE and did not analyze the SDG&E region market prices due to unavailability of data. Throughout 2020 through 2024, IMHR was lower in SCE's area than PG&E's, suggesting that gas generators in SCE's area were generally setting the price across the CAISO balancing area. Additionally, in the summer of 2020 through 2023, Aliso Canyon gas storage inventory limitations and the Aliso Canyon Withdrawal Protocol were still in effect, and noncore customers, including electric generators, had no direct access to gas storage in Southern California until September 2023.

Before the invasion of Ukraine, IMHR was moderate but exhibited seasonal peaks, with notable spikes in summer 2020 and February 2021 during Winter Storm Uri. Besides a spike in prices in summer 2020, summer 2022 saw a sharp IMHR increase, exceeding 25 MMBtu/MWh in PG&E and nearing 20 MMBtu/MWh in SCE—far above typical generator efficiency. This suggests scarcity pricing rather than the use of older or less efficient power plants. PG&E's IMHR was higher than SCE's, likely due to lower gas prices in the PG&E area together with higher CAISO electricity prices, which amplified its IMHR calculation. By contrast, in winter 2022-23, IMHR was relatively low, ranging between 8MMBtu/MWh and 10MMBtu/MWh in the SCE service territory and 10MMBtu/MWh and 13MMBtu/MWh in the PG&E service territory.

Figure 19: Monthly Average (Peak): IMHR, Energy & Gas Prices by Zone



Scarcity Pricing and Extreme IMHR Events

Staff set an hourly IMHR threshold of 20 MMBtu/MWh as a benchmark to compare summer 2022 against other recent summers and determine whether there were more scarcity pricing events and high IMHR events in summer 2022 than normal.

When IMHR exceeded this threshold, electricity prices were not just tracking fuel costs but also reflecting scarcity pricing, congestion or other system stress. Such elevated IMHR levels are consistent with structural scarcity caused by reduced imports, operational constraints, and high demand. Staff found there were fewer high IMHR events that summer than in others, until September 2022. This is due to higher gas prices than normal, leading to higher electricity prices but more market-based scarcity pricing caused by underlying market fundamentals like fuel costs.

Hourly instances where IMHR exceeded 20 MMBtu/MWh for PG&E and SCE during the peak summer months (July–September) from 2020 to 2024 were counted and shown in Table 5. This threshold helps to compare years against each other. Staff counted the number of times in each month that IMHR exceeded the 20 MMBtu/MWh threshold as well as evaluated monthly trends in average IMHR, gas prices, and NP-15 or SP-15 energy prices to understand the key drivers behind these spikes.

In September 2022, IMHR volatility rose sharply. PG&E saw 40 hours where IMHR exceeded the 20 MMBtu/kwh threshold, while SCE had 29. PG&E's average IMHR reached 25.6 MMBtu/MWh alongside a ~$250/MWh energy price. This indicates that while most of 2022 had lower IMHR levels, late-summer gas price increases contributed to price stress in both territories. Likely drivers include scarcity pricing not tied to fuel costs, shifts in bidding strategies, operational constraints, and increased reliance on peakers.

These results show that summer 2022 had relatively stable market behavior compared to prior years, with fewer extreme IMHR events despite record-high gas prices.

Table 5: Monthly Frequency of Extreme IMHR Based on Mean Gas Price (# of Hours)

		Frequency		Average				
Year	Month	PGE IMHR > 20	SCE IMHR > 20	PGE IMHR	SCE IMHR	PGE Gas Price	SCE Gas Price	Energy Price
2020	7	33	10	19.00	12.04	$2.46	$3.85	$47.33
2020	8	64	32	57.35	24.69	$3.10	$6.12	$187.90
2020	9	36	15	19.56	12.79	$3.62	$5.37	$71.62
2021	7	58	15	22.75	14.50	$5.30	$8.23	$121.65
2021	8	30	4	16.87	11.28	$5.56	$8.26	$94.38
2021	9	19	3	15.35	10.35	$6.88	$9.82	$104.69
2022	7	7	1	13.54	11.94	$8.24	$9.34	$112.23
2022	8	19	7	15.64	12.88	$10.13	$12.19	$158.78
2022	9	40	29	25.59	19.09	$9.25	$11.43	$250.00
2023	7	57	16	22.32	13.60	$4.68	$7.71	$108.63
2023	8	51	25	26.75	16.87	$5.27	$8.40	$147.73
2023	9	10	0	15.31	9.59	$3.77	$6.06	$57.77
2024	7	91	35	29.77	19.29	$3.23	$4.95	$96.36
2024	8	54	13	22.16	13.84	$2.84	$4.55	$65.16
2024	9	43	16	25.22	14.73	$2.66	$4.52	$67.22

IMHR increases in PG&E's area are related to a single electricity clearing price across the CAISO and gas generators in SCE's area largely setting the price. Focusing on IMHR increases and scarcity in SCE's area, summer 2020 saw significant IMHR exceedances, particularly in July and September, when SCE had 10 and 15 exceedances respectively. This period coincided with California's severe heat wave, leading to supply shortages, emergency conditions, and significant price spikes. Additionally, in the summer of 2020 Aliso Canyon gas storage inventory limitations and the Aliso Canyon Withdrawal Protocol were still in effect, and noncore customers and electric generators had no direct access to gas storage in Southern California.

In contrast, 2022 exhibited the lowest number of high IMHR events in the dataset, particularly in July and August, since gas prices were elevated all over CAISO. In July 2022, PG&E recorded only seven high IMHR events, and SCE had just one—the lowest recorded in the dataset—while in August 2022 PG&E had 19 high IMHR events and SCE had seven, still significantly lower than in 2020 and 2021.

The low number of high IMHR events is particularly notable because 2022 had the highest mean gas prices in the dataset (~$9-$10/MMBtu). High gas prices would drive IMHR lower if electricity prices do not increase proportionally. In early 2022, electricity prices were more directly aligned with fuel costs than in previous years, as shown by much lower IMHR levels. On average, PG&E's IMHR in July 2022 was 13.5 MMBtu/MWh—much lower than in 2020 and 2024. This suggests that higher gas prices were passed through to power prices. Through summer 2023, high gas prices were more concentrated in the SoCalGas service territory due to lack of noncore storage, the Aliso Withdrawal Protocol, pipeline outages, and PG&E's greater access to Canadian gas and lesser dependence on freeze-off prone Texas production basins.

However, September 2022 saw a notable rise in high IMHR events (40 in PG&E, 29 in SCE), with an average IMHR of 25.6 MMBtu/MWh in PG&E, coinciding with an energy price of approximately $250/MWh. This increase in high IMHR events indicates that while most of 2022 had lower IMHR levels compared to other periods, late-summer gas price increases led to significant electricity price increases and market stress in both PG&E and SCE.

The analysis of scarcity pricing and extreme IMHR events further highlights how winter 2022-23 differed from previous years. Unlike summer 2020, which saw extreme IMHR spikes due to heat waves and rolling blackouts, summer 2022 had fewer instances of excessive IMHR in PG&E and SCE areas despite record-high gas prices. Staff found there were fewer high IMHR events in summer 2022 compared to other years, until September 2022. This is due to higher gas prices than normal, leading to higher electricity prices but more market-based scarcity pricing caused by underlying market fundamentals like fuel costs.

This suggests that SoCalGas prices were more directly aligned with electricity costs in 2022 and that PG&E gas prices were more correlated with SoCalGas prices as well, reflecting reasonable bidding behavior. However, by late 2022 and into 2023, IMHR volatility surged again, driven by increases in natural gas prices in the SoCalGas area and no increase in PG&E's area, leading to the sharp increase in IMHR in PG&E's area. Scarcity pricing that does not reflect gas prices or operational costs, changes in bidding strategies, transmission constraints, and increased reliance on peaking generators may have also led to increases in IMHR during this time.

Overall, winter 2022-23 was a pivotal period for California's energy markets, marked by high volatility, shifting generator profitability, and a strong correlation between gas and electricity prices. While gas-fired power plants faced fluctuating profit margins depending on location and gas prices, non-gas generators benefited from elevated electricity prices throughout CAISO. Due to gas price volatility and energy scarcity due to extreme weather trends, IMHR diverged from historical patterns. This period set the stage for continued price volatility into 2023 and 2024.

Profitability Analysis of Power Generators

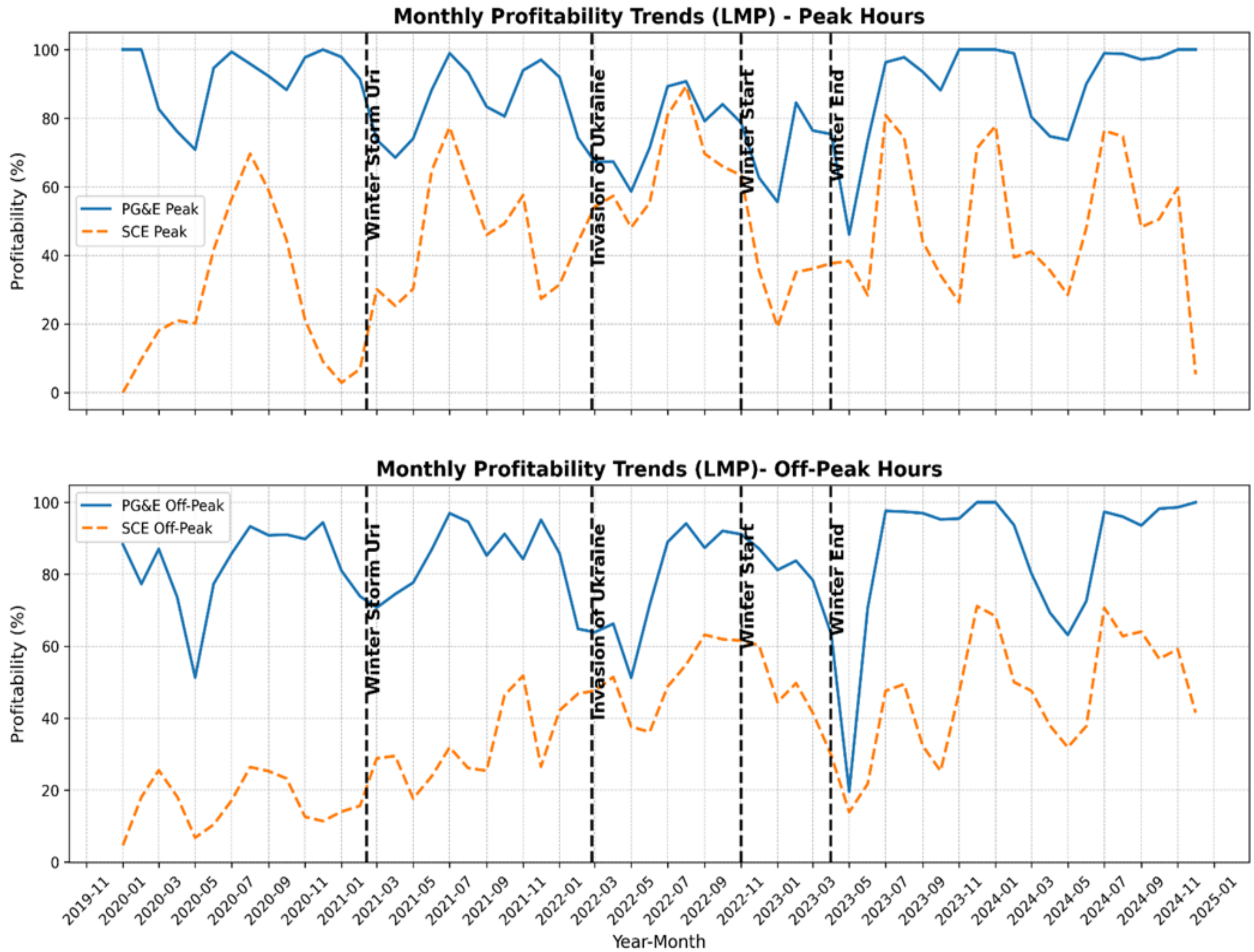
This section evaluates monthly profitability trends for gas and non-gas generators across PG&E and SCE territories. Profitability analysis assumes a breakeven point in heat rate to determine when generators are likely receiving revenue greater or less than operating cost. The goal is to assess how market conditions, especially fuel price volatility, affected generator margins over time. The analysis uses IMHR results to show trends in profitability. Simulated profitability was consistently higher for generators in PG&E's area than in SCE's region, due to natural gas prices in SoCalGas area causing electricity prices in SCE area to increase. PG&E area saw lower gas prices, which meant higher profitability when revenue is set by high electricity prices in SCE area.

The breakeven threshold was set at 10 MMBtu/MWh for peak hours, which is similar to a combustion turbine plant, and 7 MMBtu/MWh for off-peak hours, which resembles a more efficient combined cycle power plant. This threshold is used as a proxy indicator for when a power plant on the margin was operating at a profit or loss relative to gas prices and other costs and is used to assess profitability for gas and non-gas generators. Results are summarized in Figure 20 below.

The figure shows profitability trends in the PG&E and SCE regions from 2019 to early 2025, segmented into peak and off-peak hours. The top chart (Peak Hours: Hour Ending (HE) 17-22) shows that hypothetical combustion turbine generators operating at the threshold heat rate in PG&E's area (solid blue line) consistently maintained higher profitability, averaging between 80 and 100 percent, while SCE (dashed orange line) had greater fluctuations, generally ranging from 20 to 80 percent. The bottom chart (Off-Peak Hours outside of HE 17-22) follows a similar trend, with the hypothetical combined cycle generator in PG&E's area maintaining stronger profitability, while SCE remained more volatile and generally less profitable, fluctuating between 20 and 60 percent. Using this proxy comparison, generators in the PG&E region consistently earned greater profit margines than those in the SCE region, mainly because of lower local gas prices, which improved their cost recovery. In contrast, SCE generators faced greater price swings in profitability due to overall higher fuel costs.

Gas-fired power plants in PG&E's territory initially saw a drop in simulated profitability during winter 2022-23 but recovered quickly because gas prices in PG&E's area, although high, were still lower, on average, than those in the SoCalGas territory. Meanwhile, gas-fired power plants in SCE's territory struggled with low simulated profitability longer due to higher gas costs and greater price swings. Since gas-fired plants often set electricity prices, non-gas power sources like hydro, nuclear, and renewables benefited the most—they didn't face higher fuel costs but still earned higher electricity prices, boosting their profits significantly.

Figure 20: Monthly Gas Generator Profitability Trends by Region

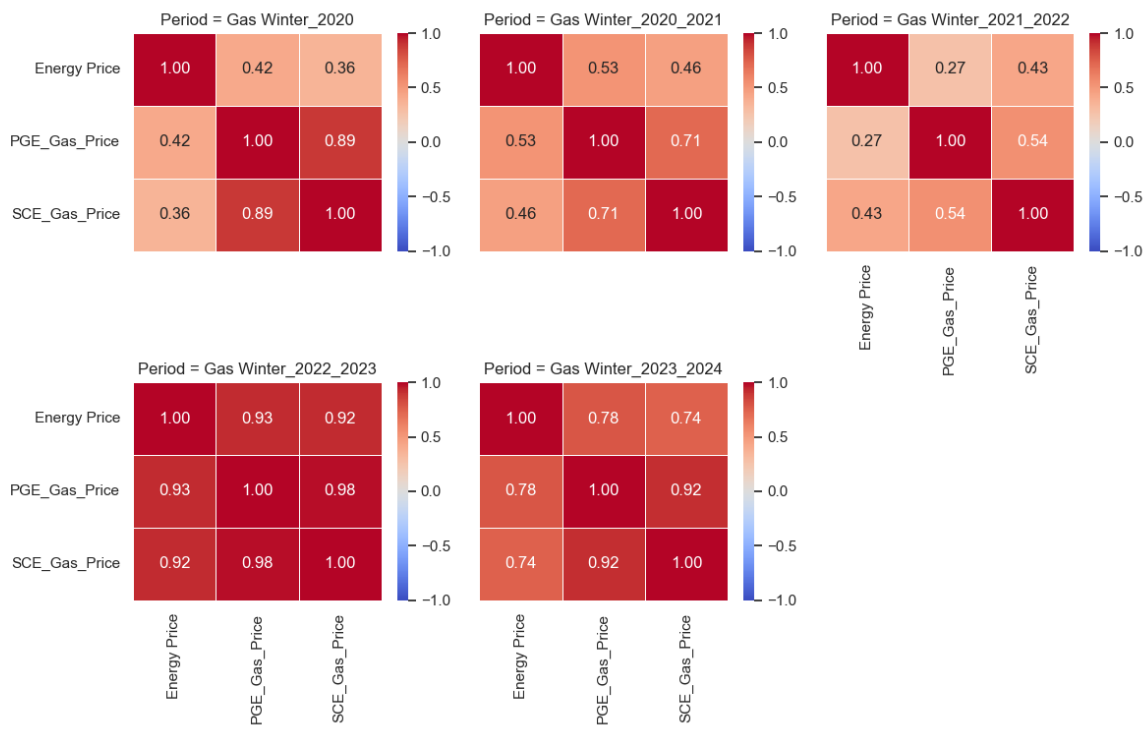


Correlation Metrics for Winter and Summer, 2020-24

Prior to winter 2022, energy prices were weakly correlated to gas prices with correlation coefficients generally below 0.45. During winter 2022-23, gas prices became the dominant driver, with a high correlation of 0.93 for PG&E and 0.92 for SCE, meaning that as gas prices increased, energy prices also increased, demonstrating how gas generators were driving electric prices in both regions. Additionally, PG&E and SCE gas prices were nearly identical in their movements—even if the prices themselves were different—showing a near-perfect correlation of 0.98. This pattern confirms that both electricity markets experienced extreme price swings together, and that both were dependent on SoCalGas prices for fuel. By winter 2023-24, the relationship between gas and energy prices weakened slightly but remained stronger than in earlier years, suggesting that while the gas market was stabilizing, gas prices still had a significant influence on energy costs.

Prior to winter 2022-23, correlations between gas and energy prices were much lower (generally below 0.45), particularly in winter 2020 and 2021, when gas prices explained only part of the variation in electricity prices. Notably, gas prices in the SoCalGas area did not consistently show stronger correlations to electricity prices than PG&E gas prices, as previously assumed. In fact, the data show mixed results, with SoCalGas sometimes higher (e.g., 2021) and sometimes lower (e.g., 2020). This suggests that price-setting behavior varied year to year and was not dominated by one region. However, after 2022, the correlation between gas pricing and electricity prices across all regions increased, showing that both gas and electricity prices moved together more closely, reinforcing the conclusion that gas prices drove electricity prices across CAISO. See that in winter 2022-23 and winter 2023-24, the rows where PGE_Gas_Price on the Y axis cross the SCE_Gas_Price on the X axis increase towards a value of 1 and get darker red.

Figure 21: Correlation of gas prices to electricity prices in Winter: PG&E and SCE



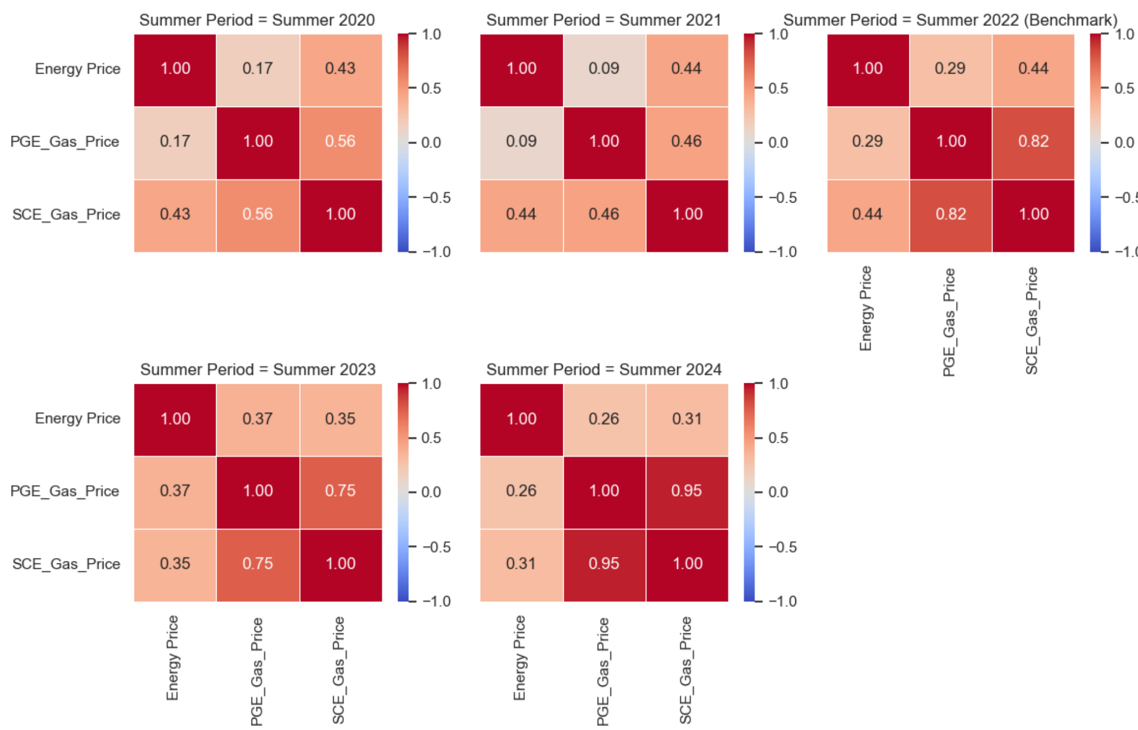
The correlation analysis indicates that summer 2022 exhibited the strongest relationship between gas prices and energy prices compared to other summers, with correlations ranging from 0.29 to 0.44. This data suggests that higher gas prices likely contributed to elevated energy prices during this period.

In earlier summers (2020 and 2021), the correlation between gas and energy prices was weaker than in summer 2022, with values ranging from 0.09 to 0.44, implying that energy prices were less directly influenced by gas price movements during those years. After summer 2022, this correlation declined, suggesting that other market factors played a larger role in energy price formation in subsequent years.

Meanwhile, PG&E and SCE gas prices became increasingly synchronized over time, with their correlation rising from 0.46 in summer 2021 to 0.95 in summer 2024. This reflects stronger gas market alignment than previous years across the two regions.

Overall, the correlation patterns in summer 2022 support the observation that extreme gas price spikes were a key factor in higher electricity prices that year. However, in subsequent summers, the influence of gas prices on energy prices weaken, indicating that other factors may have played a more significant role. Correlation between PG&E gas prices and SoCalGas prices become more correlated after 2022 in both winter and summer, but the effect appeared stronger in the winter season. Energy prices likewise appear to become much more correlated to gas prices in the winter, and the summer shows no increase in correlation to gas prices over the period.

Figure 22: Correlation of gas prices to electricity prices in Summer: PG&E and SCE



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Gas and Electricity Price Volatility Analysis Comparing 2022-23 to Other Years 2020-2024

Winter Price Volatility Analysis during 2022-23

Winter 2022-23 was significantly more volatile than other years after 2020 for gas and electricity prices in both PG&E and SCE regions. During this time, gas prices spiked dramatically, and fluctuations became highly unpredictable, making it difficult for energy providers to manage costs effectively. In winter 2022-23, gas prices spiked higher and fluctuated much more than in previous years.

To better understand this period, Staff undertook analysis of volatility in energy and gas prices for the PG&E and SoCalGas/SCE regions across different seasonal periods, utilizing statistical measures such as distribution analysis, mean, variance, Levene's Test, (which tests for meaningful differences in price volatility between two time periods), T-Test, and VaR/ CVaR analysis.[97] VaR measures expected value of potential losses on investments or cost increases due to commodity price within a 95 percent confidence level, while CVaR expresses the total potential losses that exceed the 95 percent threshold measured in VaR.

As shown in Figure 23 and Figure 24 gas price distribution across both PG&E and SCE territories generally clustered to the left side of the graph indicating persistent lower prices, while for winter 2022, there were considerably more instances of gas prices at higher levels spreading out to the right of the other years. The periods analyzed are: Gas Winter_2020, Gas Winter_2020_2021, Gas Winter_2021_2022, Gas Winter_2022_2023, and Gas Winter_2023_2024. Winter 2020 only includes the second half of the winter. Gas prices were compared across winter 2020 through 2023-24 showed that the winters of 2021-22 and 2022-23 were distributed to the right of the other years, and winter 2022-23 had an especially long right tail, indicating higher price variability and the occurrence of extreme price spikes. Gas prices in the SCE area were significantly higher than in the PG&E area as illustrated by thicker tails to the right in winter 2022-23.

97 *Statistics Definitions in Plain English with Examples - Statistics How To* explains these complex statistical tests in plain terms. T test, Levene's Test and VaR/CVaR refer to complex statistical tests that are used in economics analysis.

Figure 23: Distribution of PG&E Gas Price Across Winter Periods

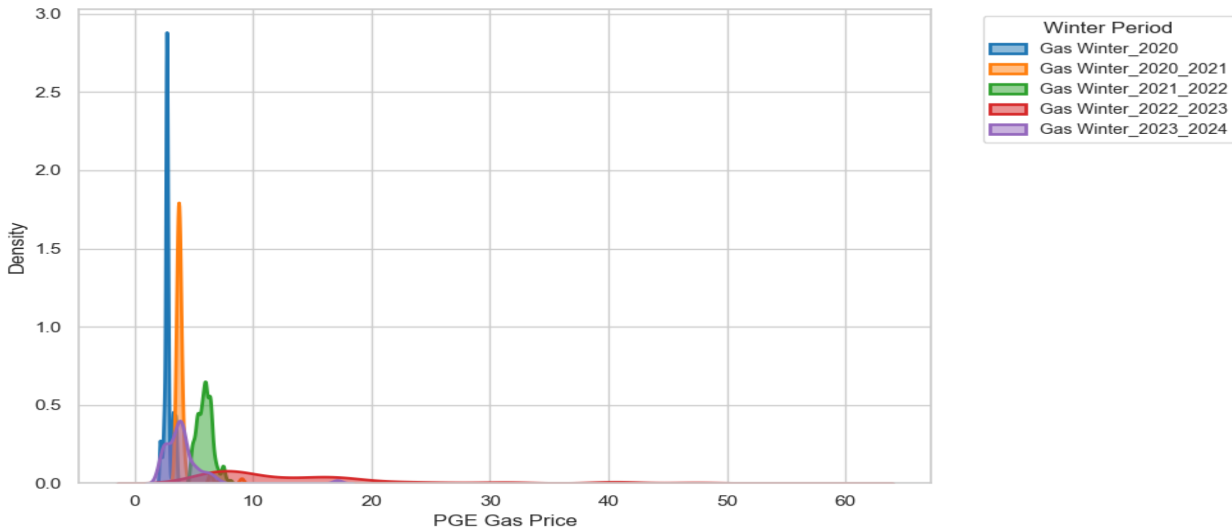
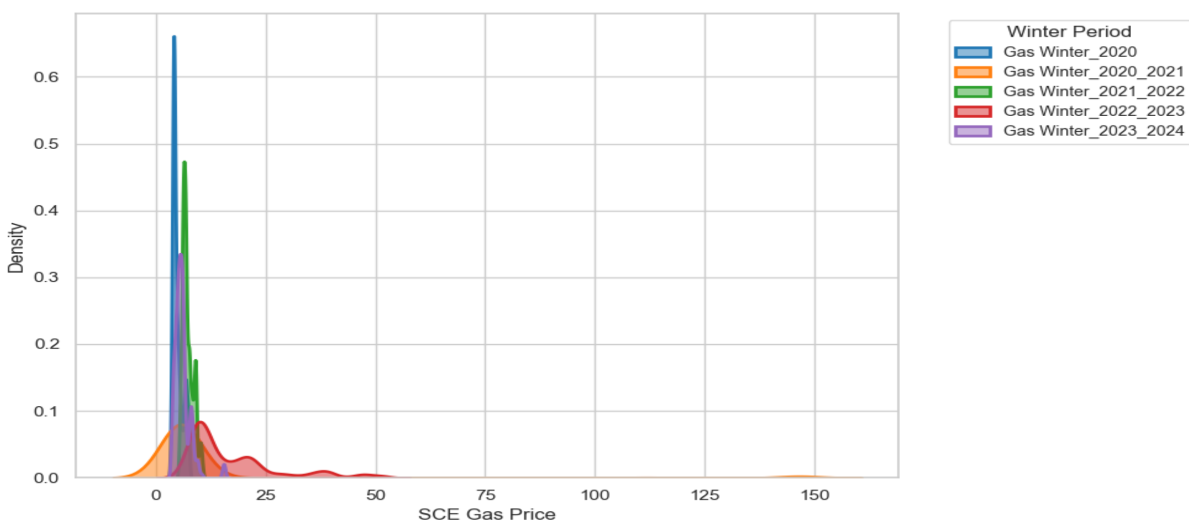


Figure 24: Distribution of SCE Gas Price Across Winter Periods



Gas and Electricity Price Volatility Analysis During Summer 2022 Compared to Other Periods

Gas and energy prices exhibit seasonal volatility, and their distribution across different summer periods provides insight into market stability and price fluctuations. This analysis examines the distribution of PG&E Gas Prices, SCE Gas Prices, and Energy Prices from summer 2020 to summer 2024, using summer 2022 as the benchmark due to its significant price spikes. Data show that summer 2022 had the highest gas price levels and the broadest distribution, reflecting extreme volatility compared to other years. This elevated volatility is consistent with market stress and structural scarcity conditions.

PG&E Gas Price Distribution

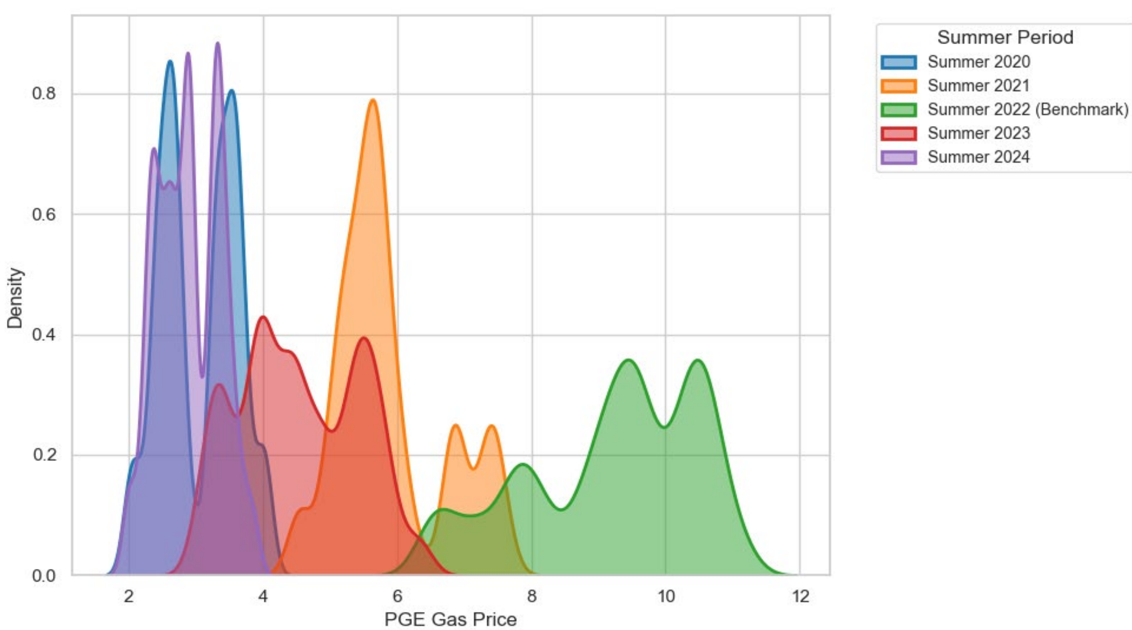
For PG&E, the gas price data show a clear progression from stable, low-cost summers in 2020 and 2024 toward increasingly volatile and elevated pricing in 2021 and especially 2022.

In summer 2020 and summer 2024, gas prices remained relatively low, primarily concentrated between $2 and $3.50/MMBtu. There were multiple price peaks within these periods. Summer 2021 saw a shift toward higher prices, centered around $6/MMBtu, with a more concentrated distribution and less spread compared to other years.

The benchmark year, summer 2022, experienced the highest gas prices, ranging from $5 to $11/MMBtu. The distribution was wide and multi-modal, meaning there is more than one mode or most common value, seen by having more than one hump among these four years analyzed. This shows that some years, like 2022, saw higher prices and a wider spread of prices than other years, suggesting increased volatility. In summer 2023, prices were generally higher than in 2020 and 2024 but remained below the 2022 peak levels. The distribution spanned from $3 to $6/MMBtu, with distinct peaks around $4 and $5.50/MMBtu.

Gas price volatility was also the most pronounced in 2022, with the widest distribution and the highest observed prices. Summer 2021 also showed an increase in gas prices compared to earlier years, marking a trend of rising gas costs even before the peaks seen in 2022.

Figure 25: Distribution of PG&E Gas Price Across Summer Periods



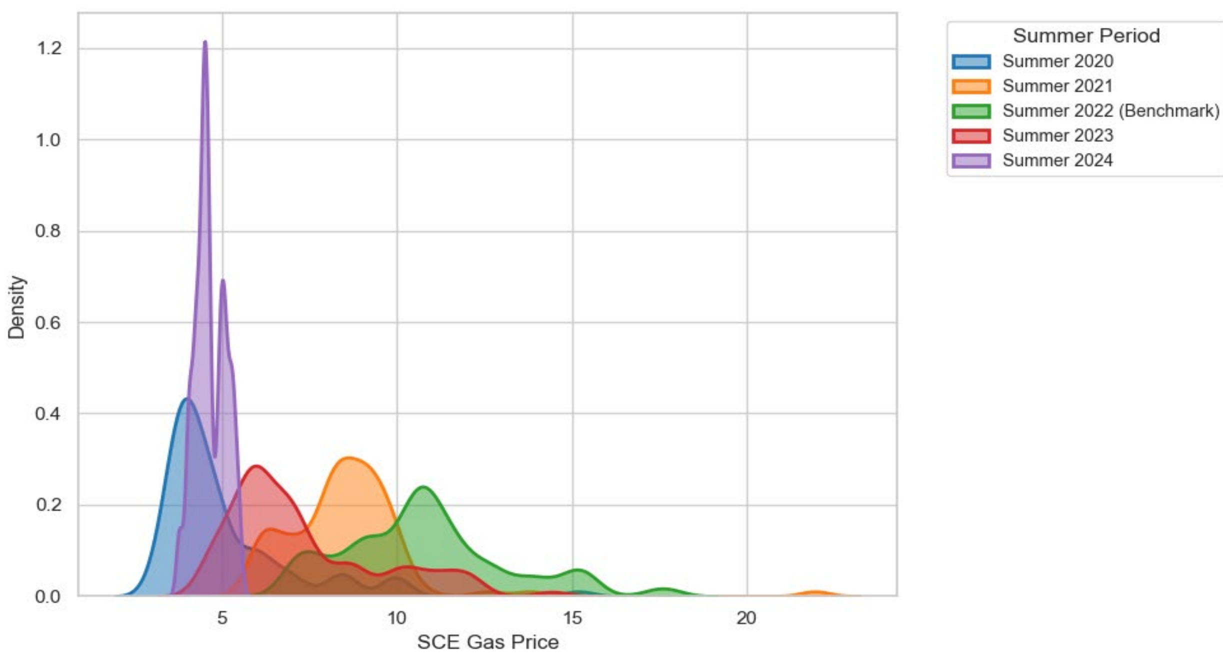
SoCalGas Gas Price Distribution

This section examines seasonal trends and volatility in SoCalGas gas prices from summer 2020 to summer 2024, with summer 2022 serving as a benchmark. By analyzing the distribution of prices over multiple years, Staff aimed to evaluate whether summer 2022 stood out from other years in terms of price risk and unpredictability. Staff found that in summer 2020 and summer 2024, SoCalGas gas prices remained relatively low, primarily concentrated between $4 to $6/MMBtu. Summer 2024, for example, displayed a high incidence of values around $5/MMBtu, indicating a more stable price in a lower range during that period. Summer 2021 saw a shift toward higher prices, centered around $8/MMBtu, with a more concentrated distribution and less spread compared to other years. The distributions also appeared multi-modal. There was not one single average price that appeared more common than other price levels, indicating high volatility.

The benchmark year, summer 2022, experienced the highest gas prices (shown as values furthest to the right), ranging from $5/MMBtu to over $20/MMBtu. The distribution was wide and multi-modal, indicating increased volatility and price spikes. In summer 2023, prices were generally higher than in 2020 and 2024 but remained below the 2022 peak levels. The distribution spanned from $4 to $10/MMBtu, with distinct peaks around $6 and $8/MMBtu.

Analysis of patterns in SoCalGas gas price data leads Staff to conclude that summer 2022 represented a period of exceptional volatility in Southern California gas markets—driven by system-wide stress and possibly compounded by infrastructure constraints.

Figure 26: Distribution of SoCalGas Gas Price Across Summer Periods



Summer CAISO Electricity Price Distribution

This section examines the distribution of CAISO electricity prices during the summer months (July–September) from 2020 to 2024, using summer 2022 as the benchmark. By comparing seasonal price patterns across years, Staff aimed to assess whether summer 2022 exhibited unusually high volatility or pricing extremes relative to recent historical norms.

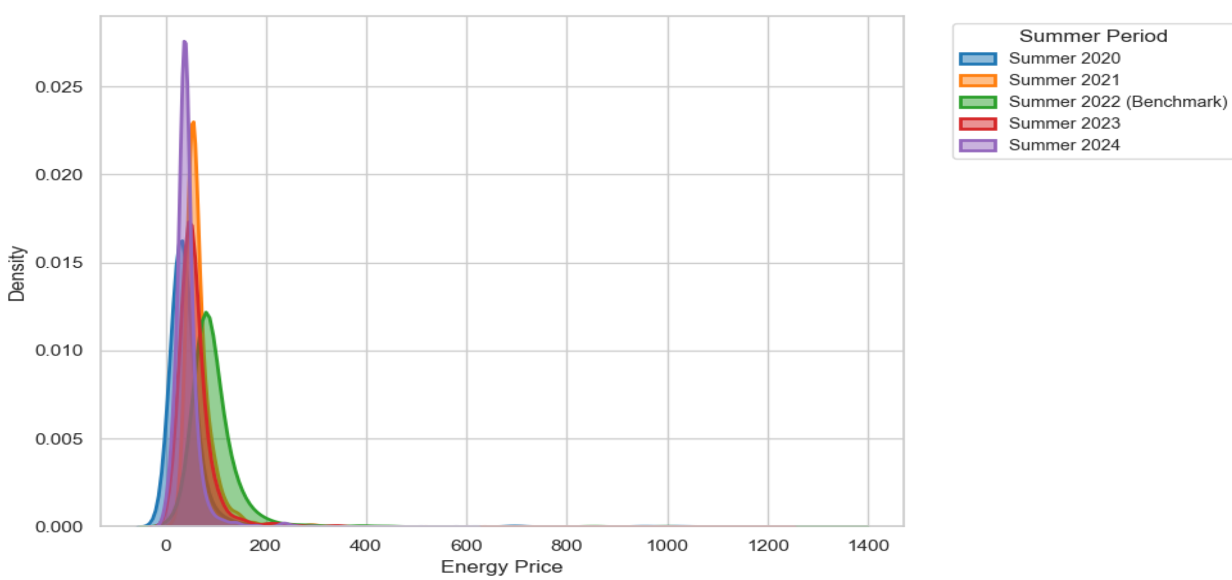
In summer 2020 and summer 2024, electricity prices remained relatively low, primarily concentrated between $0 and $100/MWh. The distributions were tightly clustered, with summer 2024 exhibiting the sharpest peak, indicating greater price stability compared to other summers.

In summer 2021, electricity prices increased slightly, with values centered between $50 and $150/MWh. The distribution was more concentrated, suggesting a moderate rise in price levels while maintaining relatively contained volatility.

The benchmark year, summer 2022, exhibited the widest electricity price range, spanning $0 to over $400/MWh, with extreme spikes exceeding $1,000/MWh. The broader right tail suggests heightened price volatility and suggests the presence of scarcity pricing events and underlying supply-side constraints.

In summer 2023, electricity prices were higher than in 2020 and 2024 but remained below the 2022 peak levels. The distribution was broader, with most prices falling between $50 and $200/MWh, indicating some residual volatility but a clear decline from the extremes of 2022. Overall, these results confirm that summer 2022 was an outlier in terms of both price level and volatility, pointing to a period of market stress not observed in other recent summers.

Figure 27: Distribution of Energy Prices Across Summer Periods ($)



Variance Analyses

Staff's analysis of volatility in mean prices show that winter 2022-23 exhibited the most extreme pricing behavior across both gas and electricity markets, in terms of both average levels and volatility.

Staff made a statistical comparison (mean and variance analyses) of both gas and energy prices to measure both average prices and their variability over time, with results segmented by electric peak hours (17:00–22:00 on weekdays) and off-peak hours (non-peak weekday and weekend hours). Since gas is priced daily, the primary difference between peak and off-peak periods for gas prices occurs on weekends, when only off-peak hours are present. For winter periods, we define seasons that span multiple years, including the months of November, December, January, February, and March.

Staff found that gas price spikes in 2022-23 were significantly higher than in any period between 2020 and 2024. Although peak hourly prices sometimes significantly exceeded mean values, increasing up to $50 or more in some hours, overall mean values are analyzed here.

During winter 2022-23, PG&E and SoCal Citygate gas prices saw a sharp spike, making that winter (from November to March) the most volatile winter period between 2020 and 2024. Before this, winter gas prices had been relatively stable, but in 2022-23, winter peak-hour PG&E gas prices averaged $15.00/MMBtu, up from $2.80/MMBtu in 2020. Similarly, SoCal Citygate average peak gas prices rose to $16.90/MMBtu, compared to $4.90/MMBtu in 2020. In both regions, peak hourly prices exceeded the mean prices referenced above, meaning that gas ratepayers sometimes endured even larger cost impacts than are shown here.

To determine whether these differences in mean energy price were statistically significant, Levene's Test was used to compare variance across different winters. This test assesses whether price volatility (variance) differs meaningfully between periods. Table 7 summarizes the results, showing volatility was not just random noise—it had changed significantly over time—particularly during winter 2022-23.

Additionally, a T-Test was performed to compare the average prices (mean) of winter 2022-23 against other winters. The T-Test evaluates whether differences in mean prices are statistically significant or simply due to random fluctuations. The test results indicated a P-value of 0, which means the observed price increases were highly significant and extremely unlikely to be due to chance. The results showed that variance during winter 2022-23 was significantly different from the other winters studied, across both off-peak and peak hours, with P-values of 0.0 in each comparison. This indicates that the spike in volatility was statistically significant and not the result of random fluctuations.

Table 6: Summary of Statistical Analysis: Winter 2020 through Winter

Winter Period	Category	Variance	Statistic	Value	Mean	Statistic	Value
Winter 2020	Off-Peak	84	1,039	0.0	26	59	0.0
Winter 2020	Peak	91	205	0.0	40	30	0.0
Winter 2021	Off-Peak	762	1,282	0.0	36	51	0.0
Winter 2021	Peak	9,291	83	0.0	67	17	0.0
Winter 21-22	Off-Peak	318	1,299	0.0	49	45	0.0
Winter 21-22	Peak	289	280	0.0	74	22	0.0
Winter 22-23	Off-Peak	7,758	N/A	N/A	123	N/A	N/A
Winter 22-23	Peak	11,228	N/A	N/A	165	N/A	N/A
Winter 2024	Off-Peak	733	1,425	0.0	44	47	0.0
Winter 2024	Peak	754	330	0.0	63	24	0.0

Risk Analysis

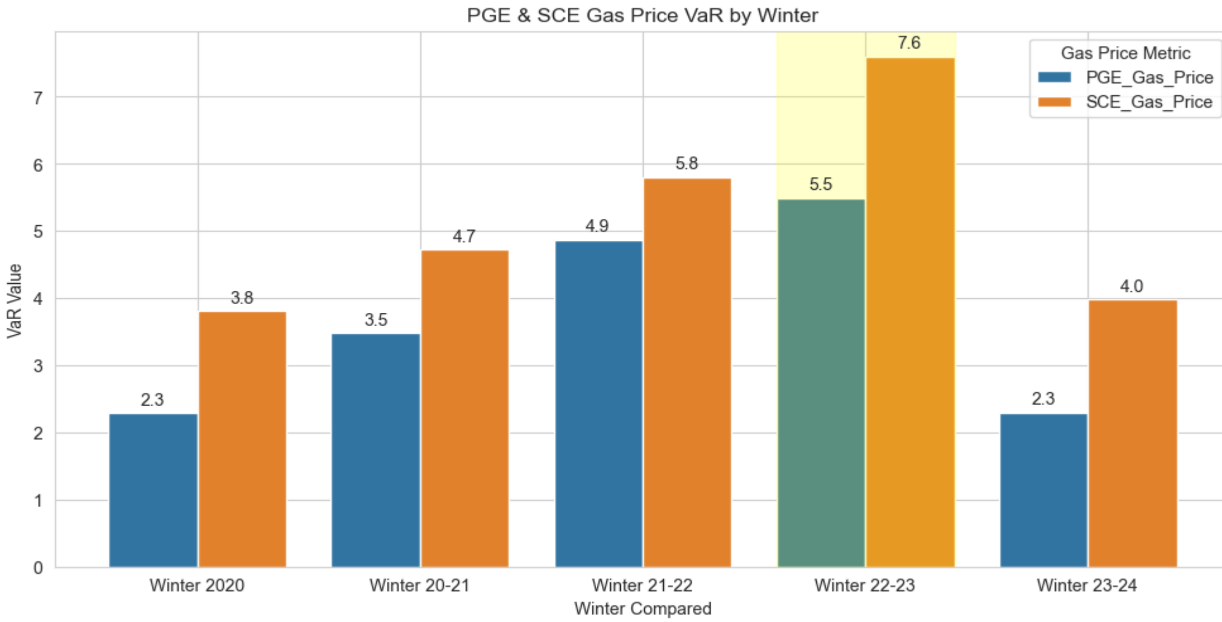
In this section, Staff analyze VaR and CVaR to measure the potential for extreme price increases across different winters. VaR estimates the maximum expected price increase at a 95 percent confidence level, representing a worst-case price spike within that range. In contrast, CVaR measures the average magnitude of price increases in the tails, meaning the area of the distribution outside the 95 percent confidence interval. CVaR captures the extent of extreme risk beyond the expected levels.

Using winter 2022-23 as a benchmark, Staff compared it against winter 2019-20 (excluding November and December 2019 due to the absence of data), as well as winter periods that span multiple years and include the months of November, December, January, February, and March: winter 2020-21, winter 2021-22, and winter 2023-24. This comparison assesses whether winter 2022-23 represents a period of elevated upward risk. The analysis covers both PG&E and SCE gas prices, as well as CAISO energy prices, segmented by peak and off-peak hours, as described in previous sections.

Gas Price Risk Analysis Using Winter 2022-23 as a Benchmark (Upward Risk Approach)

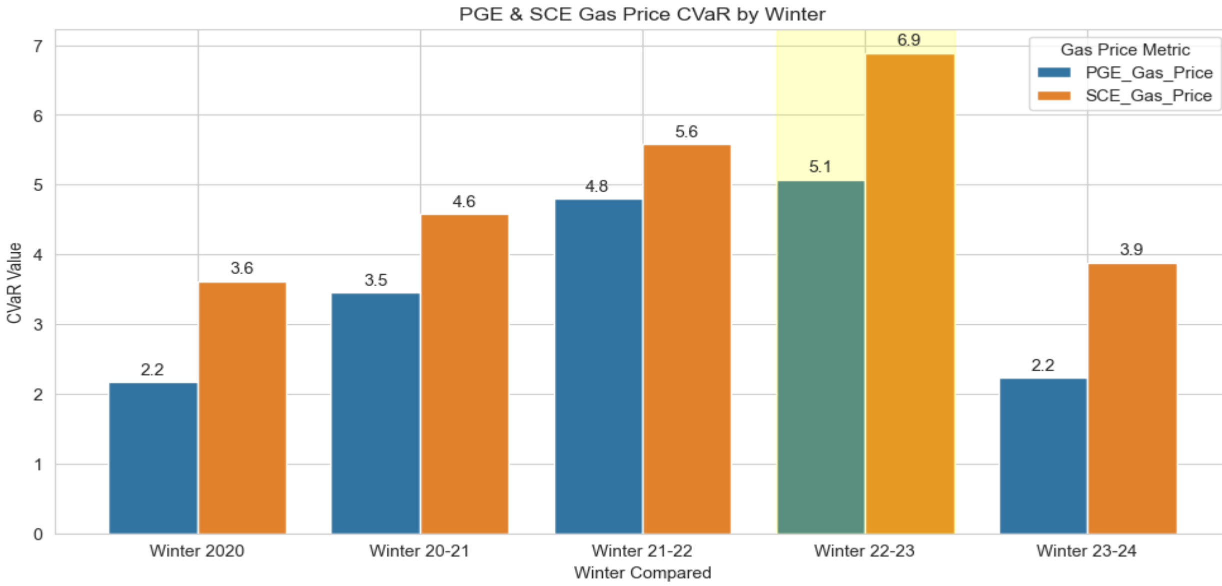
During winter 2022-23, VaR in PG&E gas prices equaled $5.50/MMBtu while VaR for SoCalGas reached $7.60/MMBtu—both significantly higher than any winter since 2020. Gas price VaR is shown in Figure 28 below, confirming that winter 2022-23 had the most significant volatility and VaR in the recent past.

Figure 28: PG&E and SCE Gas Price VaR by Winter ($/MMBtu)



CVaR also peaked in winter 2022-23. As shown in Figure 29 below, for PG&E, CVaR equaled $5.10/MMBtu, compared to just $2.20/MMBtu in winter 2020, while SCE's reached $6.90/MMBtu, up from $3.60/MMBtu in winter 2020. In extreme events during winter 2022-23, customers in the SoCalGas territory may see cost increases of as much as $6.90 in each MMBtu of gas purchases on average, nearly twice the expected cost increases in extreme events from winters before. Gas prices increased substantially, which was harmful, but winter 2022-23 also saw spikes in the amount of cost risk each customer faced on top of average cost increases. These figures show that extreme price increases were not only more frequent but also larger in scale than in prior and subsequent years.

Figure 29: PG&E and SCE Gas Price CvaR by Winter ($/MMBtu)



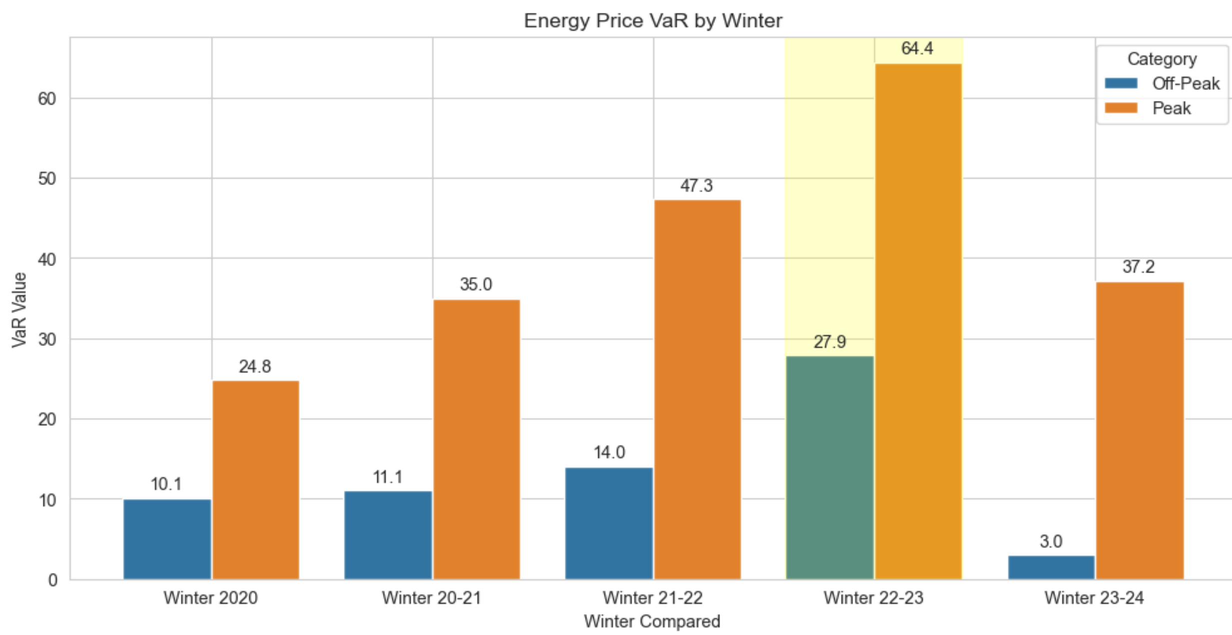
By winter 2023-24, both VaR and CVaR dropped significantly, indicating a return toward stability. PG&E's VaR fell back to $2.3/MMBtu—its 2020 level—while SCE's dropped to $4.00/MMBtu, still slightly above pre-2022 levels. CVaR followed the same pattern, with PG&E returning to $2.20/MMBtu and SCE decreasing to $3.90/MMBtu.

These findings are backed by statistical tests that confirmed winter 2022-23 was a true anomaly. The high VaR and CVaR values proved that gas price spikes were not random fluctuations but part of a broader, severe market disruption. Although winter 2023-24 saw a return to more normal levels of customer cost risk, prices have not fully returned to pre-2020 stability, suggesting that some market uncertainty persists.

Energy Price Risk Analysis Using Winter 2022-23 as a Benchmark (Upward Risk Approach)

Similar to gas prices, winter 2022-23 was the most extreme period for energy price spikes since the energy crisis of 2000-01, with record-breaking levels of price instability compared to previous winters. The worst-case price surges (VaR analysis) showed that Off-Peak prices spiked significantly, reaching $27.90/MWh, while Peak-hour prices soared to $64.40/MWh, confirming that sharp price swings strongly exacerbated electric cost risk also. The expected magnitude of extreme price spikes (CVaR analysis) further emphasized the cost to customers of this volatility, with peak-hour CVaR reaching $49.10/MWh—far exceeding previous winters—indicating that both the frequency and magnitude of extreme price events increased. By winter 2024, price risks had decreased significantly, with off-peak volatility almost disappearing and peak-hour price volatility dropping notably. However, some lingering instability remained, meaning the market had not yet fully returned to pre-2022-23 stability levels. Overall, statistical analysis confirms that winter 2022-23 was an outlier in terms of both severity and unpredictability of price spikes.

Figure 30: CAISO Energy Price VaR by Winter ($/MWh)



Conclusions From Statistical Modeling and Areas for Further Investigation

This analysis confirms that the winter 2022-23 gas price increase had a direct and large impact on California's electricity markets. Cold weather, reduced electricity imports, and limited supply flexibility led to greater gas dependency, elevated electricity prices, and unusually high volatility.

The analysis of scarcity pricing and extreme IMHR events further highlights how winter 2022-23 differed from previous years. Unlike summer 2020, which saw extreme IMHR spikes due to heat waves and rolling blackouts, summer 2022 had fewer instances of excessive IMHR in PG&E and SCE areas despite record-high gas prices. However, these levels were consistent with prior summer patterns and occurred within the framework of FERC's 2021 order that raised the energy market bidding cap to $2,000/MWh. A record-setting heat wave in early September 2022 further contributed to high demand and scarcity pricing. This suggests that electricity prices were not only reflecting fuel costs but also scarcity conditions and broader system stress.

The strong correlation between gas and electricity prices (over 0.90), along with growing co-integration between PG&E and SoCalGas hubs, underscores the structural nature of this market shift.

This analysis provides a perspective of events around periods of high gas and electric prices between 2020 and 2024, including emerging trends in the natural gas and electric markets. Instead of clear evidence of non-market behavior, price outcomes seem to have been driven by underlying market fundamentals.

To build on these findings, the following areas may warrant further study

- Assessing gas supply and demand balance and resilience, especially during periods of extreme cold or heat, combined with supply disruptions such as pipeline or storage outages. Comparing daily gas sendout and receipts, alongside weather indicators like Heating and Cooling Degree Days (HDD/CDD), can help show how weather conditions influence gas demand.
- Monitoring continued electric grid reliance on gas and the growing penetration of flexible resources—including batteries, ramping capability, and renewable solar output—to assess how much gas is needed when more flexible options are unavailable or constrained.
- Effectiveness of electricity market signals, such as forward prices, in giving utilities and buyers enough warning to manage risks.
- Analyzing transmission and import limitations, to understand whether congestion or restricted access to out-of-state electricity made it more difficult to manage costs during tight market conditions.
- Understanding why PG&E and SoCalGas prices became more closely correlated after 2022.

(END ATTACHMENT A)