American Gas Association

Winter Heating Season Performance

2023-2024 Natural Gas Utility Winter Performance Report

Prepared by

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Executive Summary

Natural gas utilities deliver essential heating energy to homes and businesses across the United States, serving roughly 79 million customers. Reliable service during winter depends on advance planning: utilities build diversified supply portfolios anchored by firm transportation and supported by underground storage, citygate purchases, and peaking resources. They establish design-day assumptions to size peak-day capacity, secure supply under a mix of contract terms and pricing structures and use financial hedging and operational tools to manage price risk and real-time system conditions.

To track how these planning practices perform in operation, AGA conducts its Winter Heating Season Performance Survey. This report presents findings for the 2023-2024 winter heating season, drawing on responses from 33 member local distribution companies (LDCs) representing 23 million sales customers across 37 states and all five storage regions.

The latest survey results point to several broad conclusions about gas utility winter planning and performance, including the importance of diversified supply portfolios, underground storage, and targeted price-risk management. Operational tools, such as operational flow orders (OFOs) and limited interruptible curtailments also continued to play an important role in managing stress events without widespread service disruption.

Key Findings

- **Planning and reliability are anchored in firm supply.** Utilities rely on structured design-day methodologies, most commonly a 1-in-30-year standard, and firm transportation services as a central component of winter supply portfolios. Twenty two of the survey respondents rely on firm transport for more than 25 percent of total winter supply and 13 for over 50 percent.
- **Procurement strategies balance flexibility and risk management.** A significant share of supply is priced using market-based mechanisms (daily and first-of-month), with mid-term contracts accounting for more than half of winter supply.
- **Hedging is widely used to protect consumers.** Sixty-nine percent of respondents used financial instruments to hedge an average of 35 percent of their winter supply. Respondents cited reductions in customer exposure to price volatility as their primary reason for hedging.
- **Portfolios show increased firm reliance during storms.** Compared with prior survey years, respondent data suggests a greater reliance on firm-delivered supply and reduced use of interruptible transportation during winter storm events.
- **Storage and operational tools remain critical.** Underground storage was used by 94 percent of respondents during the winter heating season and accounted for about 20 percent of seasonal supply, while operational tools such as OFOs and limited curtailments helped manage system stress without widespread disruption.

Introduction

Natural gas utilities provide a critical source of essential energy to homes and businesses across the U.S. In 2024, natural gas provided 34.6 quadrillion Btu of energy, or nearly 40 percent of total U.S. primary energy consumption, underscoring its central role in meeting the nation's energy needs.[1]

Reliable service is especially important in the winter. The winter heating season (WHS), defined as November 1 through March 31, is a critical period for natural gas local distribution companies (LDCs) because cooler temperatures drive higher energy consumption. During an average WHS season consumption increases by 12 percent above spring and fall season volumes.[2] Colder days lead to even higher daily consumption.

Gas utilities have decades of operational experience planning for winter conditions. Their supply portfolios are built to meet customer obligations for natural gas delivery on a daily, weekly, monthly, and seasonal basis, including under extreme weather conditions. Companies plan for natural gas deliveries by matching supply resources to forecasted demand and planning for "design day" conditions (an estimate of the maximum throughput the system might require on the coldest day). Utilizing historical data and experience while adhering to regulatory requirements, LDCs employ a full suite of natural gas supply assets and tools to fulfill their obligations.

This report analyzes the 2023-2024 WHS based on data from 33 American Gas Association (AGA) member LDCs collected through AGA's WHS Performance Survey.[3] The sample represents data from 37 unique states and all five storage regions, as defined by the Energy Information Administration (EIA). Survey participants reported a cumulative peak day sendout of 23.5 billion cubic feet (Bcf) and a cumulative WHS sendout of 1.6 trillion cubic feet (Tcf). Respondents served approximately 23 million sales customers, which represents a market share of around 32 percent, according to 2023 EIA Form-176 data on sales customers.

[1] Energy Information Administration Total Annual Energy Review Table 1.3

[2] The five-year average U.S. primary energy consumption was 8.1 quadrillion Btu per month between the 2019-2020 winter heating season and the 2023-2024 winter heating season. The shoulder season occurs during the spring and fall, when energy consumption is typically lower due to milder weather conditions. The five year-average U.S. primary energy consumption was 7.3 quadrillion Btu per month between the 2019-2020 shoulder season and the 2023-2024 shoulder season. Energy Information Administration Total Annual Energy Review Table 1.3

[3] Please note that his report reflects member utility responses to AGA's Winter Heating Season Performance Survey for the 2023-2024 winter heating season. AGA did not collect survey data for the 2024-2025 winter season while the survey's structure, cadence, and objectives were under review. Data collection will resume with the 2025-2026 winter heating season, and an updated, more timely report is planned for 2026.

2023-2024 WHS Overview

The U.S. natural gas system added more than 670,000 new residential and commercial customers in 2023 and over 610,0000 in 2024. On a weather-normalized basis[4], efficiency gains in buildings and appliances have largely offset that customer growth, keeping aggregate residential consumption relatively flat.[5] Peak-day demand, however, continues to rise. As a result, short-duration cold events place growing operational demands on the system even as average consumption holds steady.[6]

Figure 1 illustrates the seasonal profile of natural gas demand in the Lower 48, showing daily consumption by sector from November 2022 through March 2024. Demand typically rises during the winter and summer months to meet space heating and gas-powered electricity generation needs and declines during the fall and spring when temperatures are milder. During the WHS, falling temperatures are the dominant driver of short-term demand variability, causing daily consumption to increase sharply as space heating requirements intensify.

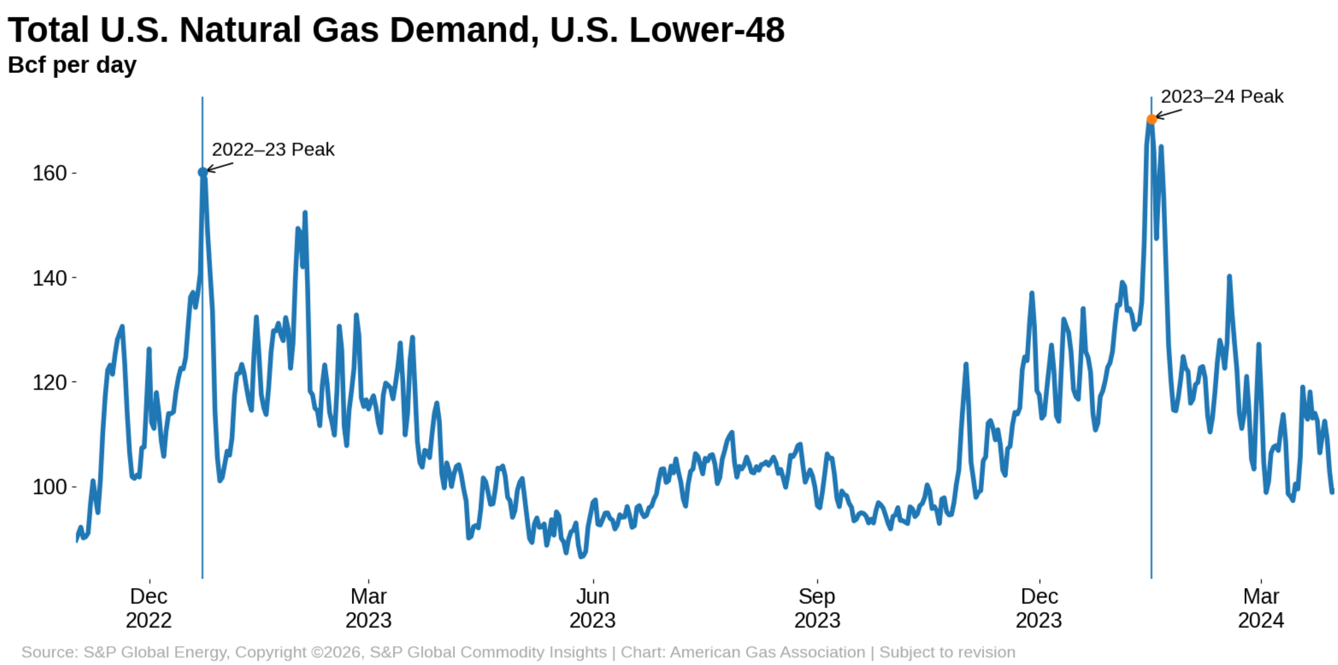

Figure 1.
Source: S&P Global Energy.[7]

[4] Weather-normalized consumption adjusts for unusually warm or cold weather so that natural gas use can be compared more consistently across years.
[5] https://www.aga.org/research-policy/resource-library/average-use-per-residential-natural-gas-consumer/
[6] https://www.aga.org/research-policy/resource-library/peak-daily-domestic-demand-for-natural-gas-and-electricity/
[7] Data disclaimer: Certain information, data, and material used in this report, including natural gas demand data and related market information ("Content"), are sourced from S&P Global Commodity Insights. Reproduction, redistribution, or other use of the Content in any form is prohibited except with prior written permission from the relevant rights holder. S&P Global Commodity Insights, its affiliates, and suppliers ("Content Providers") do not guarantee the accuracy, adequacy, completeness, timeliness, or availability of any Content and are not responsible for any errors or omissions, regardless of cause, or for the results obtained from the use of such Content. In no

During the 2023–2024 WHS, average total domestic demand reached 92.2 Bcf per day, an increase of 22.4 Bcf per day relative to baseload demand (during the fall and spring) but 0.5 percent lower than the previous winter (2022–2023).[8] Despite the seasonal decrease in consumption, peak daily demand rose year-over-year, increasing by 6.1 percent and reaching a seasonal high of 147 Bcf per day on January 16, 2024. As shown in *Figure 1*, winter demand is characterized not only by elevated averages relative to other seasons of the year, but also by volatility in response to rapid and extreme cold conditions.

Importantly, this volatility is not distributed evenly across sectors. *Figure 2* shows that during the 2023–2024 WHS, residential and commercial demand was the most weather-sensitive component, deviating from its seasonal average by about ±10.5 Bcf per day as space-heating loads in homes and businesses respond quickly to temperature changes. By comparison, electric power demand varied by ±3.2 Bcf per day and is shaped by factors such as generator dispatch, fuel competition, and regional load conditions, while industrial demand remained relatively stable at ±1.0 Bcf per day. This concentration of temperature-driven variability in the residential and commercial sector helps explain why winter system demand requirements can change rapidly and underscores the importance of advance planning by LDCs.

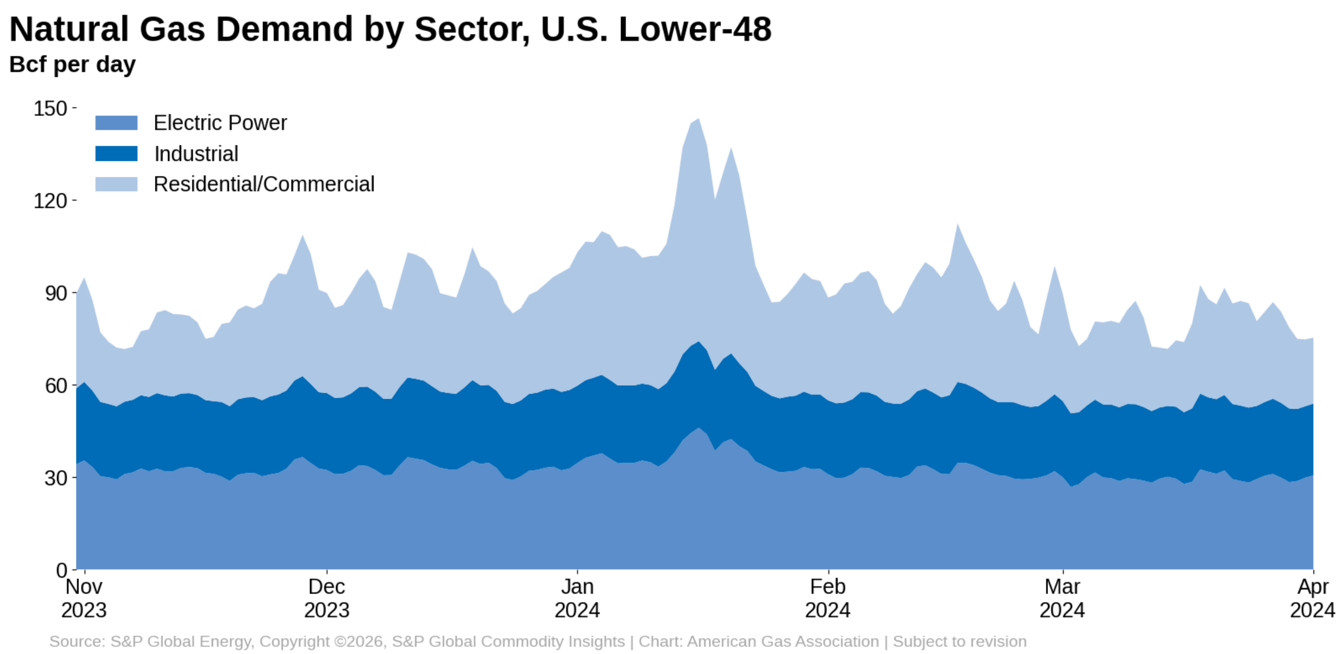

Figure 2.
Source: S&P Global Energy.[9]

The January 2024 winter storms offer a valuable case study of rapid demand ramping and subsequent LDC response. Peak winter demand on January 16 occurred during the Winter Storms Gerri and Heather period, which extended from January 10 through January 17, 2024.[10] During this period, residential and commercial demand rose

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[8] For this report, domestic demand is defined by the sum of U.S. consumption in the residential, commercial, industrial, and electric power sectors.

[9] For additional information, refer to the data disclaimer in footnote 7.

[10] In subsequent sections of this report, analysis of the January winter storms refers to the period from January 10 to January 17, 2024. This analytical period is based on [FERC's April 2024 system performance review](), which states that Winter Storms Gerri and Heather

to 58 Bcf per day, a 65 percent increase above its seasonal average of 35 Bcf per day. Over the same timeframe, electric power demand increased by 22 percent, while industrial demand rose by 8 percent, illustrating how extreme cold disproportionately spikes residential and commercial consumption.

Figure 3 compares residential and commercial natural gas consumption with utility-weighted heating degree days (HDDs). HDDs measure relative coldness based on how many degrees daily mean temperatures fall below 65°F, the threshold at which buildings typically require space heating. Throughout the winter heating season, residential and commercial demand closely tracked HDD fluctuations, with both reaching their highest levels on January 16 during the January winter storms. This alignment underscores the correlation between HDDs and space-heating loads. Because residential and commercial customers use natural gas primarily for space heating, colder weather can cause sharp, near-term increases in demand across a large portion of the system load. As a result, fluctuations in residential and commercial consumption is the primary driver of winter demand volatility.

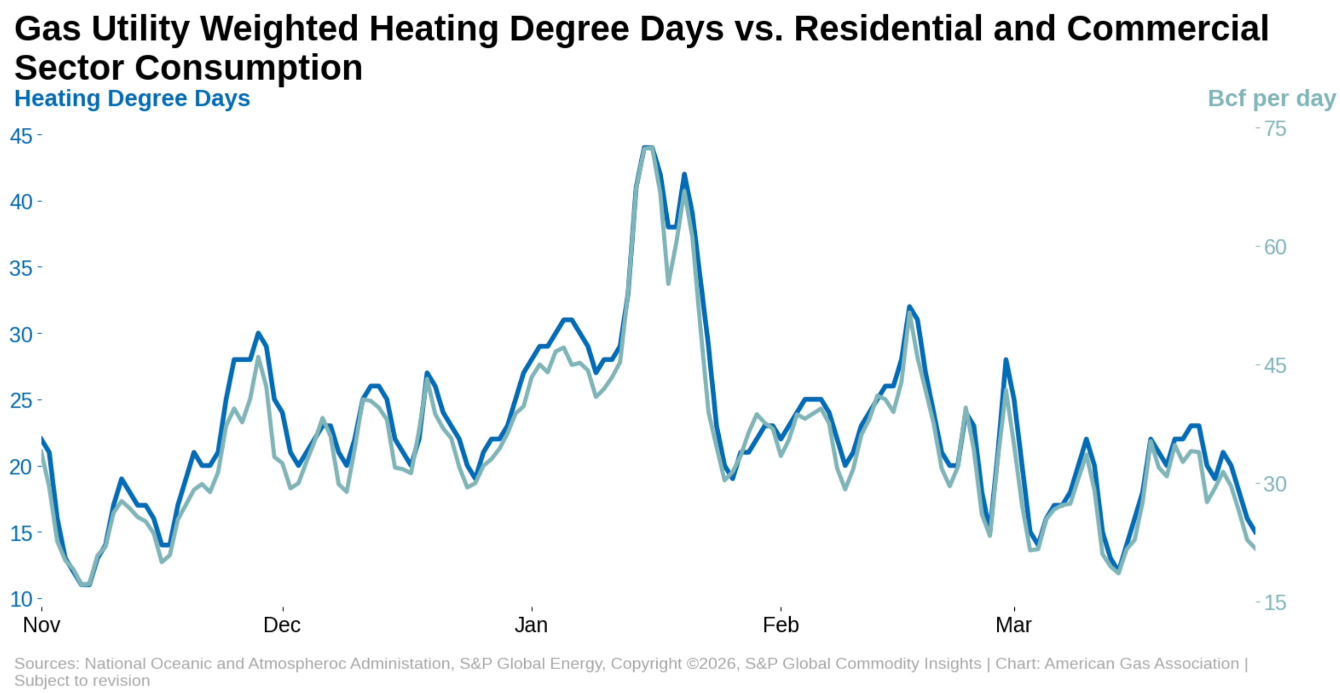

Figure 3.
Source: National Oceanic and Atmospheric Administration & S&P Global Energy. [11]

Despite the January winter storms, the 2023–2024 winter heating season was relatively mild overall. Between November 1, 2023, and March 31, 2024, total HDDs reached 3,487, which was 10.9 percent warmer than normal,

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moved across North America from January 10 through January 17, 2024. FERC notes that Gerri began in the Pacific Northwest on January 10, moved through the Rockies, Midwest, and Great Lakes, and reached southern Canada by January 13; Heather arrived the same day and moved through the Pacific Northwest, northern mountain states, South-Central U.S., Mid-Atlantic, Northeast, and Canada by January 17.

Winter storm summaries from the National Weather Service Weather Prediction Center separately document significant weather events overlapping this period, including the January 9-10 Central and Eastern U.S. Major Winter Storm, the January 12-15 Northwestern U.S. Winter Strom, the January 12-15 Midwest to Great Lakes Winter Storm, and the January 16-17 South-Central Plains to Northeast Winter Storm.

[11] For additional information, refer to the data disclaimer in footnote 7.

and marked the warmest winter in seven years. *Figure 4* places the season in historical context, comparing total winter HDDs over the past ten years relative to the 30-year normal.

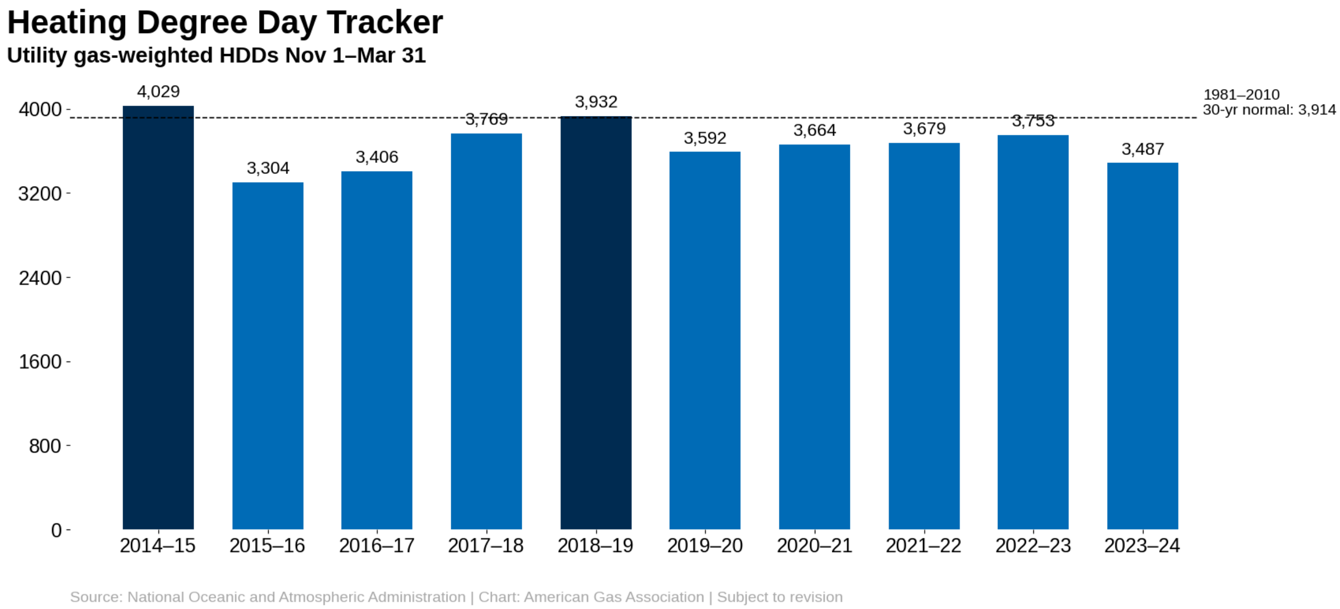

Figure 4.
Source: National Oceanic and Atmospheric Administration.

Weather Forecasting

Weather forecasting plays a central role in LDC winter planning. The inherent uncertainty surrounding the timing, duration, and geographic footprint of these events introduces planning risk, even during mild winters.

To help mitigate some of this uncertainty, utilities employ a design day. The design day represents a statistically derived estimate of the coldest day that could reasonably occur within a given risk tolerance, based on historical weather data and probabilistic modeling. Rather than a single forecast, the design day reflects a planning assumption used to ensure that sufficient supply, storage, and transportation capacity are available to meet system demand under extreme conditions. Methodological choices vary by company and region, but all LDCs work closely with regulators and commissioners to select an approach that balances system reliability with cost efficiency for customers.

Respondents most frequently reported using a 1-in-30 years design standard, meaning the planning case is based on cold-weather conditions with an estimated annual probability of occurrence of roughly once in a 30-year period. This approach was reported by 13 out of 32 respondents, followed by “other methodologies” (8 out of 32) and a 1-in-20 years (4 out of 32) risk of occurrence. Responses characterized as “other methodologies” included a range of company-specific planning approaches, such as planning based on historical cold-weather benchmarks, capacity-anchored assumptions tied to maximum firm deliverability, historical peak-day conditions adjusted for load growth, probabilistic Monte Carlo/regression-based approaches targeting high-percentile peak outcomes, and territory-specific HDD design criteria that vary by division.

The results highlight that design day selection is not a one-size-fits-all exercise, but rather a risk management decision shaped by system characteristics, customer composition, regulatory frameworks, and regional weather exposure.

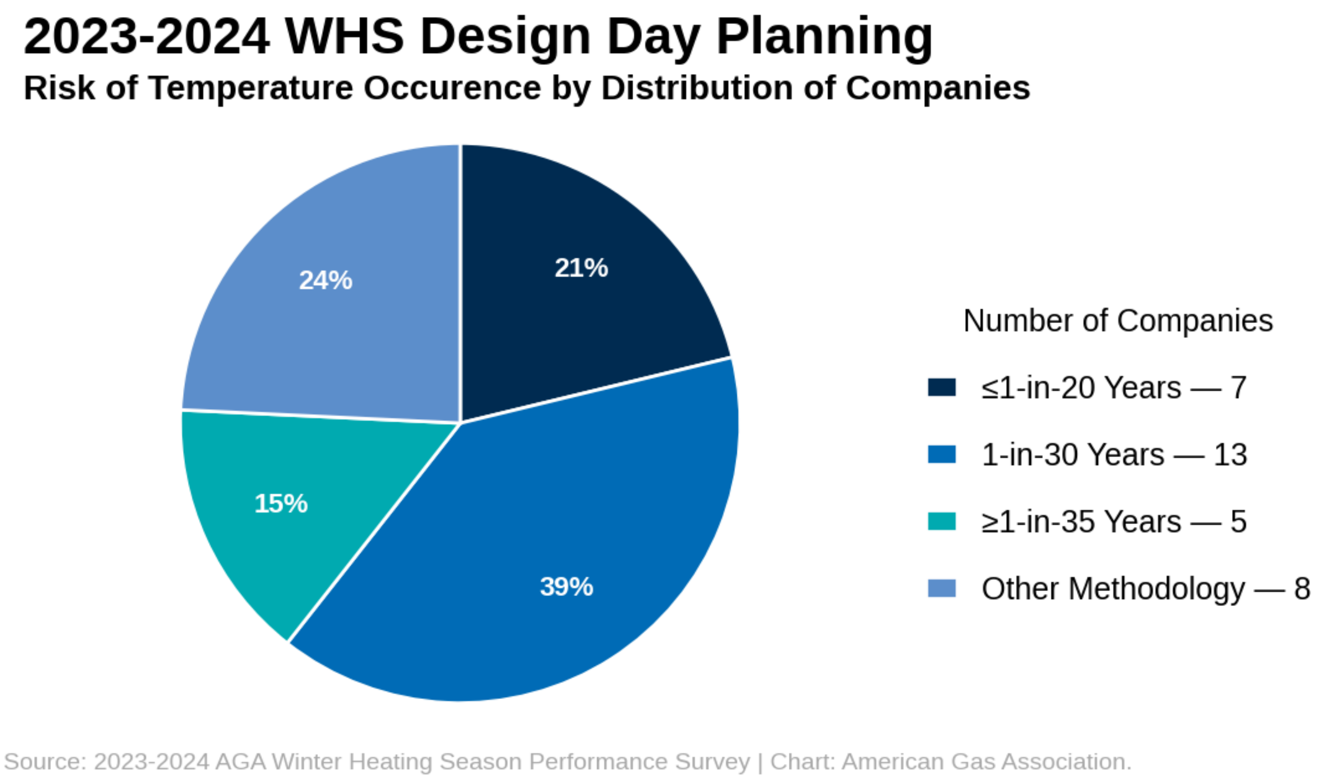

Figure 5. The chart aggregates responses less than or equal to a 1-in-20 years risk of occurrence and greater than or equal to a 1-in-35 years risk of occurrence.

Gas Supply Portfolios

Design day assumptions translate into utility supply portfolio choices and winter reliability strategies. Every year LDCs build and manage a portfolio of supply, storage, and transportation services to meet seasonal demand requirements, including the coldest day of the year. Local market conditions and geography help determine gas procurement strategies and operations management.

The survey asked respondents about the sources they used for three periods: the entire WHS season, the peak demand month of the WHS, and the peak demand day of the WHS. Sources are grouped into the following categories: citygate purchases for transportation customers; citygate purchases for sales customers; LNG/propane-air/SNG; local production; on-system underground storage; pipeline or other storage; purchases moved via firm transportation; purchases moved via interruptible transportation; asset managed contracts; and other supply sources.[12]

WHS Supply Portfolio

Respondents reported diversified WHS supply portfolios, with most supply sources clustered in the 1-25 percent band, and several clustered in the 26-50 percent range. These sources frequently appear in this low-

[12] See Appendix A, Section I for a definition of each supply source.

end range because they function primarily as flexible balancing tools, often constrained by cost, capacity, and intended operational role:

- **Local production**- Nearby in-basin gas receipts are typically used as a steady supplement to contracted firm supply. Helpful for diversification and sometimes cost but usually limited in volume and ramp capacity.
- **Pipeline and other storage**- Storage and linepack-type services are used to help cover load swing and balancing, covering day-to-day volatility, cold snaps, and operational imbalances rather than serving as a primary energy source.
- **LNG/propane-air/SNG**- peaking and emergency supply dispatched on the coldest days or in constrained system areas. Higher variable cost and limited sendout duration reduce volume share relative to other sources during the WHS.
- **Citygate purchases (sales and transportation customers)**- short-term delivered purchases at the citygate used to fine-tune portfolios. Often cover forecast error, nomination variation, and balancing needs. The exposure to price spikes and deliverability risk limits LDC reliance.

Purchases moved via firm transportation are frequently used at higher portfolio shares. Twenty-two respondents reported using firm-transported volumes for shares of the WHS portfolio greater than 25 percent, and of these, 13 respondents indicated using volumes secured via firm transport for 51-100 percent of their WHS portfolio. The pattern is consistent: gas utilities utilize firm, dependable supply to meet typical demand patterns, with additional tools deployed to manage temperature-driven demand swings and operational variability.

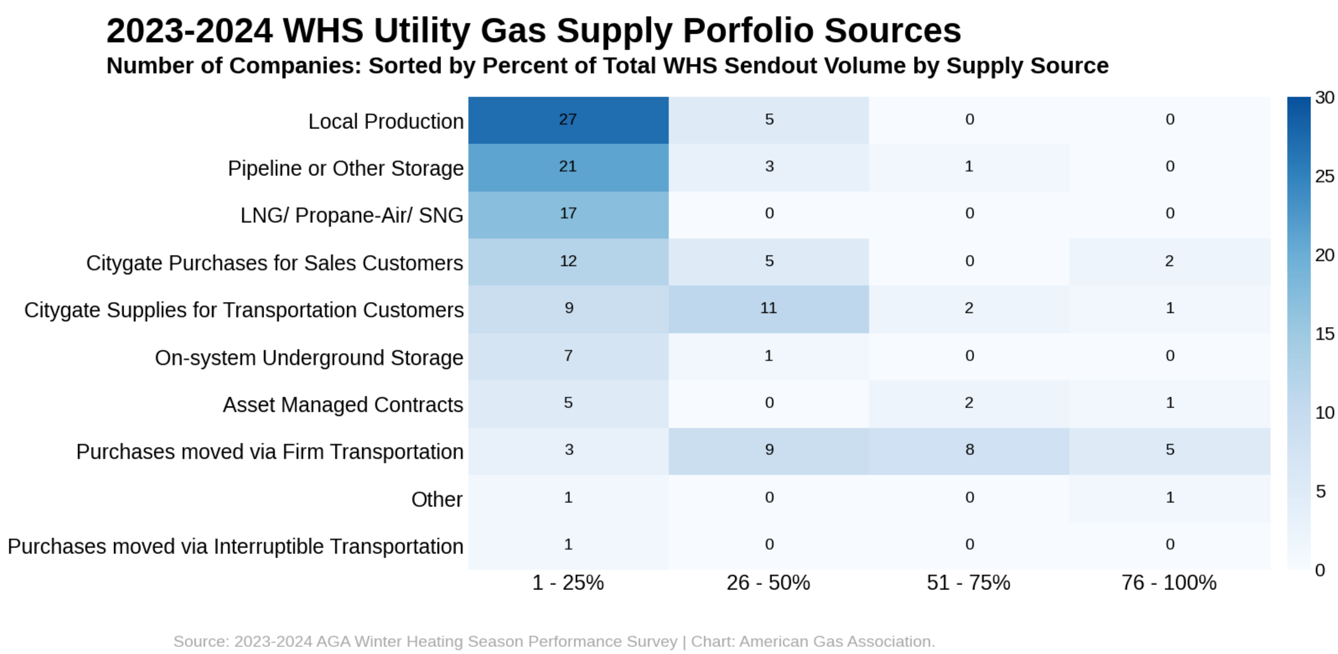

Table 1. For each utility, volumes were grouped by supply source and expressed as a share of that utility's total WHS sendout. Values shown in the heat map are a total of the number of utilities that fell into each share range.

Peak Day Supply Portfolio

On the peak day, purchases moved via firm transportation shifted toward mid-range reliance, with utilities reporting 26-50 percent shares increasing from nine during the WHS to 14, and those reporting 51-100 percent shares declining from 13 to eight. This suggests that firm supply remains the portfolio backbone, but the coldest-day spike is often met with flexible, high-deliverability tools such as storage and citygate purchased supply to manage rapid load ramps and localized constraints.

2023-2024 WHS Peak Day Utility Gas Supply Porfolio Sources

Number of Companies: Sorted by Percent of Total Peak Day Sendout Volume by Supply Source

	1 - 25%	26 - 50%	51 - 75%	76 - 100%
LNG/ Propane-Air/ SNG	17	0	0	0
Citygate Supplies for Transportation Customers	15	7	1	0
Citygate Purchases for Sales Customers	12	7	0	1
Pipeline or Other Storage	9	12	3	0
Asset Managed Contracts	5	2	0	1
Local Production	4	0	1	0
On-system Underground Storage	3	5	0	0
Other	3	0	1	0
Purchases moved via Firm Transportation	1	14	5	3
Purchases moved via Interruptible Transportation	1	0	0	0

Source: 2023-2024 AGA Winter Heating Season Performance Survey | Chart: American Gas Association.

Table 2.

As with design-day assumptions, each LDC's portfolio reflects its specific system configuration and operating constraints, including pipeline capacity, storage assets, geographic and weather exposure, market liquidity, and customer mix. This is especially prominent during system peak.

On a regional basis, the Eastern respondents reported the largest contribution from pipeline or other storage, while the Midwest and Mountain-Pacific regions relied more heavily on firm transport. The Midwest also reported that on-system underground storage accounted for roughly 25 percent of total supply, more than in the East or the Mountain-Pacific. Mountain-Pacific respondents reported comparatively higher use of balancing tools, such as transport imbalances and off-system displacement.[13] In this case, the negative percentage is reported as a net value by respondents and is best interpreted as higher use of balancing tools, such as imbalances being paid back or linepack being rebuilt, rather than negative supply in the physical sense.[14]

The results highlight an increased reliance on pipeline and other storage in the East, suggesting regional access to substantial off-system storage services and pipeline capacity through third-party contracts for the provision of swing supply. Utilities in the Midwest tend to own more storage assets, so they more frequently relied on on-system storage to manage rapid load swings during cold snaps.

[13] See 'Other" supplies in Appendix A, Section I for a definition of transport imbalances and off-system displacement.

[14] Balancing tools help utilities manage day-to-day differences between gas supply and customer demand. Since these tools are reported as net values, they can appear as either positive or negative depending on the direction of the adjustment. A negative value does not mean the system had "negative supply"; it generally means the utility was settling prior balances, such as paying back gas used earlier or restoring gas held in the pipeline system.

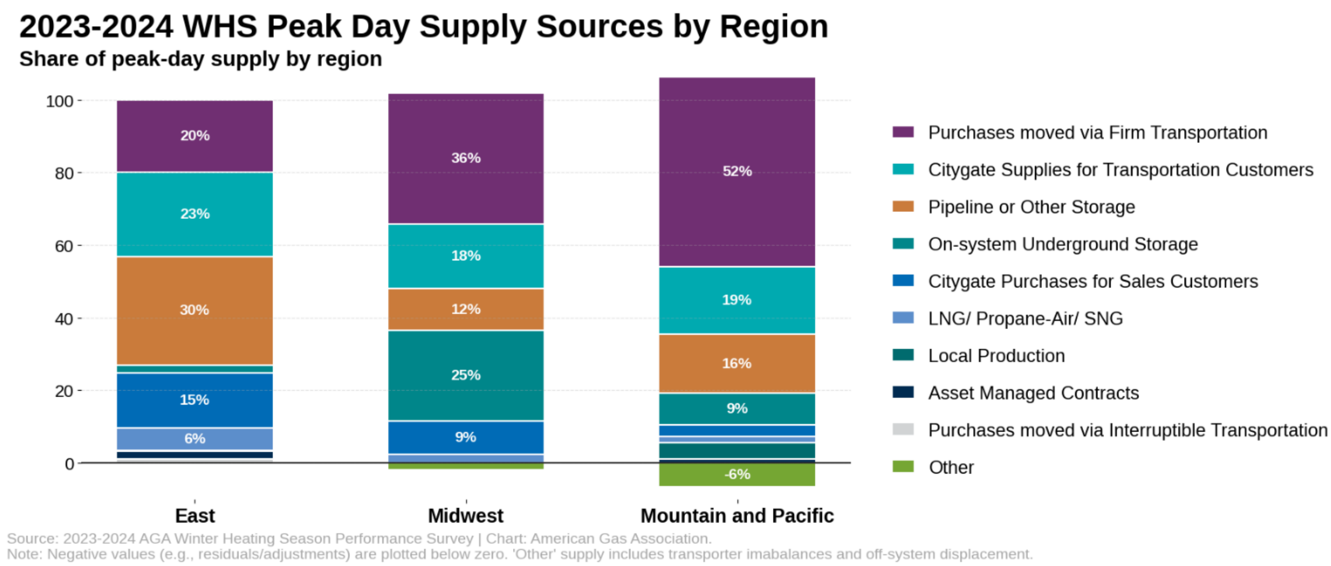

Figure 6. Aggregated total peak-day supply volumes categorized by EIA storage region.

Winter Storm Supply

The survey also asked respondents about their supply sendout during the January 2024 winter storm period regardless of whether their WHS system peak fell within that window.

Winter Storm Uri stands as an outlier relative to Elliott, Heather, and Gerri. Winter Storm Uri impacted the central U.S. and Texas in February 2021 and was a critical event for the gas and electric system. Extreme cold spiked electric and heating demand, while also causing gas pipelines and wellheads to freeze. Supply constraints resulted in days of power outages and several lives were lost. For natural gas LDCs, Uri became a defining stress test for winter preparedness, reinforcing the importance of supply reliability, operational readiness, and planning for extreme design-day conditions.

During Winter Storm Uri, respondents reported a substantially higher reliance on local production (25 percent of total supply) than in later events, even as freeze-offs constrained upstream output—underscoring the vulnerability of portfolios that depend heavily on weather-sensitive supply during extreme cold. In the same period, purchases moved via firm transportation accounted for roughly 30 percent of supply, notably lower than in subsequent storms, and a small share of supply was still moved via interruptible transportation (2 percent).

Post-Uri survey results suggest a shift toward more firm-delivered supply and away from interruptible exposure. Interruptible transportation declined to near zero during Elliott and remained negligible during Heather & Gerri, while firm transportation became the dominant component of aggregate supply in both storms. Because the respondent sample differs across survey years, these comparisons should be interpreted as illustrative rather than definitive. Even so, the pattern suggests a stronger emphasis on deliverability and reduced dependence on weather-sensitive supply during extreme cold.so it

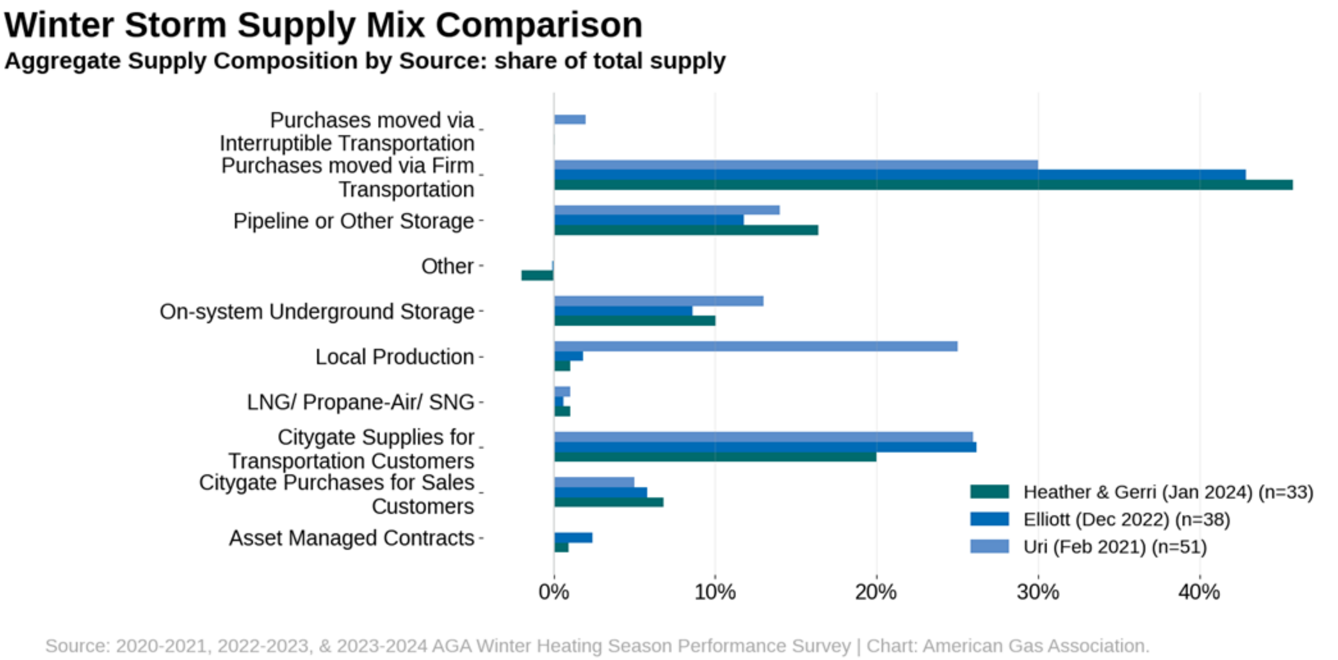

Figure 7.

Asset Management Agreements

Asset management agreements (AMAs) are commercial contracts in which utilities relinquish operational or dispatch rights of physical assets (such as storage, transportation capacity, or a bundled supply portfolio) to a third-party in exchange for a fee and/or fixed price.

While only utilized for procuring a small portion of peak day and peak January winter storm supply during the 2023-2024 WHS, AMAs are still a notable portion of the planned supply portfolio. In the survey, AMA(s) utilization was reported by 15 of 32 respondents (47 percent), with a similar share reported for the January storm period (14 of 30 respondents, or 47 percent). Among the responding utilities that used AMAs (one or more), agreements covered only a portion of the portfolio (60 percent for peak day supply and 57 percent during the January storm period).

For portfolios that utilized AMAs, respondents most frequently reported that agreements applied to specific pipelines within their supply portfolios (93 percent overall and 93 percent during the January storm period). The January storm results also indicate a stronger emphasis on specific storage assets (71 percent), suggesting AMAs may be deployed to target constraint-driven flexibility needs during discrete winter windows. The results highlight an increased reliance on pipeline and other storage in the East, suggesting regional access to substantial off-system storage services and pipeline capacity through third-party contracts. These resources can represent contracted access to storage deliverability, transportation capacity, or related pipeline services, providing utilities with flexible supply options that are not necessarily owned directly by the utility. In practice, this flexibility can function as swing supply[15], allowing utilities to increase or adjust supply as heating demand changes during cold-weather events without relying solely on utility-owned assets.

[15] Swing supply refers to supply that can be adjusted upward or downward over a short period to respond to changes in demand, particularly during cold-weather events when heating load can rise quickly.

Contractual Agreements & Pricing Mechanisms

Contract terms and pricing structures shape how utilities secure winter supply, operational flexibility, and commodity cost exposure.

The survey shows that utilities employ a diverse set of contractual agreements and pricing mechanisms to secure adequate gas supplies for the winter season at a reasonable cost. The contract term defines the duration of the supply commitment, while the pricing mechanism defines how the gas price is set over that period. Contracting periods typically span short-term agreements (one month or less), mid-term agreements (one month to one year), and long-term agreements (greater than one year). Utilities often distribute volumes across different terms rather than relying on a single contracting horizon. In parallel, utilities procure supply under multiple pricing structures to balance day-to-day flexibility with greater price stability across larger volume blocks.

Gas Supply Contract Terms

Mid-term contracts (ranging from one month to one year) were a dominant contracting strategy for the 2023-2024 WHS. In aggregate, responding LDCs procured 51.1 percent of supply under mid-term agreements, compared with 28.7 percent under short-term agreements and 20.2 percent under long-term agreements. At the company level, 18 of 32 respondents used mid-term contracts for more than half their WHS supply.

Mid-term agreements can be an attractive contractual strategy for LDCs because they secure supply ahead of weather-driven demand shifts that can spike commodity pricing and supply availability, while still preserving some of the hedging and portfolio flexibility that longer-term arrangements cannot provide.

Short-term contracts, by contrast, were used selectively—21 of 32 respondents favored them in 50 percent or less of their portfolio.

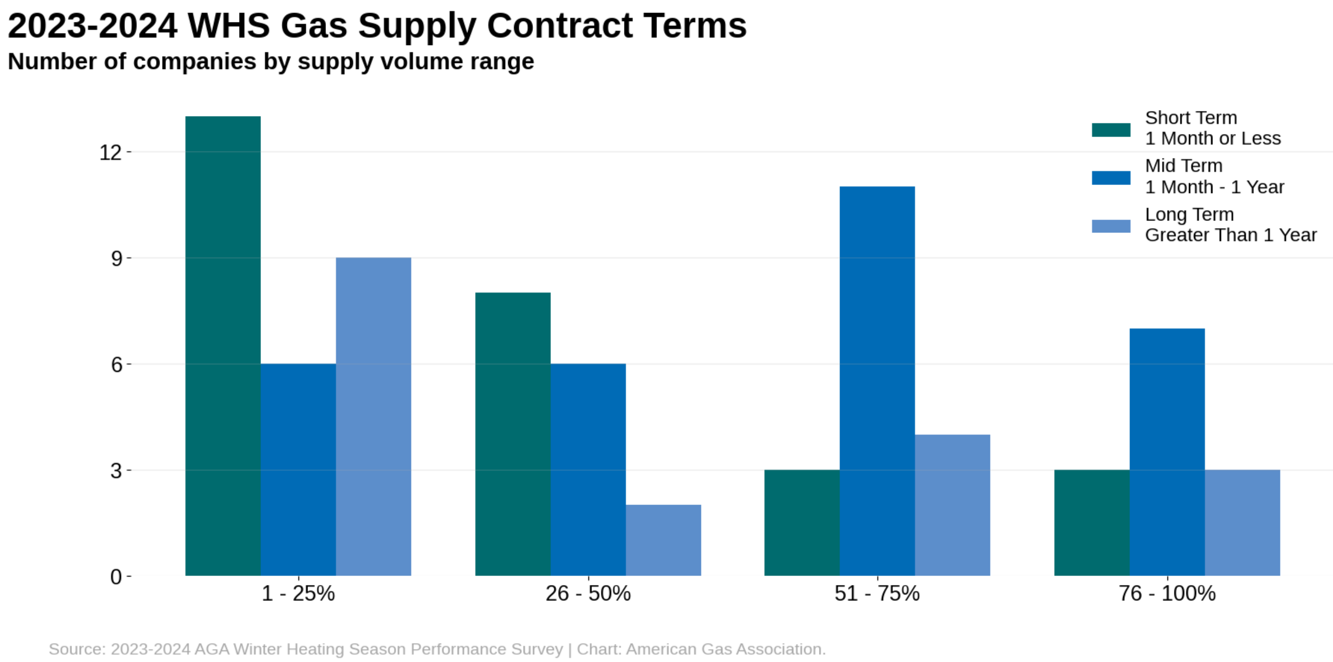

Figure 8. Contract terms used by responding utilities by grouping purchased volumes by contract length and expressing each as a share of the LDC's total WHS supply. Values shown represent the number of responding companies in each range for each contract term.

Gas Supply Pricing Mechanisms

Index-based pricing accounted for the largest share of procurement. In aggregate, first-of-month (FOM) pricing accounted for 44 percent of reported supply and daily spot/index pricing for 39 percent. Fixed-price contracts made up just 11 percent, with NYMEX-linked and other mechanisms covering the remainder.[16]

The concentration of daily and FOM pricing for more than 50 percent of supply suggests that larger portions of utility gas portfolios are indexed to prevailing market prices rather than locked into fixed-price arrangements. This approach prioritizes price transparency and procurement flexibility (e.g., the ability to adjust daily supply decisions) while managing volatility through portfolio tools such as storage and transportation optionality, procurement governance, and approved cost-recovery mechanisms. Fixed-price contracts are used as a targeted hedge layer to limit price variance for specific portfolio segments, not as the primary pricing structure.

Open-ended comments reinforce a picture of procurement stability. Most respondents reported no material change in portfolio management relative to the prior winter season. Among those that did, changes were incremental and risk-management oriented, indicating reduced reliance on daily purchases by maintaining higher inventories or higher base supplies, increased use of fixed-price coverage, and greater use of mid- and long-term purchases price at FOM indices.

[16] See Appendix A, Section II for a definition of each supply pricing mechanism.

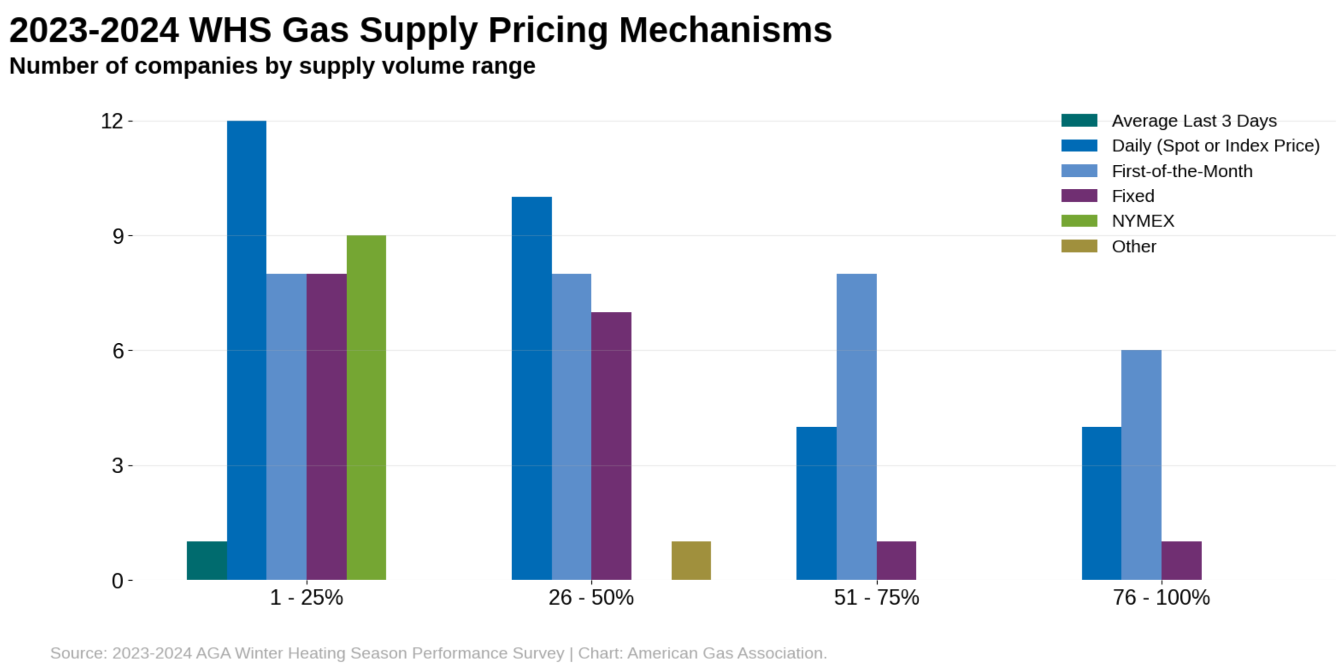

Figure 9. Pricing mechanisms are used by responding companies across a range of supply volumes. Values shown represent the number of responding companies in each range.

Risk Management & Financial Tools

Even when physical supply is available, winter volatility can create meaningful commodity-price and basis exposure, making risk management an important complement to procurement strategy. Physical procurement structures (daily, FOM, fixed, NYMEX-linked) define how supply costs are calculated but are only one component of price-risk management. Respondents also reported using financial hedges and hedge-like contracting tools to manage exposure to commodity price movements, basis risk, and winter volatility. Roughly 69 percent of respondents (22 out of 32) reported using financial instruments to hedge a portion of their gas supply during the WHS. Among respondents that reported hedging, LDCs hedged an average 35 percent of their gas supply.

Financial Hedging Instruments

Fixed price contracts (13 of 22 respondents) and options (11 of 22) were the most commonly reported hedging tools during the 2023-24 WHS, while futures (5 of 22) and swaps (5 of 22) were used by fewer companies. Other instruments (2 out of 22) were the least common.[17]

Fixed-price physical contracts and options are often attractive to LDCs because they align more directly with winter procurement needs. Fixed-price contracts can lock in commodity costs while also embedding commercial terms tied to deliverability, whereas futures and swaps typically hedge only the price component and must be paired with separate physical procurement. Options can also be better suited to weather-driven demand uncertainty because

[17] See Appendix A, Section III for a definition of each financial hedging instrument.

they provide protection against price spikes while preserving flexibility if market prices fall or actual volumes differ from forecast.

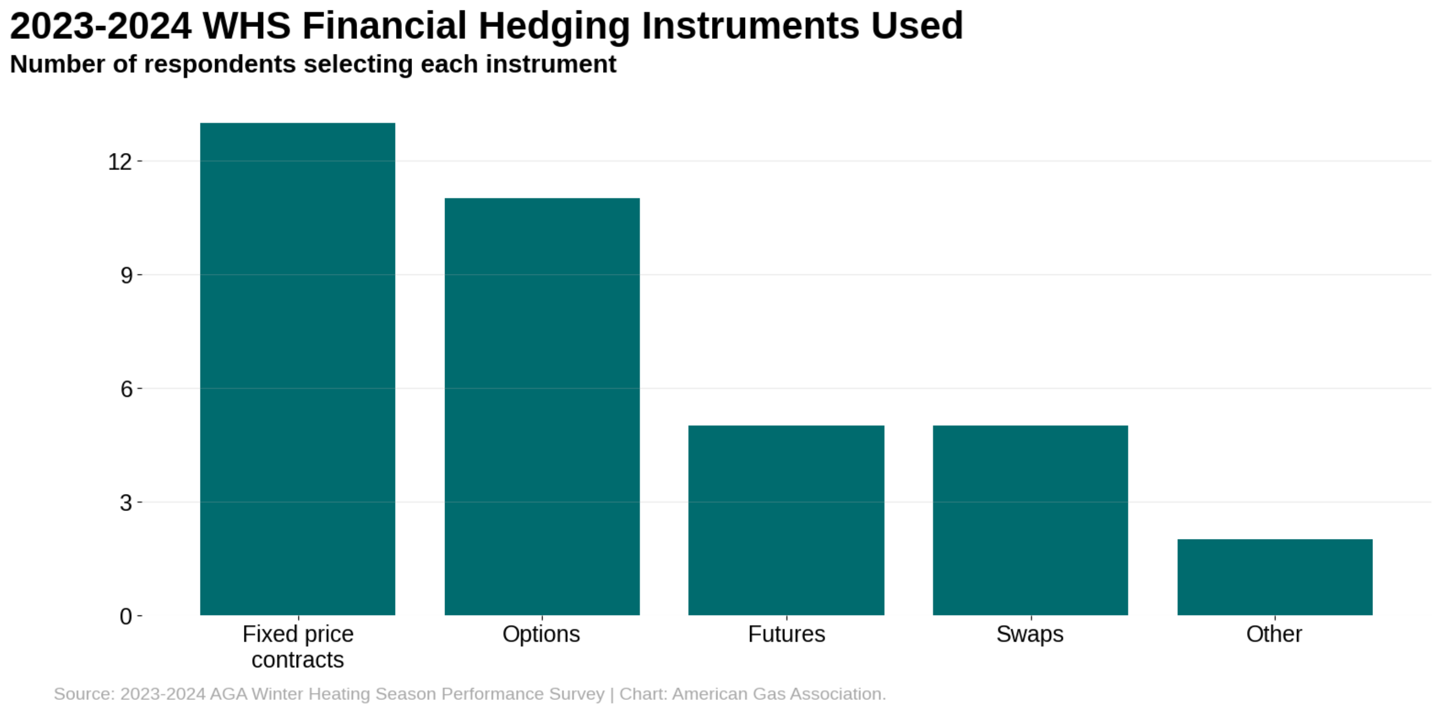

Figure 10. Hedging instruments used during the WHS, reported by number of companies

Fixed-price contracts were most prevalent in the East and Pacific-Mountain, while Midwest respondents reported a stronger preference for options (with futures and swaps more prevalent in Pacific-Mountain than in the East). Regional dynamics and market fundamentals (such as basis volatility, pipeline and storage constraints, and local liquidity at pricing points) contribute to hedging instrument choices.

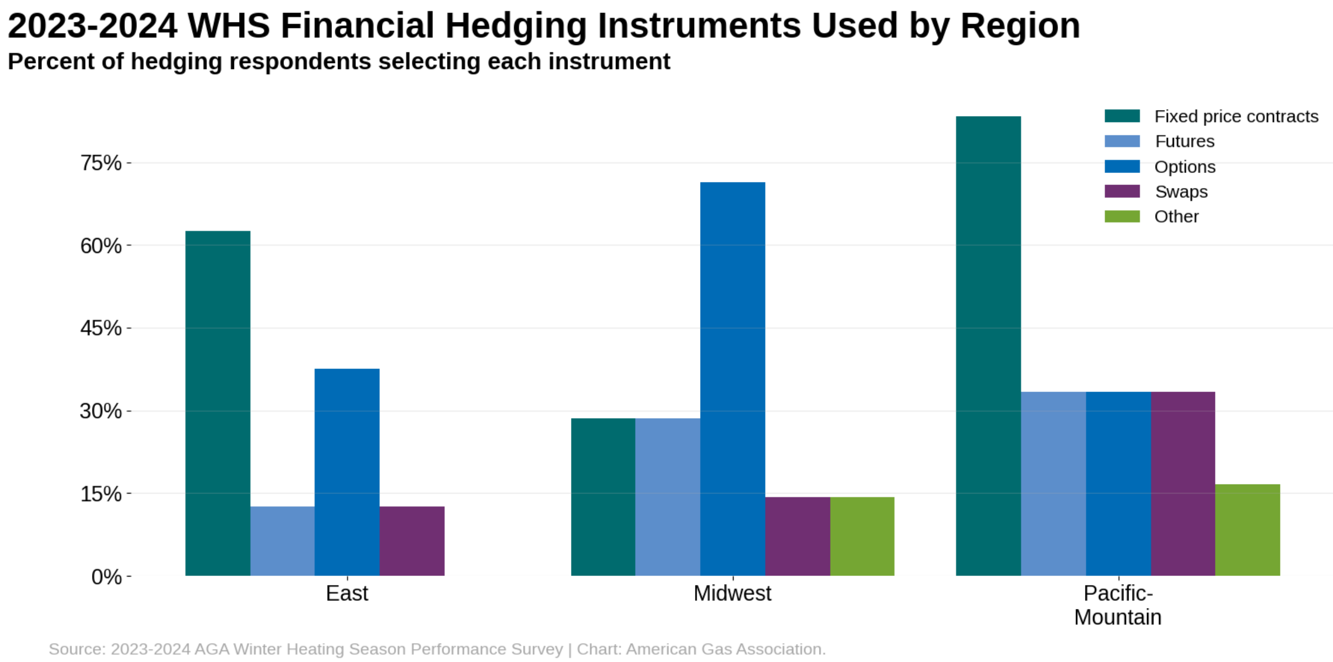

Figure 11. Regional breakdown of hedging instruments utilized by LDCs.

Regardless of instrument or region, hedging decisions were made with customer benefit as the primary objective. The most frequently cited reasons were customer-driven or voluntary hedging (13 companies), regulatory requirements (6), and "other" (6), including mitigation of customer rate volatility. Consistent with this, nearly all respondents that reported using hedging identified reduced price volatility relative to an unhedged approach as the primary customer benefit.

Natural Gas Storage

Storage is one of the most important winter reliability tools for LDCs. While it is a portion of the broader supply portfolio, natural gas storage assets provide fast, physical flexibility when demand rises faster than scheduled supply can adjust. The ability to store physical molecules of gas is a defining feature of the commodity and a key advantage for utility winter demand planning and management.

LDCs can draw on several storage types, often serving a unique purpose. Underground storage and linepack are commonly used as backup and balancing resources that supplement supply and strengthen system reliability when demand rises. Other resources, such as liquified natural gas (LNG), compressed natural gas (CNG), and propane-air, are typically reserved for high-demand events, including winter storms.

LDCs may own storage facilities directly or secure storage services through third-party markets or asset owners under ratchet agreements. In addition to operational value, storage can function as a physical hedge. For utility-owned assets, companies can inject gas when prices are lower and withdraw it when prices spike due to constraints, helping reduce exposure to high-priced spot purchases during peak demand. Contracted assets can also be utilized in this form, although the ratchet provisions often limit the volume of gas available to the utility more than when an LDC owns the entire storage capacity.

Nearly all utilities (31 of 33) reported using underground storage, either on-system or pipeline, for a portion of their gas supply, averaging 20 percent seasonal volumes. During the January 2024 winter storms, storage's role grew: 28 out of 31 respondents drew on underground storage for an average of 28 percent of supply.

WHS Storage Influences

Many factors influence the use of storage during the winter season.[18] Survey responses indicate that storage is primarily deployed as a reliability and system-balancing tool in winter planning, with market optimization playing a secondary role. Nearly all companies (30 of 31) cited weather-induced demand as the primary reason for underground storage use, followed by pipeline OFOs (22), no-notice requirements (20), "must turn" contract provisions (20), and arbitrage opportunities (11). The prevalence of OFOs and no-notice requirements underscores storage's role in managing intra-day volatility and maintaining operational compliance during constrained conditions.

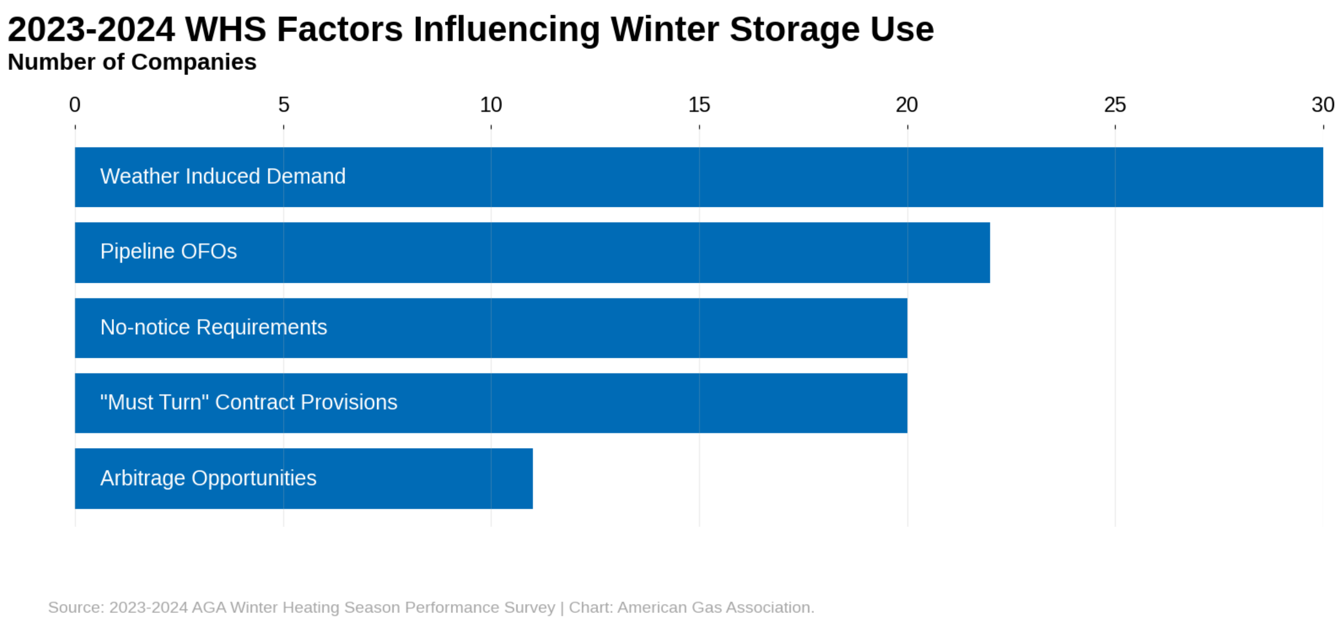

Figure 12. Factors that influenced the use of storage assets during the WHS by number of companies.

Demand Management & Regulatory Context

Winter reliability depends on supply assets, but also the operational directives and regulatory frameworks that govern how utilities manage imbalances, customer impacts, and cost recovery.

Among the 30 responding companies with interruptible customers, 20 percent reported interruptible curtailments[19], all on peak day, with 83 percent also reporting interruptions on off-peak days. On average, companies initiated interruptions three times over the season, primarily in response to cold weather conditions and planned or

[18] See Appendix A, Section IV to find definitions for weather induced demand, OFOs, no-notice requirements, "must turn" contract provisions, and arbitrage opportunities.
[19] See Appendix A, Section V for a definition of interruptible curtailments.

emergency pipeline maintenance. Even so, volumes interrupted remained modest, averaging only about 1 percent of total system throughput.

Flow Orders

Flow orders were more common: 78 percent (25 of 32) indicated that the LDC posted at least one flow order during the season. In most cases, these orders were enforced through customer charges for unauthorized volumes, non-compliance penalties, or both (88 percent of respondents). The most frequently cited driver was an upstream pipeline OFOs (19 of 25), followed by system constraints due to demand load (12 of 25). By contrast, power generation behind the LDC citygate was rarely cited as a reason for posting a flow order.

The relatively frequent use of flow orders, alongside limited curtailment volumes, suggests that many LDCs relied on operational directives and imbalance penalties as a first-line tool for managing system conditions before resorting to more disruptive service interruptions. Additionally, the prominence of upstream pipeline OFOs as a driver of utility flow orders underscores the extent to which LDC winter operations remain shaped by upstream transportation conditions and regional pipeline constraints.

Demand-Side Management

Responses suggest that formal demand-side management (DSM)[20] requirements remain uneven across jurisdictions. Thirty-five percent of companies reported policy-driven DSM programs, while 65 percent said they were not currently subject to legislative or regulatory mandates to implement such initiatives. The uneven presence of policy-driven DSM programs likely reflects not only differing state policy priorities, but also the fact that natural gas utilities generally have fewer practical DSM options than electric utilities.

Climate and load profile may further shape how DSM is used, particularly whether it is intended to address weather-driven peak demand. In colder climates, where space heating contributes to winter peaks, DSM may have a clearer role in reducing consumption during high-demand periods. In milder climates, DSM programs may still exist but are more likely to be driven by broader energy efficiency, affordability, conservation, or emissions-related policy goals rather than peak load management.

Existing gas utility DSM efforts are concentrated primarily in energy efficiency, rather than a broad suite of dispatchable or scalable demand-side tools, which limits the role DSM can play in peak-demand and reliability planning relative to traditional supply, system, and reliability planning measures.

Regulatory Environment

Regulatory requirements to submit gas supply plans also varied. Roughly one-quarter to one-third of respondents reported being required to make winter, annual, or statute-defined filings, while the remainder reported no such mandates. Differences in required gas supply filings may reflect the fragmented nature of state regulatory frameworks, with some commissions relying on formal seasonal planning submissions and others addressing procurement oversight through broader review processes.

Most LDCs did not report heightened regulatory scrutiny or intervention related to gas acquisition practices during the 2023-2024 WHS. Although 44 percent of respondents said regulators in at least one operating state were formally reviewing gas purchasing activity, all described these proceedings as routine reviews rather than special investigations or extraordinary actions, suggesting that existing review and cost recovery frameworks were largely

[20] See Appendix A, Section V for a definition of DSM.

sufficient for the 2023-2024 season, and that market or operational conditions did not rise to a level that prompted unusual commission action.

Cost recovery mechanisms were also broadly stable across respondents. No respondents reported delayed cost recovery, either for the winter season as a whole or for gas purchases made during the January 2024 winter storms. Nearly half of companies reported recovering gas costs on a deferred basis with interest, while another 41 percent used a similar pass-through structure without interest. Other approaches, including blended jurisdictional methods or alternative recovery formulas, were uncommon. The prevalence of familiar deferred and pass-through recovery mechanisms indicates a broadly stable regulatory environment in which both utilities and commissions continue to rely on established approaches to gas cost recovery.

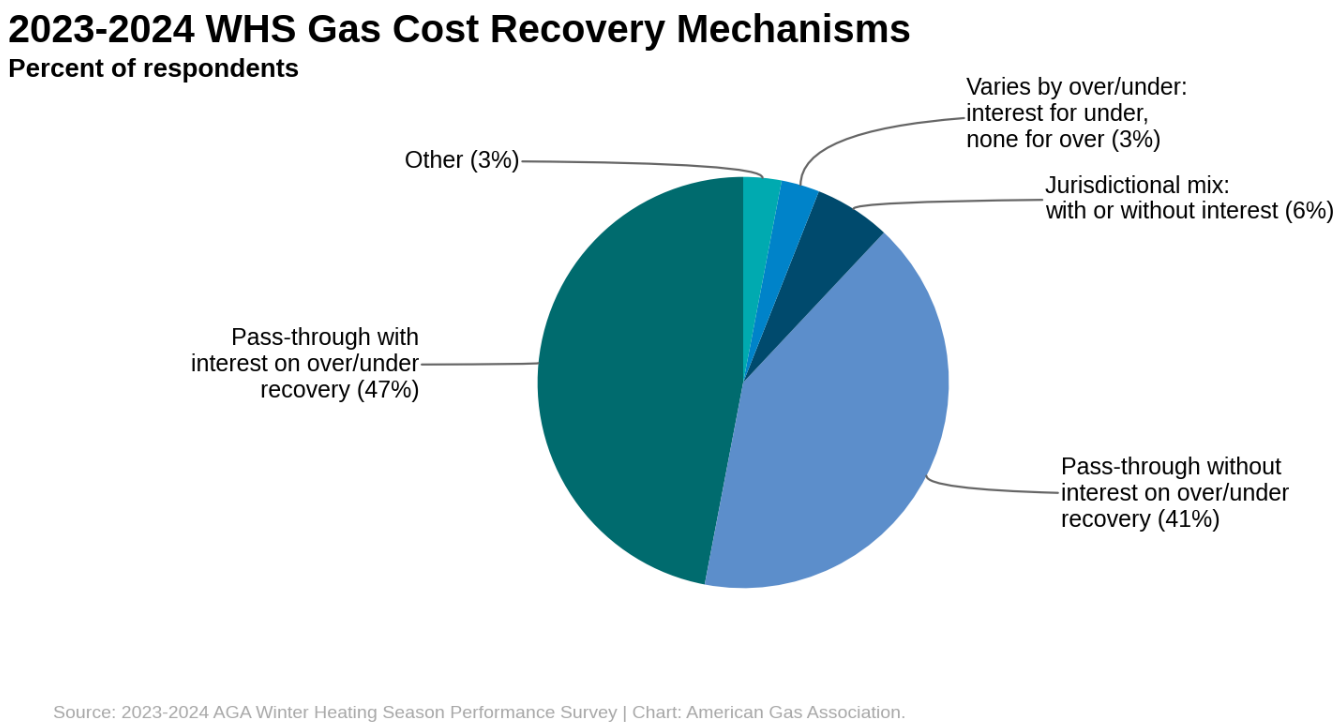

Figure 13.

When asked whether regulators discouraged the use of any specific supply or risk management tools, most respondents indicated that no tools were restricted. A small number of companies expressed interest in broader use of asset management programs or fixed-price physical purchases, but these responses did not suggest that such limitations materially constrained winter planning.

Conclusion

Utility winter planning must account not only for seasonal demand patterns, but for short-duration cold events that can sharply increase load over a matter of days. Although the 2023-2024 winter was relatively mild overall, the January 2024 storm period and peak-day data provided meaningful insight into utility preparedness and highlighted the importance of managing rapid, weather-driven demand increases.

LDCs drew on decades of winter planning experience to meet their obligations. Supply portfolios are often anchored by firm transportation and supported by underground storage, citygate purchases, and other balancing tools tailored to local system needs, relying on design-day planning, predominantly mid-term contracting, index-based pricing, and targeted hedging strategies to balance deliverability, cost, and flexibility. Operational tools such as OFOs, no-notice service, and limited interruptible curtailments remained important for managing intra-day volatility and maintaining system integrity during stressed conditions.

Most respondents also reported established cost-recovery mechanisms, access to risk-management tools, and routine rather than extraordinary oversight, pointing to a broadly stable regulatory and operational environment.

While each winter offers lessons, the industry's sustained commitment to proactive supply planning and operational readiness is paramount to winter success. As affordability remains a central concern for customers and policymakers, future winter planning should continue to prioritize those capabilities.

Looking Ahead

The January 2026 Winter Storm Fern, one of the most geographically widespread winter storms since Uri, offered early evidence that post-Uri improvements are working.[21] While survey evidence on utility planning practices is not yet available, AGA's forthcoming 2025-2026 WHS Survey should provide valuable insights into lessons from past winter heating seasons that have been successfully operationalized and where additional learnings may emerge, informing continued improvements in gas supply planning to support system reliability and resilience.

[21] Holding the Line: U.S. Natural Gas Performance During Winter Storm Fern.

Appendix A – Glossary of Key Terms

I. Gas Supply Portfolios

Asset Managed Contacts – commercial contracts in which utilities relinquish operational or dispatch rights of physical assets (such as storage, transportation capacity, or a bundled supply portfolio) to a third-party in exchange for a fee and/or fixed price.

Citygate Purchases for Sales Customers – Natural gas purchased by the utility at or near the citygate (the delivery point from an interstate or intrastate pipeline into the local distribution system) and used to serve sales customers, for whom the utility procure gas and provides bundled commodity service.

Citygate Purchases for Transportation Customers – Natural gas delivered at the citygate on behalf of transportation customers, where the customer or their marketer arranges gas supply, and the utility on provides distribution service.

LNG/propane-air/SNG – Includes vaporized LNG injected into the distribution system from LNG facilities and propane-air mixture or synthetic natural gas (from non-traditional feedstocks) injected into the distribution system as a supplemental peakshaving or emergency supply source.

Local Production – Natural gas produced from wells within or near the service territory and delivered directly into the local distribution system (i.e., not acquired as an upstream market purchase).

On-system Underground Storage – Natural gas withdrawn from on-system underground storage assets (e.g. depleted reservoirs, aquifers, salt caverns).

'Other' Supplies – Any additional supply source not covered by the supply categories. For this survey, companies with sendout volumes in this category reported using sources such as linepack, transporter imbalances, and off-system displacement. *Linepack* refers to natural gas stored within the pipeline system itself, which can be drawn down or restored as pipeline pressure changes. *Transportation imbalances* occur when the amount of gas delivered into a pipeline system does not exactly match the amount taken out over a given period, creating a balance that must later be settled. *Off-system displacement* refers to arrangements in which gas delivered or sourced at one location is used to offset supply needs at another location, helping utilities manage differences between where gas is available and where it is needed.

Pipeline or Other Storage – Natural gas withdrawn from or delivered out of storage facilities or storage-like supply arrangements other than on-system underground storage and LNG/propane-air/SNG. This category includes volumes sourced from upstream pipeline storage, no-notice or park-and-loan type storage services, off-system underground storage, and other third-party storage assets used to physically supply the system.

Purchases Moved via Firm Transportation – Upstream natural gas purchases delivered under firm transportation contracts, excluding volumes reported as on-system underground storage, pipeline or other storage, LNG/propane-air/SNG, and local production.

Purchases Moved via Interruptible Transportation – Upstream natural gas purchases delivered under interruptible transportation contracts, excluding volumes reported as on-system underground storage, pipeline or other storage, LNG/propane-air/SNG, and local production.

II. Gas Supply Pricing Mechanisms

Average Last Three Days – A natural gas pricing mechanism based on the arithmetic average of published daily natural gas index prices over the final three trading days of the month, commonly used to establish or approximate monthly physical gas prices.

Daily (Spot or Index Price) – Natural gas priced using prevailing daily market prices for physical delivery, typically referenced to published spot or daily index prices at a specified receipt point, market center, or citygate.

First-of-the-Month – Natural gas priced using a monthly bidweek or first-of-the-month index, reflecting the market price established for physical natural gas deliveries over the full month at a specified location.

Fixed – Natural gas purchased at a predetermined commodity price for a specified volume and delivery period, with the price set in advance and not subject to subsequent market index movements.

NYMEX – A natural gas pricing mechanism based on the NYMEX Henry Hub futures contract, either as a direct fixed reference or as part of a formula price such as NYMEX plus or minus basis.

Other – Any natural gas pricing mechanism not captured by the categories above, including alternative index formulas, blended pricing structures, or other negotiated pricing arrangements.

III. Financial Hedging Mechanisms

Fixed Price Contracts – Contracts used to lock in a fixed natural gas price for a future period, reducing exposure to changes in natural gas commodity prices. This category refers to fixed-price arrangements used for price-risk management.

Futures – Standardized exchange-traded financial contracts, such as NYMEX Henry Hub futures, used to hedge exposure to changes in future natural gas prices.

Options – Financial instruments that provide the right, but not the obligation, to buy or sell a natural gas futures contract at a specified price, used to manage exposure to adverse natural gas price movements while retaining some upside flexibility.

Other – Any financial hedging mechanism not captured by the categories above, including collars, costless collars, three-way structures, basis hedges, or other over-the-counter natural gas risk-management instruments.

Swaps – Financial agreements in which one party exchanges a floating natural gas price exposure for a fixed price, or otherwise exchanges one pricing basis for another, for a specified volume and period.

IV. WHS Storage Influences

Arbitrage Opportunities – Using storage to buy/inject when prices are relatively low and withdraw/sell (or avoid spot purchases) when prices are higher, a physical hedging mechanism.

"Must turn" provisions – Contract terms requiring minimum injection/withdrawal activity or cycling of volumes over a period, which can drive storage use even absent extreme weather.

No-notice requirements – Service obligations that require gas to be available on short notice without advance scheduling. Storage supports fast response to intra-day swings.

Operational Flow Orders (OFOs) – Pipeline-issued operational directives used to maintain system balance and operational integrity, often by requiring shippers to keep receipts, deliveries, and/or usage within specified limits. Storage withdrawals can provide operational flexibility by helping shippers balance scheduled gas flows with actual demand and reduce exposure to imbalance penalties, when available.

Weather-induced demand – Higher demand requirements driven by cold temperatures and peak day conditions, prompting withdrawals to meet load and maintain pressure.

V. Demand Management & Regulatory Context

Demand-side management – Programs, policies, or measures designed to help customers reduce or better manage energy use. For natural gas utilities, DSM efforts commonly focus on energy efficiency and may include rebates for high-efficiency furnaces, boilers, and water heaters; weatherization measures such as insulation and air sealing; home energy audits; smart thermostat incentives; and low-income efficiency assistance.

Interruptible curtailments – Refers to instances in which a natural gas LDC temporarily reduces or suspends service to customers served under interruptible service arrangements, consistent with tariff provisions or contractual terms. These curtailments are typically used a system management tool during periods of constrained supply, high demand, pipeline maintenance, or other operational conditions.

Appendix B – Methodology Notes

Methodology Notes

Respondents reported data for parent companies and subsidiaries, and several had service territories across multiple states, some of which spanned multiple storage regions. Regional analysis will include 32 of 33 respondents for the East, Midwest, and Mountain-Pacific to comply with EIA regional storage definitions and to protect respondent identity per AGA's protocol.

Respondent counts may vary by section and question depending on company structure, data availability, and question relevance. Unless otherwise noted, percentages are calculated using the respondents to the specific question, and the applicable response count (n) is reported in the text, table, or figure note.

In some sections, exhibits summarize the number of companies in a portfolio-share range, while others summarize aggregate reported sendout volumes across respondents; captions indicate which approach is used.