Winter 2020-2021 Southern California Gas Conditions and Operations Report

BY CALIFORNIA PUBLIC UTILITIES COMMISSION STAFF

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Executive Summary

The Southern California gas system in winter 2020-21 continued ongoing trends. The largest deviation from everyday activity was caused by supply reductions resulting from February winter storm impacts in neighboring states. The gas system's behavior during this event provides lessons for future system planning.

Declining Demand, Increasing Prices, Average Weather

Weather and demand were moderate in Southern California from November 2020 through March 2021 (this winter). Average daily temperatures were a slight 0.4 degrees cooler than the 10-year winter average, while the coldest day was 0.4 degrees warmer than the average of the previous 10 years' coldest days. Winter storms brought heavy precipitation but not unusual cold. Despite the moderate weather, average daily demand of 2,703 million cubic feet/day (MMcfd) was 5 percent below the 10-year average. The highest demand of the winter occurred on January 25, when demand reached 3,895 MMcfd. This was 3 percent below the 10-year average for the highest winter demand day. Thus, weather was average and average daily demand and peak daily demand were below average. The declines are consistent with trends over the past decade but difficult to disentangle from the impacts of the pandemic and its economic effects, which increased some demand types and decreased others.

Supply was sufficient to meet demand. The Southern California Gas Company (SoCalGas) system experienced no weather-related curtailments in winter 2020-21. There were no purchases for Southern System reliability, and recorded linepack did not drop below usual levels even during the coldest days of the winter or during Winter Storm Uri.[1] The SoCalGas Gas Acquisition Department (Gas Acquisition), which purchases gas for core customers, purchased 2 percent more gas this winter than it delivered.

The SoCalGas System Operator, which manages gas flows on the system, used a typical combination of flowing gas supplies, storage, and linepack to meet demand. Across the winter, pipeline receipts filled 95 percent of net demand. Linepack, used to address hourly fluctuations throughout the day, filled or absorbed up to a third of demand at daily peaks and valleys. Nine percent of demand was met with storage withdrawals, with the net difference approximately representing injections. Although pipeline receipts were below the available potential indicated in CPUC's gas balance analysis for this winter, SoCalGas ended the winter with 53 billion cubic feet (Bcf) of gas in storage, well above the 15.3 Bcf minimum.[2]

Excluding the week of the polar vortex, average daily spot prices at the SoCal Citygate in winter 2020-21 were up 10 cents from the previous winter to $3.85 per million British thermal units (MMBtu). Similarly, average spot prices at the SoCal Border rose by 81 cents to $3.09/MMBtu, narrowing the gap between Border and Citygate. Daily spot prices do not proportionally reflect impacts to core customers, whose gas is

[1] Linepack is created by the difference between a pipeline's minimum and maximum pressure. Gas is stored in the pipeline when it is closer to its maximum pressure; as gas is withdrawn, the pipeline moves towards its minimum pressure. Linepack must stay within an acceptable range. If there is too much gas in the pipeline, high pressure could cause it to rupture. It there is too little, the gas doesn't flow properly.

[2] The month-end minimums are described in 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.

purchased by Gas Acquisition. The CPUC requires Gas Acquisition to hold a set range of longer term, firm contracts as well as storage supplies to ensure reliability and price stability for core customers.[3]

Polar Vortex Impacts in California

While California experienced a mild winter, nationwide average February 2021 temperatures were the coldest since 1989 during Winter Storm Uri, with some areas experiencing their coldest weather in a century. This mid-February storm resulted from a polar vortex weather pattern that brought cold weather from Canada south through much of the United States. Nationwide gas demand reached its second highest level in U.S. history, while gas production dropped, resulting in gas shortages and power outages in the Southwest, particularly in Texas. Many Texas gas production wells "froze off," becoming inactive for the duration of the cold spell. Gas production from the Permian Basin, a major supply region for Southern California, dropped by 25 percent.

With supply down and demand up, gas spot prices rose to historic highs during this storm. On February 13, the average spot price reached $144 per million British thermal units (MMBtu) at the SoCal Citygate and $104 per MMBtu at the SoCal Border for the three-day weekend. Including these prices brings the winter's average spot price up to $6.62 per MMBtu at the Citygate and $5.52 per MMBtu at the Border, representing 77 and 140 percent increases from the previous winter's averages, respectively. Daily prices outside California rose even higher, reaching $1,193 per MMBtu in Oklahoma on February 18.

Although SoCalGas issued curtailment watches for its Southern System, Southern California did not experience any curtailments during the polar vortex. While much of the country experienced record gas demand driven by heating demand, mild Southern California weather during the polar vortex led to below-average core demand. Gas Acquisition served core demand and incurred no operational flow order (OFO) penalties.[4] Three factors helped to balance Southern California supply and demand during this time: mild weather, gas storage, and reductions in noncore demand.

While gas storage typically addresses variations in demand, in this case it supported a drop in supply. On the coldest day in Southern California, January 26, demand was 3,637 MMcfd and pipeline receipts reached 2,748 MMcfd.[5] As Uri approached and gas prices increased, pipeline receipts dropped daily after February 3, reaching a low of 1,344 MMcfd on February 15, when demand was 2,231 MMcfd. Storage helped fill the resulting gap. On that day, 945 MMcfd was withdrawn from storage, nearly equaling the 990 MMcfd withdrawn on January 26, despite the latter having much higher demand.

Demand reductions also played a substantial role in balancing the Southern California gas system during Winter Storm Uri. Most of this reduction came from noncore demand. The greatest reductions occurred in gas consumption for electric generation (EG). While California electricity load continued to be served, EG gas use dropped by 75 percent on February 16, in the middle of the storm. It was relatively flat throughout

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[3] For information on the amount of firm interstate pipeline capacity Gas Acquisition is required to hold, see SoCalGas, Advice Letter 3969: Request to Continue SoCalGas Interstate Pipeline Capacity Acquisition Procedures, approved April 3, 2009, available at https://tariff.socalgas.com/regulatory/tariffs/tm2/pdf/3969.pdf.

[4] Penalties are charged to gas customers who consumed more than they delivered during a low OFO or less than they delivered during a high OFO. See "Gas Prices" section below for more on OFOs.

[5] These data are for a midnight-to-midnight day, whereas some data use a 7 AM to 7 AM day.

the day during February 14-16 rather than showing its usual morning and evening peaks. Some use of gas for electricity generation shifted to Northern California during this time.

Noncore, non-EG usage reduced to a lesser extent, dropping by 25 percent. Even though noncore customers' usage declined, they still delivered less gas than they burned, causing them to accrue over $1.4 million in low OFO penalties. Some shippers may have been able to sell their gas elsewhere for higher prices. These reductions in noncore demand reflect shippers' economic response to the interaction of price and availability, resulting in gas directed away from California to higher-price areas.

The national experience during the storm points to these and additional lessons, as noted by the Federal Energy Regulatory Commission (FERC) and other observers. Weather patterns continue to drive peak demand and merit more precise forecasting. Without well winterization, Texas gas supplies will continue to be at the mercy of cold weather. Industrial gas demand reduction can absorb some of the reduction in supply, as can electricity demand when the weather is mild. However, electricity demand for heating can increase during storms and will rely on gas until alternatives are available. Gas-electric interface policies, including gas generators' contract structures, electric loading order, and gas curtailment order, therefore play key roles during extreme weather events. Given the energy system changes ahead, FERC and others have asserted these patterns merit increased policy coordination among industry participants and regulating agencies.

For related discussion of winter 2020-2021, see the CPUC's "Southern California Gas Company Summer 2021 Technical Assessment."[6]

Weather and Daily Demand

Southern California weather and gas demand were moderate in winter 2020-21, also referred to as "this winter" in this report. Weather was slightly colder than the previous year, but demand was slightly lower. Note that the COVID-19 pandemic complicates recent year-to-year comparisons of total demand since both residential and commercial demand patterns changed significantly during this period. The coldest day and highest demand this winter occurred during the strongest storm.

Gas demand forecasts often use heating degree days, which are defined as each day's degrees Fahrenheit below 65 degrees. That is, each degree below 65 on a given day is counted as a heating degree-day. For example, a day that is 60 degrees Fahrenheit has 5 HDD. Thus, colder days have more heating degree days. If the temperature is 65 degrees or warmer, there are no heating degree days (HDD) that day. These degree-days are used to signify potential indoor heating demand. This winter had an average of 7.0 HDD per day, up from the previous winter's 6.6 daily average HDD, but still well below the 8.1 daily average HDD seen in the winter of 2010-2011, which was the coldest winter in the preceding decade. Similarly, the coldest day this winter had 17.5 HDD, just over a degree colder in HDD than the previous year's coldest day, but still much warmer than the 19.6 HDDs seen on the coldest day in the past 10 years. The standard deviation of

[6] CPUC, *Southern California Gas Company Summer 2021 Technical Assessment,* April 2021, https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/natural-gas/aliso-canyon/socalgas-summer-2021-technical-assessment.pdf.

HDD within this winter was 3.8 HDD, compared to an average of 4.3 for the last 10 years, which indicates that daily temperatures this winter varied less than usual.

Table 1: Heating Degree Days in Recent Winters

	Coldest Winter in Previous 10 Years	10-Year Average	Preceding Winter	This Winter
Years	2010-2011	2010-2020	2019-2020	2020-2021
Coldest Date	Dec 31	Jan 2	Nov 28	Jan 26
Coldest Day HDD	19.6	17.9	16.3	17.5
Average Daily HDD	8.1	6.4	6.6	7.0
Standard Deviation of HDD	4.7	4.3	3.9	3.8

Data from CPUC data request to SoCalGas.

Southern California was not merely cold on January 26; an atmospheric river brought the biggest storm of California's season. Snow closed down the "grapevine" portion of the Interstate 4 highway, and the Los Angeles Basin saw hail and downpours. Northern and Central California were also affected, with some areas receiving record rainfall.

While weather in California warmed after January, national weather saw a historic cold spell. During February 13-18, Sudden Stratospheric Warming over the north pole brought polar vortex weather from arctic regions south into the U.S. The resulting Winter Storm Uri covered 73 percent of the continental U.S. in snow by February 17, and some locations reached their lowest temperatures in a century. This dramatic cold, interacting with policy and infrastructure, affected gas and electricity systems in many U.S. states, especially in the Southwest. Texas experienced the most dramatic impacts, including an approximately 50 percent drop in gas production. Since California gets most of its gas from out of state, and Southern California relies on gas from the most affected regions, these events also impacted the Southern California gas system.

Average daily demand for Southern California (including SoCalGas and SDG&E) this winter was 2,703 MMcfd (million metric cubic feet per day), down 5 percent from the 10-year average. This decrease is consistent with the moderate weather and a long-term trend of declining demand, although it is likely complicated by pandemic-related shifts in demand. The highest daily total demand this winter was 3,895 MMcfd, down 3 percent from the 10-year average. Peak demand typically occurs during cold periods, although not necessarily on the coldest day of the winter, as can be seen by comparing Tables 1 and 2. This winter, total demand peaked on January 25, during the strongest storm of the season, one day before the coldest day. Peak demand was well below the 10-year peak and the forecast "1-in-10" cold day demand used as the utility's design standard.

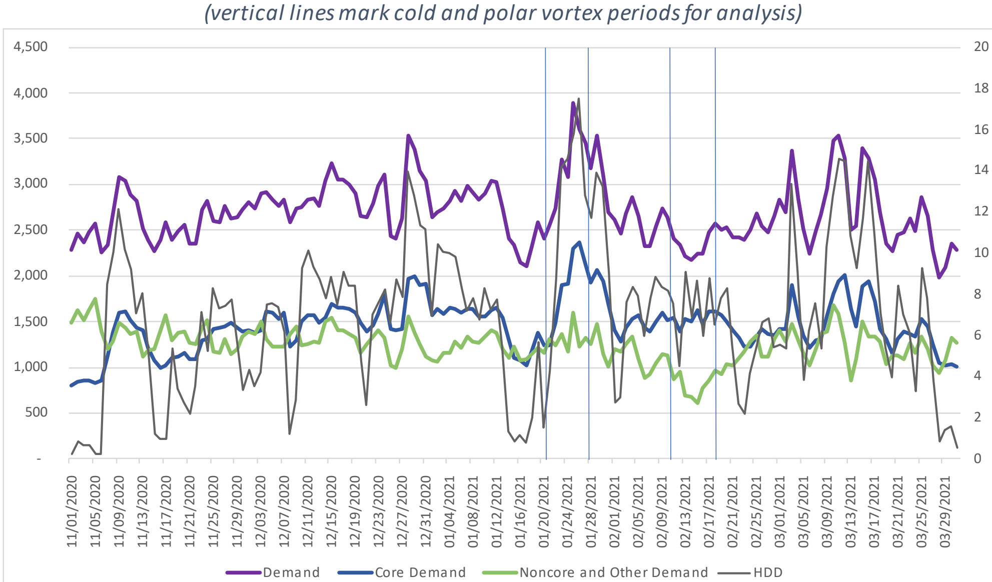
Table 2: Demand in Recent Winters (MMcfd)

	Coldest Winter in Previous 10 Years	Highest Demand Winter in Previous 10 Years	10-Year Average	Preceding Winter	This Winter	1-in-10 Demand Forecast
Year	2010-2011	2012-2013	2010-2020	2019-2020	2020-2021	For 2020-2021
Highest Demand Date	Nov 29	Jan 14	N/A	Dec 18	Jan 25	Dec/Jan
Highest Demand	4,328	5,056	4,236	3,937	3,895	4,983
Lowest Demand Date	Mar 12	Mar 31	NA	Nov 17	Mar 28	N/A
Lowest Demand	2,193	2,105	2,014	2,052	1,988	N/A
Average Day	3,025	3,081	2,847	2,790	2,703	N/A
Daily Standard Deviation	468	566	455	396	348	N/A

Data from Envoy. Days are 7 AM to 7 AM.

Demand patterns for core demand, other demand, and total demand relative to HDD are shown in Figure 1. Core retail demand (blue line in Figure 1) peaks when HDDs peak (thin gray line), as seen on the high demand days of November 9-10, December 28-29, January 25-26, and March 3, 11-12, and 15-16. Core demand this winter began at a low of 798 MMcfd on November 1 and peaked at 2,371 MMcfd on January 26. Other demand (pale green line) sometimes peaks on these cold days, especially towards the beginning of a cold spell, as on December 28, January 25, March 10, and March 15, but other times stays near its average levels while core is peaking, as on December 29-January 1, January 26-28 and March 16-17. Other demand reached its lowest levels all winter during the polar vortex, as will be discussed below.

Figure 1: Daily Demand (MMcfd) and HDDs During Winter 2020-2021
(vertical lines mark cold and polar vortex periods for analysis)

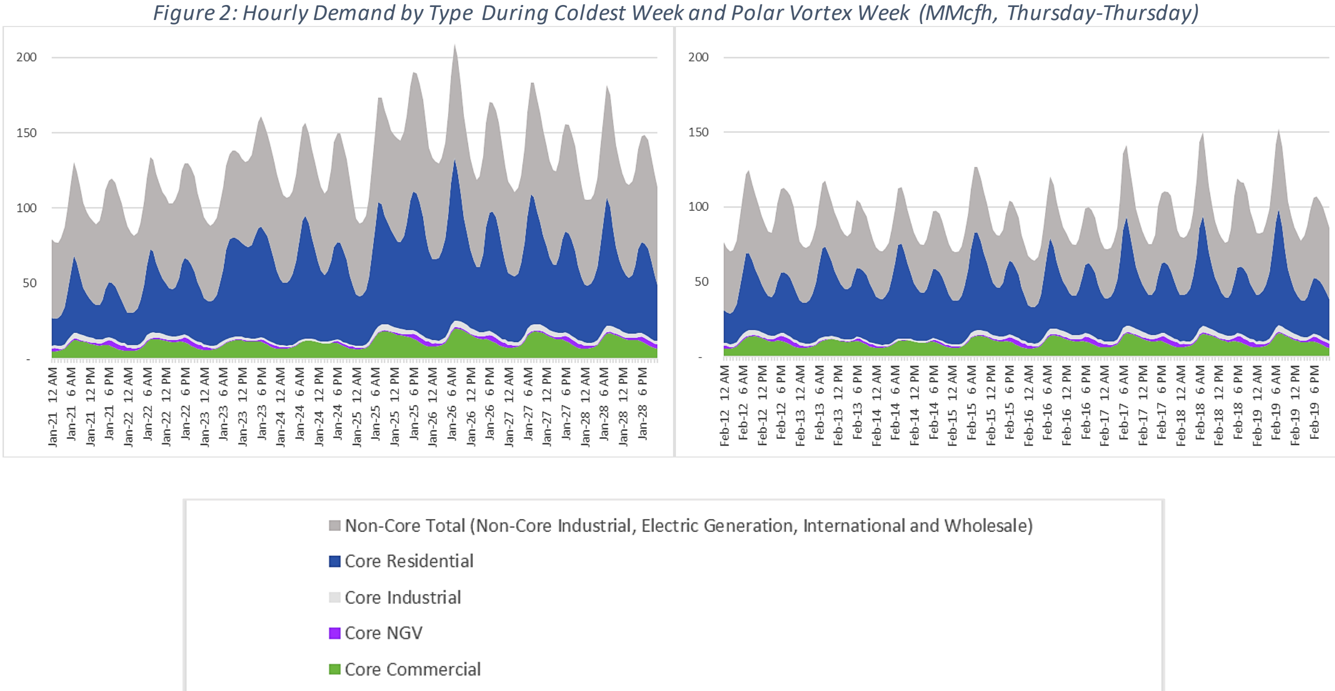


Data from data request to SoCalGas.

This report's discussion of hourly and daily gas system dynamics this winter will focus on the two Thursday-through-Thursday periods marked by vertical lines in Figure 1: January 21-28, the period surrounding the coldest day this winter, and February 11-18, the polar vortex period. Additional analysis will discuss the eight days preceding the polar vortex period, and for comparison, the first eight days of winter.

Hourly peak demand in winter is driven largely by morning and evening peaks in core residential demand, as seen in Figure 2. Winter gas demand typically peaks within 5AM – 10 AM. Note that in these charts, "Noncore Total" consists of gas delivered to gas-fired electric generation, other large industrial customers, and other wholesale or international customers including utilities and customers in Mexico. San Diego Gas & Electric gas load is classified as wholesale and included in the noncore totals. Demand during the polar vortex, shown on the right, was similar in shape and lower in quantity than during the coldest week, shown on the left. Commercial demand varies less than core demand but also features two daily peaks. Core natural gas vehicle demand (NGV) is small and contributes to an evening peak.

Figure 2: Hourly Demand by Type During Coldest Week and Polar Vortex Week (MMcfh, Thursday-Thursday)



Data are consumption during hour beginning with time shown.

On average throughout the winter, core demand was 1,406 MMcfd and noncore demand was 1,298 MMcfd. Heating degree days explain 69 percent of the variance in core deliveries, while they explain zero percent of the variance in total noncore winter demand.

However, weather may have a more meaningful relationship with some subcategories of noncore demand.[7] In particular, noncore electric generation (EG) demand—gas for gas-fired power plants—appears to have

[7] CPUC Decision D.14-15-016 specifies that the Decision "follow[s] a 15/15 Rule for the public posting of data concerning commercial, industrial and agricultural data. We anticipate that more information, including procedures for masking data, will permit us to depart from this requirement in the future." A 15/15 rule refers to keeping confidential any subtotal that

an interesting relationship with weather. Heating degree days explain a statistically significant 3 percent of variation in electric generation demand and are negatively correlated, meaning that during this winter, electric generation demand went down slightly when temperatures dropped. Electric utility decisions to rely less on gas generation during cold days may have contributed to this pattern. However, during some periods, such as mid-March, EG demand rose and fell with HDDs rather than opposite them. EG demand peaked this winter on January 9, a day with HDDs barely above zero.

The most significant drop in EG demand this winter occurred during the polar vortex, when EG demand was well below its usual levels for several days, reaching a low of 25 percent of its winter average on February 16. Average daily EG demand was only 144 MMcfd during February 15-17, and was nearly flat throughout the day during February 14-16, rather than peaking twice a day, as it usually does.

Although the resulting electricity generated from natural gas and consumed in Southern California fell during approximately February 12-20, it appears that increased fossil fuel use elsewhere helped fill in the gap.[8] Gas-generated electricity in Northern California increased during February 13-18, compared to the rest of February, and coal use to serve Southern California increased during February 12-18.[9] While no gas was curtailed during this time, the reduction in Southern California gas-generated electricity production may reflect plants minimizing their operations in light of the polar vortex and its effects on gas prices, including via the cost of Operational Flow Orders (OFO). OFOs and prices during the polar vortex are discussed further below.

Compared to core and EG demand, noncore, non-electricity load—that is, refinery, enhanced oil recovery, other noncore industrial, and noncore commercial demand, collectively considered industrial load—was relatively constant during much of the winter. However, it too dropped during the polar vortex to 75 percent of its average this winter. The total drop in noncore demand this winter is reflected in Figures 1 and 2.

Core Demand Forecasting and Purchasing

SoCalGas' Gas Acquisition Department (Gas Acquisition) purchases gas for all core customers. To predict how much gas will be needed, this department uses its own daily demand forecasts. While actual HDDs explain much of estimated actual core demand, forecasts explain more, even though they are created before actual HDDs are known.[10] Across the winter, 87 percent of variation in daily demand is explained by forecasts, while 82 percent is explained by HDDs. During February 13-18, the height of the polar vortex, while actual HDDs explained only 27 percent of core demand variation, forecasts were able to account for

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includes fewer than 15 customers, or any single customer account reflecting more than 15 percent of the total. Electric generation demand and other subcategories of noncore demand include some customers which account for more than 15 percent of their subcategories' totals, on most days. On February 15-17, no customer accounted for more than 15 percent of EG demand.

[8] Based on CPUC analysis of generator-specific data provided by the California Independent System Operator. Some electricity imported from out of state is not associated with a particular generation source.

[9] Northern California gas prices were below Southern California gas prices during this time.

[10] Percent of variance explained is a measure of how accurately the estimated actual core demand can be predicted using the explanatory variable (HDD or forecast). If the percent were 100%, it would mean that demand can be predicted with complete accuracy using only the explanatory variable.

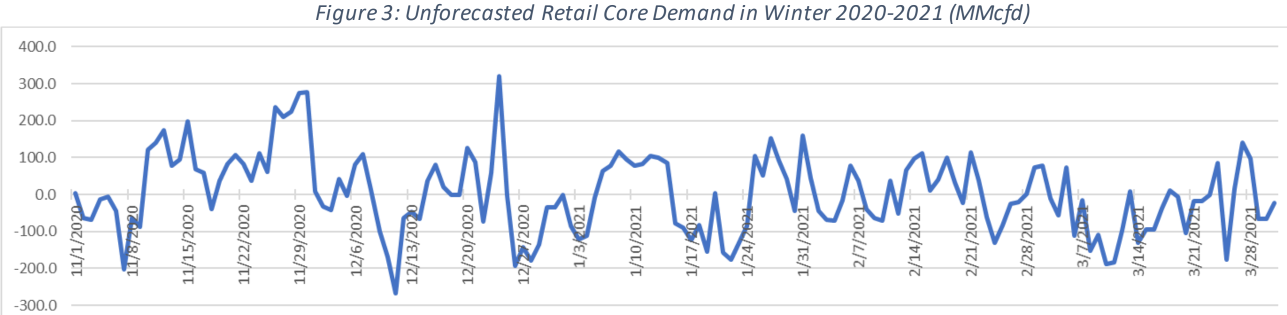
59 percent of variation in core demand. That is, HDDs alone are a good predictor of core demand but SoCalGas' forecasts are better, including under unusual conditions.

Table 3: Percent of Variance in Daily Estimated Retail Core Demand Explained

	Explained by HDD	Explained by Forecast
Winter	82%	87%
OFO Days	87%	88%
Jan 21-28	90%	92%
Feb 11-18	59%	55%
Feb 13-18	27%	59%

This winter, actual burn was within +/- 5 percent of the forecast on about 43 percent of days (compared to 51 percent the previous winter) and within +/- 10 percent on 84 percent of days (compared to 80 percent the previous winter). Average forecasts and average actual demand were equal. As seen in Figure 3, days with more than 200 MMcfd of unforecasted demand were November 26-31, i.e., Thanksgiving Day through the following Monday; and December 24, Christmas Eve. Actual core demand on these days was not unusually high (see Figure 1). Consistent with this, the percentage of unforecasted demand explained by unforecasted cold (forecasted temperature minus actual temperature) is 4 percent, indicating that unforecasted demand is not generally attributable to weather forecast inaccuracy but to other factors.

Figure 3: Unforecasted Retail Core Demand in Winter 2020-2021 (MMcfd)



CPUC analysis of data from data request to SoCalGas.

During the previous winter, Gas Acquisition was required to use forecasted gas use as the target which they purchased gas to match. Since April 2020, Gas Acquisition has instead been required to balance their gas purchases to their estimated actual demand.[11] Like other wholesale gas customers, Gas Acquisition is not required to match the gas deliveries they receive one-to-one with the demand they serve; rather, they must be within plus or minus 8 percent on a monthly basis or pay additional costs. For days when an Operational Flow Order is called, they must be within 5 percent or incur financial penalties (see OFO discussion below).

Gas Acquisition's total daily gas purchases (aka "deliveries") this winter exceeded core demand by 2 percent, or 33 MMcfd. The difference between Gas Acquisition's purchases and core demand on a given day had a standard deviation equivalent to 10 percent of demand, meaning that deliveries are commonly 10 percent

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[11] CPUC, Decision D.19-08-002, August 2019, http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M310/K135/310135933.PDF.

above or below actual demand. Nevertheless, for the underforecasted days discussed above, underdeliveries were never beyond 150 MMcfd. These calculations use a midnight-to-midnight day, whereas OFO gas balancing requirements use a 7AM-7AM day. Gas Acquisition incurred lower OFO penalties for underdeliveries than incurred by noncore shippers, as discussed later in this report.

Gas Acquisition uses a variety of contract types to purchase gas over various time periods. If the average purchase price is below a calculated benchmark, the resulting savings are split between SoCalGas and ratepayers, per the Gas Cost Incentive Mechanism. This winter, the resulting savings were $185 million.[12] February made up a substantial proportion of these savings and may reflect Gas Acquisition's taking the opportunity to sell excess gas to higher demand areas outside California.

Separately from Gas Acquisition, SoCalGas' System Operator, which operates their gas system and balances receipts and deliveries in real time, is allowed to purchase gas if needed to maintain reliability on its Southern System. However, no such purchases were made this winter.

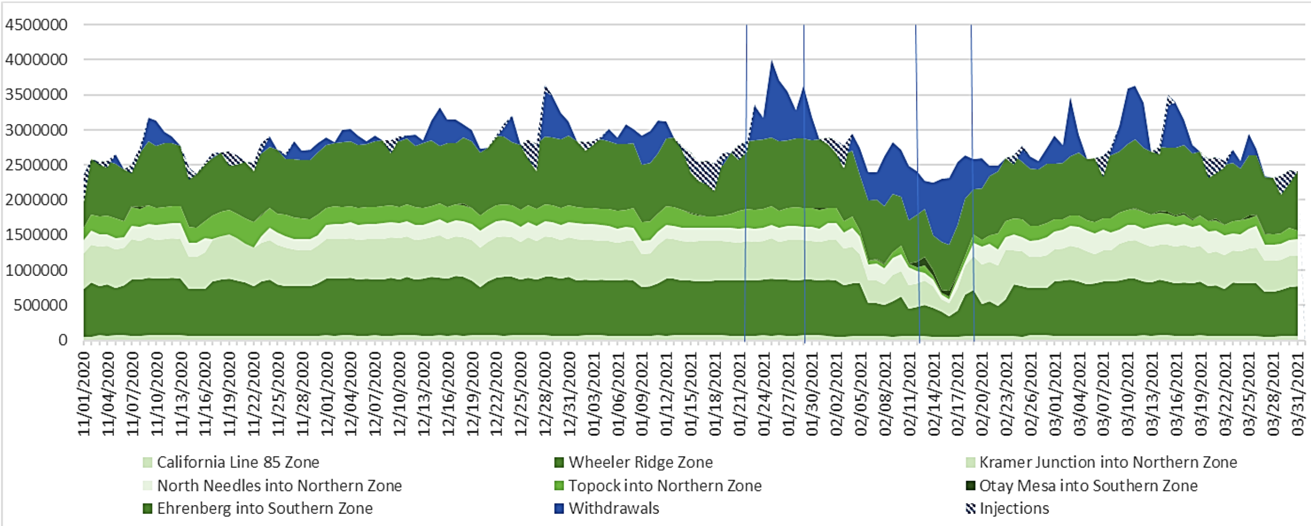
Meeting Demand

Across the winter season, 95 percent of customer demand was met with pipeline receipts. Gross storage withdrawals filled 9 percent of demand. These sum to more than 100 percent, with the difference roughly representing gross injections. A detailed gas balance, reflecting actual data for the past winter, is given in Appendix A.

Figure 4 shows the use of pipeline receipts and storage throughout the winter, with vertical lines indicating the cold and polar vortex periods. Consistent out-of-state pipeline receipts filled most daily demand, with substantial drops during the polar vortex period. Storage withdrawals played their largest role this winter during the cold and polar vortex periods.

[12] SoCalGas, "Application of Southern California Gas Company Regarding Year 27 (2020-2021) of its Gas Cost Incentive Mechanism," June 2021, https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M388/K519/388519086.PDF.

Figure 4: Daily Pipeline Receipts and Storage Withdrawals/Injections in Winter 2020-2021 (MMcfd)



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Gas demand was met on a daily basis with gas received by pipeline, withdrawn from storage fields, and withdrawn from linepack, i.e., gas that is "stored" in the pipelines themselves. The bulk of supplies came from pipeline receipts, supplemented by storage withdrawals on selected days. Unlike electricity, supplies do not need to equal demand at all moments; rather, the difference is made up by linepack. The contributions of these three sources to gas supply during different periods this winter are shown in Table 4. Demand filled by linepack shows the percentage of demand which was in excess of supply and thus fulfilled by linepack, on an hourly basis. For example, during November 1-8, linepack supplied up to 25 percent of demand during any given hour, and during other hours, absorbed supplies that were up to 37 percent above demand. The roles of pipeline supplies, storage withdrawals, injections, and linepack during the cold period and polar vortex period are discussed below.

Table 4. Supply and Demand During Periods of Winter 2020-2021 (MMcfd)

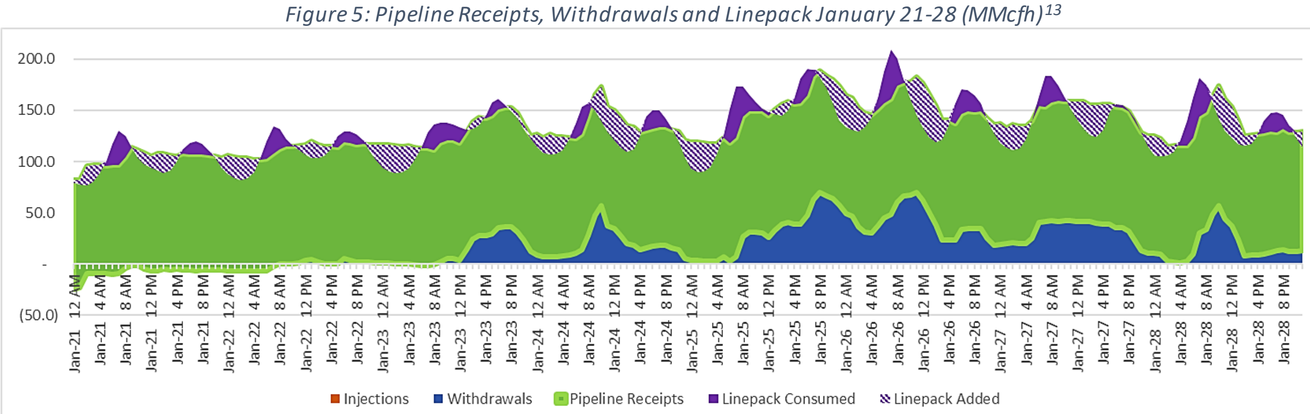
	Average Demand	Average Pipeline Receipts	Average Net Storage Withdrawals				Demand Filled by Linepack Minimum	Demand Filled by Linepack Maximum
	Total	Total	Aliso Canyon	Honor Rancho	La Goleta	Playa del Rey		
Winter	2,656	2,517	104	38	33	(2)		
November 1-8	2,358	2,417	(17)	(11)	40	(16)	-37%	25%
January 21-28	3,114	2,748	255	63	103	12	-28%	22%
January 26	3,637	2,748	612	157	197	24	-32%	29%
February 3-10	2,521	2,189	311	18	49	-	-34%	26%
February 11-18	2,275	1,603	417	217	101	1	-35%	25%

February 15	2,231	1,344	455	375	112	6	-34%	33%

Data from data request to SoCalGas. Days are midnight to midnight and therefore may not match Table 2.

Figure 5 shows the roles of pipeline receipts, storage withdrawals and linepack during the coldest week this winter. Storage withdrawals are shown in blue at the bottom of the figure. Quantities below the horizontal axis seen on January 21-22 represent injections into storage. The graphs do not have a separate color for storage injections because the colors show the source of the gas that was injected (pipeline receipts). Injections sometimes occur on the same day as withdrawals, not necessarily from the same storage fields. The area outlined in light green shows pipeline supplies. For linepack, solid purple areas extending above the green area and striped-purple extending down into the green area show positive and negative amounts of linepack consumed, reflecting the role of linepack in alternately absorbing supply and providing it. Thus, the upper green line shows total supply while the outline of the solid and striped-purple areas shows total demand. In many cases, e.g., the January 26 four AM to noon period seen in the middle of the figure, demand peaks and withdrawals peak hours thereafter to refill linepack. Since neither storage withdrawals nor supply match hourly demand, linepack fills in the difference.

Figure 5: Pipeline Receipts, Withdrawals and Linepack January 21-28 (MMcfh)[13]



On an average day for this cold period, hourly linepack ranged from providing 21 percent of load to absorbing supply 29 percent above load. Linepack as shown here represents the difference between hourly measured demand and other supply sources, and therefore also includes lost and unaccounted for gas (LUAF) as well as the small amount consumed by SoCalGas itself (company use) and other non-hourly-metered demand. This approach is used so that the total equals total load; daily patterns are similar regardless of whether this measure or a more direct measure of linepack is used.[14]

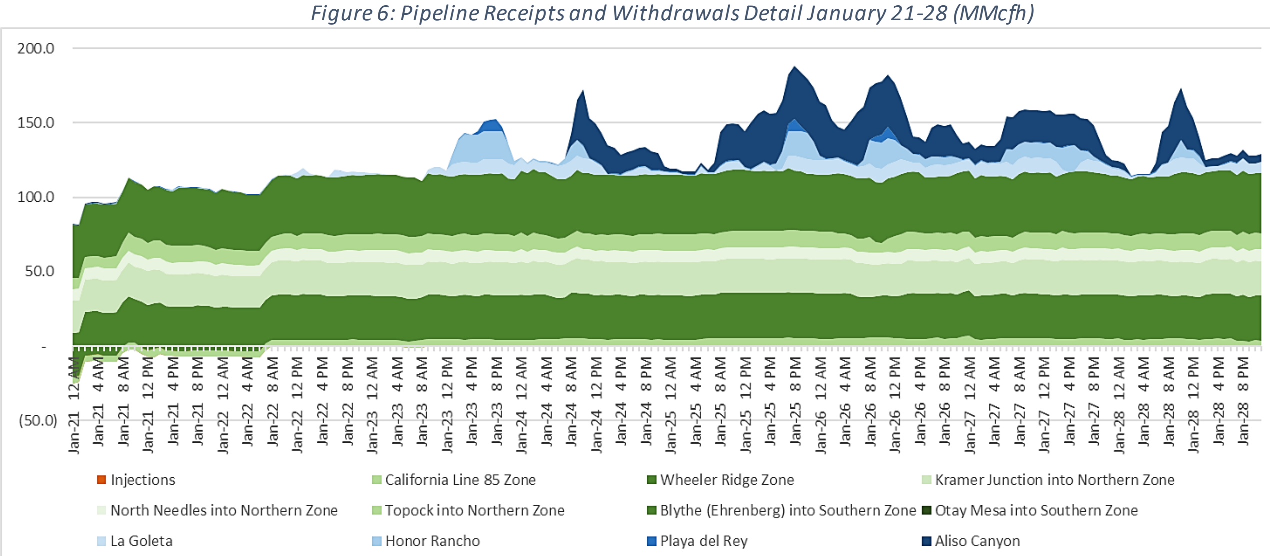
While linepack played a similar role each day, the use of storage varied significantly during this cold week. Overall, withdrawals from storage played a relatively large role in meeting demand, shown in Figure 5. These are shown in further detail in Figure 6, which shows receipts by receipt point and storage field; for clarity linepack is no longer shown. As above, amounts below the x axis represent injections. On January 23, storage withdrawals came from Honor Rancho, La Goleta, and Playa del Rey, with Playa del Rey

[13] Million cubic feet per hour.

[14] On average for January 21-28, directly measured linepack ranged from providing 26% of load to absorbing 21% of load.

contributing a smaller amount for a shorter time. As the cold weather continued, storage withdrawals rose several times during January 24-28, with Aliso Canyon often contributing more than half, and the remaining storage withdrawals coming largely from Honor Rancho and La Goleta. On January 26, the coldest day of the year, Aliso withdrawals totaled 612 MMcfd and non-Aliso withdrawals 378 MMcfd. Pipeline receipts throughout the period averaged 115 MMcf per hour, or 2,748 MMcfd, and varied little. Daily load shapes on January 26–28 were quite similar, as shown in Figure 5, but the timing of storage withdrawals was noticeably different, as shown in Figure 6, with linepack addressing the difference.

Figure 6: Pipeline Receipts and Withdrawals Detail January 21-28 (MMcfh)



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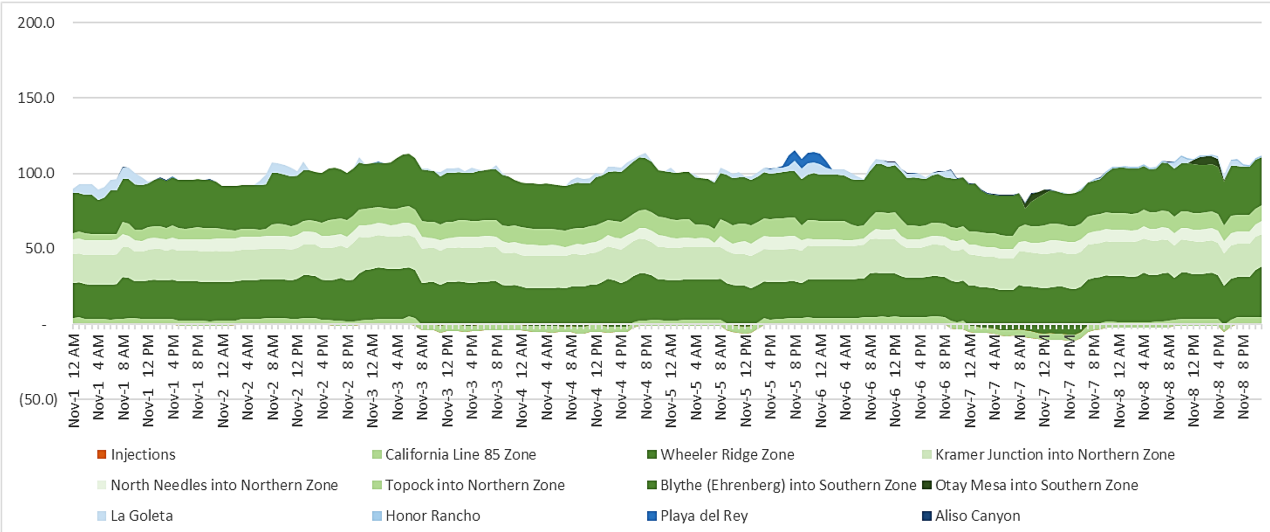
For comparison, the first week of winter, which included the warmest days this winter (November 1, 5, 6), is shown in Figure 7. This period saw consistent receipts at most pipeline receipt points as well as injections into storage and low withdrawals, largely from La Goleta and Playa del Rey storage fields. When the weather turned colder on November 7 and 8, gas was also brought in at Otay Mesa, a less-used pipeline receipt point connecting to Mexico. Average hourly pipeline receipts were 101 MMcf, or 2,417 MMcfd, during these first eight days of the winter gas season.

Figure 7: Pipeline Receipts and Withdrawals Detail November 1-8 (MMcfh)



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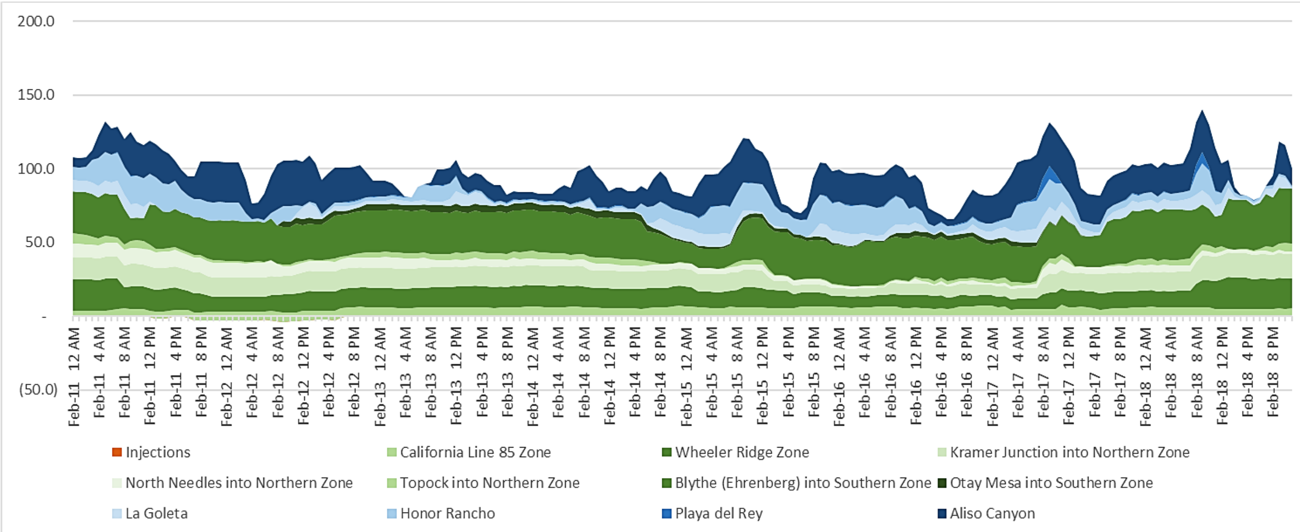
During the polar vortex, shown in Figure 8, less demand was filled with pipeline receipts and more with storage withdrawals. Southern California weather during this time was mild, averaging only 7.3 HDD daily. Pipeline receipts, which had reached 2,748 MMcfd on January 26, fell to 1,817 MMcfd on February 13, the first day of major polar vortex conditions outside California. Receipts from the east—North Needles, Topock, and Blythe (Ehrenberg)—and even from the north—Wheeler Ridge and Kramer Junction—dropped further for repeated periods during February 14-17. Total receipts reached an hourly low of 47 MMcfh at 4 AM on February 15, the lowest this winter, compared to a winter average of 105 MMcfh. Daily receipts bottomed out at 1,295 MMcfd on February 16. Receipt point utilization—the percentage of available pipeline capacity used on a given day—for gas entering Southern California pipelines reached its lowest level at 47 percent on February 17 (Cycle 3). Gas was purchased at Otay Mesa throughout much of February 12-17.

These low pipeline receipts likely resulted from high out-of-state demand, low production, and the resulting high price conditions. National gas production fell roughly 16.7 percent from above 90 billion cubic feet per day (Bcfd) to around 75 Bcfd, while Permian production fell about 25 percent from around 12 Bcfd to below 9 Bcfd. Pipelines reaching Southern California from the east draw much of their gas from the Permian Basin in Texas and New Mexico. Many gas wells in this area do not have heating equipment sufficient to operate during freezing conditions and/or require electricity from the grid to operate and therefore were not able to provide gas during the extreme cold and power shutoffs that occurred. The El Paso interstate pipeline system, which supplies Southern California's eastern gas receipt points, experienced systemwide draft— dropping pressure due to low volumes of gas—and cut firm deliveries in the face of unavailable supply. The reduction in Southern California pipeline receipts may also reflect some shippers' decisions to sell their gas to buyers outside of the region, taking advantage of higher prices.

Figure 8: Pipeline Receipts and Withdrawals Detail February 11-18, Including the Polar Vortex Period (MMcfh)



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While storage typically addresses variation in demand, in this case it also helped fill in for a drop in supply. Withdrawals from La Goleta, Honor Rancho, Aliso Canyon, and occasionally during peak times, Playa del Rey, made up for the drop in pipeline receipts. From February 11–18, 5,953 MMcf of gas was withdrawn from storage, bringing total storage levels down to 60 billion cubic feet (Bcf). Daily pipeline receipts didn't rise back to 2,401 MMcfd, or 100 MMcfh, until February 23 (not shown), a warmer day (HDD= 2.65) when gas was injected into storage. Daily withdrawals from storage during February 10-19 are shown in Table 5.

Table 5: Daily Storage Withdrawals February 10-19 (MMcfd)

	2/10	2/11	2/12	2/13	2/14	2/15	2/16	2/17	2/18	2/19
Non-Aliso	643	863	613	369	753	964	806	898	602	361
Aliso Canyon	376	350	177	156	335	508	360	356	238	197
Total	1,019	1,213	790	525	1,088	1,472	1,166	1,254	840	558

The trend of price increases and pipeline receipt decreases began in early February, during the week *preceding* the polar vortex. Receipts for the week of February 3-10 are shown in Figure 9 and prices in Table 6. This week foreshadowed the vortex that was to come. On February 3, pipeline receipts totaled 2,671 MMcfd, and gas was injected into storage until the 7 AM end of the preceding gas day. Receipts dropped daily after this, as prices rose, increased on February 9 and 10 when prices fell slightly. then declined again when prices increased by over a dollar on February 11. The greatest reductions in pipeline receipts occurred at Wheeler Ridge, Kramer Junction, and Topock (north and northeast). The largest daily drop in pipeline receipts during the month of February, even greater than during the vortex itself, occurred between February 5 and 6. Between these two days, prices at the SoCal Border increased from $2.94 to $3.51 and pipeline receipts dropped from 2,420 MMcfd to 2,041 MMcfd. Storage withdrawals that week grew to meet the demand not met by receipts, reaching a high of 807 MMcfd on February 9. SoCalGas withdrew gas from Aliso Canyon during early February per Condition 2 of the Aliso Canyon Withdrawal Protocol, since the Aliso Canyon inventory was above 70 percent.[15] Forecasts of impending polar vortex weather may also have contributed to price increases and shippers' decisions to reduce pipeline receipts.

Figure 9: Pipeline Receipts and Withdrawals Detail February 3-10, Preceding the Polar Vortex

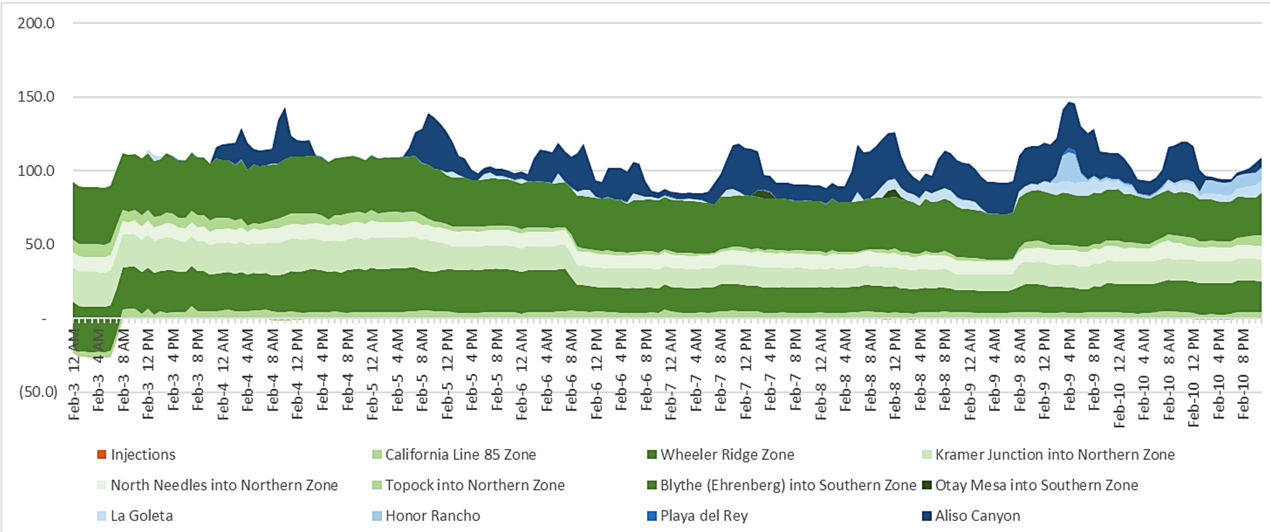

Table 6: Daily Gas Prices February 1-11 ($/MMBtu)

	2/1	2/2	2/3	2/4	2/5	2/6	2/9	2/10	2/11
SoCal Citygate	3.295	3.14	3.24	3.175	3.07	3.655	3.525	3.595	4.97
SoCal Border Average	2.865	2.87	2.99	2.965	2.94	3.51	3.445	3.47	4.665

As discussed, gas in storage was drawn down significantly during the January cold period and polar vortex periods, as seen in Figure 10. Nevertheless, SoCalGas ended this winter (March 31) with 53 Bcf of gas in storage, slightly above last year's level and well above the minimum 15.3 Bcf SoCalGas has defined as necessary for reliability.[16]

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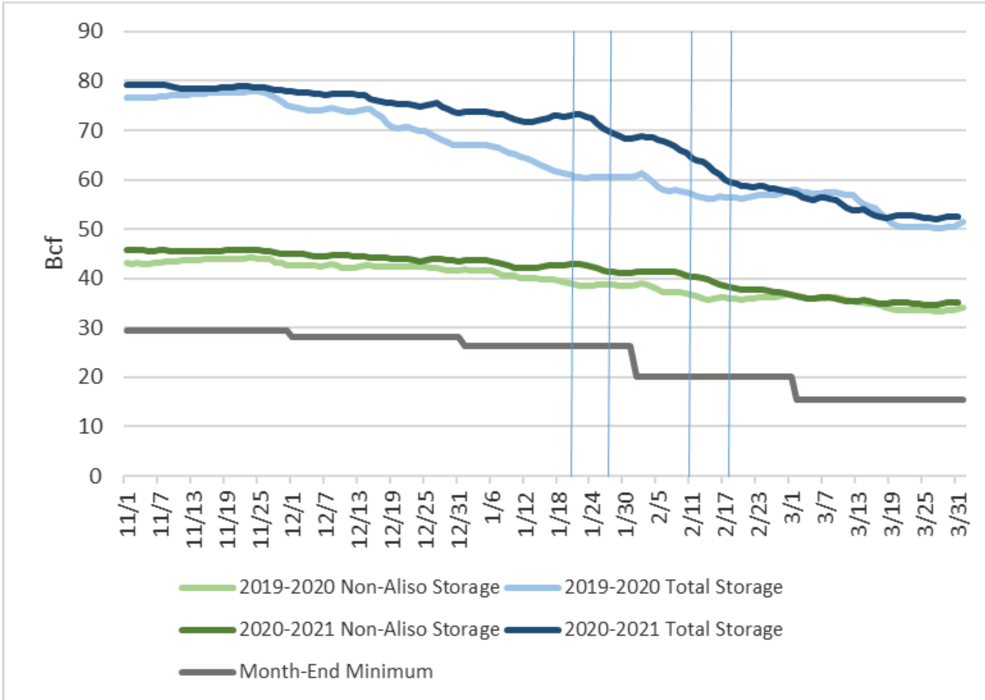
[15] CPUC, *Aliso Canyon Withdrawal Protocol*, revised in April 2020, available at https://www.cpuc.ca.gov/-/media/cpuc-website/files/uploadedfiles/cpucwebsite/content/news_room/newsupdates/2020/withdrawalprotocol-revised-april12020clean.pdf. Month-end minimums in this document are not current; see footnote 11 for current values.

[16] Defined in Southern California Gas Company, *Southern California Gas Company Comments Aliso Canyon Risk Assessment Technical Report Winter 2018-19 Supplement*, November 2018, https://efiling.energy.ca.gov/GetDocument.aspx?tn=225785&DocumentContentId=56458.

Figure 10: Comparison of Winter 2019-20 and Winter 2020-21 Storage Inventory with Month-End Minimums



The role of linepack continued during the polar vortex. During the polar vortex and cold week periods, linepack did not fall unusually low. During February 3-10, it ranged from absorbing 38 percent above demand to supplying 33 percent of demand. During February 11-18, calculated linepack ranged from absorbing supply 51 percent above demand to supplying 33 percent of demand (February 16). The somewhat high amount it absorbed may reflect SoCalGas allowing linepack to trend high in order to "store" gas as a hedge against possible drops in other supplies. Linepack usage maximum and minimum levels are shown in Table 4 (above), showing that the outer bounds of linepack use during the polar vortex were not more extreme than during comparison periods discussed in this report. Note that *recorded* linepack dropped significantly lower during Thanksgiving week than either the polar vortex or coldest week. Thanksgiving week was another period with relatively low temperatures (HDD=8.30 on November 25) and high demand.

Demand was met throughout the winter with the exception of maintenance-related curtailments. SoCalGas posted a curtailment watch for its Southern Zone from February 14 through 19, but no curtailment occurred.

Gas Prices

Southern California Citygate gas prices averaged $3.85/MMBtu this winter if the polar vortex week is excluded. This is 10 cents higher than the previous year's winter average. Citygate prices include the cost of transporting the gas from the SoCal Border to the customer. At the SoCal Border, prices were up even more compared to the previous winter, at $3.09 excluding the polar vortex week, compared to $2.28 the previous winter. Daily price variation was down slightly at both the Border and Citygate, as reflected in lower standard deviations. These are prices for daily gas markets (spot market); longer contracts and price hedging are not addressed here. Table 7 shows spot gas prices for the periods of time whose gas flows are reflected in Table 4.

Table 7. Spot Gas Prices During Periods of Winter 2020-2021 and Winter 2019-2020 ($/MMBtu)

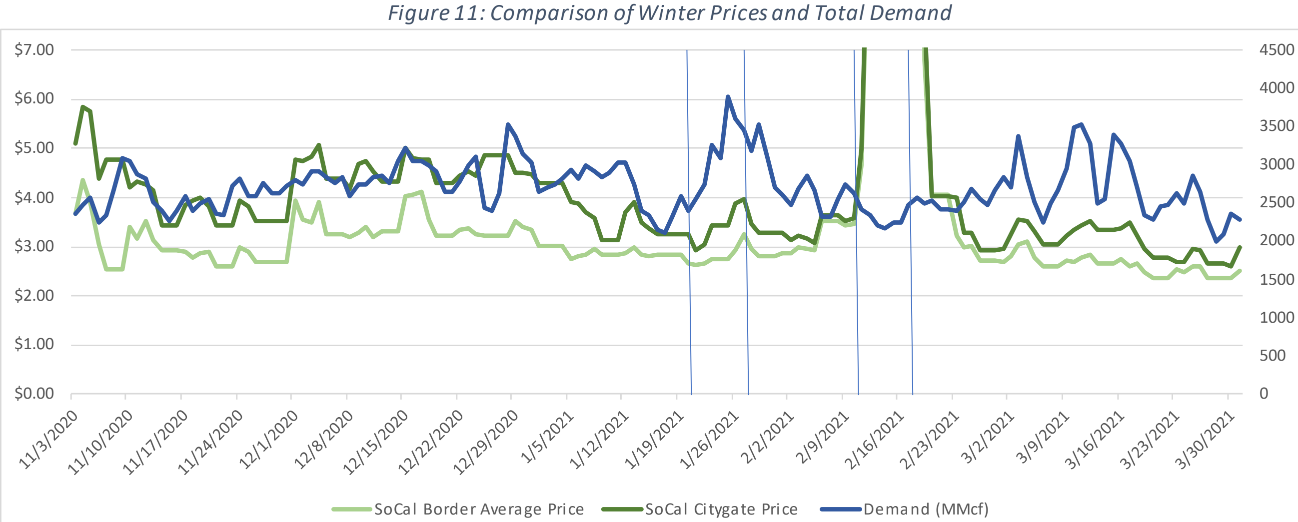
	SoCal Border			SoCal Citygate		
	Median	Average	Standard Deviation	Median	Average	Standard Deviation
Winter 2019-20	$2.27	$2.28	$0.62	$3.48	$3.75	$1.52
Winter 2020-21 Excluding February 11-18	$2.94	$3.09	$0.58	$3.68	$3.85	$0.82
Winter 2020-21	$2.97	$5.54	$15.01	$3.81	$6.62	$17.68
November 1-7*	$3.67	$3.50	$ 0.71	$5.10	$5.17	$0.63
January 21-28	$2.83	$2.86	$0.23	$3.44	$3.45	$0.42
January 26	$2.93	$2.93	NA	$3.88	$3.88	NA
February 3-10	$3.22	$3.22	$0.28	$3.38	$3.38	$0.25
February 11-18	$30.14	$52.58	$52.08	$26.93	$59.88	$63.79
February 13	$ 104.31	$104.31	NA	$144.00	$144.00	NA

**Gas is only sold on the daily spot market Monday through Friday and shown here for the first day of its delivery, so there is no price for November 8, January 24-25, February 7-8, February 14-16 (President's Day weekend), or on other weekends/holidays. Gas received during these days is sold on the preceding Friday. Averages are unweighted.*

When the polar vortex week is included, the winter average gas price increases to $5.54 at the Border and $6.62 at the Citygate, reflecting the influence of high prices during that week.

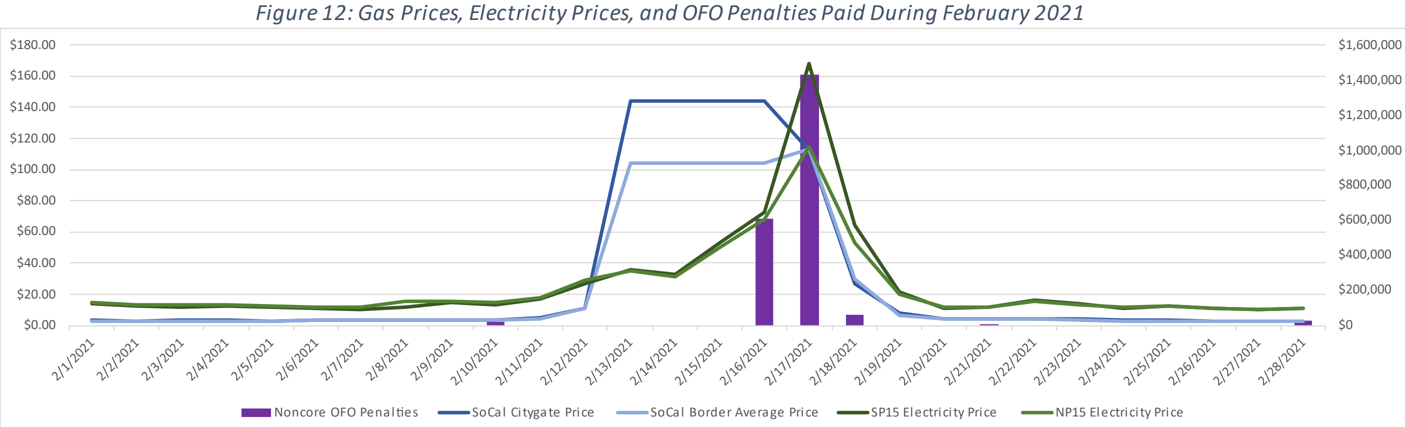
Price dynamics compared to demand are shown in Figure 11. During the cold spell, prices peaked on January 27, although this was far from their highest level this winter. Citygate prices were approaching border average before the polar vortex. Despite demand nearing its lowest all winter, prices saw an uptick around February 5, discussed above in relation to demand, foreshadowing their polar vortex highs.

Figure 11: Comparison of Winter Prices and Total Demand



As in much of the western U.S., SoCal Border average and Citygate prices reached record highs during the polar vortex, as shown in Figure 12. Daily average SoCal Citygate prices rose to $11.29 on February 12 and peaked at $144/MMBtu on February 13 for gas delivered on February 13-16, a three-day weekend with gas prices shown as horizontal lines in Figure 12. Citygate prices fell to just below SoCal border average on February 17, an unusual occurrence reflecting higher demand conditions outside of California. The West Texas/Southeast New Mexico price point was also $144/MMBtu for February 13-16, but rather than falling on February 17, it increased to $195/MMBtu, its high point for the winter. As prices rose, gas shippers serving California may have prioritized selling to out-of-state buyers offering higher prices. Low demand during the polar vortex reflected noncore shippers' response to these pricing conditions and resulted in more gas available to serve historic demand outside California.

Figure 12: Gas Prices, Electricity Prices, and OFO Penalties Paid During February 2021



Left axis corresponds to gas and electric prices. Right axis corresponds to OFO penalties. No core OFO penalties are shown because none were accrued during this time.

These dynamics were particularly dramatic for electricity generation. As noted by the California Independent System Operator (CAISO), Southern California gas prices play a substantial role in setting statewide electricity prices, with high gas prices during the polar vortex resulting in higher electricity prices statewide.[17] Daily electricity prices on CAISO's spot market were previously below $20 per megawatt hour (MWh) but followed a February pattern not unlike gas prices. They began to rise after February 7, dipped for a day on February 10, and continued rising to reach $115/MWh in Northern California and $168/MWh in Southern California on February 17. Some trades occurred at much higher prices, with CAISO waiving conditions to allow after-market cost recovery at prices above $1,000/MWh, effective February 16. While some gas generation continued to occur, the electricity market responded to these conditions by reducing Southern California gas generation, which reached a low of 25 percent of its winter average gas usage on February 16.

Gas generation continued to play a role in serving some electricity demand during the polar vortex. Gas generation increased somewhat on February 17, and the CAISO market provided net exports to serve out-of-state electricity load during some daytime hours each day on February 12-14 and 16-18. This electricity may have helped support other states as they faced historic power outages.

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[17] CAISO, *2021 First Quarter Report on Market Issues and Performance,* June 2021, available at http://www.caiso.com/market/Pages/MarketMonitoring/AnnualQuarterlyReports/Default.aspx.

Figure 12, using the axis on the right, shows the OFO noncompliance penalties paid by noncore customers for providing insufficient gas compared to their usage during the polar vortex. Low OFOs are called when there is insufficient gas on the system. Higher stages mandate increasingly severe financial penalties for gas customers who do not match their gas deliveries with their gas burn. In this way, a low OFO encourages the delivery of more gas. During a Stage 4 low OFO, such as that called from February 16 to 18, gas customers must pay a penalty of $25 for each MMBtu of shortfall if they do not deliver enough gas to the system to fulfill at least 95 percent of their actual gas burn. While OFOs apply equally to noncore gas customers and to Gas Acquisition's purchases on behalf of core customers, only noncore customers accrued OFO penalties during the time shown in Figure 12.

On February 16, noncore gas customers reduced their scheduled gas quantities by 142 MMcf[18] even after the OFO was called, the opposite of the desired effect, likely reflecting low gas availability and high prices. For this they paid $606,345 in penalties. On February 17, customers increased their scheduled quantities by a slight 81 MMcf after the OFO was called, but still paid $1,430,633 for delivering less than their gas burn. Noncore gas customers include gas-fired electric generators.

While the polar vortex saw the largest noncore OFO charges, noncore customers also paid a total of $647,487 in OFO penalties on the next highest day for noncore OFO penalties, November 7. This day saw some of the lowest prices of the winter, and unusually, both low and high OFOs were called on the same day. High penalties on November 7 may be due to the fact that it was a Sunday when it is difficult to execute new gas trades. Noncore OFO penalties totaled less than $53,000 for any single day the rest of the winter.

Gas Acquisition, in purchasing for core demand, did not incur any OFO penalties during the polar vortex. Their highest daily OFO penalties this winter were $109,897 on November 7, and they incurred no other daily OFO charges above $33,000.

While most core customers receive their gas from Gas Acquisition, some opt to be customers of Core Transport Agents (CTAs) instead. Core transport agents purchase the gas commodity and sell it to core customers at unregulated prices. Both CTAs and their customers were impacted by the polar vortex event. Tiger Energy bases their prices on the SoCal Citygate price and received complaints regarding prices during the polar vortex. Just Energy Solutions, Inc. declared bankruptcy due to "unforeseeable liquidity challenges" resulting from the polar vortex events.

Supply Sufficiency and the CPUC's Winter Outlook

In its "Winter 2020-21 Technical Assessment," published in October 2020, the CPUC conducted monthly gas balance analyses for winter 2020-2021 in the case of average or cold weather.[19] A gas balance identifies the average daily difference, or margin, between future available capacity (or supply) and forecast demand

[18] 1 MMcf is approximately 1.030 MMBtu. This average was calculated by SoCalGas using historic gas receipt point data.

[19] CPUC, *Southern California Gas Company Winter 2020-21 Technical Assessment,* October 2020, https://www.cpuc.ca.gov/-/media/cpuc-website/files/uploadedfiles/cpucwebsite/content/news_room/newsupdates/2020/winter-2020-21-technical-assessment.pdf.

each month to determine in general whether capacity is enough to meet demand. It also simulates the impact to month-end storage inventory levels from average daily storage injections and withdrawals. This section compares actual pipeline and storage use in winter 2020-21 to the forecasted gas balances in order to check the usefulness of the forecasts and suggest improvements for future Technical Assessments.

As predicted by the gas balance for average weather, pipeline receipts and storage withdrawals were sufficient to meet demand this winter. The average weather gas balance, this winter's actual values, and the difference are shown in Appendix A.[20] Because the gas balance focuses on what is possible, rather than attempting to forecast what is most likely, differences between actuals and the gas balance are to be expected. All MMcfd values discussed in this section are winter monthly averages.

The gas balance had indicated sufficient pipeline capacity for pipeline receipts across the winter to exceed average demand. Thus, if the gas balance was correct and if customers chose to purchase that much gas, the system could end the winter with more gas in storage than when the winter began.. As discussed above, Gas Acquisition's gas purchases this winter did exceed their demand by 2 percent. However, total supply procured by all customer types throughout the winter was 6.5 percent (174 MMcfd) below demand and 13 percent (332 MMcfd) less than the gas balance had forecast could be procured. This pattern was not limited to the polar vortex period (February).

The difference between forecasts and actuals was distributed across all receipt points. Of the large receipt points, Blythe (Ehrenberg) into the Southern Zone in particular saw less use than in the gas balance. Also, while California supplies on Line 85 were similar to the gas balance (59 vs 60 MMcfd), Otay Mesa's monthly average usage was 5 MMcf, peaking at 15 MMcfd in February, compared to the gas balance's 30 to 50 MMcfd each month.

Because it focuses on net monthly averages, the gas balance does not include any injections into storage. Actual winter injections averaged 62 MMcfd (26 percent of withdrawals). Nevertheless, greater reliance on storage than in the gas balance resulted in lower storage inventory at the end of the winter, 53 Bcf, than the 70 Bcf in the gas balance.

The gas balance used demand forecasts from the 2020 California Gas Report.[21] While actual demand averaged 4 percent below the average weather-based forecast, it did not drop in March as much as expected. One clear takeaway from this review is that lower gas receipts at Otay Mesa should be used in future gas balance forecasts. Some refinement of gas delivery and storage usage assumptions could also be considered.

Polar Vortex Outside California

Winter Storm Uri's impacts were most dramatic outside California. Throughout the Southwest and Midwest, record temperatures brought record energy demand. In some cases, especially in Texas, these were followed

[20] The cold weather gas balance, representing higher demand, is not discussed here because it is farther from this winter's actual weather, but is available in the report cited in footnote 7.

[21] SoCalGas et al, *2020 California Gas Report,* undated, accessed December 2020. This report and SoCalGas' supporting workpapers are available at https://www.socalgas.com/regulatory/cgr.shtml.

by record gas and power outages, human hardship, and policy change proposals. These events present a case study regarding gas system operations and events outside California which impact the state. California receives over 90 percent of its gas from outside the state, including from the Southwest's Permian Basin.

Weather

The polar vortex impacts on Europe and North America were predicted as early as December as a potential outcome of Sudden Stratospheric Warming occurring over the north pole.[22] Sudden Stratospheric Warming events typically occur multiple times each decade. These events can bring unpredictably cold "polar vortex" weather south from the polar regions or alternatively, cause unusually warm weather. The resulting occasional cold events are expected to continue even as climate change increases average temperatures and heating events. More detailed use of such forecasts could facilitate cost-effective gas planning.

Weather Impacts on Gas Supply

While changing weather patterns are widely known to affect gas demand, extreme weather can also affect supply, especially where supply equipment is not prepared for it. During Winter Storm Uri, gas production nationwide fell 17 percent from above 90 billion cubic feet per day to around 75 Bcfd. Production in Texas, Oklahoma, and Louisiana dropped by more than 50 percent from its January average to its lowest day during the storm, February 17.[23] Most of this reduction occurred in Texas,[24] which includes most of the Permian Basin. Gas production in the Permian Basin fell about 25 percent from around 12 Bcfd to below 9 Bcfd. Some interstate pipelines experienced systemwide draft—or dropping pressure due to low volumes of gas—and firm deliveries were cut in the face of unavailable supply.

Two major factors transformed the rare cold weather into lower gas exports from the Permian Basin: wellhead freeze-offs and wellhead loss of electric power.[25] Weather impacts on gas production were the greatest contributor to production declines.[26] Texas has approximately 10,000 unwinterized gas wells, or wells that do not have heating equipment installed to enable them to operate during freezing conditions. Some gas processing also failed in response to the weather as early as February 11, and some wells were shut off due to power outages.

Low gas supplies resulted in high spot prices. While Southern California prices peaked at $144/MMbtu for February 14-16, the West Texas/SE New Mexico regional average (Permian Basin area) peaked at

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[22] NOAA, "On the Sudden Stratospheric Warming and Polar Vortex of Early 2021," January 2021, https://www.climate.gov/news-features/blogs/enso/sudden-stratospheric-warming-and-polar-vortex-early-2021.

[23] FERC et al, *FERC – NERC – Regional Entity Staff Report: The February 2021 Cold Weather Outages in Texas and the South Central United States*, November 2021, available at https://www.ferc.gov/news-events/news/final-report-february-2021-freeze-underscores-winterization-recommendations.

[24] EIA, "February 2021 weather triggers largest monthly decline in U.S. natural gas production," *Today in Energy*, 5/10/21, https://www.eia.gov/todayinenergy/detail.php?id=47896.

[25] University of Texas at Austin Energy Institute, *The Timeline and Events of the February 2021 Texas Electric Grid Blackouts*, July 2021, https://energy.utexas.edu/sites/default/files/UTAustin%20%282021%29%20EventsFebruary2021TexasBlackout.pdf.

[26] FERC, *Winter Energy Market and Reliability Assessment 2021-2022*, October 2021, https://www.ferc.gov/media/winter-energy-market-and-reliability-assessment-2021-2022-report.

$191.92/MMBtu for February 17. Prices in some states reached even higher levels, with spot prices in Oneok, Oklahoma hitting $1,193.15/MMBtu on February 18.

Low delivery volumes, by driving high spot prices, translated into windfall profits on gas sales for pipeline operators. Kinder Morgan, owner of the El Paso pipeline system that serves areas in the Southwest, reported $1.4 billion in first quarter profits (compared to $300 million in losses in the previous year's first quarter), primarily from these high spot prices.[27] Of the various pipelines they operate, Kinder Morgan attributes these profits to its pipelines within Texas as well as its Tennessee Gas Pipeline. Similarly, pipeline owner Energy Transfer LP, which also serves much of Texas, reported gains of $2.4 billion attributable to the storm.[28]

Kinder Morgan and Energy Transfer LP initially pursued $192 million in penalties for gas customers who used more gas than they contracted for during the polar vortex but have since waived those penalties. Penalties from the 2011 Texas cold spell were similarly waived.[29] Much of this gas was used for electricity generation.

Weather Impacts on Gas Demand and Electricity Demand

February's historic cold drove increases in gas demand, including record nationwide residential demand. In Texas, gas volume delivered to residential customers in February was 49 percent above the 10-year average and 46 percent above the previous February average. [30] Electric generation demand also rose in many areas but it was constrained by power outages. Texas gas consumption for electric generation was 25 percent higher than the 10-year average. However, it was 2 percent below the previous February. As noted by the EIA, with over 60 percent of Texas residences using electric heat, electricity demand would have risen much further during the storm if not for power outages.[31] Not enough gas was available to meet the demand. The situation in Texas provides lessons for other states as well as implications for Southern California due to California's reliance on the Permian Basin.

More than two-thirds of Texas residents lost power during February 14-20, for an average of 42 hours. Around 400-1,000 deaths in Texas have been attributed to the impacts of the storm and resulting gas and power failures. Shorter, less deadly power outages occurred in parts of Louisiana, Oklahoma, Georgia, and elsewhere, as electricity system operators in the Southwest and Midwest lost less power in their territories and imported power from less impacted areas. A joint report by the Federal Energy Regulatory Commission (FERC), the North American Electric Reliability Corporation (NERC), and regional power entities (the FERC Report) found that the top two causes of the region's power outages were generation facilities'

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[27] Kinder Morgan, "Kinder Morgan Increases Divident 3 Percent and Raises 2021 Guidance," April 21, 2021, https://ir.kindermorgan.com/news/news-details/2021/Kinder-Morgan-Increases-Dividend-3-Percent-and-Raises-2021-Guidance/default.aspx.

[28] Energy Transfer, "Energy Transfer Reports First Quarter 2021 Results," May 6, 2021, https://ir.energytransfer.com/news-releases/news-release-details/energy-transfer-reports-first-quarter-2021-results.

[29] See FERC dockets RP21-838, RP21-887, RP21-888, RP21-889 at https://elibrary.ferc.gov/eLibrary/search regarding this winter.

[30] CPUC analysis of data from EIA, *Texas Natural Gas Consumption by End Use*, September 2021, http://www.eia.gov/dnav/ng/ng_cons_sum_dcu_stx_m.htm.

[31] See footnote 10.

unpreparedness for cold weather and the unavailability of natural gas for generation. This report found gas unavailability responsible for 27 percent of unplanned power outages.[32] Gas plants represented 55 percent of the offline generation during the storm.

High gas spot prices translated into financial losses in the electricity sector. For example, Xcel Energy has attributed about $1 billion in losses to gas costs associated with Winter Storm Uri.[33] Xcel Energy, the parent company to utilities in Texas, New Mexico, Colorado, and five midwestern states and the largest generation operator in Texas, buys about half its gas on the spot market. Relying on the spot market, rather than firm contracts, for gas supply leaves electric generators more exposed to market volatility. Although some electricity utilities kept their costs down by using power from other sources, the gas cost increases to electric utilities generally translated to costs for the utilities or their customers.

Nationwide (lower 48 states), gas use for electric generation in winter 2020-2021 was down 7 percent compared to the previous winter.[34] Notwithstanding the regional power outages discussed above, the EIA attributes this overall decline to the gas price increases, competition from renewable energy sources, and gas-to-coal fuel switching.[35] New solar and wind winter electric capacity are expected to outpace new gas generation in winter 2021-2022.[36]

Industrial sector gas consumption also dropped in Texas during the polar vortex, responding to low availability and high prices. February industrial gas use was 85 percent of its 10-year average and only 75 percent of its previous year's level, [37] likely reflecting greater drops during the most affected days. Similar to the industrial sector in California during this time, these demand reductions show the potential for the industrial sector to help balance the gas market during periods of peak heating demand. However, given the very high gas prices that led industrial users to cut back, it is not clear at what price they would be willing to scale back production.

Policy Responses to Polar Vortex Impacts

Winter Storm Uri and its effects have generated significant policy attention. Common recommendations focus on weather forecasting, infrastructure winterization, market design, and gas-electric coordination.

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[32] FERC et al, *FERC – NERC – Regional Entity Staff Report: The February 2021 Cold Weather Outages in Texas and the South Central United States*, November 2021, available at https://www.ferc.gov/news-events/news/final-report-february-2021-freeze-underscores-winterization-recommendations, p. 172.

[33] Xcel Energy, "Xcel Energy First Quarter Earnings Report," April 2021.

[34] Staff analysis of data from EIA hourly electric grid monitor: *Real-time Operating Grid - U.S. Energy Information Administration (EIA)*, https://www.eia.gov/electricity/gridmonitor/dashboard/electric_overview/US48/US48.

[35] EIA, "U.S. natural gas generation in 2021 sees its first year-over-year decline in three years," *Today in Energy, 5*/24/21, https://www.eia.gov/todayinenergy/detail.php?id=48076.

[36] FERC, *Winter Energy Market and Reliability Assessment 2021-2022*, October 2021, https://www.ferc.gov/media/winter-energy-market-and-reliability-assessment-2021-2022-report, in comparison with previous year's report.

[37] CPUC analysis of data from: EIA, *Texas Natural Gas Consumption by End Use*, 9/30/2021, http://www.eia.gov/dnav/ng/ng_cons_sum_dcu_stx_m.htm. See also FERC report.

The FERC Report mentioned above goes on from analyzing the winter storm's impacts on the electric grid to provide detailed recommendations focused on preventing similar situations in the future.[38] In addition to electricity-focused measures, these recommendations included many focused on the natural gas system. These proposals echo several themes raised in FERC and NERC's analysis of 2011 weather events, including consideration of gas production and processing winterization requirements, voluntary curtailment plans, and plans for prioritization of residential and generation customers.[39] Other energy policy organizations such as the Electric Power Research Institute (EPRI) and National Association of Regulatory Utility Commissioners' (NARUC) National Regulatory Research Institute have made similar recommendations.

Weather Forecasting

The 2021 polar vortex serves as a reminder of the value of weather forecasting in utility planning. Reflecting recognition of climate variability and changes over time, the FERC Report suggests greater use of weather forecasting in utility planning. Multiple weather models should be used, including to predict regional differences. Electricity balancing authorities should also understand heat pump behavior in extreme weather, and planning scenarios should consider flows within load pockets and between balancing areas, including reversals of usual flows, under extreme conditions.

On the electric side, FERC is acting on some of these concepts with two Notices of Proposed Rulemaking issued in June 2022, proposing to require electric transmission providers to describe their current weather vulnerability assessment processes and to develop extreme weather planning cases based on past heat and cold weather events and future projections, including electric resource availability across broad areas, as well as corrective action plans in case of underperformance.[40]

Infrastructure Winterization

In response to the failures of natural gas infrastructure during the polar vortex, the FERC Report recommends both voluntary and required winterization measures. As soon as possible, the report suggests, gas production, gathering, and processing should undertake voluntary preparations including equipment protections, coordination with electric customers and authorities, and longer-term activities such as undergrounding flow lines. By winter 2023-2024, gas infrastructure should be required to be winterized. Incentives could be provided for this purpose. The report also suggests gas operators consider Supervisory Control and Data Acquisition (SCADA) equipment upgrades to enable production changes in response to real-time events.

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[38] See footnote 17 for full report, and also FERC, "Final Report on February 2021 Freeze Underscores Winterization Recommendations," November 2021, https://www.ferc.gov/news-events/news/final-report-february-2021-freeze-underscores-winterization-recommendations for summary. Detailed recommendations regarding natural gas begin on p. 217 of full report.

[39] FERC et al, *Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011,* August 2011, https://www.ferc.gov/sites/default/files/2020-04/08-16-11-report.pdf.

[40] FERC, "Notice of Proposed Rulemaking: Transmission System Planning Performance Requirements for Extreme Weather," Docket No. RM22-10-000, June 2022, and FERC, "Notice of Proposed Rulemaking: One-Time Informational Reports on Extreme Weather Vulnerability Assessments Climate Change, Extreme Weather, and Electric System Reliability," June 2022, Docket Nos. RM22-16-000 and AD21-13-000.

Market Design and Infrastructure Planning

The polar vortex's impacts highlight the importance of market design and regulatory policies, including as they relate to gas and electricity system interactions. During the storm, some gas production lost power and thus was unable to provide gas for residential and electric demand, and some power plants lost gas. Therefore, the FERC Report recommends changing the gas curtailment order during emergencies so that critical gas-fired power generation is preserved, second only to residential gas demand. Similarly, it suggests protecting critical gas infrastructure from being subject to electricity load shed. To support the latter, they also recommend preventing natural gas infrastructure from signing up as available for demand response programs, as had occurred in Texas. These steps would enhance reliability of the electric and gas systems.

In response to the storm and its impacts, the Texas legislature adopted weatherization requirements for critical infrastructure, while allowing well owners to decide whether their wells are critical infrastructure (SB 3, Schwertner and Paddie 2021). The specifics of these regulations are designed and implemented by the Texas Railroad Commission, which has jurisdiction over gas infrastructure comparable to CPUC jurisdiction in California. FERC had recommended that load-serving entities provide the definitions of "critical gas infrastructure."

The FERC report also notes that Texas' isolation contributed to the impacts in that state, suggesting that the Electric Reliability Council of Texas (ERCOT) study increasing interconnections with other electric balancing authorities. A report by NARUC's research institute echoes many of FERC's suggestions, commenting on how free market approaches to both electricity and gas, software design, and inattention to extreme winter weather contributed to the events in Texas.[41]

Gas-Electric Coordination

Many studies have highlighted the inter-reliance of the gas and electricity systems. Before and after Winter Storm Uri, the Electric Power Research Institute (EPRI) recommended increased focus on the gas-electric interface, which a 2018 study commissioned by the Western Electricity Coordinating Council (WECC) has identified as particularly significant in Southern California. This study's recommendations focus on increased gas-electric coordination, more precise gas purchasing structures such as adding gas nomination days or requiring gas purchased to match consumption more closely, and policy alignment in areas such as resource adequacy and curtailment order.[42] The FERC report similarly focuses substantial attention on the interactions between these two energy systems.

In discussing gas-electric coordination, the FERC Report highlights gas generators' reliance on non-firm contracts. Research across the U.S. for 2012-2018 finds that gas generators with firm contracts have less frequent power outages.[43] Noting that less than one-third of the natural gas generators that lost power during Winter Storm Uri had firm gas supply and transportation contracts, the FERC Report provides

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[41] Pechman and Nethercutt, *Regulatory Questions Engendered by the Texas Energy Crisis of 2021*, March 2021, available at https://www.naruc.org/about-naruc/press-releases/new-research-paper-examines-the-questions-underlying-the-regulatory-and-market-issues-of-the-texas-energy-crisis/.

[42] Wood Mackenzie, *Western Interconnection Gas-Electric Interface Study*, June 2018, available at https://www.wecc.org/SystemAdequacyPlanning/Pages/Gas-Electric-Interface-Study.aspx.

[43] Carnegie Mellon University, "Switching to firm contracts may prevent natural gas fuel shortages at US power plants," *ScienceDaily*, February 16, 2021, https://www.sciencedaily.com/releases/2021/02/210216115001.htm.

several recommendations focused on increasing use of firm contracting. These include examining which entity could require this, whether firm gas contracting could be a requirement for generator facility accreditation, and market and public funding options. In particular, the study recommends that electric balancing authorities require generators to report the nature of their gas contracting, including whether it is firm or non-firm and any force majeure clauses and the resulting percentage of their capacity that can be relied upon during cold weather. Given that it is not 100 percent, they suggest revisiting what portion of gas generation is included in winter electricity reserve calculations. Although less specific, FERC's 2021 "Order Approving Cold Weather Reliability Standards" (176 FERC ¶ 61,119) for electric generation, adopted after the winter storm, also includes consideration of fuel availability.

A National Forum

After a similar cold spell in 2011, FERC coordinated a similar report. This report's recommendations discussed firm contracting as well as coordination between the gas and electric market's purchasing "day," followed by changes to the gas day to extend the first scheduling period and add an additional, final scheduling period. The recent FERC Report raises these topics again and reiterates an idea from its earlier report: convening a national forum to discuss these and other ways to address the "recurring challenges stemming from natural gas-electric infrastructure interdependency." FERC notes that at present, "Natural gas production facilities are almost entirely intrastate and unregulated." On July 25, FERC and the North American Energy Reliability Corporation (NERC) issued a letter asking that this forum be held by the North American Energy Standards Board (NAESB).[44] The first meeting of the Gas-Electric Harmonization Forum was held on August 30, 2022.[45]

Overall, Southern California's gas system operated successfully in winter 2020-21. Nevertheless, the polar vortex events, economic and policy responses to them, and ongoing trends in the gas and electric systems suggest potential directions for the future of the gas system.

[44] FERC and NERC letter to NAESB, July 25, 2022, https://www.naesb.org/pdf4/ferc_nerc_letter_072922_to_NAESB.pdf.
[45] North American Energy Standards Board, "Announcement of the Initial NAESB Gas-Electric Harmonization Forum Meeting – August 30, 2022 from 2:00 pm to 4:00 pm Central," , August 30, 2022, https://www.naesb.org/pdf4/geh083022announcement.docx.

Appendix A. Monthly Gas Balance Outlook vs. Actuals

		2020-2021 Winter Actuals					Gas Balance Outlook with Normal Weather						Gas Balance Difference from Actuals				
Demand (MMcfd)		**Nov**	**Dec**	**Jan**	**Feb**	**March**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**March**	**Nov**	**Dec**	**Jan**	**Feb**	**March**
Core*		1,065	1,311	1,366	1,261	1,234	701	1,030	1,459	1,383	1,362	1,098	-35	148	17	101	-136
Noncore including EG		1,076	1,020	995	846	1,024	1,194	1,138	1,202	1,066	1,071	937	62	182	71	225	-87
Wholesale & International		409	458	435	369	394	346	394	483	415	432	337	-15	25	-20	63	-57
Co. Use and LUAF		15	74	45	(7)	27	29	33	40	37	37	30	18	-34	-8	44	3
Subtotal Demand		*2,566*	*2,863*	*2,840*	*2,470*	*2,679*	2,270	2,595	3,184	2,901	2,902	2,402	29	321	61	432	-277
Storage Injection (Non-Aliso Fields)		47	44	51	32	68	165	0	0	0	0	0	-47	-44	-51	-32	-68
Storage Injection (Aliso)		11	7	25	8	17	0	0	0	0	0	0	-11	-7	-25	-8	-17
Sub Total Storage Injection		*58*	*51*	*77*	*40*	*85*	*165*	*0*	*0*	*0*	*0*	*0*	*-58*	*-51*	*-77*	*-40*	*-85*
System Total Throughput		2,623	2,914	2,917	2,509	2,763	2,435	2,595	3,184	2,901	2,902	2,402	-28	270	-16	393	-361
Supply (MMcfd)													0	0	0	0	0
California Line 85 Zone		57	62	62	54	59	60	60	60	60	60	60	3	-2	-2	6	1
Wheeler Ridge Zone		725	784	755	539	720	765	765	765	765	765	765	40	-19	10	226	45
Blythe (Ehrenberg) into Southern Zone		794	893	889	770	848	700	980	980	980	980	980	186	87	91	210	132
Otay Mesa into Southern Zone		2	1	2	15	6	0	30	50	50	50	50	28	49	48	35	44
Kramer Junction into Northern Zone		526	546	534	409	464	550	550	550	550	550	550	24	4	16	141	86
North Needles into Northern Zone		141	214	194	195	260	200	200	200	200	200	200	59	-14	6	5	-60
Topock into Northern Zone		271	232	236	125	160	240	240	240	240	240	240	-31	8	4	115	80
Sub Total Pipeline Receipts		*2,516*	*2,733*	*2,671*	*2,107*	*2,517*	2,515	2,825	2,845	2,845	2,845	2,845	309	112	174	738	328
Storage Withdrawal (Non-Aliso Fields)		75	87	129	171	128	0	0	239	56	57	0	-75	152	-73	-114	-128
Storage Withdrawal (Aliso)		24	101	117	231	123	0	0	100	0	0	0	-24	-1	-117	-231	-123
Sub Total Withdrawal		*99*	*188*	*246*	*401*	*252*	*0*	*0*	*339*	*56*	*57*	*0*	*-99*	*151*	*-190*	*-344*	*-252*
Total Supply		2,615	2,921	2,918	2,508	2,769	2,515	2,825	3,184	2,901	2,902	2,845	210	263	-17	394	76
DELIVERED BALANCE (MMcfd)		-8	7	0	-1	6	80	230	0	0	0	443	238	-7	0	1	437
Storage Increase / Reserve Margin**		-0.3%	0.2%	0.0%	-0.1%	0.2%	3%	9%	0%	0%	0%	18%					
Non-Aliso Month-End Storage (Bcf)	46	45	44	41	37	35	50	50	43	42	40	40	5	0	0	2	4
Aliso Month-End Storage (Bcf)	33	33	30	27	21	18	34	34	31	31	31	31	0	0	3	9	13
Total Storage Inventory	79	78	74	68	58	53	84	84	74	72	70	70	6	0	4	12	17

*Some core customers are unmetered and therefore do not have data available on a calendar month basis. Reported deliveries not assigned to other demand categories are therefore assigned to core. Without this adjustment, core monthly amounts, starting with November, would be 1,013 MMcfd, 1,316 MMcfd, 1,347 MMcfd, 1,190 MMcfd, and 1,205 MMcfd, respectively, with little impact on this analysis.

**Storage Increase / Reserve Margin row shows 2020-2021 actual storage increases and gas balance reserve margins.