American Gas Association

Energy Analysis

ENERGY ANALYSIS AND STANDARDS
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LDC SUPPLY PORTFOLIO MANAGEMENT DURING THE 2018-2019 WINTER HEATING SEASON

I. Introduction

Every year, local natural gas utilities create strategies to meet customer energy requirements during the winter heating season. Guided by experience and regulatory oversight, utilities study several considerations when building out a seasonal natural gas supply portfolio. Based on individual utility-specific conditions, utilities plan for reliable natural gas deliveries on a daily, weekly, monthly, and seasonal basis by matching supply resources to forecasted demand and preparing for “design day” conditions (or a historic peak day load). Demand requirements may be shaped by local weather conditions or system requirements from past years. Gas utilities carefully consider supply resources such as firm pipeline capacity, access to on-system or pipeline storage, peak-shaving capabilities, local production, and even third-party transportation arrangements. Plans to manage supply pricing risks may also be in place. In many cases, these plans are submitted to state regulators for approval before the start of the winter heating season.

This Energy Analysis details the critical elements of the 2018-2019 winter heating season (WHS) from the perspective of natural gas utility supply portfolio planning. The information in this analysis originates from data collected from AGA member local distribution companies (LDCs) through the AGA *LDC Winter Heating Season Performance Survey*. The survey questions focus on peak-day and peak-month supply practices, pricing mechanisms, regulatory frameworks, and market hedging practices—acknowledging that each winter heating season may be unique or exceptional in many ways. The previous LDC Winter Heating Season Performance Survey was published for the 2014-2015 winter heating season and can be found on the AGA website for reference.

This year's data reflects responses from 69 local gas utilities with service territories in 37 states. The sample companies had an aggregate peak-day send out of 53,890,664 Dekatherm (Dth) or 53.9 billion cubic feet (Bcf) for the 2018-2019 winter heating season, understanding that the peak day did not occur on the same calendar day for each company. However, these same companies *planned* for a peak-day of 61,276,278 Dekatherm (Dth) or 61.3 billion cubic feet (Bcf) in aggregate, meaning that about 88 percent of the planned peak send out volume was actually required during the 2018-2019 winter heating season compared to 82 percent during the winter heating season of 2014-2015.

This report documents gas delivery system operations of the surveyed local gas utilities during the 2018-2019 winter heating season and helps provide insights into gas supply trends and procurement portfolio management. ***The aggregated data presented in this report are not to be interpreted as standards or best practices for gas supply management.*** Instead, they represent a snapshot of aggregated supply procurement practices of those companies that participated in this survey. The need for and timing of any of the described practices will vary with each operator based on several factors, including, but not limited to, unique regulatory, geographic and operational characteristics.

In some cases, the report compares survey results for this 2018-2019 winter heating season with the previous year's data. It should be noted, however, that the compared samples are not identical, and the supporting data are not audited or normalized for sample differences, weather, or other factors. As stated previously, the last LDC Winter Heating Season Performance Survey was published for the 2014-2015 winter heating season and can be found on the AGA website for reference.

II. Executive Summary

- This report is based on survey responses submitted by 69 AGA member local gas utilities in 37 states. These companies had a cumulative, non-coincident, peak-day send out of 53,890,664 Dekatherm (Dth) or 53.9 billion cubic feet (Bcf) and an average peak-day send out of 792,510 Dth, which was 18 percent and 5 percent lower than the sample of companies for the previous winter heating season survey from 2014-2015. The coldest day of the 2018-2019 winter heating season, as reported by 56 out of the 68 respondents, occurred predominantly in January, primarily the 21st or the 30th 2019. During the 2014-2015 winter, 45 of 79 respondents had reported their peak day primarily in mid-February.

- Results in this winter heating season survey are generally presented as counts of companies that fit into percentage ranges of supply volumes (e.g., 1-25 percent, 26-50 percent, and so forth). The intent of this report is to document the data as a snapshot of supply behavior by large purchasers of natural gas—in this case, the surveyed local distribution companies (LDCs).

Natural Gas Market

- Natural gas consumption in the U.S. reached new highs in 2018 driven largely by increases in the electric power sector, with the generation mix showing natural gas and renewables shifting from coal-fired generation during the year. Natural gas consumption also increased in the industrial, residential, and commercial sectors in 2018 as a result of unusually cold weather in the first quarter of 2018, in particular in early January 2018.[1]

- Natural gas storage stocks touched very low levels in 2018, according to the EIA. Natural gas storage inventories ended the previous heating season on March 31, 2018, at their lowest level since 2014. Natural gas storage inventories started the winter season on November 1, 2018, at lower levels than in previous years, contributing to unusual price volatility in later months of the year as well.[2]

- During the period of November 1, 2018, through March 31, 2019, the total consumption of natural gas in the U.S. ranged from about 68 Bcf per day on a warm day to 137 Bcf on January 30, 2019.

[1] https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2019/01_10/
[2] https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2019/01_10/

- The residential and commercial segments of the market were most responsible for the dramatic swings in load requirements during the 2018-2019 winter heating season, ranging from over 74.8 Bcf per day on a cold January day in 2019 to a winter heating season-low of about 22.1 Bcf per day on a mild March day. Stated plainly, managing these swings in daily load requirements reliably while preserving customer value is what local gas utilities do.

Weather

- Heating degree days (HDD)are a measure of the coldness of the weather experienced, based on the extent to which the daily mean temperature falls below a reference temperature (65° F). For example, on a day when the mean outdoor dry-bulb temperature is 35°F, there would be 30 degree-days experienced. (A daily mean temperature represents the sum of the high and the low readings divided by two.) HDD's help define the general need for heating as part of the planning for residential or commercial buildings, which is why it's considered a risk management tool that utilities can use to hedge their activities that depend on weather, such as energy needs.[3]

- The United States compiled 3,924 heating degree days during the five-month winter heating season period November 2018-March 2019. By comparison, the winter heating season of 2014-2015, which included the polar vortex event, compiled 4053 HDD. The average cumulative HDD count for November–March has been 3,729 HDD since 2010, with the average per month being 173 HDD per month, according to the EIA.[4]

- Between December 2018 and February 2019, temperatures were colder than average on the Northern Plains, Pacific Northwest, and West Coast, while the Southeastern United States saw warmer than normal temperatures.[5]

- Temperatures in December and January were overall warmer than average across much of the country. However, in February, the western half of the country, across the Northern Plains and stretching into the Pacific Northwest, observed temperatures more than 11°F lower than the typical for the month.[6]

- February 2019 was the second-coldest February since 1895 in North Dakota and Montana as well as the third-coldest in South Dakota, and fifth-coldest in Washington. On the other hand, the Southeast region of the U.S. experienced a top-ten-warmest February pushing the overall U.S. trend for the 2018-2019 winter heating season to be above average, according to NOOA.[7]

Gas Supply Portfolios and Pricing Mechanisms

- The participating utilities had an aggregate peak-day send out of 53,890,664 Dekatherm (Dth) or 53.9 billion cubic feet (Bcf) for the 2018-2019 winter heating season, understanding that the peak day did not occur on the same calendar day for each company. However, these same companies planned for a peak-day of 61,276,278 Dekatherm (Dth) or 61.3 billion cubic feet (Bcf) in aggregate, meaning that about 88 percent of the planned peak send out volume was actually required during the 2018-2019 winter heating season.

[3] https://www.investopedia.com/terms/h/heatingdegreeday.asp
[4] https://www.eia.gov/opendata/qb.php?category=1039991&sdid=STEO.ZWHDPUS.A
[5] https://www.climate.gov/news-features/blogs/enso/winter-outlook-2018-2019-how%E2%80%99d-we-do
[6] https://www.climate.gov/news-features/blogs/enso/winter-outlook-2018-2019-how%E2%80%99d-we-do
[7] https://www.climate.gov/news-features/blogs/enso/winter-outlook-2018-2019-how percentE2 percent80 percent99d-we-do

- Many factors including weather, storage levels, end-use demand, pipeline capacity, operational issues, and financial markets play a role in the market pricing of the gas commodity and transportation services. The market fundamentals that impact price have also expanded to include interest rates, other investment opportunities, the price of other commodities and even currency exchange rates.

- Such broad market influences affect LDCs and other gas suppliers, making planning increasingly challenging for all stakeholders. To deal with the inherent uncertainty of the market—even considering the relative stability of natural gas markets in recent years—supply planners use a portfolio approach to pricing gas supplies mirroring their approach to supply sources, providers, and transportation options.

- This portfolio approach includes pricing mechanisms and contract terms such as fixed, first-of-the-month and daily spot and index pricing as well as daily, monthly and mid-term contracts.

- For the 2018-2019 WHS survey, companies described their methodology for determining their design day calculation as follows: 3 (4 percent) used a 1-in-50-year risk of occurrence, 24 (36 percent) employed a 1-in-30 year, 4 (6 percent) used a 1-in-20, two used a 1-in-15, 4 a 1-in-10 occurrence probability.

- Fourteen companies utilized an alternative period criterion, ranging from 20 years to 1-in-90 years, which is similar to the methodologies used in the 2014-2015 survey. In addition, 16 companies used other methodologies, including Multilinear regression, design day weather standard, historical peak or severe weather event from a specific year, to name a few.

- When examining the natural gas purchasing practices of companies during the past several winter heating seasons, it is clear that first-of-month (FOM) index pricing has dominated the market for the largest portion of supply agreements, whether short, long, or mid-term. However, with sustained lower market prices, daily pricing mechanisms have become more prevalent.

- Twenty-two out of 31 company respondents used long-term contracted supplies during the past winter heating season, followed by 21 of the 53 responding companies using short-term contracts for 26-50 percent of their supply volume followed by 17 of the 55 respondents using mid-term supply contract terms for 76-100 percent of their supply volume.

- For gas pricing mechanisms, the 2018-2019 winter heating season respondents primarily used first-of-the-month pricing, with daily (spot or index) utilized second-most. First-of-month indices continued to be the predominant pricing mechanism, like the 2014-2015 and 2013-2014 winter. This is not surprising since the first-of-month index is not only a measure of market movement but often also serves as a baseline from which hedging strategies can be measured.

- Daily pricing also played a significant role, particularly for volumes representing less than half of winter supplies. The prevalence of this pricing mechanism may be explained by the relative price stability that appears to have developed in the natural gas market recently. Weekly and average three-day pricing played the least significant role in gas supply pricing mechanisms this season, similar to the 2014-2015 survey as well.

- It should be noted that LDCs build gas supply portfolios and pricing strategies based on prior as well as anticipated experiences. Even state regulator-approved pricing mechanisms may appear favorable one year while less so the next. Flexibility and constructive policy reviews, rather than second-guessing, can have a positive effect on the delivery of natural gas and services to customers at the lowest possible cost.

Hedging

- Seventy-five percent of responding companies (50 of 67) said they used financial instruments to hedge a portion of their 2017-2018 and 2018-2019 winter heating season gas supply purchases. Ninety-eight percent of companies reported using financial instruments in 2018-2019. Still, this percentage is significantly larger than in 2004-2005 (70 percent of respondents) and in 2001-2002, where only 55 percent of respondents reported using financial instruments to hedge gas supply costs. It is important to note that the company makeup and size of the survey sample differ from year to year. For the 2013-2014 winter, 49 of 77 responding companies hedged up to 50 percent of their gas supply purchases.

- Respondents used one or more of the following instruments to hedge a portion of their 2018-2019 WHS gas supply purchases: options (30 companies), fixed-price contracts (22 companies), swaps (16 companies), and futures (8 companies). The use of financial instruments may be understated in this report since some of the volumes delivered to LDCs from marketers, and other suppliers are hedged by a third party rather than the LDC and may have been excluded from the LDC's data. That said, according to the data collected for this winter heating season, an average of 3 percent and a median of 28 percent of the gas delivered by the companies in the survey during the 2018-2019 winter heating season was hedged.

- Only one company reported using weather derivatives during the 2018-2019 winter heating season. This compares with 4 companies out of 78 respondents during the 2014-2015 WHS, 4 companies out of 73 respondents during the 2012-2013 WHS, 5 of 76 companies in 2006-2007, 7 of 54 in the 2004-2005 survey.

- When asked about how far into the future hedging strategies extended, 24 of 51 companies with hedging programs (47 percent) indicated that they applied a six-month or less strategy for a portion of their hedges for the 2018-2019 winter heating season. 21 (41 percent) companies used a 7-13-month strategy, and 11 (22 percent) companies employed a greater than 13-month strategy. Of course, a single company may use one or all strategies simultaneously. In fact, 17 (33 percent) of the respondents did just that, compared with 28 in the 2013-2014 survey year.

- In some jurisdictions, there are no formal standing hedging plans. In others, LDCs may be required to have in place their hedging plans for future gas supplies by predetermined dates. Variations on these themes are many and are geared to be compatible with the interplay among local distribution companies, regulators, and local market conditions. Seventeen of 66 responding companies said that they are required to secure pre-approval from their regulator, and 15 indicated that they are required to operate within set parameters, such as particular financial instruments, time limits, or volume restrictions.

- When asked about their regulatory environment, the majority of respondents (59 of 66) reported no change in their regulator's receptivity to financial hedging during the 2018-2019 winter heating season compared to the prior year, and two reported increased receptivity on the part of their regulator or public utility commission (PUC). No companies indicated that their PUC was less receptive this past winter heating season. Thirty-eight of 61 responding companies (62 percent) did not believe that the events of the 2018-2019 winter would influence regulatory views of hedging strategies.

- Fifty-one of 57 responding companies reported that their regulator treated the financial losses and the gains related to hedging equally. This 89 percent response compares with 88 percent (or 45 of 51 companies) from 2011-2012. Additionally, 51 of 51 companies that answered the question said yes when asked if costs associated with their financial hedging programs were fully recoverable.

- When asked about the focus of their regulator with respect to natural gas purchases, 12 of the 64 respondents (19 percent) indicated that their regulator was primarily interested in the lowest possible price, 6 of 64 (9 percent) said that the focus was on stable prices, and 37 companies (58 percent) said their regulator was equally concerned with both low and stable prices.

- Among LDCs, motivations surrounding hedging programs vary. When asked about the impetus behind their financial hedging programs, 19 of 64 companies (30 percent) cited regulatory requirements, 28 (44 percent) said it was a voluntary decision (in certain cases influenced by customers), and 10 identified other or additional reasons or goals, such as price stability and cost stabilization.

- When asked how customers benefited from their financial hedging compared with no hedging, 49 respondents noted the reduced-price volatility as a benefit to customers, while 23 companies identified reduced gas costs as valuable to customers. Of the respondents, 23 cited both lower prices and more stable prices as benefits to consumers resulting from structured hedging plans.

Gas Storage

Production and market area storage are key tools for efficiently managing LDC gas supply and transportation portfolios. However, it should be noted that storage practices are no longer dictated solely by local utility requirements to serve winter peaking loads. Storage services now support natural gas parking, loaning, balancing, other commercial arbitrage opportunities at market hubs and city gates, and even supply resources during summer cooling periods.

- Local distribution companies are concerned with managing gas supply and transportation portfolios efficiently and cost-effectively. Production area storage and market area storage help LDCs meet these goals. The use of storage facilities helps LDCs to both meet short- term swing opportunities and satisfy peaking needs. Table 8 shows storage levels as estimated by the Energy Information Administration for December 2017- September 2018 compared to the same period in 2019.

- The storage story for the 2018-2019 winter begun in April 2018 when net injections began to refill inventories after the prior winter's drawdown. By the beginning of the 2018-2019 winter heating season, working natural gas stocks were their lowest levels since 2005, totaling 3,198 Bcf in November 2018.

- The withdrawal season started quicker this winter heating season, with colder-than-normal temperatures resulting in larger-than-normal withdrawals of 206 Bcf in November, being approximately twice as much as the five-year average. According to the EIA's Natural Gas Weekly Update for the end of the winter heating season, the pace of withdrawals decelerated during December, totaling 320 Bcf, which compared with the five-year average of 523 Bcf is much less. Even though the highest weekly net withdrawals happened the week of February 1, with 237 Bcf of natural gas being pulled out of storage, the extractions from January- December 2019 followed the five-year average pattern.

- Net withdrawals from storage during the 2018–2019 winter heating season was 2,061 Bcf, which is 5 percent below the five-year average for the season, according to the EIA. The 2018–2019 U.S. winter heating season was characterized by periods of colder-than-normal temperatures around the Upper Midwest, which resulted in considerable natural gas storage withdrawals.

- The 2018-2019 winter heating season had the 10th-highest net withdrawals on record, falling far short of the 2013–2014 winter heating season record of 2,958 Bcf. Throughout the 2017–2018 winter heating season net withdrawals from storage also fell below the 2,417 Bcf reported making the 2013–2014 and 2017–2018 winter heating seasons trend significantly colder-than-normal temperatures.[8]

- A variety of reasons also underlie LDCs' decisions to use their existing stored gas supplies. Ninety-six percent of survey companies (66 of 69) used underground (on-system or pipeline) storage for a portion of their gas supply during the 2018-2019 winter heating season, which is consistent from the 2014-2015 participant replies. Fifty-nine reported that up to 50 percent of their 2018-2019 winter supplies were drawn from storage.

- Participants indicated that multiple factors influenced their use of storage during the past winter heating season with weather-induced demand and no-notice requirements being the majority at 76 percent and 53 percent respectively. Other factors included "must-turn" contract provisions (38 percent of participants), pipeline operational flow orders (35 percent of participants), and arbitrage opportunities (11 percent of participants). Twenty-six percent of the participants indicated that all the above factors influenced their use of storage during the past winter heating season.

- Various factors also influenced participant storage refill decisions during the spring and summer of 2018. Supply reliability topped the list of reasons that motivated LDCs to inject gas supplies into storage with 68 percent of participants choosing this option, while operational issues (50 percent) and price considerations (48 percent) were also significant factors. Fill ratable over the injection season (26 participants), regulatory plans or mandates (22 participants) and term of asset management agreement (10 participants) impacted the storage strategy as well. Of course, more than one variable may influence injections of gas supplies into storage as 7 of these companies were motivated by all six factors.

- The gas purchases made for storage injections during the 2018 refill season, in preparation for the 2018-2019 winter heating season, were based primarily on first-of-month (FOM) indices (56 participants) and daily spot pricing (42 participants). However, fixed and NYMEX-based gas pricing also received some play, particularly for small volumes of gas destined for underground storage with 22 participants and 20 participants respectively.

- This season saw a continuing trend of 25 of 69 participants indicating that more than 75 percent of supplies purchased for storage injections were FOM priced. Additionally, the second most used tool was "daily spot pricing" (42 participants). Although simple in concept, just the fact that flowing gas was available—given the demand levels and persistent cold—is consistent with the 2014-2015 winter heating season perception of the U.S. gas supply market, to the extent to which domestic production has grown since the beginning of the shale revolution.

- When asked about their future plans at the end of the 2018-2019 winter heating season, only 4 of 69 companies indicated that they were considering the option to expand their underground storage facilities within the next five years. In addition, 17 companies were considering expanding market-area LNG or propane air peak-shaving facilities. Perhaps because of this gas supply picture, when asked whether the events of the past winter heating season would cause them to modify storage-related supply planning for the next winter, 92 percent of respondents (61 of 66) said that it would not have an impact on their storage-related decisions for the following WHS.

[8] https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2019/04_11/

LDC Transportation and Capacity Issues

- As previously mentioned, preparing for transportation capacity and supply is normally influenced by weather, economic activity, and other factors that impact gas consumption. Efficiently managing interstate pipeline capacity is a challenge for LDC's and may include the release of capacity to the secondary transportation market, if events allow.

- LDCs were asked to identify the percentage of held pipeline capacity that they released to the secondary market each month from April 2018 - March 2019. Many respondents consistently released less than 25 percent of their capacity throughout the year. A few also released up to 50 percent. As might be expected, the opportunity to release significant capacity (up to 50 percent) to secondary markets is much more limited during the critical heating load months of January through March.

Local Gas Utility Regulatory, Rates and Other Issues

- Considering regulatory issues, survey participants were asked if regulators in their state(s) of operation were formally investigating their gas acquisition practices for the 2018-2019 winter heating season. About half of the 67 surveyed companies said yes (34 companies); however, all but one described the investigations as routine, which is similar to the results of the 2014-2015 winter heating season survey responses.

- When asked whether regulators had significantly delayed the full recovery of gas sales costs incurred during the 2018-2019 winter, all 67 of the companies responding said "no," again the same as the responses from 2014-2015.

- The method for recovering gas costs was further described: 27 of 67 companies (40 percent of respondents) recover gas costs by passing them through to customers, as incurred over a period, and over-or under- recovered cost is deferred and collected or distributed, with interest, during a subsequent period. Twenty-three companies (34 percent of participants) have a similar approach, except interest is not applied to the deferred amounts. For seven companies (10 percent of participants), the addition of interest depends on whether the gas costs have been under or over-recovered from customers, while for four (6 percent of participants) other companies the treatment of interest varies by service territory or jurisdiction.

- When asked whether their state regulator permitted them to retain some or all revenues from off-system wholesale natural transactions, 30 of the 67 (~45 percent) companies to which the question applied said yes while 10 answered no and 27 answered not applicable.

- Furthermore, of the 67 surveyed companies, 40 (60 percent of participants) were permitted to use weather normalization clauses within their rate structures.

- Additionally, when asked if they offered fixed-price options to their customers, 13 of the 67 companies (19 percent) said that they offered fixed-price options to their customers, while the remaining 81 percent said no; which is the same ratio as participants claimed in the 2014-2015 winter heating season survey.

III. Natural Gas Market Overview

Why does a natural gas utility build a *portfolio* of natural gas supply tools to meet customer requirements during a given winter heating season? While the apparent reason is that companies want to deliver low-cost and reliable natural gas to customers, an additional fundamental motivator is mitigating market uncertainty. Of course, weather often introduces an element of the unknown for gas supply planners throughout the country. For example, in mid-June 2018 natural gas consumption in the United States was about 63 Bcf per day, according to Bentek Energy, LLC. Six and a half months later in January 2019, peak-day consumption in the United States reached 137 Bcf.

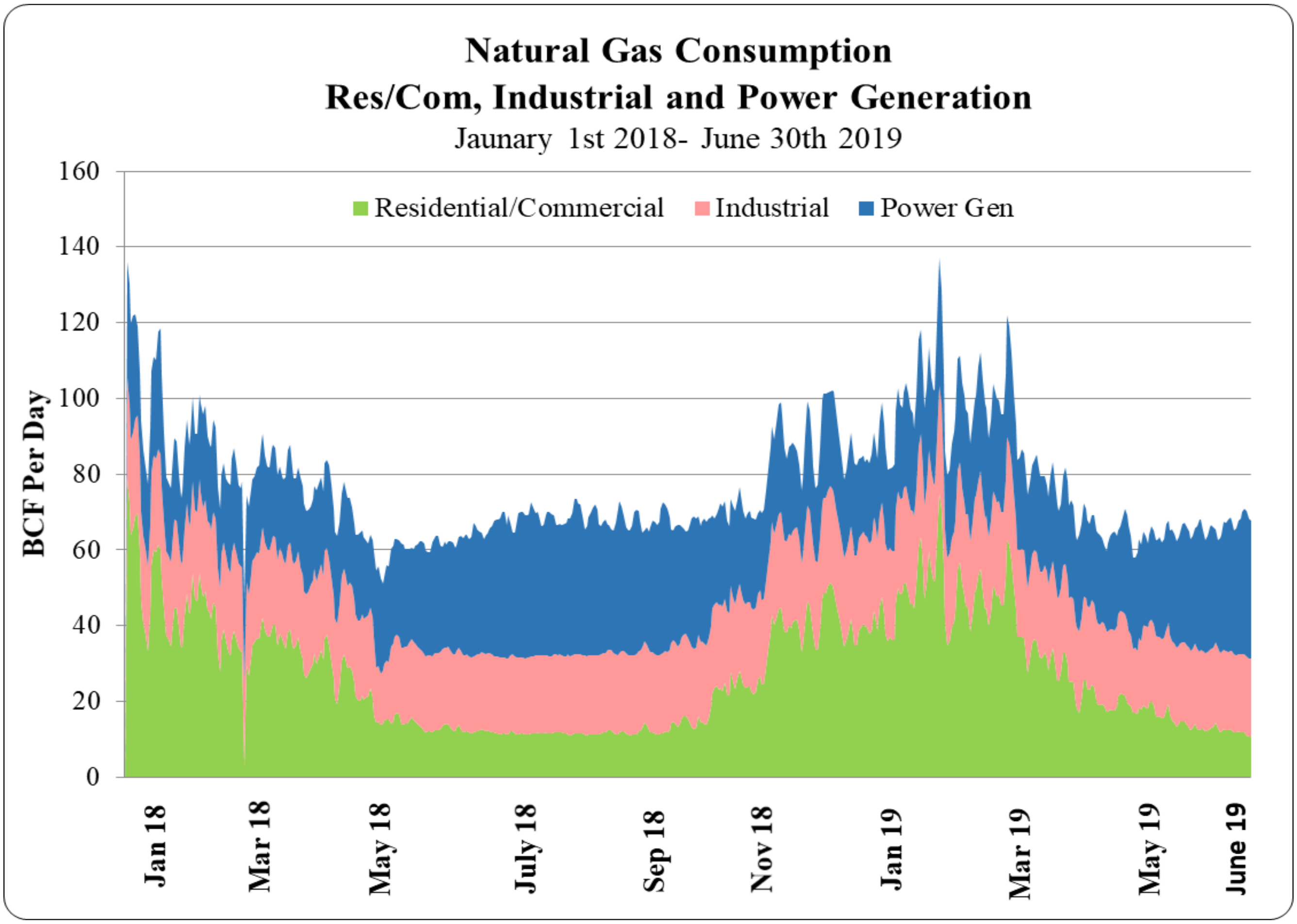
As a national trade association, AGA usually describes national natural gas markets, based on annual or monthly data. From 1995 to 2009, U.S. natural gas consumption was steady at about 22-23 Tcf annually, while U.S. natural gas production held at about 18-19 Tcf annually.[9] By 2011 domestic dry natural gas production grew to 24 Tcf annually, and consumption continued to rise. The growth pattern continued with production reaching 32 Tcf in 2018, according to the Energy Information Administration.[10] Even though these data indicate a level of stability and growth in the gas market, gas supply planners at local utilities face a very different picture—one that varies daily with fluctuating conditions that may turn extreme during winter heating season months.

It is common knowledge that a balanced natural gas market is characterized by supply matching demand. Today's U.S. natural gas market balances consumption with domestic and international suppliers at about 75 Bcf per day on average. However, on a daily basis during a winter heating season, natural gas consumption can fluctuate significantly.

The graph in Figure 1 represents daily natural gas consumption from January 2018 - June 2019. Winter heating season daily consumption does not necessarily correspond to annual or monthly averages. For example, from January 1 through March 31, 2018, daily natural gas consumption ranged from as little as 47.1 Bcf to over 136 Bcf. The graph also shows that consumption fell to an average of 60 Bcf per day for much of May 2018, but history and the graphic tells us that demand increases again in July and August to meet natural gas-fired power generation requirements. In terms of the November 2018-March 2019 winter heating season, the total average was 91.6 Bcf per day with a minimum of 19.1 and a maximum of 74.8 Bcf per day.

[9] https://www.eia.gov/dnav/ng/hist/n9140us2A.htm
[10] https://www.eia.gov/dnav/ng/hist/n9050us2a.htm

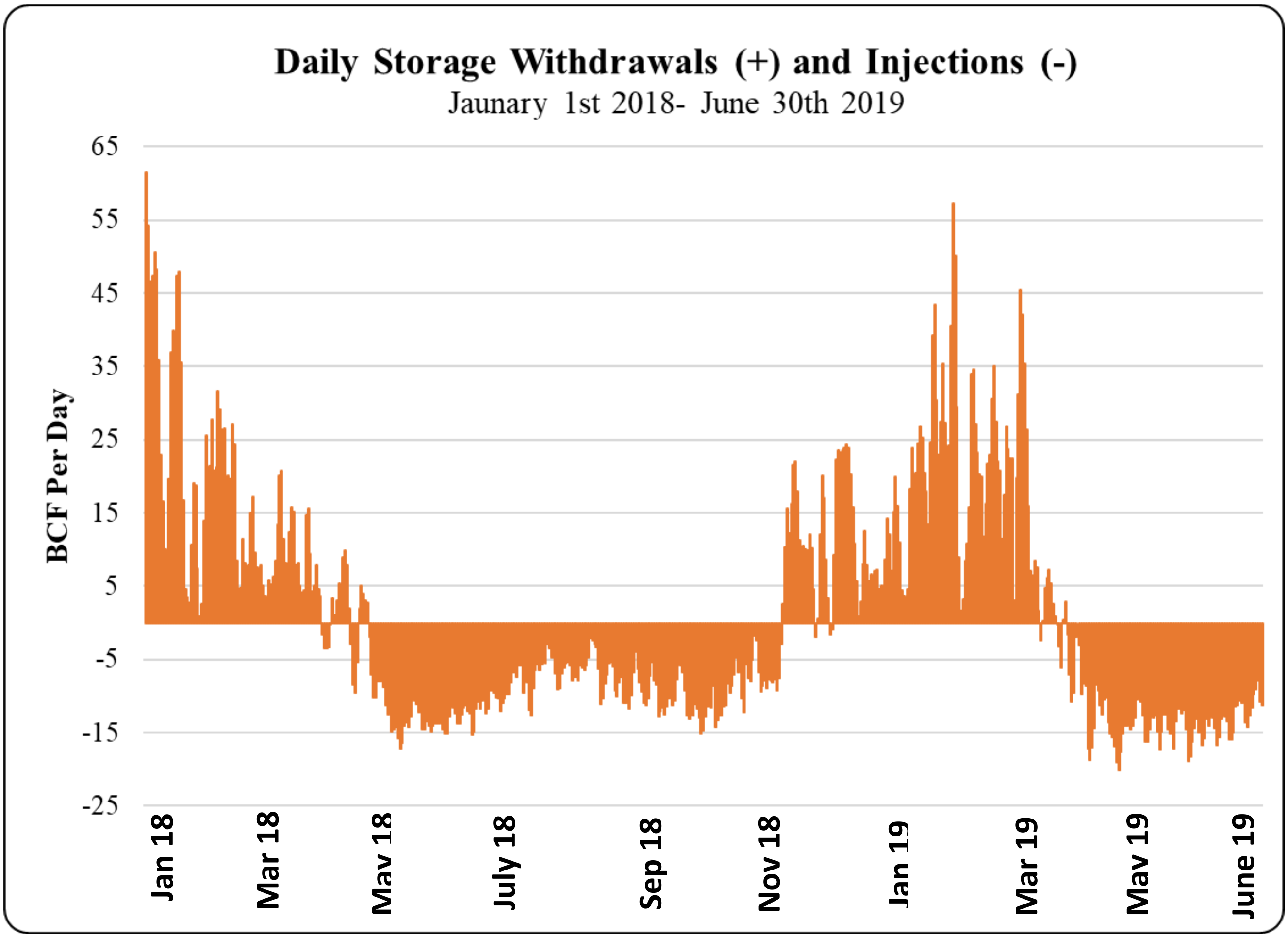
FIGURE 1



Source: Bentek Energy, Energy Market Fundamentals Reports, 2018-2019.

Other physical flow and market fluctuations can be identified such as those seen in Figure 2, which shows net withdrawals from storage as a positive supply source and net injections as a demand requirement (below the zero line). Underground natural gas storage is, in fact, a valuable physical tool for managing sudden changes in weather-induced natural gas demand. As seen in Figure 2 below, during the Winter heating season for 2018-2019 the average was 13.9 Bcf/day with a minimum of -10.8 and a maximum of 57.3 Bcf/day.

FIGURE 2

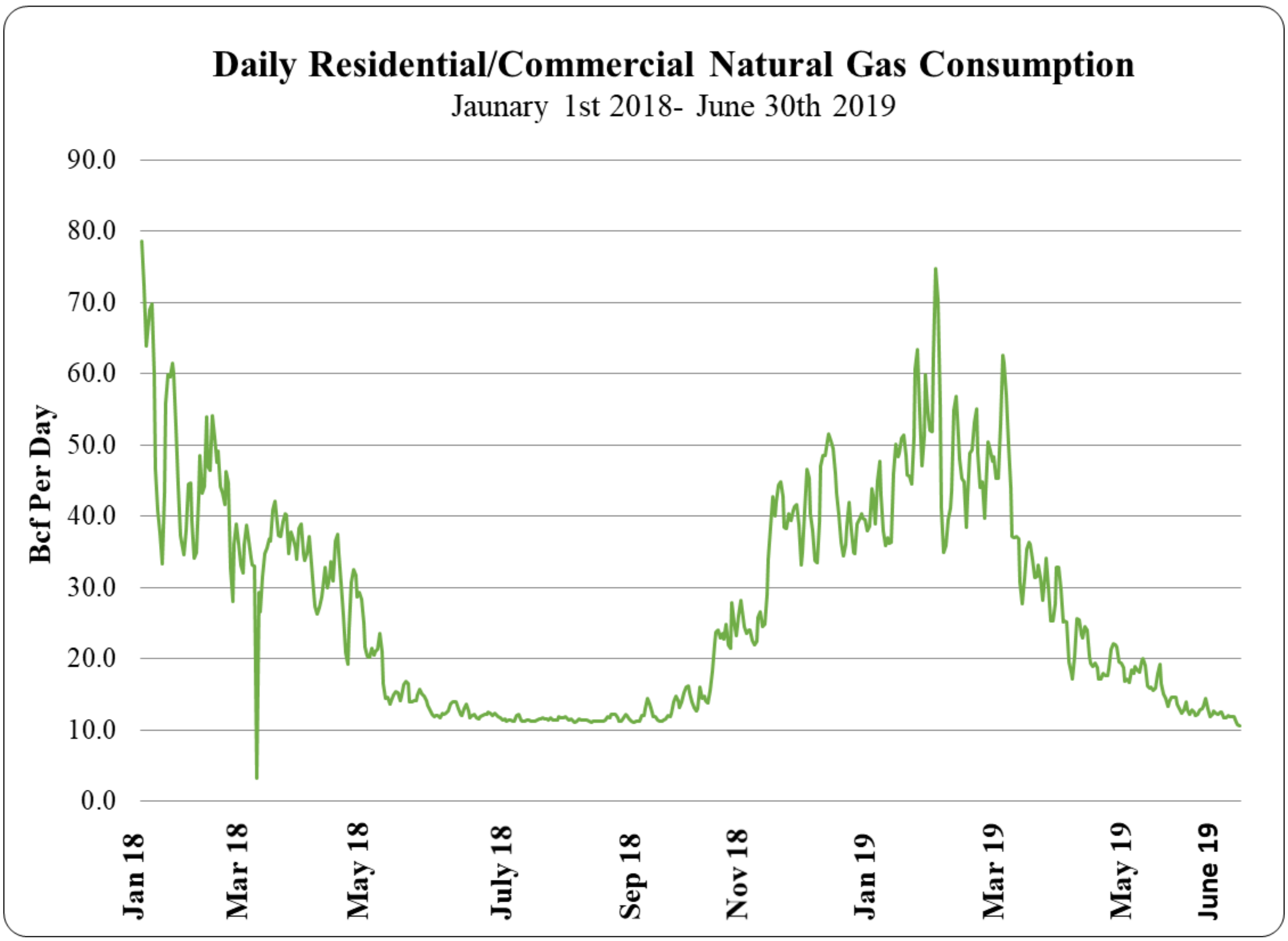


Source: Bentek Energy, *Energy Market Fundamentals Reports*, 2018-2019.

A look at the residential and small commercial sectors provides a sense of how extreme demand and consumption fluctuations can be on a day-by-day basis. Figure 3 graphs residential and commercial natural gas consumption data from January 2018 - June 30, 2019. Here we see daily sector consumption as low as 21.9 Bcf per day in early November 2018 sharply contrasted with an over 70 Bcf consumption day at the end of January.

On a national basis, this represents a 180 percent load swing for natural gas utilities collectively during the winter heating season. In most cases, changes in natural gas requirements are met with a package of supply tools including underground storage, peak-shaving facilities, and others. For an individual utility, this poses the ongoing challenge of meeting customer requirements each day of every winter and is the starting point for developing a portfolio of tools that are geared toward meeting this challenge.

FIGURE 3



Source: Bentek Energy, *Energy Market Fundamentals Reports*, 2018-2019

IV. Weather 2018-2019 Winter Heating Season

The United States compiled 3,924 heating degree days (HDD) during the five months of November 2018-March 2019. While in the 2014-2015 survey, they had complied with just under 4,000 HDD while also experiencing the polar vortex. The average cumulative HDD count for November – March has been 3,729 HDD since 2010, with the average per month being 173 HDD per month according to the EIA.[11]

Temperatures were colder than average on the Northern Plains, Pacific Northwest, and West Coast, while the Southeastern United States saw warmer than normal temperatures between December 2018 and February 2019. Temperatures in December and January were overall warmer than average across much of the country. However, in February, the western half of the country, across the Northern Plains, stretching into the Pacific Northwest, observed temperatures more than 11°F lower than typical for the month. February 2019 turn into the second-coldest February since 1895 in North Dakota and Montana as well as the third-coldest in South Dakota, and fifth-coldest in Washington. On the other hand, the Southeast region of the U.S. experienced a top-ten-warmest February pushing the overall U.S. trend for the 2018-2019 winter heating season to be above average according to NOAA.[12]

TABLE 1

Monthly Comparison of National Heating Degree Data
October 2011 – March 2018

Month	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19
October	-9.4%	-2.9%	-7.7%	-19.7%	-19.7%	-40.3%	-27.7%	-2.9%
November	-13.1%	-1.5%	5.1%	12.4%	-17.5%	-23.3%	-9.2%	10.9%
December	-12.3%	-14.3%	3.2%	-12.9%	-16.3%	-2.4%	-1.0%	-11.1%
January	-17.9%	-8.7%	5.6%	-2.5%	-5.4%	-15.3%	-3.2%	-4.6%
February	-10.0%	2.0%	13.0%	20.3%	-12.2%	-24.3%	-11.5%	1.6%
March	-36.8%	10.5%	14.8%	-0.9%	-23.7%	-6.9%	2.0%	8.8%
TOTAL	-16.8%	-3.5%	6.8%	0.7%	-14.5%	-15.9%	-6.1%	-0.5%

Red = Warmer
Blue = Colder

Source: U.S. Department of Commerce, National Oceanic, and Atmospheric Administration

[11] https://www.eia.gov/opendata/qb.php?category=1039991&sdid=STEO.ZWHDPUS.A
[12] https://www.climate.gov/news-features/blogs/enso/winter-outlook-2018-2019-how percentE2 percent80 percent99d-we-do

V. Gas Supply Portfolios

LDCs build and manage a portfolio of supply, storage, and transportation services to meet expected peak-day, peak-month, and seasonal gas delivery requirements. In today's business environment, gas portfolio managers continually attempt to strike a balance between their need to minimize gas-acquisition risks and their obligation to provide reliable service at the lowest possible cost. Given the reality of significant deviations from normal weather patterns (warm and cold) and regulatory scrutiny of costs to consumers, local gas utility exposure to hindsight analysis regarding gas supply practices is ever-present.

With that said, local gas utilities apply a specific methodology for determining a design day temperature calculation, and this influences the construct of their gas supply portfolio. For the 2018-2019 WHS survey, companies described their methodology for determining their design day calculation as follows: 3 (4 percent) used a 1-in-50 year risk of occurrence, 24 (36 percent) employed a 1-in-30 year, 4 (6 percent) used a 1-in-20, two used a 1-in-15, 4 a 1-in-10 occurrence probability. Fourteen companies utilized an alternative period criterion, ranging from 20 years to 1-in-90 years, which is similar to the methodologies used in the 2014-2015 survey. In addition, 16 companies used other methodologies including Multilinear regression, design day weather standard, historical peak or severe weather event from a specific year, to name a few.

Peak-day consumption predominantly occurred in January for 83 percent of survey respondents (55 of 66 companies). The aggregate peak-day send out of 68 participating companies was 53.8 million Dekatherms, making up 88 percent of the 61.3 million Dekatherms projected for peak-day requirements. This past season was down 18 percent from the 65.8 million Dekatherms during the 2014-2015 WHS which was 82 percent of the 70 million Dekatherms projected for 2014-2015 respondents.

As part of the winter heating season survey, respondents were asked to depict their peak day and peak month delivered gas volumes by supply source. Table 2 and Figure 4 and 5 illustrate the diversity of gas supply sources available to LDCs. Since last year, the option for pipeline storage and citygate supplies for transportation customers were the most used sources of peak gas supplies for the 2018-2019 winter heating season compared to firm pipeline transportation which provided much of the gas to consumers for the peak day and peak month during the 2014-2015 WHS.

Fifty-seven of 68 companies (84 percent) indicated that pipeline storage formed a part of their peak-day gas supply portfolio, including 52 companies that showed 1 to 50 percent of their required peak-day volumes coming from firm supplies and 53 companies that showed 1 to 50 percent of their required peak-month volumes coming from firm supplies. As shown in Table 2, peak-month supplies were heavily weighted toward pipeline transportation as well. Also, peak-day and peak-month volumes were supplemented with city gate deliveries for transportation customers, city gate purchases for sales customers, LNG or propane air, on-system underground storage, asset managed contracts and local production.

TABLE 2

Sources of Participant Peak Gas Supplies by Number of Companies 2018-2019 Winter Heating Season (68 Local Distribution Companies)										
Supply Volume Percentage Ranges	**Interruptible Transport**	**Local Production**	**On-system Underground Storage**	**LNG Propane -Air**	**Citygate Purchases**	**Firm Transport**	**Citygate for Transp. Customers**	**Pipeline Storage**	**Other**	**Asset Managed Contracts**
Peak Day										
1 - 25%	2	15	9	26	21	12	29	30	7	7
26 - 50%	0	1	11	1	8	20	17	22	0	2
51 - 75%	0	0	1	0	1	11	4	5	1	2
76 - 100%	0	0	0	0	1	3	1	0	0	3
0%	66	52	47	41	37	22	17	11	60	54
Peak Month										
1 - 25%	2	9	14	26	19	9	20	37	4	7
26 - 50%	0	0	4	0	6	19	21	16	0	1
51 - 75%	0	0	1	0	2	11	7	1	1	3
76 - 100%	0	1	0	0	1	6	2	0	0	3
0%	66	58	49	42	40	23	18	14	63	54

Table 2, Figure 4 and 5 also demonstrate that companies tend to diversify their supply strategy in increments that often amount to less than 50 percent of their total supply package. Besides pipeline transportation, other gas supply sources are also important for peak-day deliveries such as Citygate purchases for sales customers, LNG / Propane-air / SNG, local production, on-system underground storage, purchases moved via firm transportation, purchases moved via interruptible transportation, and asset managed contracts. The other also included purchases to supplement imbalances with third party suppliers, on-system balancing and linepack.

FIGURE 4

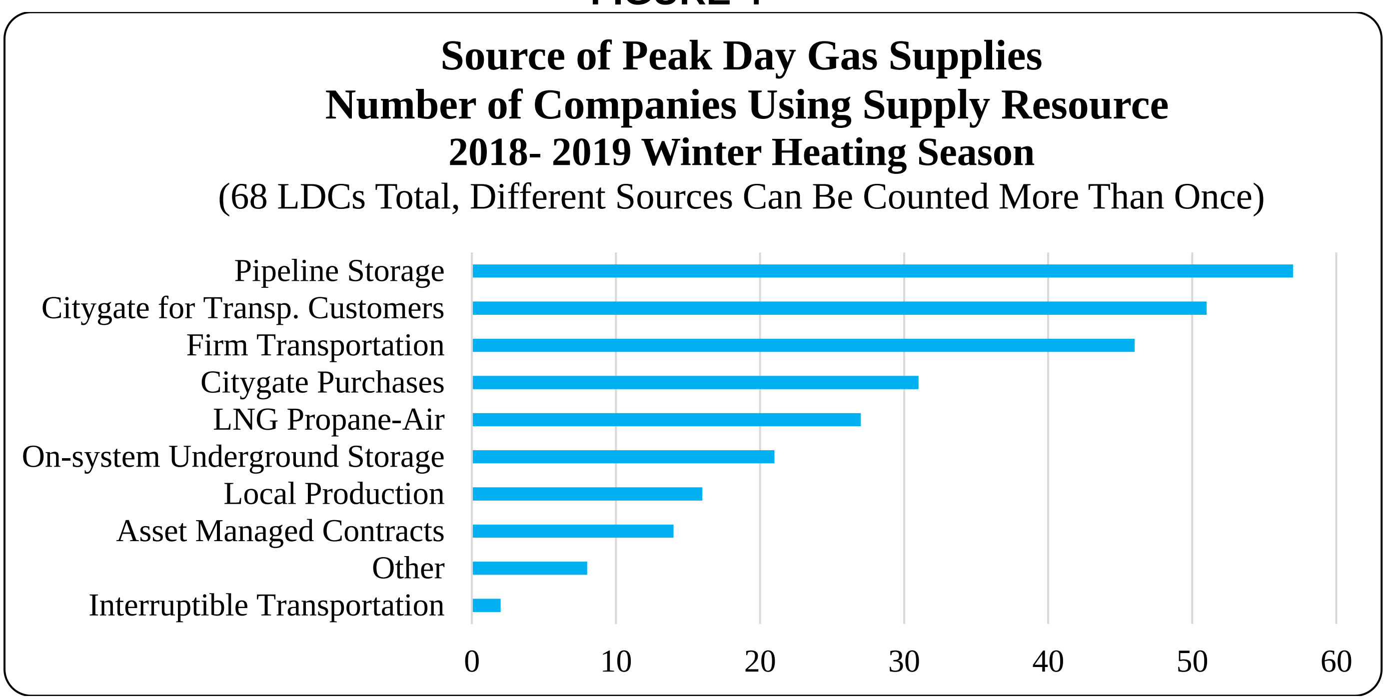
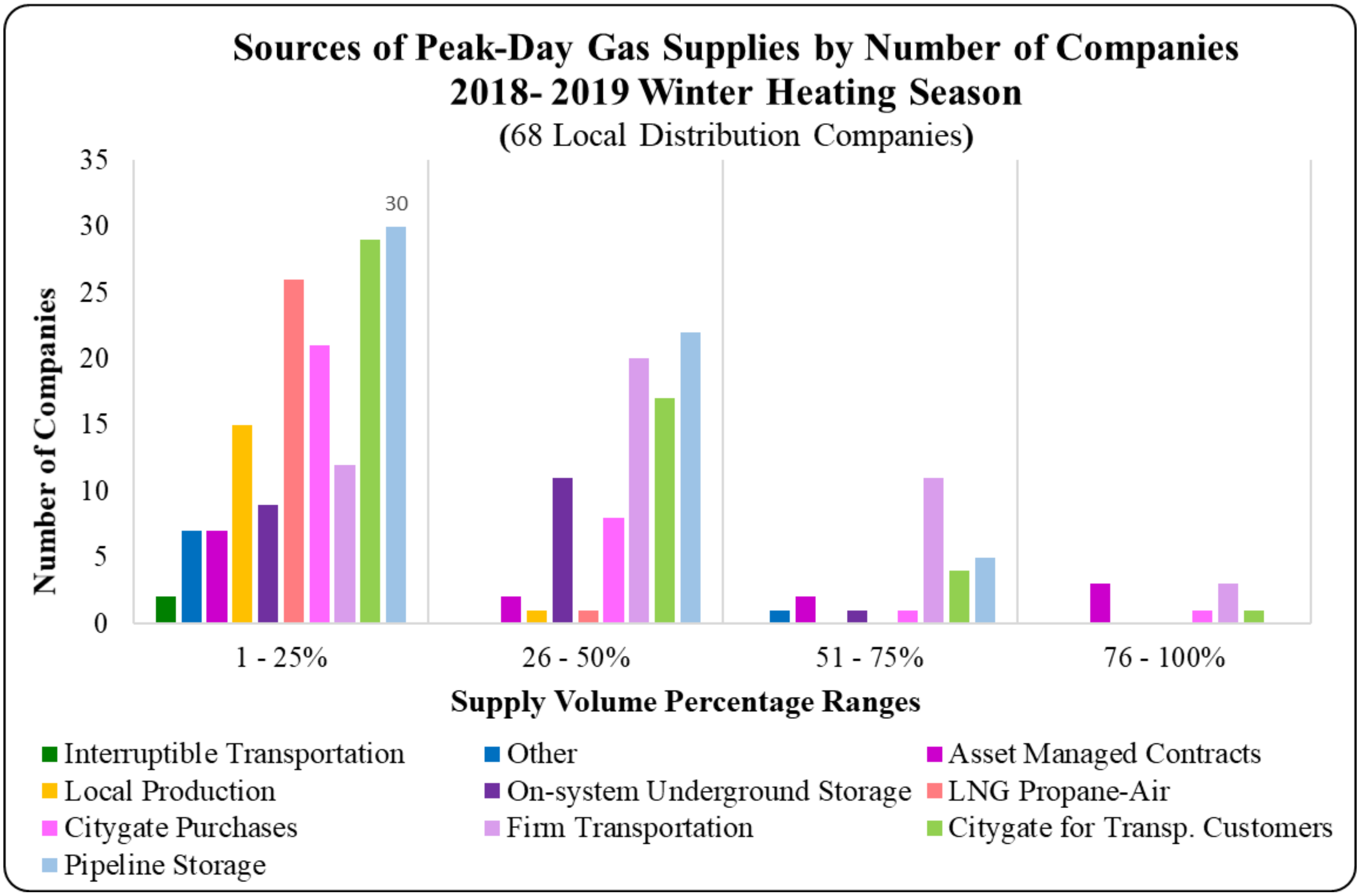


FIGURE 5



Sources of Peak-Day Gas Supplies by Number of Companies
2018- 2019 Winter Heating Season
(68 Local Distribution Companies)
Number of Companies
35
30
25
20
15
10
5
0
30
1 - 25%
26 - 50%
51 - 75%
76 - 100%
Supply Volume Percentage Ranges
Interruptible Transportation
Other
Asset Managed Contracts
Local Production
On-system Underground Storage
LNG Propane-Air
Citygate Purchases
Firm Transportation
Citygate for Transp. Customers
Pipeline Storage

It is helpful to look at the supply sources used by local gas utilities in aggregate, as a percentage distribution of overall peak day volumes. Table 3 points to the majority of purchases moved via pipeline storage and citygate supplies for transportation customers—highlighting their importance as a source of natural gas supply.

TABLE 3

Aggregate Peak Day and Peak Month Supplies
2018-2019 Winter Heating Season
(68 Local Distribution Companies)

Supply Source	Peak Day		Peak Month	
	Volume	**%**	**Volume**	**%**
Citygate purchases for sales customers	2,691,971	5%	41,837,122	4%
Citygate supplies for transportation customers	11,470,697	21%	298,722,643	29%
LNG / Propane-air / SNG	1,409,515	3%	4,825,820	0.5%
Local production	612,396	1%	12,673,341	1%
On-system underground storage	8,661,677	16%	106,674,636	10%
Pipeline or other storage	9,649,878	18%	137,421,361	13%
Purchases moved via firm transportation	15,663,078	29%	334,926,995	33%
Purchases moved via interruptible transportation	356,840	1%	4,089,731	0.4%
Asset Managed Contracts	1,092,771	2%	23,666,410	2%
Other	2,691,633	5%	62,173,126	6%
TOTAL	**54,300,456**	100%	**1,027,011,186**	100%

Supply diversity is not limited to the gas source. Local gas utilities also employ a diverse set of contractual arrangements to procure their gas supplies, including long-term, mid-term, monthly and daily agreements. A mix of contracts allows the LDC to balance between competing needs, such as the obligation to serve its customers as the supplier of last resort and the need to maximize efficiency while minimizing costs. In many cases, longer-term contracts contribute to baseload obligations, while shorter-term contracts allow companies to respond to market changes.

Generally, the 2014-2015 data show a relative balance among contract lengths of peak-day and peak-month supply volumes, as seen in Table 4. However, the use of daily and mid-term deals is becoming more prominent, particularly in cases where they make up 50 percent or more of a company's gas requirements.

TABLE 4

Contract Terms for Gas Purchases by Number of Companies
2018-2019 Winter Heating Season
(68 Local Distribution Companies)

Supply Volume Percentage Ranges	Daily	Monthly	Mid-Term (>1 Month<1 Year)	Long-Term (> 1 Year)	Other
Peak Day					
1 – 25%	27	22	11	20	0
26 – 50	10	8	8	1	0
51 – 75	5	1	12	2	1
76 – 100	6	5	14	6	2
0	20	32	23	39	65
Peak Month					
1 – 25%	27	22	11	23	0
26 – 50	13	5	8	0	0
51 – 75	4	4	13	4	1
76 – 100	4	5	14	4	2
0	20	32	22	37	65
Winter Season					
1 – 25%	24	20	15	21	0
26 – 50	17	7	9	1	0
51 – 75	4	4	10	2	1
76 – 100	4	5	14	6	2
0	19	32	20	38	65

Asset management agreements (AMA) are contractual associations where a party is selected to manage gas supply and delivery arrangements, including transportation and storage capacity, for another party. These AMAs are "typically when a shipper holding firm transportation and/or storage capacity on a pipeline or multiple pipelines temporarily releases all or a portion of that capacity along with associated gas production and gas purchase agreements to an asset manager. The asset manager uses that capacity to serve the gas supply requirements of the releasing shipper, and, when the capacity is not needed for that purpose, uses the capacity to make releases or bundled sales to third parties" according to FERC.[13]

When asked whether their company used asset management agreements for any portion of their gas supply purchases during the 2018-2019 winter heating season, 32 of the 68 (47 percent) companies

[13] https://www.ferc.gov/whats-new/comm-meet/2015/101515/G-4.pdf

said yes— a greater number compared with the 2014-2015 winter heating season survey where 29 of 79 companies (37 percent) said yes. Of these 32 companies, 7 used asset management for 25 percent or less of their winter heating season supplies, while 12 companies used asset management agreements for 76-100 percent of 2018-2019 winter heating season supplies, as seen in table 5.

TABLE 5

Portions of Winter Heating Season Acquisitions Via Asset Management Agreements for Peak-Day Supply by Number of Companies (32 Local Distribution Companies)			
Supply Volume Percentage Ranges	**Peak Day**	**Winter Season**	**Annual**
1 – 25%	11	7	7
26 – 50	6	7	3
51 – 75	4	4	1
76 – 100	10	12	16

VI. Supply Pricing Mechanisms

Many factors play a role in the market pricing of the gas commodity and transportation services, including weather, storage levels, end-use demand, pipeline capacity, operational issues, and financial markets. The market fundamentals that impact price have also expanded to include interest rates, other investment opportunities, the price of other commodities and even currency exchange rates. Such broad market influences impact LDCs and other gas suppliers, making planning increasingly challenging for all stakeholders. To address the inherent uncertainty of the market—even considering the relative stability of natural gas markets in recent years—supply planners use a portfolio approach to pricing gas supplies mirroring their approach to supply sources, providers, and transportation options.

This portfolio approach includes pricing mechanisms and contract terms, such as fixed-price and long-term contracts; however, while their prevalence waned for many years, the idea of fixed- price longer-term as a value-added tool for managing price stability is regaining traction in today's market. For example, future key gas supply projects, such as those aimed at coordinating natural gas and power generation loads, may require longer-term demand-pull contract arrangements to be successful.

When examining the natural gas purchasing practices of companies during the past several winter heating seasons, it is clear that first-of-month (FOM) index pricing has dominated the market for the largest portion of supply agreements, whether short, long, or mid-term. However, with sustained lower market prices, daily pricing mechanisms have become a strong player, also. Table 6 provides a closer look at the balance of pricing mechanisms among survey respondents during the 2018-2019 winter heating season.

As shown in Table 6, 22 out of 31 company respondents used long-term contracted supplies during the past winter heating season, followed by 21 of the 53 responding companies using short-term contracts for 26-50 percent of their supply volume and then 17 of the 55 respondents using mid-term supply contract terms for 76-100 percent of their supply volume.

TABLE 6

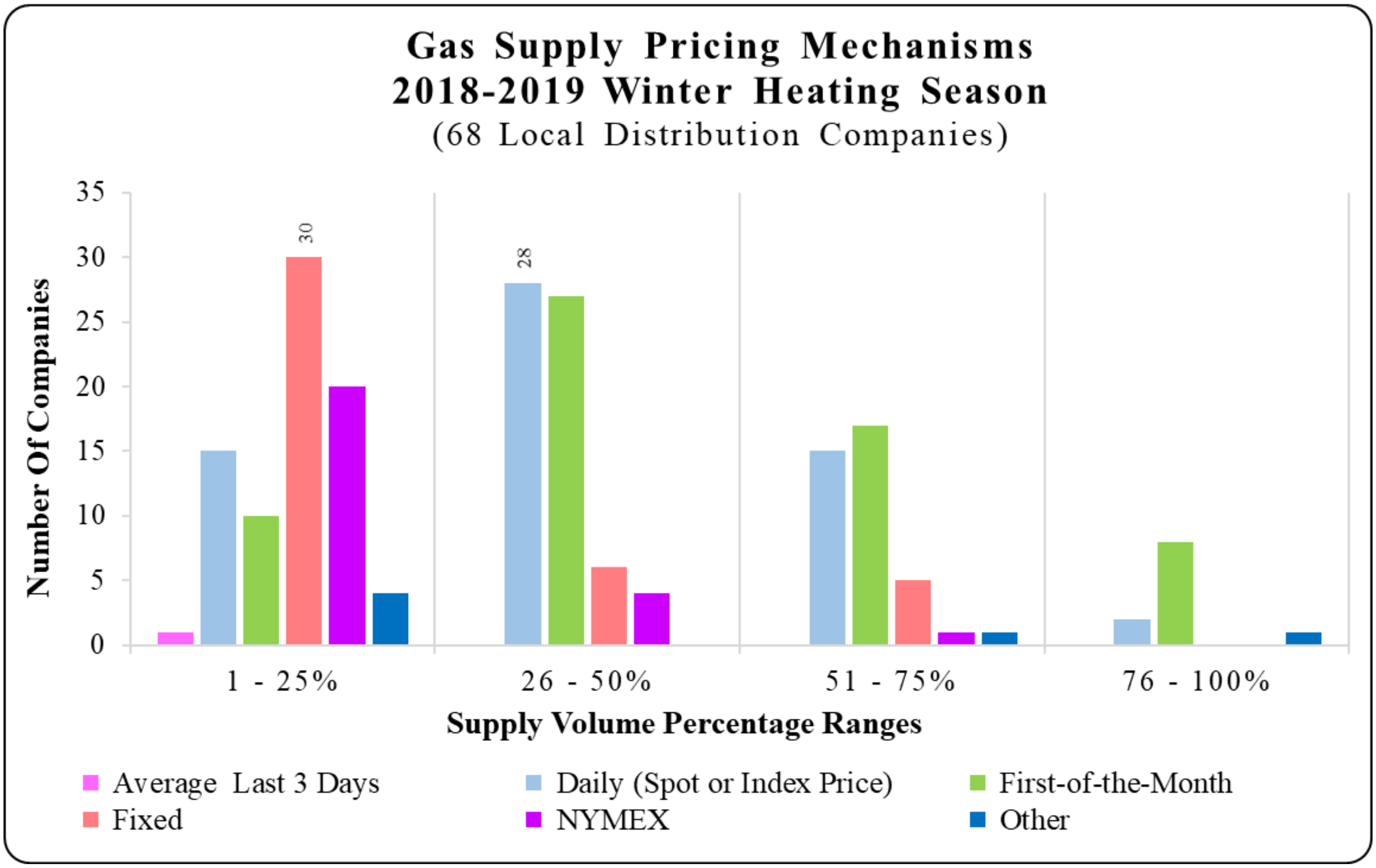
Gas Supply Contract Terms by Number of Companies 2018-2019 Winter Heating Season			
Supply Volume Percentage Ranges	**Short Term % 1 Month or Less (53 Companies)**	**Mid Term % 1 Month - 1 Year (55 Companies)**	**Long Term % Greater Than 1 Year (31 Companies)**
1 – 25%	12	8	22
26 – 50	21	15	1
51 – 75	8	15	4
76 – 100	12	17	4

Table 7 and Figure 6 show the pricing mechanisms employed by the 2018-2019 survey participants. For gas pricing mechanisms, the 2018-2019 winter heating season respondents primarily used first-of-the-month pricing, with daily (spot or index) second. First-of-month indices continued to be the predominant pricing mechanism, similar to the 2013-2014 and 2014-2015 winter. This is not surprising since the first-of-month index is not only a measure of market movement but often also serves as a baseline from which hedging strategies can be measured. Daily pricing also played a significant role particularly for volumes representing less than half of winter supplies. The prevalence of this pricing mechanism may be explained by the relative price stability that appears to have developed in the natural gas market recently, given an overall strong natural gas supply position based on consecutive years of growth in domestic production. Weekly and average three-day pricing played the least role in gas supply pricing mechanisms this season similar to the 2014-2015 survey as well.

TABLE 7

Gas Supply Pricing Mechanisms – Winter Heating Season 2018-19 By Number of Companies (69 Local Distribution Companies)							
Supply Volume Percentage Ranges	**Average Last 3 Days**	**Daily (Spot or Index Price)**	**First-of-the-Month**	**Fixed**	**NYMEX**	**Weekly**	**Other**
1 - 25%	1	15	10	30	20	0	4
26 - 50%	0	28	27	6	4	0	0
51 - 75%	0	15	17	5	1	0	1
76 - 100%	0	2	8	0	0	0	1
0	67	8	6	27	43	68	62

FIGURE 6



It should be noted that LDCs build gas supply portfolios and pricing strategies based on prior, as well as anticipated, experiences. Even state regulator-approved pricing mechanisms may appear favorable one year while less so the next. Flexibility and constructive policy reviews, rather than second-guessing, can have a positive effect on the delivery of natural gas and services to customers at the lowest possible cost.

VII. Hedging Mechanisms

Market developments since the early 1990s have expanded the options for acquiring gas supply, trading transportation capacity, and using financial instruments. Today industry players use futures contracts and other tools to offset the risk of commodity price movements. These financial instruments, which include fixed-price gas purchase contracts, futures, swaps, and options, allow gas supply portfolio managers to hedge or lock in a portion of the commodity cost component of gas supplies. This is accomplished well when the required level of risk and the rewards or benefits of managing such risk are properly balanced by the company, consumers and regulatory bodies.

Seventy-five percent of responding companies (50 of 67) said they used financial instruments to hedge a portion of their 2017-2018 and 2018-2019 winter heating season gas supply purchases, with 98 percent of companies reported using financial instruments in 2018-2019. Still, this percentage is significantly larger than in 2004-2005 (70 percent of respondents) and in 2001-2002, when only 55 percent of respondents reported using financial instruments to hedge gas supply costs. It is important to note that the company makeup and size of the survey sample differ from year to year. For the 2013-2014 winter, 49 of 77 responding companies hedged up to 50 percent of their gas supply purchases.

Respondents used one or more of the following instruments to hedge a portion of their 2018-2019 WHS gas supply purchases: options (30 companies), fixed price contracts (22 companies), swaps (16 companies), and futures (8 companies). The use of financial instruments may be understated in this report since some of the volumes delivered to LDCs from marketers and other suppliers are hedged by a third-party rather than the LDC and may have been excluded from the LDC's data. That said, according to the data we collected for this winter heating season an average of 35 percent and a median of 28 percent of the gas delivered by the companies in the survey during the 2018-2019 winter heating season was hedged.

Only one company reported using weather derivatives during the 2018-2019 winter heating season. This compares with 4 companies out of 78 respondents during the 2014-2015 WHS, 4 companies out of 73 respondents during the 2012-2013 WHS, 5 of 76 companies in 2006-2007, 7 of 54 in the 2004-2005 survey.

When asked about how far into the future hedging strategies extended, 24 of 51 companies with hedging programs (47 percent) indicated that they applied a six-month-or-less strategy for a portion of their hedges for the 2018-2019 winter heating season. Twenty-one (41 percent) companies used a 7-13-month strategy, and 11 (22 percent) companies employed a greater than 13-month strategy. Of course, a single company may use one or all strategies simultaneously. In fact, 17 (33 percent) of the respondents did just that, compared with 28 in the 2013-2014 survey year.

In some jurisdictions, there are no formal standing hedging plans. In others, LDCs may be required to have in place their hedging plans for future gas supplies by predetermined dates. Variations on these themes are many and are geared to be compatible with the interplay among local distribution companies, regulators, and local market conditions. Seventeen of 66 responding companies said that they are required to secure pre-approval from their regulator, and 15 indicated that they are required to operate within set parameters, such as particular financial instruments, time limits or volume restrictions.

When asked about their regulatory environment, the majority of respondents (59 of 66) reported no change in their regulator's receptivity to financial hedging during the 2018-2019 winter heating season compared to the prior year, and two reported increased receptivity on the part of their regulator or public utility commission (PUC). No companies indicated that their PUC was less receptive this past winter heating season. Thirty-eight of 61 responding companies (62 percent) did not believe that the events of the 2018-2019 winter would influence regulatory views of hedging strategies.

Fifty-one of 57 responding companies reported that their regulator treated the financial losses and the gains related to hedging equally. This 89 percent response compares with 88 percent (or 45 of 51 companies) from 2011-2012. Additionally, 51 of 51 companies that answered the question said *yes* when asked if costs associated with their financial hedging programs were fully recoverable.

When asked about the focus of their regulator with respect to natural gas purchases, 12 of the 64 respondents (19 percent) indicated that their regulator was primarily interested in the lowest possible price, 6 of 64 (9 percent) said that the focus was on stable prices, and 37 companies (58 percent) said their regulator was equally concerned with both low and stable prices.

Among LDCs, motivations vary surrounding hedging programs. When asked about the impetus behind their financial hedging programs, 19 of 64 companies (30 percent) cited regulatory requirements, 28 (44 percent) said it was a voluntary decision (in certain cases influenced by customers), and 10 identified other or additional reasons or goals, such as price stability and cost stabilization.

When asked how customers benefited from their financial hedging compared with no hedging, 49 respondents noted the reduced-price volatility as a benefit to customers, while 23 companies identified reduced gas costs as valuable to customers. Of the respondents, 23 cited both lower prices and more stable prices as benefits to consumers resulting from structured hedging plans.

VIII. Gas Storage

As noted earlier, local distribution companies are concerned with managing gas supply and transportation portfolios efficiently and cost-effectively. Production area storage and market area storage help LDCs meet these goals. The use of storage facilities helps LDCs to both meet short-term swings in demand and satisfy peaking needs. Table 8 shows storage levels as estimated by the Energy Information Administration for December 2017- October 2018 compared to the same period in 2019.

TABLE 8

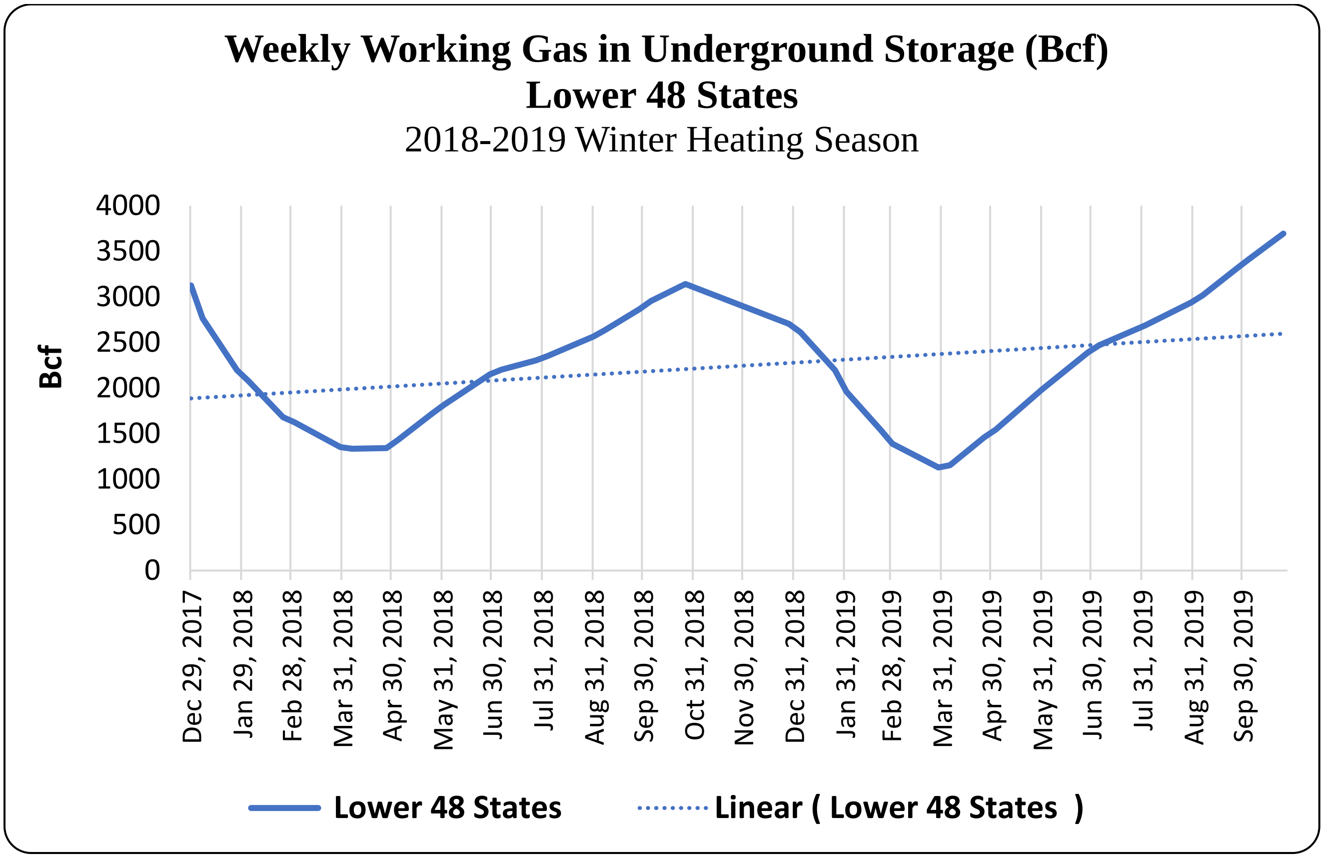
Weekly Working Gas in Underground Storage (Bcf)
2018-2019 Winter Heating Season

2018									2019								
Date	Lower 48 States	East	Midwest	Mountain	Pacific	South Central	Salt South Central	Nonsalt South Central	Date	Lower 48 States	East	Midwest	Mountain	Pacific	South Central	Salt South Central	Nonsalt South Central
29-Dec-17	3126	740	875	183	268	1060	324	809	28-Dec-18	2705	661	798	147	220	878	296	582
5-Jan	2767	664	778	167	251	907	302	759	4-Jan	2614	651	763	132	204	865	302	563
26-Jan	2197	525	596	137	220	719	151	578	25-Jan	2197	527	606	114	178	771	278	493
2-Feb	2078	488	543	131	213	703	169	550	1-Feb	1960	468	522	105	172	692	241	451
23-Feb	1682	382	398	102	189	611	175	440	22-Feb	1539	354	385	79	122	598	199	399
2-Mar	1625	359	380	97	177	612	183	429	1-Mar	1390	311	338	73	112	557	180	377
30-Mar	1354	229	266	87	166	606	181	422	29-Mar	1130	210	241	64	113	502	156	347
6-Apr	1335	217	246	83	171	618	188	419	5-Apr	1155	209	240	64	119	523	166	357
27-Apr	1343	223	221	86	187	626	182	421	26-Apr	1462	279	290	75	152	666	224	442
4-May	1432	243	240	92	195	662	190	436	3-May	1547	299	309	78	162	699	234	466
25-May	1725	328	315	113	221	748	226	496	31-May	1986	414	436	101	213	821	256	565
1-Jun	1817	351	341	121	231	773	235	514	7-Jun	2088	440	469	111	227	842	256	586
29-Jun	2152	460	455	139	257	841	252	583	28-Jun	2390	526	568	134	255	907	259	648
6-Jul	2203	480	477	143	260	843	245	596	5-Jul	2471	544	597	140	263	927	257	669
27-Jul	2305	552	552	146	249	807	215	605	26-Jul	2634	597	677	156	270	934	226	708
3-Aug	2353	574	580	148	244	808	206	601	2-Aug	2689	613	701	161	272	941	221	719
31-Aug	2567	659	702	162	246	799	188	613	30-Aug	2941	714	827	177	276	947	197	749
7-Sep	2636	679	734	166	250	806	183	615	6-Sep	3019	739	864	183	275	958	199	759
28-Sep	2866	763	836	177	262	829	173	634	27-Sep	3317	826	973	199	291	1029	220	809
5-Oct	2956	790	871	180	262	854	181	648	4-Oct	3415	854	1009	203	296	1054	229	825
26-Oct	3143	826	956	180	262	919	218	678	25-Oct	3695	913	1095	211	298	1178	293	885

Source: Energy Information Administration.

Figure 7 visually shows the trend from December 2017- September 2018 compared to the same period in 2019. The storage story for the 2018-2019 winter begins in April 2018 when net injections began to refill inventories that were used in the prior winter. Entering the 2018-2019 winter heating season, working natural gas stocks were their lowest levels since 2005, totaling 3,198 Bcf in November 2018. They declined during the winter at a rate consistent with historical trends, however, the net withdrawals from storage during the 2018 -2019 winter heating season were 2,061 Bcf, which is 5 percent below the five-year average for the season according to the EIA. The 2018 - 2019 U.S. winter heating season was characterized by periods of colder-than-normal temperatures around the Upper Midwest, which resulted in considerable natural gas storage withdrawals.[14]

Figure 7



Source: Energy Information Administration.

Additionally, the withdrawal season started quicker this winter heating season with colder-than-normal temperatures resulting in larger-than-normal withdrawals of 206 Bcf in November, being approximately twice as much as the five-year average. According to the EIA's Natural Gas Weekly Update for the end of the winter heating season, the pace of withdrawals decelerated during December, totaling 320 Bcf, which compared with the five-year average of 523 Bcf is much less. Even though the highest weekly net withdrawals happened the week of February 1, with 237 Bcf of natural gas being pulled out of storage, the extractions from January- December 2019 followed the five-year average pattern. The 2018-2019 winter heating season had the 10th-highest net

[14] https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2019/04_11/

withdrawals on record, falling far short of the 2013–201 winter 4 heating season record of 2,958 Bcf. Throughout the 2017–2018 winter heating season, net withdrawals from storage fell below 2,417 Bcf, following the 2013–2014 and 2017–2018 winter heating seasons trend of having significantly colder-than-normal temperatures.[15]

A variety of reasons also underlie LDC decisions to use their existing stored gas supplies. Ninety-six percent of survey companies (66 of 69) used underground (on-system or pipeline) storage for a portion of their gas supply during the 2018-2019 winter heating season, which is consistent from the 2014-2015 participant replies. Fifty-nine reported that up to 50 percent of their 2018-2019 winter supplies were derived from storage. Participants indicated that multiple factors influenced their use of storage during the past winter heating season with weather-induced demand and no-notice requirements being the majority at 76 percent and 53 percent respectively. Other factors included "must-turn" contract provisions (38 percent of participants), pipeline operational flow orders (35 percent of participants), and arbitrage opportunities (11 percent of participants). 26 percent of the participants indicated that all the above factors influenced their use of storage during the past winter heating season.

Various factors also influenced participant storage refill decisions during the spring and summer of 2018. Supply reliability topped the list of reasons that motivated LDCs to inject gas supplies into storage with 68 percent of participants choosing this option, while operational issues (50 percent) and price considerations (48 percent) were also big factors. Fill ratable over the injection season (26 participants), regulatory plans or mandates (22 participants) and term of asset management agreement (10 participants) impacted the storage strategy as well. Of course, more than one variable may influence injections of gas supplies into storage as 7 of these companies were motivated by all six factors.

[15] https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2019/04_11/

Table 9 and Figure 8/9 show that many of the gas purchases made for storage injections during the 2017-2018 refill season, in preparation for the 2018-2019 winter heating season, were based primarily on first-of-month (FOM) indices (56 participants) and daily spot pricing (42 participants). However, fixed and NYMEX-based gas pricing also got some play, particularly for small volumes of gas destined for underground storage with 22 participants and 20 participants respectively.

TABLE 9

Pricing Mechanisms for Gas Injected into Underground Storage by Number of Companies
(69 Local Distribution Companies)

2017 Refill Season (April-October)							
Supply Volume Percentage Ranges	**Average Last 3 Days**	**Daily (Spot or Index Price)**	**First-of-the-Month**	**Fixed**	**NYMEX**	**Weekly**	**Other**
1 - 25%	1	23	7	13	12	0	1
26 - 50%	0	13	13	4	2	0	0
51 - 75%	0	4	13	3	2	0	0
76 - 100%	0	3	23	2	4	0	3
0	68	26	13	47	49	69	65
2018 Refill Season (April-October)							
Supply Volume Percentage Ranges	**Average Last 3 Days**	**Daily (Spot or Index Price)**	**First-of-the-Month**	**Fixed**	**NYMEX**	**Weekly**	**Other**
1 - 25%	1	22	6	16	12	0	1
26 - 50%	0	13	12	2	3	0	0
51 - 75%	0	5	13	2	3	0	0
76 - 100%	0	2	25	2	2	0	3
0	68	27	13	47	49	69	65

The pricing mechanisms used for the 2017 storage injections are reflected in Figure 8. Every year presents a slightly different picture, reflecting overall pricing trends, demands on flowing gas during the summer for both storage injections and gas-fired power generation, among other factors. Looking back to 2007, we find that 27 of 57 companies indicated that more than 75 percent of supplies purchased for storage injections were FOM priced, while 23 of 53 companies did the same in 2008 as well as 19 of 55 in 2009. This season we see a continuing trend of 25 of 69 participants indicating that more than 75 percent of supplies purchased for storage injections were FOM priced. Additionally, the second most used tool of "daily spot pricing" (42 participants), Although simple in concept, just the fact that flowing gas was available—given the demand levels and persistent cold—is consistent with the 2014-2015 winter heating season perception of the U.S. gas supply market, to the extent to which domestic production has grown since the beginning of the shale revolution.

When asked about their plans at the end of the 2018-2019 winter heating season, only 4 of 69 companies indicated that they were considering the option to expand their underground storage facilities within the next five years. In addition, 17 companies were considering expanding market-area LNG or propane air peak-shaving facilities. Perhaps because of this gas supply picture, when asked whether the events of the past winter heating season would cause them to modify storage-related supply planning for the next winter, 92 percent of respondents (61 of 66) said that it would not have an impact on their storage-related decisions for the following WHS.

FIGURE 8

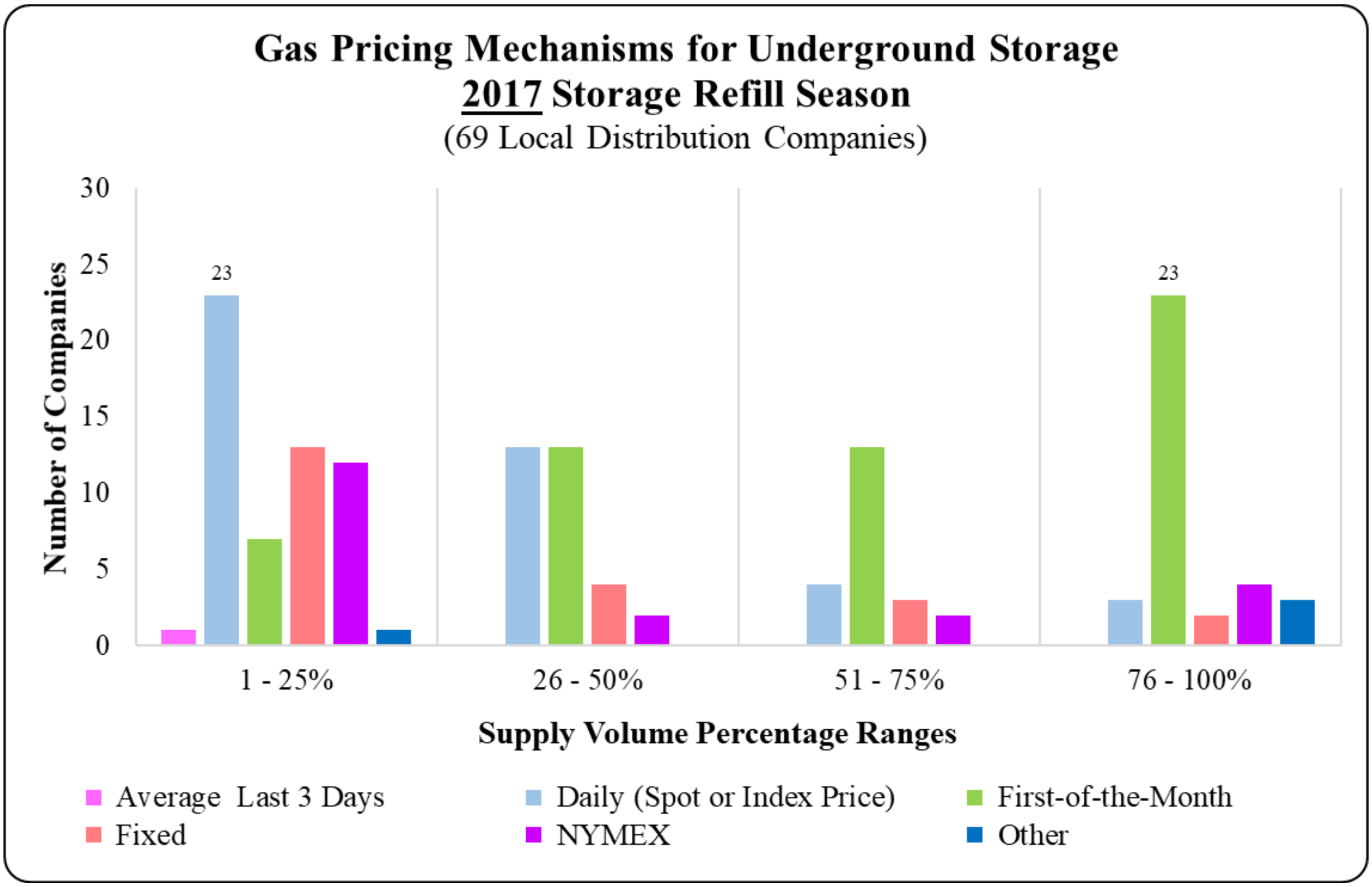
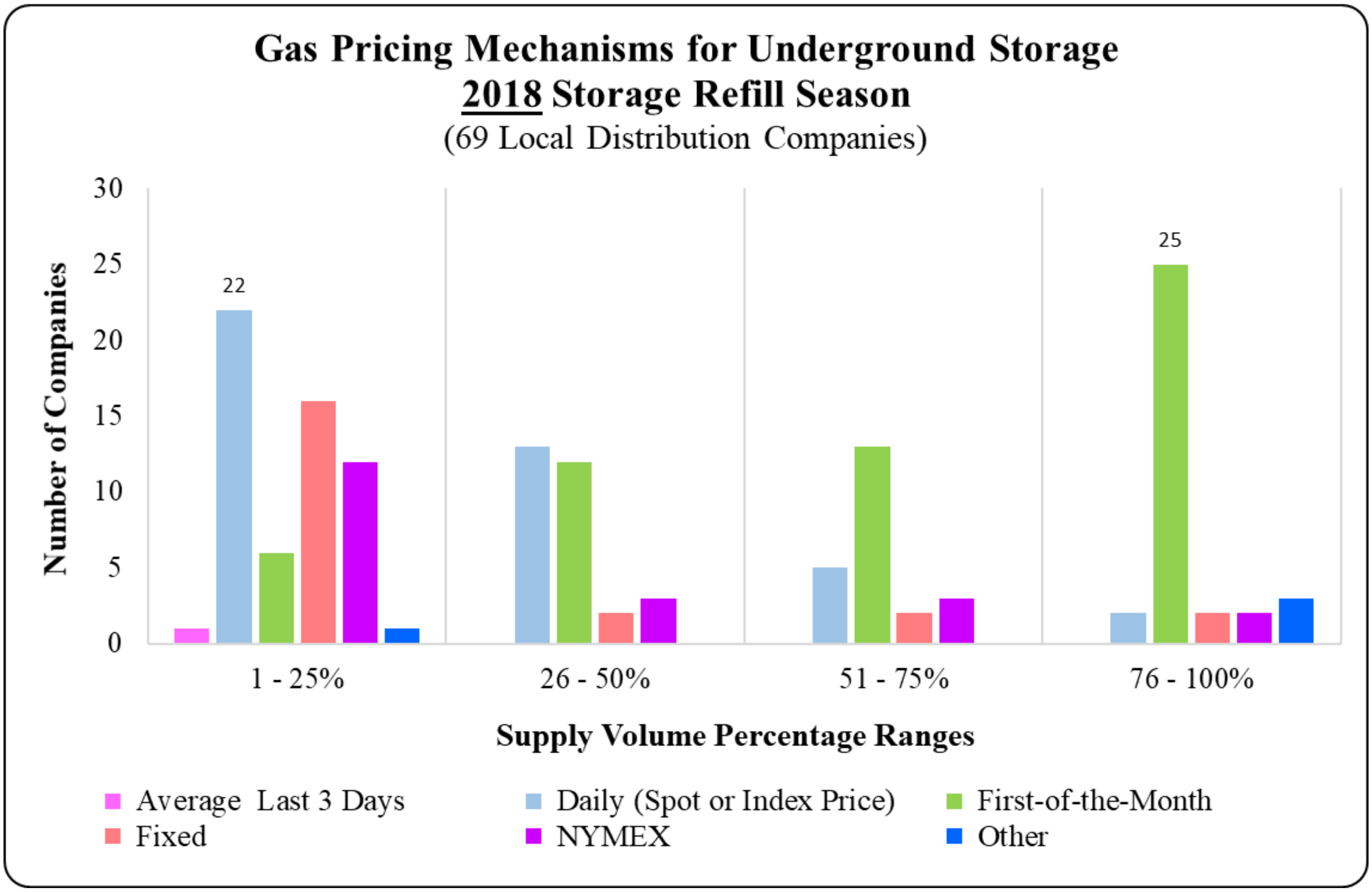


FIGURE 9



IX. LDC Transportation and Capacity Issues

As previously mentioned, preparing for transportation capacity and supply is normally influenced by weather, economic activity and other factors that impact gas consumption. Efficiently managing interstate pipeline capacity is a challenge for LDC's and may include the release of capacity to the secondary transportation market, if events allow.

Table 10, which presents a brief view of this topic, highlights some interesting elements. LDCs were asked to identify the percentage of held pipeline capacity that they released to the secondary market each month from April 2018 to March 2019. Many respondents consistently released less than 25 percent of their capacity throughout the year, however, a few also released up to 50 percent. As might be expected, the opportunity to release significant capacity (up to 50 percent) to secondary markets is much more limited during the critical heating load months of January through March.

Table 10

Percent of Pipeline Capacity Released by Local Distribution Company												
April 2018 – March 2019												
Capacity Percentage	**Injection Season 2018**							**Winter Heating Season 2018-2019**				
	33 Companies							29 Companies				
	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
1 – 25%	25	25	27	25	24	25	20	28	28	28	27	27
26 – 50	4	3	3	4	5	2	8	0	0	0	0	1
51 – 75	0	2	2	3	3	4	0	0	0	0	0	0
76 - 100	1	1	1	1	1	1	1	1	1	1	1	1
0	38	37	35	35	35	36	39	39	39	39	40	39

X. Local Gas Utility Regulatory, Rates and Other Issues

Concerning regulatory issues, survey participants were asked if regulators in their state(s) of operation were formally investigating their gas acquisition practices for the 2018-2019 winter heating season. About half of the 67 surveyed companies said yes (34 companies); however, all but one described the investigations as *routine,* which is similar to the results of the 2014-2015 winter heating season survey responses. In addition, when asked whether regulators had significantly delayed the full recovery of gas sales costs incurred during the 2018-2019 winter, all 67 of the companies responding said “no,” again the same as the responses from 2014-2015.

The method for recovering gas costs was further described: 27 of 67 companies (40 percent of respondents) recover gas costs, by passing them through to customers, as incurred over a period, and over-or under- recovered cost are deferred and collected or distributed, with interest, during a subsequent period. Twenty-three companies (34 percent of participants) have a similar approach, except interest is not applied to the deferred amounts. For seven companies (10 percent of participants), the addition of interest depends on whether the gas costs have been under or over-recovered from customers, while for four (6 percent of participants) other companies the treatment of interest varies by service territory or jurisdiction.

When asked whether their state regulator permitted them to retain some or all revenues from off-system wholesale natural transactions, 30 of the 67 (~45 percent) companies to which the question applied said yes while 10 answered no and 27 answered not applicable. Furthermore, of the 67 surveyed companies, 40 (60 percent of participants) were permitted to use weather normalization clauses within their rate structures. Additionally, when asked if they offered fixed-price options to their customers, 13 of the 67 companies (19 percent) said that they offered fixed-price options to their customers, while the remaining 81 percent said no; which is the same ratio as participants claimed in the 2014-2015 winter heating season survey.

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