LDC SUPPLY PORTFOLIO MANAGEMENT DURING THE
2014-15 WINTER HEATING SEASON

I. Introduction

Each year local natural gas utilities develop a plan to reliably meet customer needs during winter heating season peak consumption periods. The plan is usually based on a forecast of expected loads and is later adjusted to actual weather-induced demand requirements. Numerous scenarios are examined when building a seasonal natural gas supply portfolio—always against the backdrop of “normal,” which is defined by companies based on local weather information and system requirements from years past. Supply tools, such as firm pipeline capacity, access to on-system or pipeline storage, peak-shaving capabilities, local production and even third-party transportation arrangements, are carefully considered. Plans to manage supply pricing risks may also be in place. In many cases, these plans are submitted to state regulators for approval prior to the start of the winter heating season.

As local gas utilities and natural gas consumers approached the 2014-15 winter heating season (November 2014 through March 2015), several things were in play. No one could have anticipated the sustained weather impacts of a polar vortex earlier in the year, essentially much of the first quarter of 2014. Ultimately, it would take storage inventories two injection cycles to regain peak inventory volumes prior to November 2015, after record volumes of natural gas had been supplied and consumed during that first quarter of 2014. However, other factors in the natural gas market were at work.

Following Henry Hub spot price peaks in February 2014 of $6 per MMBtu and more, wellhead acquisition prices began a steady decline, spending much of the 2014-2015 winter heating season (the target of this analysis) below $3 per MMBtu. In fact, the price slide did not stop, as one year later during the first quarter of 2016 Henry Hub spot prices landed below $2 per MMBtu. What that meant during the 2014-2015 winter was that even with colder than normal cumulative conditions for much of the country (only the Mountain and Pacific regions were warmer than normal) natural gas remained an excellent consumer value for heating homes and businesses. Stronger natural gas demand had been met by an onslaught of growing gas supply, primarily from shale basins around the country.
Given this backdrop, the analysis in this paper regarding critical elements of the 2014-15 winter heating season (WHS) originates from data acquired from AGA member local distribution companies (LDCs) through the AGA LDC Winter Heating Season Performance Survey. Survey questions focus on peak-day and peak-month supply practices, pricing mechanisms, regulatory frameworks, and market hedging practices—acknowledging that each winter examined is often unique and exceptional in many ways.

This year responses (whole or subsets) were received from 79 local gas utilities with service territories in 46 states. The sample companies had an aggregate peak-day send out of 65.8 million Dekatherm (Dth), 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 80.0 million Dth in aggregate, which means that about 82 percent of the planned peak send out volume was actually required during the 2014-15 winter heating season (WHS) compared to 88 percent during the prior polar vortex winter of 2013-2014. Even though aggregate actual peak-day send out fell short of aggregate design peak-day volumes for responding companies, an 80 percent plus utilization factor is relatively high for the past decade, when often only 75 percent or less of design day expectations where required during a given winter heating season.

The purpose of this report is to document gas delivery system operations of the surveyed local gas utilities during the 2014-15 winter heating season and to help 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 year’s survey. The need for and timing of any of the described practices will vary with each operator based on a number of factors, including unique regulatory, geographic and operational characteristics.

In some cases, the report compares survey results for the 2014-15 winter heating season with those reported one year or several years prior. 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.

II. Executive Summary

This report is based on survey responses submitted by 79 AGA member local gas utilities in 46 states. These companies had a cumulative, non-coincident, peak-day send out of 65.8 million Dth and an average peak-day send out of 832,333 Dth, which was surprisingly ten percent higher than the sample of companies for the previous winter heating season (2013-14). The coldest day of the 2014-15 winter heating season, as reported by respondents, occurred predominantly in mid-February with 45 of 79 responses indicating a peak day in February. During the 2013-2014 winter, (70 of 84 respondents) had reported their peak day primarily in early January.

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%, 26-50%, 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**

- The U.S. natural gas market balances supply and consumption today at about 75 Bcf per day on average. However, requirements for natural gas by consumers—and particularly during the winter heating season—are not average.
During the period of November 1, 2013 through March 31, 2014, total consumption of natural gas in the U.S. ranged from about 68 Bcf per day on a warm March day to 139 Bcf on January 7, 2014. Consumption during the 2014-2015 winter was not as high as the prior year polar vortex winter but the highest consumption day (January 8, 2015) still recorded 132 Bcf consumed – a very strong daily consumption number in any historical context. (Note that more companies reported a non-coincident peak day in February 2015, however, the highest single consumption day occurred in early January 2015.)

The residential and commercial segments of the market were most responsible for the dramatic swings in load requirements during the 2014-2015 winter heating season, ranging from over 71 Bcf per day on a cold January day in 2015 to a winter heating season low of about 22 Bcf per day in late March. Stated plainly, managing these swings in daily load requirements reliably while preserving customer value is what local gas utilities do.

Weather

The 2013-14 winter heating season (WHS) was exceptional not only for the occurrence of the polar vortex but also for the degree of temperature deviations from normal and for the wide geographic coverage. Also, low temperature conditions persisted for long stretches during the coldest months. The 2014-2015 winter (the subject of this analysis) was also cold for much of the United States on balance, however, national statistics were influenced back to near normal by winter’s end because the Pacific and Mountain regions were off the chart warm during the cumulative period November 2014 through March 2015.

The United States compiled just under 4,000 heating degree days (HDD) during the five month period November 2014-March 2015. Normal is actually 3,907 HDD, so the winter was slightly colder than normal and would have been much colder than normal if the Mountain and Pacific regions had not been 15 percent and 32 percent cumulatively warmer, respectively.

Although the month of October 2014 was warmer than normal for the country as a whole, November kicked off the traditional winter heating season 12.4 percent colder than normal, though December and January 2015 followed with warmer than normal conditions overall. February 2015 was cold, however – 20.3 percent more HDD days than normal, which is a significant deviation from the norm. March 2015 then returned to slightly warmer than normal temperatures, according to National Oceanographic and Atmospheric Administration (NOAA).

Even though February was colder than normal as noted above, the peak consumption day for the winter heating season occurred on January 8, 2015, according to Bentek Energy. In fact, for 45 of the surveyed companies their peak day occurred in February, while 22 identified January and 12 selected December as the month in which their peak day load occurred.

For the previous WHS period of November 1, 2013 through March 31, 2014, cumulative heating degree days were more than in 2014-2015 and all five months of the traditional winter heating season recorded sustained cold periods with more heating degree days than normal. That said, temperatures for much of the country during February 2015 behaved similarly and demand requirements responded accordingly.
Gas Supply Portfolios

Local gas utilities build and manage a portfolio of supply, storage and transportation services, which include a diverse set of contractual and pricing arrangements, to meet anticipated peak-day and peak-month gas requirements. Looking back at the 2012-13 winter heating season, surveyed companies planned for 71.8 million Dth of peak-day gas send out, but only 75 percent (54.1 million Dth) of the volume was actually required because of the lower than projected peak consumption levels nationwide. That relationship between design peak day and actual peak day usage was typical for the prior decade. The ratio of actual to planned peak day demand requirements were much stronger for the 2013-14 winter with 88 percent of planned assets utilized to meet the non-coincident peak days of the 84 companies responding to AGA’s survey. For 2014-2015 about 82 percent of the non-coincident planned peak volumes were required.

Local gas utilities apply a specific methodology for determining a design day temperature calculation, which influences the construct of their gas supply portfolio. For the 2014-15 WHS survey, twenty-nine companies noted using a 1-in-30 year risk or probability of occurrence, and ten used a 1-in-20 year probability. Twenty-four companies used other methodologies including one in 40, 50 and even up to 90 year expectation of occurrence as well as hybrids such as 1-in-35 for core customers and 1-in-10 for firm core customers.

- It should be no surprise that purchases moved by firm transportation provided much of the gas to consumers for the peak day and peak month. Sixty-seven of 79 companies indicated that firm supplies were a part of their gas supply portfolio, including 54 companies that used firm supplies to meet between 25 and 76 percent of their peak-day volume requirements. Twenty-one companies used purchases tied to firm transportation for more than 50 percent of their peak day supply.

- However, there are other sources of peak day gas. Sixty-two companies indicated that up to 50 percent of peak-day supplies originated from pipeline or other storage, 57 companies noted that up to 50 percent of the deliveries arriving at their city gate on a peak day were earmarked for transportation customers on their system and 36 companies said that up to 50 percent of their peak-day volumes were city gate purchases for sales customers. Nineteen companies flagged on-system storage as the source of up to 50 percent of peak-day supplies.

- In aggregate, supply sources for the non-coincident peak day during the 2014-15 winter heating season are broken down as follows: 34 percent of the 65.8 million Dekatherm delivered arrived at LDC city gates via firm pipeline transportation, 18 percent from pipeline or other storage, 16 percent as shipments for transportation customers, and 16 percent from on-system underground storage, adding up to 84 percent of peak day supplies. Also those same four sources of gas supply accounted for 82 percent of peak-month gas supply.

- Mid-term agreements (more than one month and up to one year) were the most utilized for 2014-15 peak day purchases, with 63 of 77 responding companies having such contract terms. Moreover, 29 companies indicated that more than 50 percent of their peak-day natural gas supplies were acquired via mid-term agreements. Long-term agreements (defined as longer than one year), were used by 42 of 77 reporting companies within their peak day gas supply portfolio (compared to 40 of 84 in WHS prior); however, only nine companies used long-term contracts for more than 50 percent of purchased gas on a peak day, which is the same as during the 2013-2014 winter.

- When asked to describe the distribution of gas supply purchases among types of suppliers, respondents cited independent marketers, producers, producing company affiliates, and LDC marketing affiliates and pipeline marketing affiliates more than any other class of supply aggregators.
When asked if the company used asset management agreements for any portion of its gas supply purchases during the 2014-2015 winter, 29 companies (37 percent) answered “yes;” which is down from 43 percent of companies in 2013-2014.

Supply Pricing Mechanisms and Hedging Issues

Many factors play a role in the market pricing of natural gas and of transportation services, including weather, storage levels, end-use demand, financial markets and various operational issues. When asked to identify the tools most effective to manage the market pricing of natural gas and of transportation services, survey respondents largely cited physical storage, while also mentioning fixed pricing (including advanced purchases at fixed prices), index pricing (both first of month and daily), purchasing natural gas reserves in the ground and call and swing options.

For long-term supplies (greater than one year), 34 of the 45 companies responding to questions regarding long-term arrangements used first-of-month (FOM) pricing for a portion of their supplies, including 21 companies that used FOM for at least 50 percent of long-term gas purchases. Seven companies utilized daily pricing for 50 percent or more of long-term supply, while eight used some form of fixed pricing.

Of the 64 companies that have mid-term purchases (more than one month, less than one year), 54 reported these purchases as most often tied to FOM indices, of which 48 companies used this pricing for significant volumes of gas. Also included in the mid-term pricing basket were daily mechanisms (for 37 companies), fixed prices (25 companies) and NYMEX indices (17 companies—although mainly for small volumes).

During the 2012-13 winter heating season, 84 percent of surveyed companies (62 of 74) indicated that they used financial instruments to hedge at least a portion of their supply purchases. During the polar vortex winter that percentage had dropped to 79 percent. For the 2014-2015 winter 62 of 77 companies indicated that they had hedged at least part of their gas supply portfolio with financial instruments pushing the percentage back up to 81 percent. Today’s numbers contrast with the 2004-05 winter where only 70 percent of survey companies used financial tools, while only 55 percent did so three years prior (during the 2001-02 winter).

For the 2014-15 WHS companies hedged as little as three percent and as much as 96 percent of winter heating season supply using financial instruments. The median supply volume hedged for the 2014-15 sample of companies was 36 percent.

Options and fixed-price contracts were most often cited (by 37 and 28 companies, respectively) as tools used to hedge a portion of gas purchases. Other regularly used financial tools include swaps (24 companies) and futures (15 companies). The use of financial tools may be understated in this report inasmuch as some volumes delivered to LDCs from marketers and other suppliers are hedged by the third-party rather than the LDC and may have been excluded from the LDC hedging calculation.

Companies use a portfolio of timed hedges to balance their approach to strategic price planning. When asked about the strategic timing of their hedges, 50 of 62 companies (81 percent) indicated that they hedge six months or less forward for a portion of their supplies, while 49 companies also employed a seven to 13 month strategy. In addition, 29 companies hedged forward more than 13 months for a portion of their supplies. Of these 62 companies that hedged supplies, 24 employed all three timing strategies.
On the physical side in preparation for the 2014-2015 WHS, 76 of 79 respondents (96 percent) reported using storage as a natural hedging tool. Thirty of those companies hedged between 25 and 51 percent of winter heating season supplies using underground storage, compared with 37 companies last year. Another 43 companies employed this physical hedge for 1 to 25 percent of their supply portfolio.

Only four of 78 survey respondents indicated that they used weather derivatives during the 2014-15 winter heating season. This compares with two of 51 companies four winter heating seasons prior.

When asked about their own regulatory environment, 58 of the 60 companies that answered the question with an answer other than “not applicable” indicated that financial losses and gains tied to hedging were treated equally by the regulator.

When asked about the focus of their regulator regarding gas purchases, 46 of the 78 respondents that knew the answer indicated that their regulator was equally interested in stable prices and the lowest price possible. Eight said that a lowest price was the only focus, while 15 tagged stable prices as the regulator’s concern. Nine did not know.

Only two of 77 companies indicated that regulators overseeing their services and activities in preparation for the 2014-2015 winter heating season were less receptive to hedging than in the prior year. Two companies perceived regulators as more receptive to hedging strategies, while 73 saw no change in regulator receptivity to practices and strategies in place.

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.

Seventy-two of 76 companies answering the question (95 percent) indicated that weather-induced demand compelled them to utilize storage services during the 2014-15 winter heating season, which is not a surprise. Respondents also cited no-notice requirements (61 companies), “must turn” contract provisions (49 companies), pipeline operational flow orders (42 companies), and arbitrage opportunities (31 companies) as reasons to maintain storage services within their gas supply portfolio. Among these companies, 15 noted all of these influences in their use of storage assets.

Ninety-six percent of respondents (76 of 79 companies) indicated that they used underground storage (on-system or pipeline) for a portion of their 2014-2015 winter heating season supply. That portion tended to be one to 50 percent—only three companies indicated that more than 50 percent of their WHS supply originated from underground storage.

Sixty-four of the 75 companies responding said that they used first-of-month index pricing to purchase gas for injection into storage during 2014, and 39 percent (or 25 companies) of those companies used FOM prices for 76-100 percent of gas injected into storage. Forty-four companies indicated that they purchased a portion of their stored gas in the daily market; however, daily pricing tended to account for less than 25 percent of purchased storage volumes. Thirty of 75 companies (40 percent) used fixed-price schedules for some portion of their storage purchases, compared to 38 percent last year.
None of the 79 companies responding indicated that they were currently constructing new underground storage facility, however, eight were looking at the possibility within the next five years, while 7 were considering adding market-area LNG or propane peak-shaving capacity to their gas supply assets.

**LDC Transportation and Capacity Issues**

Managing pipeline capacity efficiently is a challenge for many utilities and can involve the release of capacity to the secondary pipeline transportation market. Additionally, operational flow orders (OFO) may be issued by upstream operators in order to maintain the integrity of pipeline pressures and to balance anticipated supply volumes at given points and takeaways at others. OFOs may also be issued in order to manage storage balances and field integrity.

- From April 2014 to March 2015, 39 to 42 of the survey companies (varying with the month) released their unneeded pipeline capacity to the secondary market. Of those, 26 to 31 companies (depending on the month) released up to 25 percent of their pipeline capacity. During the spring-summer of 2014 (April through August), from 8 to 12 surveyed companies per month released 26 to 50 percent of their capacity.

- Thirty-nine of 77 companies (51 percent) indicated that operational flow orders impacted their systems during the 2014-15 winter. Two winters previously only 22 of 73 companies reported that operational flow orders (OFO) issued by pipeline companies had an impact on their service territory. During the just completed winter the median number of OFOs for the companies was 7 and the median point of reported average durations was 5 days.

- In addition to operational flow orders, fourteen companies (18 percent of those reporting) noted that pipeline critical transport days were issued during the winter heating season that impacted their operations, and eight companies identified storage critical days.

**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 obvious reason is that companies want to deliver natural gas to customers reliably and at the lowest possible cost, another 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 2014 natural gas consumption in the United States was about 56 Bcf per day according to Bentek Energy, LLC. Six and a half months later in January 2015, peak day consumption in the United States reached 132 Bcf—146 percent higher than the previous June. This epitomizes demand uncertainty.

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. By 2012 domestic dry natural gas production grew to 24 Tcf annually, and consumption continued to rise. The growth pattern continued with production reaching 27 Tcf in 2015, according to the Energy Information Administration. 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 supplies at about 75 Bcf per day on average. However, on a daily basis during the course of a winter heating season natural gas consumption can fluctuate significantly. The graph in Figure 1 represents daily natural gas consumption from January to December 2015. Clearly, winter heating season daily consumption does not necessarily correspond to annual or monthly averages. For example, from January 1 through March 31, 2015 daily natural gas consumption ranged from as little as 65 Bcf to over 120 Bcf. The graph also shows that consumption fell to below 60 Bcf per day for much of May 2015, but history and the graphic tells us that demand increases again in July and August to meet natural gas-fired power generation requirements.

FIGURE 1
U.S. Daily Natural Gas Consumption 2015

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.

**FIGURE 2**

Daily Storage Withdrawals (+) and Injections (-)

January 1 – December 31, 2015

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 1 through December 31, 2015. Here we see daily sector consumption as low as 25 Bcf for a relatively warm winter day in March sharply contrasted with an over 70 Bcf consumption day in January. On a national basis, this represents a 180 percent load swing for natural gas utilities 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**

Daily Residential/Commercial Natural Gas Consumption (Bcf) 2015

IV. Weather 2014-15 Winter Heating Season

The 2013-14 winter heating season (WHS) was exceptional not only for the occurrence of the polar vortex but also for the degree of temperature deviations from normal and the wide geographic coverage. Temperature conditions also persisted for long stretches of the coldest months. Except for the Mountain and Pacific regions, portions of the 2014-15 winter heating season were similarly challenged, particularly February 2015. The following attempts to quantify and place in context the critical metrics describing the temperature-related events of November 2014 - March 2015.

- The United States compiled 3,994 heating degree days (HDD) over the five month period of November 2014 - March 2015 (only 223 fewer HDD than the prior winter). This total was 2.2 percent “colder than normal” and followed 2013-14 WHS, which was the second coldest for the nation as a whole in 29 years.

- Regionally, the story was different as the East North Central and Middle Atlantic regions of the country experienced 7.0 and 7.7 percent more HDDs than normal. Even New England was 6.8 percent colder than normal for the six-month period October 2014 through March 2015.

- The South Atlantic, East South Central and West South central regions were between 3.6 and 6.5 percent colder than normal, too.

- Further west for the six month period noted above, it was quite a different story. From October 2014 through March 2015 the Mountain region saw HDDs fall below normal levels by 15 percent, while the Pacific region was an incredible 32 percent warmer than normal.

<table>
<thead>
<tr>
<th>MONTH</th>
<th>PERCENT CHANGE FROM NORMAL</th>
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<tbody>
<tr>
<td></td>
<td>2013-14</td>
</tr>
<tr>
<td>October</td>
<td>8.0% Warmer</td>
</tr>
<tr>
<td>November</td>
<td>6.5% Colder</td>
</tr>
<tr>
<td>December</td>
<td>3.2% Colder</td>
</tr>
<tr>
<td>January</td>
<td>5.6% Colder</td>
</tr>
<tr>
<td>February</td>
<td>13.0% Colder</td>
</tr>
<tr>
<td>March</td>
<td>14.8% Colder</td>
</tr>
<tr>
<td>TOTAL</td>
<td>6.6% Colder</td>
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</tbody>
</table>

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 of course influences the construct of their gas supply portfolio. For the 2014-15 WHS survey, companies described their methodology for determining their design day calculation as follows: 29 employed a 1-in-30 year risk of occurrence, 10 used a 1-in-20, two used a 1-in-15, one a 1-in-10, and one used a 1-in-5 year occurrence probability. Twelve companies utilized an alternative time period criteria, ranging from 22 years to 1-in-90 years. In addition, 24 companies used other methodologies including a historical peak or severe weather event from a specific year, to name a few.

Peak-day consumption predominantly occurred in February for survey respondents (45 of 79 companies). For these 79 companies, the aggregate peak-day send out was 65.8 million Dekatherms during the 2014-15 WHS, making up 82 percent of the 70 million Dekatherms projected for peak-day requirements.

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 illustrate the diversity of gas supply sources available to LDCs. It should not be surprising that purchases moved by firm pipeline transportation provided much of the gas to consumers for the peak day and peak month during the 2014-15 WHS. Sixty-seven of 79 companies indicated that firm pipeline supplies formed a part of their peak day gas supply portfolio, including 40 companies that showed 26 to 50 percent of their required peak-day volumes coming from firm supplies. Another 21 companies indicated that more than 50 percent of their peak-day supplies were moved via firm pipeline transportation.

As shown in Table 2, also peak-month supplies were heavily weighted toward purchases via firm transportation. As with peak-day supplies, peak-month supplies were almost as heavily toward pipeline (or other) storage. 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, and local production.
Table 2 and Figure 4 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 firm pipeline transportation, other gas supply sources are also important for peak-day deliveries: 66 of 79 companies indicated that up to 50 percent of peak-day supplies originated from pipeline or other storage, while 57 companies indicated that up to 50 percent of their peak-day supplies were city gate supplies for transportation customers. Forty-one companies made city gate purchases, 29 used LNG or propane air as a supply source on their peak day (compared to only 16 companies two years ago), 24 used on-system storage, and 21 utilized local production. This year, as many as three respondents used interruptible transportation for their peak deliveries, whether on a peak day or within a peak month. Three years ago, no company reported interruptible transportation as a peak day or peak month supply source, while for the 2014-2015 winter one company did note utilizing interruptible sourced gas on their peak day. The peak day “Other” category, reported by 13 companies most consistently included purchases to supplement imbalances with third party suppliers, on-system balancing and linepack.
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 again points to the preponderance of purchases moved via firm transportation (as might be expected for local gas utilities), storage assets, 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**

2014-15 Winter Heating Season

(79 Companies)

<table>
<thead>
<tr>
<th>Supply Sources</th>
<th>Peak Day</th>
<th></th>
<th>Peak Month</th>
<th></th>
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</thead>
<tbody>
<tr>
<td></td>
<td>Volume</td>
<td>%</td>
<td>Volume</td>
<td>%</td>
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<tr>
<td>Citygate purchases for sales customers</td>
<td>3,689,888</td>
<td>6%</td>
<td>58,258,351</td>
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<td>Citygate supplies for transportation customers</td>
<td>10,354,697</td>
<td>16%</td>
<td>251,237,735</td>
<td>19%</td>
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<tr>
<td>LNG / Propane-air / SNG</td>
<td>2,098,762</td>
<td>3%</td>
<td>9,216,671</td>
<td>1%</td>
</tr>
<tr>
<td>Local production</td>
<td>924,082</td>
<td>1%</td>
<td>27,188,207</td>
<td>2%</td>
</tr>
<tr>
<td>On-system underground storage</td>
<td>10,663,122</td>
<td>16%</td>
<td>163,038,106</td>
<td>12%</td>
</tr>
<tr>
<td>Pipeline or other storage</td>
<td>12,077,311</td>
<td>18%</td>
<td>194,157,899</td>
<td>15%</td>
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<td>Purchases moved via firm transportation</td>
<td>22,074,982</td>
<td>34%</td>
<td>480,534,256</td>
<td>36%</td>
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<tr>
<td>Purchases moved via interruptible transportation</td>
<td>5,754</td>
<td>0%</td>
<td>90,970</td>
<td>0%</td>
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<tr>
<td>Other</td>
<td>3,938,263</td>
<td>6%</td>
<td>134,482,309</td>
<td>10%</td>
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<tr>
<td><strong>TOTAL</strong></td>
<td>65,826,861</td>
<td>100%</td>
<td>1,318,204,503</td>
<td>100%</td>
</tr>
</tbody>
</table>

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. However, the recent waning of market volatility, particularly as it applies to natural gas acquisition prices, is resulting in a reexamination by LDCs and regulators of supply acquisition contracting, with in some cases less emphasis on absolute least cost and more stress on price stability. Some argue that longer-term contracting may be useful to underpin new supply sources in the future.

Generally the 2014-15 data show a relative balance among contract lengths of peak-day and peak-month supply volumes (see Table 4). However, the use of mid-term deals (defined as greater than one month and up to a year) is becoming more prominent, particularly in cases where they make up 50 percent or more of a company’s gas requirements.

Mid-term deals for peak day purchases were made by 63 of 77 companies reporting—more companies than those using daily (56 companies), monthly arrangements (46 companies), or long-term contracts (42 companies). A similar pattern emerges for peak month and winter season purchases. Also, during the entire 2014-15 winter heating season many companies utilized daily purchases, which may not be a surprise given overall strength in natural gas supplies.
As to supply providers, as shown in Table 5, when asked to describe the distribution of peak-day gas purchases among suppliers, 62 LDCs identified independent marketers as their supply provider. The balance of supplies acquired by LDCs were distributed among producers (36 companies), LDC energy marketing affiliates (19 companies), pipeline energy marketing affiliates (46 companies), customer owned gas (16 companies), and LDC-owned production (two companies). The other category has in some years included financial marketing affiliates, asset managers, imported LNG, storage operators and other supply aggregators.
When asked whether their company used asset management agreements for any portion of their gas supply purchases during the 2014-15 winter heating season, 29 of 79 companies (37 percent) said yes—slightly less than the prior winter heating season. Of these 29 companies, 16 used asset management for 25 percent or less of their winter heating season supplies, while eight companies actually used asset management agreements for 100 percent of 2014-15 winter heating season supplies (see Table 6).
VI. Supply Pricing Mechanisms and Hedging

Pricing Mechanisms

Many factors play a role in the market pricing of the gas commodity and of 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. In order 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-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 asked whether they would consider including fixed-price supply deals in their 3 - 10 year term supply contracts, at a price of $4 to $5 per MMBtu, if regulators would approve such deals, 17 of 78 responding companies (22 percent) said “yes,” and 39 said “maybe.” Responses possibly reflect a general feeling that Henry Hub prices will likely remain stable overall but have the potential to rise if the supply overhang of recent years is more closely balanced with natural gas demand. Of the 56 companies that answered “yes” or maybe to the pricing hypothetical above, 47 said they would consider building fixed price arrangements for less than or equal to 30 percent of their total supply. One opted for 51-60 percent, and one selected 91-100 percent. With respect to preferred contract durations for such deals, 18 companies pointed to 3-5 years as the best term for agreements while 15 companies saw 3 years or less as optimal and nine companies five years or greater.

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 7 provides a closer look at the balance of pricing mechanisms among survey respondents during the 2014-15 winter heating season.
As shown in Table 7 and graphically depicted in Figure 5, 34 of the 45 companies with long-term supplies (more than one year) used first-of-month pricing for a portion of these supplies, including 21 companies that used FOM for 51 percent or more of recent purchases. Twenty-one companies used daily pricing mechanisms for long-term supplies spread among volume ranges but were more particularly notable for volumes representing less than 50 percent of winter heating season supplies. Also 15 companies utilized some form of fixed pricing (compared to 16 of 42 two years prior).
Figures 5, 7 and 8 show the pricing mechanisms employed by the 2014-15 survey participants, and Figures 5 and 6 together present a comparison of long-term pricing arrangements for the past two winter heating seasons. The graphs clearly show that for larger volumes of gas purchased under long-term arrangements, first-of-month indices continued to be the predominant pricing mechanism during 2014-15 just as they were for the 2013-14 winter. This is not surprising, since the first-of-month index is not only a measure of market movement but often also serves as 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 no role in long-term gas purchases during the 2014-15 WHS but did turn up to a small degree in short-term and mid-term deals.
According to the 64 companies that reported mid-term supplies (of more than one month and up to one year) during the 2014-15 WHS, much of these natural gas purchases were tied to FOM indices (54 companies, including 29 that used FOM pricing 50 percent or more of their supply). However, as Table 7 and Figure 7 indicate, daily, NYMEX and fixed pricing mechanisms were used to a significant extent for smaller-volume mid-term purchases. Twenty-five companies reported using fixed pricing mechanisms for mid-term purchases, compared with 15 for long-term purchases. Also 37 of 64 reporting companies used daily prices for mid-term purchases.

As would be expected, more companies (52 of 75) used daily pricing for short-term purchases (one month or less) than for mid-term or long-term purchases during the 2014-15 WHS; however, these short-term purchases were also heavily dependent on first-of-month indices (43 companies) as well as tied to fixed prices and NYMEX indices (see Table 7 and Figure 8). 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.
**Figure 7**

LDC Mid-Term Gas Supply Pricing Mechanisms  
2014-15 Winter Heating Season  
(64 LDCs)

**Figure 8**

LDC Short-Term Gas Supply Pricing Mechanisms  
2014-15 Winter Heating Season  
(75 LDCs)
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.

Eighty-one percent of responding companies (62 of 77) said they used financial instruments to hedge a portion of their 2014-15 winter heating season gas supply purchases. This percentage is slightly higher than the prior year (when 79 percent of companies indicated using financial hedges) but generally lower than for other years, where 92 percent of companies reported using financial tools in 2010-11, 90 percent in 2009-10, and 89 percent in 2008-09, for example. Still this percentage is significantly larger than in 2004-05 (70 percent of respondents) and in 2001-02, where only 55 percent of respondents reported using financial tools 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 2013-14 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 2014-15 WHS gas supply purchases: options (37 companies), fixed price contracts (28 companies), swaps (24 companies), and futures (15 companies). The use of financial instruments may be understated in this report inasmuch as 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 report, 28 percent of the gas delivered by the companies in the survey during the 2014-15 winter heating season was hedged—exactly the same as the prior two winter heating seasons.

Only four companies reported using weather derivatives during the 2014-15 winter heating season. This compares with one during 2013-14, four of 73 companies in 2012-13 winter, five of 76 companies in 2006-07, and seven of 54 in the 2004-05 survey.

When asked about how far into the future hedging strategies extended, 50 of 62 companies with hedging programs (81 percent) indicated that they applied a six-month or less strategy for a portion of their hedges for the 2014-15 winter heating season. Forty-nine companies used a 7-13 month strategy, and 29 companies employed a greater than 13-month strategy. Of course, a single company may use one or all strategies simultaneously. In fact, 24 of the respondents did just that, compared with 28 the prior year.

On the physical side, companies view deliveries of gas supplies into storage during the summer refill season as a price hedge against potential winter price run-ups. In preparation for the 2014-15 winter heating season, 76 of the 79 reporting companies (96 percent) used storage as a physical hedge. Seventy-three companies reported using storage for up to 50 percent of winter heating season supplies.

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 company, regulator, and local market conditions. Twenty-nine of 78 responding companies said that they are required to secure pre-approval from their regulator, and 27 indicated that they are required to operate within set parameters, such as particular financial tools, time limits or volume restrictions.
When asked about their regulatory environment, the majority of respondents (73 of 78) reported no change in their regulator’s receptivity to financial hedging during the 2014-15 winter heating season compared to the prior year, and two reported increased receptivity on the part of their regulator or public utility commission (PUC). Two companies also indicated that their PUC was less receptive this past winter heating season. Seventy-four of 77 companies did not believe that the events of the 2014-15 winter would influence regulatory views of hedging strategies.

Fifty-eight of 62 responding companies reported that their regulator treated the financial losses and the gains related to hedging equally. This 94 percent response compares with 88 percent (or 45 of 51 companies) three years ago. Additionally, 59 of 62 companies that answered the question said yes when asked if costs associated with their financial hedging programs were fully recoverable, while three responded no.

When asked about the focus of their regulator with respect to natural gas purchases, eight respondents indicated that their regulator was primarily interested in the lowest possible price, fifteen said that the focus was on stable prices, and 46 companies 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, 26 of 62 companies cited regulatory requirements, 34 said it was a voluntary decision (in certain cases influenced by customers), and 12 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, 56 of 62 companies (90 percent) noted the reduced price volatility as a benefit to customers, while 17 companies identified reduced gas costs as valuable to customers. Of the 62 respondents, 16 cited both lower prices and more stable prices as benefits to consumers resulting from structured hedging plans.

VII. 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 swing opportunities and satisfy peaking needs. Table 8 shows storage levels as estimated by the Energy Information Administration for January-April 2014 compared to the same period in 2015. It is plain to see that there were considerable differences.

The storage story for the 2014-15 winter begins in April 2014 when net injections began to refill inventories that the polar vortex had reduced to their lowest in 10 years—only slightly above 800 Bcf. A record for net underground storage withdrawals had occurred in January 2014 as more than 950 Bcf was withdrawn in response to a natural gas demand of 3.2 Tcf for that month—also a national record. Furthermore, for the first time in U.S. history, a net of 3 Tcf of natural gas was withdrawn from storage during the 2013-14 WHS. By November 2014 working gas stood at 3.6 Tcf, which is solid but hundreds of Bcf below prior inventory records.

Ninety-six percent of survey companies (76 of 79) used underground (on-system or pipeline) storage for a portion of their gas supply during the 2014-15 winter heating season, of which 73 reported that up to 50 percent of their 2014-15 winter supplies were derived from storage. In preparation for that winter, the spring-summer 2014 storage refill season competed with gas flowing to power generation. In fact, 18 of 76 companies that answered the question indicated flowing volumes of gas from storage during the injection season to serve summer power generation loads.
Supply reliability and operational issues topped the list of reasons that motivated LDCs to inject gas supplies into storage. These two issues, respectively, were cited by 70 and 63 of the 76 companies that used storage. Price considerations also influenced the decisions of 57 companies, and regulatory plans or mandates impacted the storage strategy for 39 companies. Of course, more than one variable may influence injections of gas supplies into storage: In fact, 31 of these companies were motivated by all four factors.

A variety of reasons also underlie LDCs’ decisions to use their existing stored gas supplies. Of course, weather-induced demand compelled 95 percent of respondents (72 of 76) to make use of their storage services during the 2014-15 winter heating season. Other factors cited by companies were no-notice requirements (61 companies), “must turn” contract provisions (49 companies), pipeline operational flow orders (42 companies), and arbitrage opportunities (31 companies). Again more than one variable moved companies to use storage: fifteen of the companies said that they were influenced by all five reasons.
Table 9 and Figure 9 show that many of the gas purchases made for storage injections during the 2014 refill season, in preparation for the 2014-15 winter heating season, were based primarily on first-of-month indices (64 companies) and daily spot pricing, although primarily for smaller volumes, (44 companies); however, fixed and NYMEX-based gas pricing also got some play, particularly for small volumes of gas destined for underground storage—used by 30 and 20 companies, respectively.

<table>
<thead>
<tr>
<th>SUPPLY VOLUME PERCENTAGE RANGES</th>
<th>AVERAGE LAST 3 DAYS</th>
<th>DAILY (SPOT OR INDEX)</th>
<th>FIRST-OF-MONTH INDEX</th>
<th>FIXED</th>
<th>NYMEX</th>
<th>WEEKLY</th>
<th>OTHER</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 – 25%</td>
<td>1</td>
<td>26</td>
<td>7</td>
<td>14</td>
<td>10</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>26 – 50</td>
<td>1</td>
<td>11</td>
<td>19</td>
<td>6</td>
<td>2</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>51 – 75</td>
<td>0</td>
<td>3</td>
<td>13</td>
<td>4</td>
<td>5</td>
<td>1</td>
<td>0</td>
</tr>
<tr>
<td>76 – 100</td>
<td>0</td>
<td>4</td>
<td>25</td>
<td>6</td>
<td>3</td>
<td>0</td>
<td>1</td>
</tr>
<tr>
<td>0</td>
<td>73</td>
<td>31</td>
<td>11</td>
<td>45</td>
<td>55</td>
<td>74</td>
<td>74</td>
</tr>
</tbody>
</table>

The pricing mechanisms used for the 2014 storage injections are reflected in Figure 10. 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.

When asked about their future plans at the end of the 2014-15 winter heating season, only eight companies indicated that they were considering the option to expand their underground storage facilities within the next five years, although none of the companies were in a current construction phase. In addition, seven companies were considering expanding market-area LNG or propane air peak-shaving facilities and one was constructing at that point.
Management of storage assets during the 2014-15 winter was not quite as stressed as during the 2014 polar vortex, which included wide swaths of the country east of the Rockies front experiencing extended periods of cold. Storage Critical Days (SCD) during the 2014-15 winter heating season were not as prevalent as the year prior when 17 percent of the companies reporting had recorded critical events. Only eight companies (about 10 percent) indicated the need to issue critical storage day notices during the 2014-15 winter heating season.

However the 2013-14 polar vortex winter left the market with certain impressions and likely carry-over that may impact winter heating season operations permanently. For example, when challenged to maintain system deliveries during the polar vortex, answers given by the nine respondents that employed non-traditional approaches were remarkably consistent: The primary tool for managing strained storage assets during the first quarter of 2014 was the purchase of additional flowing gas on the daily market. Although simple in concept, just the fact that flowing gas was available—given the demand levels and persistent cold—is an astonishing turn of events, considering past perceptions of the U.S. gas supply market, and it lends some perspective on the extent to which domestic production has grown since the beginning of the so-called shale revolution.

Perhaps because of this gas supply picture, when asked whether the events of the 2014-15 winter heating season would cause them to modify storage-related supply planning for the next winter, 82 percent of respondents (68 of 76) said that it will not have an impact on their storage-related decisions for the 2015-16 WHS.

**VIII. LDC Transportation and Capacity Issues**

As stated earlier, planning for transportation capacity and supply is generally 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 involve the release of capacity to the secondary transportation market, if events allow it.

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 2014 to March 2015. A majority of respondents consistently released less than 25 percent of their capacity throughout the year, however, a significant number released up to 50 percent during the summer months. 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.

Regarding system operations, 51 percent of survey respondents (39 of 77 companies) indicated that their operations and/or system had been impacted by the issuance of pipeline operational flow orders (OFOs) during the 2014-15 winter heating season—a lower rate than was the case the year before when 63 percent of the companies noted having to issue OFOs. During the 2014-5 winter, companies (14 of 77) also encountered pipeline Transport Critical Days and Storage Critical Days (8 companies as noted above).

The median for the number of OFO issuances by each company doing so was seven, and the median for OFO durations was 5 days. Transport Critical Days (TCD) tended to last for a shorter duration (median of 3 days per event) and were encountered seven times per LDC (median value) over the course of the winter heating season. The main reasons for the OFOs and TCDs cited by respondents had to do with protecting system integrity, maintaining pipeline physical flow requirements and preserving storage deliverability. Historically they tend to be in response to colder-than-normal weather, compression constraints, and low line pack among others. Reasons for critical storage days revolved around below normal temperatures, low storage balances, and occasionally nominations that may exceed capacity to deliver.
TABLE 10  
PERCENT OF PIPELINE CAPACITY RELEASED BY LDCs  
APRIL 2014 – MARCH 15

<table>
<thead>
<tr>
<th>CAPACITY PERCENTAGE RANGE</th>
<th>INJECTION SEASON</th>
<th>WINTER HEATING SEASON</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2014</td>
<td>2014-15</td>
</tr>
<tr>
<td></td>
<td>47 COMPANIES</td>
<td>38 COMPANIES</td>
</tr>
<tr>
<td>APR</td>
<td>MAY</td>
<td>JUN</td>
</tr>
<tr>
<td>1 - 25%</td>
<td>31</td>
<td>29</td>
</tr>
<tr>
<td>26 - 50</td>
<td>8</td>
<td>10</td>
</tr>
<tr>
<td>51 - 75</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>76 - 100</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>0</td>
<td>7</td>
<td>7</td>
</tr>
</tbody>
</table>

IX. 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 2014-15 winter heating season. About half of the 79 surveyed companies said yes (39 companies); however, all but one described the investigations as routine. In addition, when asked whether regulators had significantly delayed the full recovery of gas sales costs incurred during the 2014-15 winter, all 78 of the companies responding said “no.”

The method for recovering gas costs was further described: 39 of 79 companies recover gas costs, by passing them through to customers, as incurred over a period of time, and over-or under-recovered costs are deferred and collected or distributed, with interest, during a subsequent period. Twenty-four companies have a similar approach, except interest is not applied to the deferred amounts. For five companies, the addition of interest depends on whether the gas costs have been under or over-recovered from customers, while for seven other companies the treatment of interest varies by service territory or jurisdiction.

When asked whether permitted to retain some or all revenues from off-system wholesale natural transactions, 27 of the 77 companies to which the question applied said yes. In addition, of the 84 survey companies, 35 were permitted to use weather normalization clauses within their rate structures. Also 15 of the 79 companies (19 percent) said that they offered fixed-price options to their customers.
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