PROMISE DELIVERED

Planning, Preparation and Performance during the 2013-14 Winter Heating Season

SEPTEMBER 2014
Promise Delivered
PLANNING, PREPARATION, AND PERFORMANCE DURING THE 2013-2014 WINTER HEATING SEASON

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Findings
Observations and Conclusions
Promise Delivered

FINDINGS, PREPARATION, AND PERFORMANCE DURING THE 2013-14 WINTER HEATING SEASON

FINDINGS, OBSERVATIONS AND CONCLUSIONS

First there was the *Promise of Natural Gas*. The 2012 American Gas Association study laid out a vision for the natural gas market in the next decade—one of relative price stability, driven by abundant supply and new demand for this domestic fuel. The paper identified significant outcomes from this structural shift in the natural gas market and examined the implications of such stability for energy consumers and the nation as a whole. The report found that:

- For at least the next decade, domestic natural gas supplies are expected to remain sufficiently robust to meet substantial growth across all gas demand sectors, and
- This strong natural gas supply position, coupled with a growing and viable delivery infrastructure, promises the nation an affordable energy that can fuel economic recovery while protecting the environment.

Two years after the study was released, this vision was tested by the second coldest winter in the U.S. since 1985. This weather event—the *polar vortex*—impacted large swaths of the country and pushed the natural gas market to unprecedented performance levels. The industry delivered record-high volumes of natural gas to consumers amid below normal temperatures and persistent harsh weather. Families used more natural gas than ever to keep warm, and power generators pulled record volumes of gas to maintain electric system reliability. Industrial demand for natural gas increased, and even exports to Mexico were strong. It was indeed an exceptional winter for natural gas deliveries.

The natural gas industry responded collectively to this historic weather event by implementing strategies, based on decades of operational experience. In particular, local distribution companies were prepared and met the challenge by executing plans made for just such contingencies.

This overview highlights findings from five AGA papers and other data, which describe the natural gas market during the 2013-14 winter heating season (WHS). The papers also provide an overview of market conditions over the past decade, which set the stage for the industry’s remarkable performance this past winter – not perfect but remarkable. These papers cover LDC gas supply portfolio planning, the contribution of underground storage, the role of interruptible customers, energy efficiency developments, and the statistical case for an extraordinary winter.

Guided by past experience and regulatory oversight, utilities plan 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). This past winter, as with others, local distribution companies used a full suite of supply assets and tools to fulfill their obligation to serve customers reliably and safely, both on an average day as well as a peak demand day.
Underground storage, as expected, proved a critical supply component. Firm pipeline capacity, local production, and third-party transportation agreements also played a role. Some utilities used liquefied natural gas (LNG) as a peak shaving asset to meet incremental load requirements on the coldest days. Also, many utilities supplemented supplies via spot commodity purchases.

Even with the range of supply options, a number of natural gas distribution operators faced constraints imposed by challenges experienced further upstream in the natural gas supply chain. High demand and bitter weather conditions pushed infrastructure to the limit. Freeze-offs disrupted production in some regions, and temporary equipment failures constricted some upstream pipeline routes. Storage drawdowns were strong and, in many instances, weather-induced withdrawals tested delivery storage capabilities, especially after the extended drawdown period as the cold persisted.

Despite the challenges, system planning and supply flexibility prevailed. Customers were served. Reliability and safe delivery were maintained. Very few system outages were reported across the country. Overall the natural gas system performed as expected. According to one utility that faced record conditions, its system performed “exceedingly well” this past winter. Another utility, which encountered record throughput, described its system as having “weathered the storm well.”

**Findings and Observations**

The natural gas distribution system comprises a diverse set of utilities with a wide range of service territories, customer bases, system designs and regulatory frameworks. Gas procurement strategies and operations management are often determined by the local geography and regional market conditions in which the utility operates. Each utility therefore develops a set of assets—tailored for specific challenges and constraints—which are geared toward matching available supply with system demand. Despite this diversity, the following observations from the 2013-14 winter heating season apply broadly across the spectrum of natural gas utilities in the U.S.

1. The 2013-14 winter set high consumption records across market sectors and thus presented the U.S. natural gas delivery system with a historic stress test. The system delivered as promised.

2. Due to the diligent planning and preparedness of natural gas utilities—involving numerous supply and operations management approaches—resources were available during peak demand periods, suggesting that the existing regime of planning, procedures, and regulatory oversight is sound and working effectively.

3. Underground storage played its most critical role ever in meeting customer needs—a result of a decade or more of investments in storage capacity expansions and improvements, which helped ensure availability and deliverability of stored gas on the coldest winter days.

4. Flowing natural gas was available for affordable spot purchases by natural gas utilities that required additional supply to meet customer demand surges, even amid system constraints. These additional supplies materialized via increases in domestic shale production close to market centers and hubs, incremental imports of Canadian gas, and even short-term boosts in LNG imports during the past winter heating season.
5. Upstream pipeline constraints have an impact on local distribution systems in the form of operational flow orders, critical days or even short-term pricing shifts at key locations. These contingencies are generally anticipated in distribution system planning; however, in particularly congested markets, regional infrastructure planning can play a key role in addressing such constraints.

6. For many utilities, interruptible service provides a valuable gas supply and operations management tool, allowing service curtailments on peak demand days to ensure reliable and safe gas service to core customers. In a number of service territories, the frequency and duration of interruptions increased this past winter due to exceptional weather conditions.

7. Relatively stable and affordable natural gas prices, coupled with energy efficiency gains, helped moderate weather impacts on customer bills. Supportive policies of utility practices, aimed at maintaining affordable prices and improving energy savings for customers, may further mitigate bill impacts during future winter events.

The facts surrounding these observations on the 2013-14 winter are explored further next. Then the case is made that industry performance this past winter reflects structural shifts in the natural gas market and is a result of years of successful planning, investment, and regulatory guidance. The implications of this new market reality are discussed with a look forward to a new vision of the industry’s future.

Findings and Observations Explored

1. The 2013-14 winter set high consumption records across market sectors and thus presented the U.S. natural gas delivery system with a historic stress test. The system delivered as promised.

During the past winter, more customers were served with larger volumes of natural gas than ever before, particularly for the period January-March 2014. The 2013-14 winter heating season was the second coldest the nation had experienced in 29 years, measuring 8 percent colder than normal from November 2013 through March 2014, even though the Pacific and Mountain regions were warmer than normal for much of the winter. During the five month period, total U.S. natural gas consumption ranged from about 68 Bcf per day on a warm March day to 139 Bcf in January—a huge swing in daily winter heating season demand and a record-setting upper limit for single day consumption (on January 7). Total U.S. natural gas demand set daily, weekly, and monthly records for a January, only to be followed by the strongest demand on record for February and for March.
Daily consumption levels reached record highs also in the residential, commercial, and power generation markets in January. January also saw the highest winter month load for electricity on record, which resulted in the largest natural gas flows to power generation to date during a January month. In fact natural gas demand by the electric power sector was 3 Bcf per day higher than the prior five-year average. Industrial demand was also above average—consistently 3 Bcf per day higher in January, compared to the five-year average for the same month.

2. Due to the diligent planning and preparedness of natural gas utilities—including numerous supply and operations management approaches—resources were available during peak demand periods, suggesting that the existing regime of planning, procedures, and regulatory oversight is sound and working effectively.

Local gas utilities build and manage a portfolio of supply sources, storage and transportation services—which include a diverse set of contractual and pricing arrangements—to meet anticipated peak-day and peak-month gas requirements. They apply a specific methodology for determining a design day temperature calculation, which influences the construct of their gas supply portfolio.
Natural gas supply assets were utilized more fully this past winter compared to recent winters. The graphic above shows how many companies used each key supply option. Based on AGA survey data from 84 member companies, natural gas utilities used 88 percent of supply assets (or projected design day volumes) this past winter. This compares to a 65 to 75 percent utilization factor, reported in prior year surveys, primarily due to warmer than normal winter conditions.

Today natural gas utilities make system integrity choices during peak winter demand, driven by not only residential and small commercial heating loads but also electric power generation requirements and industrial consumption. This shift in the natural gas market during the past decade begins to create an appreciation for system reliability and market stability for customers, even though there is increased competition for natural gas supply from all demand sectors.

3. **Underground storage played its most critical role ever in supplying gas to meet customer needs—a result of a decade or more of investments in storage capacity expansions and improvements, which helped ensure availability and deliverability of stored gas on the coldest winter days.**

More than 3.0 Tcf of working gas was supplied to the pipeline grid from November 2013 through March 2014—a winter heating season record.
The persistence of cold temperatures even late into the winter for much of the country east of the Rocky Mountains is important in that supply planning and resources such as underground storage did not get a reprieve. The pressure to continue to perform was exceptional and unrelenting.

Storage withdrawals during the 2013-14 WHS were underpinned by a decade of growth in storage infrastructure. New fields (such as salt caverns) and upgrades to existing storage facilities (such as added compression and new injection and storage wells) have steadily increased the amount of working gas capacity available to storage operators.

Given that this past winter heating season (November through March) was 8.0 percent colder than normal nationally and that working gas in storage was drawn to near record low levels at the end of the withdrawal season, it is remarkable that only 11 percent of survey companies resorted to non-traditional methods to strategically manage strained assets and maintain storage integrity. These companies indicated that they made daily gas purchases in lieu of storage withdrawals—another indicator of flowing gas supply strength even during periods of high demand.
4. Flowing natural gas was available for affordable spot purchases by natural gas utilities that required additional supply to meet customer demand surges, even amid system constraints. These additional supplies materialized via increases in domestic shale production close to market centers and hubs, incremental imports of Canadian gas, and even short-term boosts in LNG imports during the past winter heating season.

Amid the strong demand pull during this past winter, natural gas prices remained within a relatively narrow band, particularly in contrast to price fluctuations during the past decade. Even though the peak winter demand day occurred on January 7, natural gas futures prices for February delivery dropped 30 cents per MMBtu between January 6 and 10. This suggests that supply resources were robust and responsive to peaking demand markets.

This relative stability does not imply that price movements were non-existent. As cold temperatures continued through February, cumulative draws on flowing gas and storage assets resulted in price jumps for both the Henry Hub spot and contracts for next-month delivery. For three days, futures prices sat above the $6 per MMBtu mark, then fell quickly to $5 and back toward the $4 range. These short-term price movements were in part a function of persistently high demand, temporary disruptions to flowing gas, and in some cases, constrained storage supplies. They served as signals from traders to suppliers—in particular those with storage assets—to push volumes into the market.

In the Northeast and parts of the Southeast, temporary constraints on natural gas pipeline capacity created scarcity for incremental volumes of natural gas purchased on the cash market. Despite the Henry Hub commodity price remaining at relatively nominal levels, local prices for supplies entering the Boston and New York City areas jumped temporarily above $100 per MMBtu due to basis differential blowouts. It should be noted, however, that these extreme price movements represent the value paid for gas commodity at the margin.
As described earlier, natural gas utilities employ a range of supply planning approaches and pricing mechanisms to secure supplies and ensure relative price stability for consumers. For instance, 89 percent of survey utilities made arrangements for short-term supplies (less than or equal to one month) during the 2013-14 winter heating season. More than half these companies used a daily spot or index price for 50 percent or more of their short-term supplies. Companies also used other pricing mechanisms to secure short-term supplies, such as first-of-month, fixed, or NYMEX index.

In brief, despite persistently harsh weather and demand pulls, short-term supplies were available and generally affordable during the 2013-14 winter. In many cases, this afforded natural gas utilities greater flexibility in bolstering supply portfolios, maintaining system integrity and reliability (imbalance offsets and line pack), managing storage assets, and employing tactical strategies to reduce overall costs to consumers. This supply strength and elasticity is a result of growing domestic natural gas production and market-sensitive imports from Canada and even LNG. This fundamental shift in the market—which only ten years ago was viewed as supply constrained—strengthens the position of natural gas utilities in terms of reliability and improves their prospects for a sustainable business.

5. **Upstream pipeline constraints have an impact on local distribution systems in the form of operational flow orders, critical days or even short-term pricing shifts at key locations.** These contingencies are generally anticipated in distribution system planning; however, in particularly congested markets, regional infrastructure planning can play a key role in addressing such constraints.

An operational flow order (OFO) is a mechanism used to protect pipeline system integrity issued to certain shippers, or system-wide, requiring them to rigorously balance customer gas usage with delivered quantities, usually within a specified tolerance band. These orders are necessary to safe pipeline operation, particularly during system constraints, compression outages, maintenance, production freeze-offs, or *force majeure* events. Similar critical notices are issued for storage injections and withdrawals.

The 2013-14 winter presented a number of challenges to upstream systems, including service curtailments and disruptions at interstate pipelines, storage facilities, and production sites, the effects of which reverberated onto customers further downstream. Sixty-three percent of AGA survey companies encountered upstream pipeline operational flow orders which impacted their own system operations (i.e. city gate deliveries). The median number of OFO notices was eight, while the average duration was slightly above 3.5 days.
As stated, such upstream constraints impacted LDC operations. In fact 57 percent of survey companies issued their own operational or emergency flow orders to non-core customers in order to restore distribution system integrity. However, natural gas utilities facing upstream constraints are not limited to issuing critical notices of their own. For one, their mix of supply assets affords them a degree of flexibility and can serve as a buffer against such contingencies. Furthermore, some natural gas utilities add a reserve margin to design day demand forecast to protect system integrity and reliability against upstream and on-system equipment failures, force majeure events, and non-performance by third parties. Also as discussed next, interruptible service is another option available to natural gas utilities in reliably serving core customers.

6. For many utilities, interruptible service provides a valuable gas supply and operations management tool, allowing service curtailments on peak demand days to ensure reliable and safe gas service to core customers. In a number of service territories, the frequency and duration of interruptions increased this past winter due to exceptional weather conditions.

Whether gas distribution service interruptions are driven by upstream constraints or on-system disruptions, interruptible customers play an important role for many natural gas utilities on critical days, enabling them to maintain system integrity while delivering gas reliably to core customers. During periods of high usage and system constraints, prevalent on the coldest winter days, natural gas utilities may call upon customers that have contracted for interruptible gas service to cease gas usage temporarily, upon which these customers generally switch to a back-up fuel, such as fuel oil. The tradeoff for these customers is a discounted rate for the natural gas delivery service, compared with firm service rates.

A number of companies found it necessary to curtail service to interruptible customers temporarily this past winter, predominantly due to upstream system constraints. A significant number of AGA surveyed members reported a growing number of customers that were interrupted in the 2013-14 winter relative to prior winters, which is not surprising, given the exceptional weather conditions, particularly in January through March. However, the majority of companies reported that the number was unchanged, decreased, or that there were no interruptions at all.
This winter, the median number of interruption notices per local distribution company was five, and three fourths of companies initiated 10 or fewer interruptions. The median duration per interruption was two days, and nearly two thirds of companies reported average durations of two days or less. In all, the median proportion of interrupted gas relative to total utility gas deliveries was two percent. Generally, interruptions were relatively short, impacting a small number of customers as well as minimal deliveries.

**INTERRUPTIONS BY REGION**

(41 REPORTING COMPANIES)

![Interruptions by Region Chart]

Source: AGA 2013-14 Winter Heating Season Survey

7. Relatively stable and affordable natural gas prices, coupled with energy efficiency gains, helped moderate weather impacts on customer bills. Supportive policies of utility practices, aimed at maintaining affordable prices and improving energy savings for customers, may further mitigate bill impacts during future winter events.

Despite natural gas demand reaching record levels during the 2013-14 winter heating season, residential gas prices rose only 3 percent from a baseline price, and this was still lower than what households paid for natural gas during the winters from 2004 to 2012. Overall, residential customer bills increased 10 percent from the prior winter, primarily reflecting higher consumption levels. To put it in perspective, natural gas bill increases averaged $60 per winter season or about $12 per winter month. In fact, natural gas often remains the low cost option for households.

Households with electric, oil, and propane space heating also experienced rising energy costs this winter, compared to the prior. Energy costs for home space heating increased on average $40 (or 5 percent for electricity), $151 (or 7 percent) for fuel oil, and $879 (or 66 percent) for propane. Given that homes heated by electricity, oil or propane already incur higher costs on average, compared to natural gas-heated homes, the energy burden was compounded for bill payers in these residences. In colder regions, where fuel requirements are higher, energy costs climbed even further.
Not only low prices but also efficiency gains played a key role in mitigating bill increases to customers. Average natural gas usage per residential and commercial customer has declined 25 percent from 2003 levels, which has reduced or flattened consumption levels (despite increases in customers). This trend is generally factored into gas supply planning and design day requirements. Natural gas energy efficiency programs form a critical part of this trend. While the number of gas efficiency programs has plateaued since 2010, expenditures into programs has steadily increased since 2007, when data were first tracked.

Long-term improvements in energy efficiency have had a substantive effect on gas consumption and may have moderated distribution system demand this past winter. This in turn may have contributed toward the relative stability of natural gas prices. Together, low gas prices and energy efficiency, played a key role in maintaining affordable consumer bills.

**Paving the Way to a Sustainable Future**

Although these observations of the past winter are straightforward, they underscore two notable facts regarding the natural gas distribution system: 1) that it performed, and 2) that customers were served.

A stable natural gas market is predicated on today’s realities of abundant domestic supplies, diverse sources, flexible options, and affordable prices. The experience of the natural gas industry during the 2013-14 winter verifies this vision of market stability, as outlined in the *Promise of Natural Gas* study. This winter, which in effect presented a real world test of stability, showed that the natural gas market was able to deliver reliably under exceptional conditions. As the title of this study suggests, the promise of stability was kept.

A decade ago, U.S. natural gas supplies were marked by constraints and viewed as unsteady. Where perceptions of scarcity and volatility persist today, the 2013-14 winter experience offers a straightforward rebuttal. The planning, preparation, and performance of the natural gas value chain, and particularly local gas utilities, has reoriented market observers to the viewpoint of relative market stability, affordable pricing, reliability, and opportunities for growth. A new bar has been set by which future natural gas market potential may be judged.
In many ways, the tangible experience of this past winter paves the way for future development of natural gas applications in homes and businesses. This winter’s observations reinforce a vision of a U.S. natural gas market shaped by the following developments:

- Growth in natural gas production, transportation, storage, and distribution infrastructure has laid the foundation for today’s market. Future infrastructure development is key to further market growth and stability.

- Demand signals have facilitated substantial growth in domestic natural gas supplies, and future increases in demand are expected to continue this trend.

- Policies and regulatory precepts evolve with time, and the natural gas industry will undoubtedly face new challenges in the future; however, the iterative process of aligning industry opportunity with regulatory principles has been most successful when it manifests sustainable value for utilities and all their customers.

- The future of the natural gas industry is one of efficiency at its core—in production, transportation and direct-use.

More broadly, the industry’s performance during the past winter appears to validate decisions made in preparation for the winter as well as the strategies employed during the heating season. The system worked—a direct result of the planning process, investments, established procedures, policies and regulations, and retrospective analyses that utilities conduct each year. These well-established practices shape natural gas utility operations year in and year out. As these practices continue to evolve, they will facilitate natural gas growth for years to come. With this potential for U.S. natural gas demand growth, both from greater consumption and new customers, the 2013-14 winter boosts confidence in the industry’s ability to deliver and forms a proof point for new investments in the nation’s natural gas infrastructure.

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Making the Statistical Case
What makes a winter heating season unusual?

Generally, the answer to this question is deviations from the norm. Using this simple criterion, the 2013-14 winter was extraordinary, testing a natural gas value chain that had been in many ways untested for a decade.

During this past winter, the second coldest on record in twenty-nine years, the U.S. consumed greater volumes of natural gas than it ever has before. January in particular was marked as having the highest daily, weekly, and monthly requirements for natural gas ever. Residential and commercial heating demand was the principal driver, but the gas system responded to requirements much broader than those for the residential and commercial sectors.

Electricity demand also rose sharply as a result of the cold. Natural gas requirements to power generation grew accordingly, though not just as a result of the cold but also because of a longer-term structural shift in the natural gas-fired electricity market—a trend which emerged during the past few years and which is expected to continue.

Industrial demand remained strong throughout the winter as well—a function of both structural requirements and weather-sensitive heating demand. In all, the natural gas system responded to economy-wide draws to meet the nation’s energy needs this past winter.

The major driver of gas demand this past winter—or in other words, the event that fully tested the natural gas system—was the extraordinary cold brought on by the Polar Vortex. The winter heating season from November 2013 to March 2014 began with early periods of cold confined to specific geographic areas. As winter deepened, sustained periods of below normal temperatures persisted over wide swaths of the country, creating conditions requiring the deployment of all industry assets designed to meet peak day and peak month natural gas demand. This deployment presumes that such assets are functioning, flexible, and ultimately reliable. The U.S. natural gas system in fact did meet these criteria and the challenge presented during the 2013-14 winter.

Local gas utilities plan for contingencies each winter with strategies developed by understanding past events and system performance, all the while preparing for variable weather-sensitive consumption in the short-term as well as for the entire winter season. This analysis examines the conditions of this past winter and how the natural gas system responded, using metrics that governed the 2013-14 winter, such as heating degree days across the country, overall natural gas
consumption, home heating loads, demand by power producers, and critical supply components, including underground storage. This paper also reviews changes in industry metrics during the ten-year period leading up to this past winter. As noted, compared to recent history the 2013-14 winter posed an exceptional challenge.

- During 2013 and into 2014 the U.S. natural gas market balanced supply and consumption somewhere north of 70 Bcf per day on average. However, requirements for natural gas by consumers—especially during the winter heating season—were not average.

- During the period of November 1, 2013 through March 31, 2014, total U.S. consumption of natural gas (including net exports to Mexico) ranged from less than 70 Bcf per day on a warm March day to 139 Bcf on the highest consumption winter day in January—a huge swing in observed daily winter heating season demand.\(^1\)

- The residential and commercial market segments were primarily responsible for the dramatic swings in customer requirements—R&C consumption having ranged from 78 Bcf on the highest consumption day in January to a season low of 27 Bcf per day in late March.

- The power generation sector also impacted natural gas requirements: natural gas flow to power generation on the coldest days of the year has become a key driver in the natural gas market and in price rationalization, both regionally and nationally.

- To meet such requirements, production and market area storage played a key role in the efficient management of local gas utility supply and transportation portfolios. It should be noted that storage practices are no longer solely dictated by local utility requirements to serve winter peaking loads but also support natural gas parking, loaning, balancing, commercial arbitrage opportunities at market hubs and city gates, and even fueling power generation to serve summer cooling loads.

Before identifying specific statistics related to the 2013-14 winter heating season, it is worthwhile to understand at a high level the evolution of the US natural gas system during 2003 - 2013 period. In fact, by the time the polar vortex impacted temperature and weather patterns in the first quarter of 2014, ten years of customer and infrastructure growth had already significantly transformed the natural gas industry.

**Metrics Measuring the Evolution of the Natural Gas Market: 2003 - 2013**

**Customer Growth**

- For the period of 2003 - 2013, total natural gas customers in the United States grew by more than five million. Most of this growth occurred in the residential sector, although a small increase took place in the commercial sector as well.

- While the number of customers in the industrial sector shrank from 205,000 in 2003 to about 192,000 in 2013, natural gas consumption actually increased by 4.3 percent.

\(^1\) Daily demand data reported by Bentek Energy, LLC.
**Distribution Pipeline Infrastructure Expansion: Capacity and Miles**

- The natural gas distribution system also expanded during the 2003 - 2013 period. Distribution mains increased by about 170,000 miles from nearly 1.1 million to more than 1.27 million miles during this ten-year period. Likewise, capacity increased.
• This infrastructure growth is reflected in recent increases in construction costs. For all parts of the natural gas value chain, construction expenditures were consistently higher during the three-year period of 2011-2013 compared with 2003.

![U.S. Natural Gas Industry Construction Expenditures](chart)

**U.S. Natural Gas Industry Construction Expenditures**

- General Construction Expense
- Distribution Construction Expense
- Underground Storage Construction Expense
- Transmission Construction Expense
- Production Construction Expense

Source: American Gas Association, *Gas Facts*

**Natural Gas Production**

• Dry natural gas production grew from less than 20 Tcf annually to nearly 25 Tcf during the 2003 - 2013 period. Domestic production is expected to continue to grow as additional unconventional and conventional resources are developed and as demand requirements continue to pull on a growing gas market.

![U.S. Dry Natural Gas Production (Tcf)](chart)

**U.S. Dry Natural Gas Production (Tcf)**

Source: Energy Information Administration 2002-2013
Domestic Natural Gas Reserves

- As with production, natural gas reserves have grown steadily during the past decade. Underpinning domestic production capability, natural gas reserves have grown from less than 200 Tcf in 2003 to over 330 Tcf in 2013.
**Underground Storage Capacity**

- Working gas in storage provides about 15 to 20 percent of total winter heating season gas supply (November 1 through March 31).

- The share of storage working gas in the supply asset pie has grown in the past decade: according to the Energy Information Administration, design working gas capacity in America’s underground storage system grew by about 1,000 Bcf in the past 10 years.

- During the 2013-14 winter heating season, storage played a critical role as a supply source providing additional deliverability during peak load periods.

**Natural Gas Emissions Profile**

The entire natural gas value chain accounts for a very small portion of total greenhouse gas (GHG) emissions in the United States—only about two percent.

- Furthermore, natural gas emissions from the distribution system, owned and maintained by local gas utilities, is considerably smaller—accounting for less than 0.3 percent of the nation’s greenhouse gas footprint.

- Additionally, the emissions trend line for the natural gas distribution system shows a downward slope despite significant growth in installed distribution main. This can be attributed to the accelerating rate in which natural gas utilities have been replacing older pipe in their distribution systems.
Sources: U.S. Environmental Protection Agency GHG Inventory and U.S. Department of Transportation

**Efficiency Gains and Average Use per Residential and Commercial Customer**

The natural gas residential customer has shown substantial gains in energy efficiency. In 2003 the average customer used 84.1 Mcf on a weather normalized basis. A decade later the average annual use for a gas home was 63.2 Mcf, roughly a 25 percent decline. Technology improvement was the prevalent factor behind this trend: customers replaced their older gas appliances—particularly some space heating units—with more efficient models. Additionally, new homes were built to higher standards and featured better insulation, windows, and doors.

Also contributing to this sector’s enhanced efficiency were utility and government programs that support energy efficiency and conservation. Through these programs, utilities offered consumers financial incentives to upgrade equipment and retrofit home shells, while the government offered tax deductions to citizens that made home energy efficiency investments. Such programs accelerated the energy efficiency gains in homes.

The heating portion of a commercial customer’s natural gas usage is typically lower than that for a residential customer, which could imply that conservation has a lesser impact for business customers. However, these businesses also demonstrated a usage reduction that averaged 25 percent—from 322 Mcf per customer in 2003 to 243 Mcf in 2013. Impacts of such efficiency gains are discussed later in this paper.
Efficiency-Directed Local Gas Utility Investments

As mentioned earlier, utility programs played a role in efficiency gains and reduced costs to customers. A number of these programs have existed for decades; however, the pace of utility investments in efficiency programs has accelerated in recent years—having more than tripled, from 2007 $320 million in 2007 to $1.1 billion in 2012. Energy savings more than doubled as a result of these investments—from 48.4 trillion Btu of saved energy in 2008 to 135.9 trillion Btu in 2012. Also for 2013, Utilities budgeted nearly $1.5 billion (projecting a 30 percent increase in spending). This helped residential program participants save 16 percent of household gas usage on average or about 112 Therm per year, averaging $117 in cost saving on their annual energy bill.

The measures described above focus on the structural changes that have impacted the natural gas system—i.e., changes that have redefined the role natural gas plays in our energy economy. They do not encompass all the changes that affected our natural gas industry in the past decade—such as changes in regulatory structures, which are critical to the success of the natural gas utility business; in financial markets, which today support gas futures contracts aimed at hedging gas prices and maintaining market stability; and in end-use technologies, which provide efficient and economic applications for industry, businesses and homes.
**Natural Gas Market Conditions during the 2013-2014 Winter Heating Season**

**2013-14 WHS Heating Degree Days**

The 2013-14 winter heating season (WHS) was exceptional not only for the Polar Vortex phenomenon but also for the degree of temperature deviations from normal and for the wide geographic coverage. Also low temperature conditions persisted for long stretches of the coldest months.

- The United States compiled 4,217 heating degree days (HDD) over the five month period of November 2013-March 2014. This HDD total is 8 percent higher than the past 29 winter heating seasons (from 1985-86 to the present). The 2013-14 WHS was second coldest for the nation as a whole during this 29 year period.

- The East North Central portion of the country (essentially the upper Midwest) experienced 15.5 percent more HDDs than normal and as such recorded the coldest winter in 29 years.

- The East South Central region recorded 12.7 more HDDs and was the second coldest by that measure in the 29 year period.

- The Middle Atlantic region experienced its third coldest winter in 29 years and was 19.4 percent colder than normal based on HDD totals.

- Likewise, New England was the third coldest it has been in 29 years with a HDD total 8.0 percent above the norm.

- The South Atlantic region completed the east coast trifecta with temperatures resulting in 8.2 percent more heating degree days than normal—the second coldest winter in 29 years.

- Further west, it was also cold with the West North Central and West South Central regions 12.4 percent and 15.9 percent colder than normal, respectively, as measured by HDDs. For the WNC region it was the coldest in 29 years and for the WSC the second coldest.

- Only until you look at the Mountain West and Pacific Coast do you see more normal or even warmer conditions for the just past winter. The Mountain and Pacific regions were the clear exception for the country as the polar vortex that settled over the mid-continent and East Coast actually pulled the jet stream further north in the Pacific and Mountain regions bringing dry and warmer conditions. The Mountain region was 7.5 percent warmer and it was only its twenty-third coldest winter in 29 years. The Pacific region registered 19.3 percent fewer heating degree days and was thus warmer than normal this winter. It was actually the second warmest winter heating season for the Pacific Coast in 29 years, according to data from the National Oceanographic and Atmospheric Administration (NOAA).
2013-14 WHS Natural Gas Consumption

As shown in the figures that follow, natural gas consumption during the 2013-14 WHS significantly exceeded the demand levels of the recent past. Understanding the scale of this variance from past winters underscores the reliability and resilience of the natural gas value chain in meeting weather-induced challenges. It also puts into context the key supply components, such as underground storage, domestic flowing gas, and marginal supplies, as well as the pricing environment, which prevailed for much of this past winter.

- Total natural gas consumption in January 2014 reached 3.2 trillion cubic feet (Tcf) – the strongest gas demand month ever for any time of year, according to Bentek Energy LLC. In recent years a strong January winter heating season consumption month had been about 2.9 Tcf.

- In addition, 8.4 Tcf of natural gas was consumed by end-users during the entire period of January through March 2014. It is the largest volume of consumption by end-users for this three-month period on record. In fact, February recorded its strongest demand for any February on record, as did March.

**Winter Month Average Daily Natural Gas Demand All Sectors**

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Source: Bentek Energy
This sustained demand for natural gas matters, because it placed incessant pressure on the domestic supply system, from flowing gas and underground storage to marginal providers, such as supplemental LNG and propane-air pipeline imports from Canada, and even small increases in LNG imports. There was no respite from this pressure for many regions of the country.
A key development of the past decade has been the emergence of power generation as a large and critical market for natural gas. Also significant is the fact that gas to power generation not only peaks during the summer to serve cooling loads across the country but also during the winter to serve peak heating loads (see figure below).

This is particularly important in regions such as New England where, during winter months, natural gas home heating loads are strong, while demand for gas to power generation is concurrently high, given the current generation fuel mix in this region. In New England this condition is exacerbated by pipeline capacity constraints during critical winter periods.

Power generation consumption of natural gas in January 2014 set winter heating season records for average daily volumes (about 21 Bcf per day) as well as for a single day, recording the highest daily volume ever during a winter month at 31 Bcf for that day, according to Bentek Energy. But demand for gas to power generation had been nearly as strong in December and served as a harbinger for the following winter months.

**DAILY U.S. NATURAL GAS FLOW INTO POWER GENERATION — 2014**

Source: Bentek Energy

Demand levels for gas to industrial consumers rose during the 2013-14 WHS, given the additional requirements needed to maintain heat in facilities; however, it was the temperature-sensitive heating requirements for residential and commercial space heating that dominated the winter market.
Residential and commercial heating requirements reached 78 Bcf on January 7, 2014—a new record. During the prior five years a strong demand day had been closer to 56 Bcf per day on average. The events of January 7 thus led to a 40 percent increase in peak day demand. Total end-user demand reached nearly 140 Bcf for on January 7—also a historic record.

**Domestic Natural Gas Supply Sources 2013-14 WHS**

The protracted 2013-14 winter heating season event produced constant pressure on domestic natural gas supply sources; however, they generally performed up to par, due to planning and preparation, system-wide. Demand requirements were met by flowing gas from lower-48 state production, underground storage, increased availability of Canadian gas and LNG imports on critical days, and supplemental supplies from propane-air and LNG peaking facilities (often within the local gas utility’s footprint).

- According to the Energy Information Administration, domestic dry gas production in January 2014 averaged about 67 Bcf per day. Five years earlier—in January 2009—it had averaged 57 Bcf per day. As the figure below shows, domestic natural gas production has been rising steadily since 2006.

- More production signifies not only increased flowing gas during key winter heating season periods but also more availability to meet summer cooling loads and storage injections.

![Daily U.S. Dry Natural Gas Production](source: Bentek Energy)

- Natural gas market watchers are familiar with the extraordinary deployment of storage volumes to meet demand loads during the 2013-14 WHS, which resulted in the lowest inventory of working gas remaining in storage at the end of March since 2003.
• Underground storage tends to supply 15 to 20 percent of winter heating season supplies on average, dependent on various factors.

• During the 2013-14 WHS, underground storage provided in excess of 20 percent of total supply and set records for monthly withdrawals. The previous record for net volumes withdrawn from storage during a winter heating season month had been 847 Bcf in January 2003. That record was shattered in January 2014 with more than 950 Bcf withdrawn from working gas inventories across the country.

• The following figure quantifies daily changes in working gas as a positive supply element, with volumes withdrawn from storage as high as 68 Bcf for a single day—on January 7, 2014. More typical for a peak day during the preceding five years, storage inventories may have contributed 45 Bcf nationally for the peak day.
In addition to domestically produced gas and withdrawals from storage, small but critical amounts of imported LNG as well as supplemental supplies from above ground LNG and propane-air peaking facilities may be used to meet the needle-peak of coldest day demand. Of course, natural gas imports from Canada serve a critical role on a daily basis as well as on the margin on the coldest days.
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Natural Gas Storage
Meets the Polar Vortex
Promise Delivered
PLANNING, PREPARATION, AND PERFORMANCE DURING THE 2013-2014 WINTER HEATING SEASON

NATURAL GAS STORAGE MEETS THE POLAR VORTEX

By early April 2003, working gas inventories in U.S. underground storage facilities had fallen to below 650 billion cubic feet (Bcf) after beginning the winter heating season at 3,172 Bcf in late October 2002. At the end of that winter heating season, analysts and others were asking the obvious question of whether storage inventories could be sufficiently refilled in time to meet the requirements of the next winter—seven months away. History has taught us that the answer was yes; and, as history repeats itself, the familiar question is being asked again today.

With record withdrawals from underground storage of three trillion cubic feet (Tcf) during the period November 1, 2013 through March 31, 2014, lessons were learned from the performance of this critical supply asset this past winter. This paper explores the storage-related metrics associated with the 2013-14 winter heating season and examines the management of this supply tool, which is essential to meeting customer needs in winter. The choices made by storage providers and operators during critical winter days underlie the reliability and resiliency of the domestic natural gas system.

One of the most critical factors that makes natural gas reliable, efficient, affordable and available for customers in the U.S., even during periods of peak demand, is that it can be stored. Every year natural gas is injected into storage during the refill season (April - October), then transported for peak period consumption, primarily during the winter. In fact the U.S. has the largest natural gas storage system in the world along with the largest and most fully integrated pipeline system. Within this context, storage represents a physical hedge against weather-induced market uncertainty and can also serve as a price hedging tool. However, much has changed regarding the overall natural gas market during the decade following 2003, including domestic production and resource expectations, shifts in sector demand, pricing, and other measures along the natural gas value chain.

STORAGE METRICS FOR THE 2013-14 WINTER HEATING SEASON

At the end of each winter heating season, AGA surveys members regarding natural gas supply portfolio practices and system performance. Underground storage is one of the supply assets examined. The following facts regarding underground storage were gathered from the most recent survey, which covered the 2013-14 winter heating season (November through March).

- Ninety-four percent of surveyed companies (79 of 84) used on-system or pipeline storage for a portion of their 2013-14 winter heating season supply.

- Generally companies used storage to supply less than 50 percent of winter gas supply. In fact only seven companies responding to the AGA 2013-14 winter heating season survey reported that more than 50 percent of winter supplies originated from underground storage.
• Weather-induced demand was the primary reason for using storage assets (for 77 of the 79 companies); however, no-notice requirements, must turn provisions, upstream pipeline operational flow orders, and even arbitrage opportunities played a role.

• When asked whether the events of the 2013-14 winter heating season will cause them to modify storage-related supply planning for 2014-15, 65 companies said no, while 14 answered yes. Considered changes in storage management include:
  - Potentially expanding underground storage capacity;
  - Injecting more gas into existing facilities;
  - Making changes to inventory targets; and
  - Ratcheting up winter injections to ensure strong seasonal deliverability.

• During the 2013 storage injection season (April - October), refill decisions were most influenced by supply reliability requirements; however, they were also impacted by operational issues, price considerations, and regulatory plans or mandates. Thirty companies cited all four as influential factors during the 2013 injection season.

• The first-of-month index was the most cited pricing mechanism for large-volume gas purchases destined for underground storage. Smaller volumes of gas were also purchased using daily spot pricing, fixed prices and prevailing NYMEX prices.

• Interestingly 26 percent of the companies to which the question applied (19 of 73) indicated that they flowed gas from storage to power generators during the 2013 summer refill season to meet space cooling load.

• Finally and perhaps surprisingly, when asked whether this extraordinary winter caused the companies to employ non-traditional methods to strategically manage their storage assets, 75 of 84 companies said no. For the majority of those that answered yes, the primary tool for managing strained storage assets was the purchase of additional flowing gas on the daily market, in order to meet higher demand, replace storage withdrawals (even on winter days there is gas movement into storage fields as well as withdrawn from storage fields) ratchet up winter injections, and even to take advantage of lower prices on non-peak days.

While this represents a simple yet effective solution for countering constrained supplies, the fact that flowing gas was available for purchase on critical days is remarkable and a testament to the supply strength and elasticity that has evolved with the growth in domestic natural gas shale production—quite a contrast to a decade ago.
Lesson # 1: The storage pie is larger than it was ten years ago.

- By the end of the 2003-04 winter heating season, U.S. working gas inventories in underground storage had not surpassed the 3,300 Bcf historic mark, according to the Energy Information Administration (EIA).

- At the start of 2004-05 winter heating season (November 2004), there were more than 420 natural gas storage sites across the country, holding 3,327 Bcf of working gas (record volumes at the time). This launched a period of expansion and upgrades to underground storage facilities.

- Today storage sites number close to 400; however, “operationally full” working gas routinely measures at 3,800 to 3,925 Bcf. The Demonstrated Maximum Working Gas Volume for U.S facilities is now more than 4.3 Tcf, according to the Energy Information Administration.

- Local gas utilities own about one-third of the existing U.S. storage capacity and contract for approximately another third from interstate and intrastate pipelines. The balance is owned by marketers and independent operators. Pipelines also own and operate some storage capacity, mainly for system integrity management.

- Local distribution companies (LDC) primarily use underground storage as a supply asset designed to meet peak demand loads and sustained demand pulls, principally during the winter heating season. As such, LDCs generally complete storage refills by mid-November, leaving more discretionary storage decisions to other players.

Lesson # 2: Storage is a dynamic supply asset capable of meeting seasonal load variability.

Traditional perceptions and realities of storage facility dynamics often focus on the flexibility of salt caverns (in terms of deliverability and cycling capability) relative to depleted reservoirs or aquifers. This view of underground storage infrastructure is fundamental to understanding asset utilization and function in today’s natural gas market. That said, facilities operate not only on an individual basis but also on a regional and national scale, collectively providing a vital and diverse supply source during critical demand periods.

- During the five winters immediately prior to the 2013-14 winter heating season, natural gas customers (all sectors) required as little as 1,483 Bcf of natural gas from underground storage (November 2011 - March 2012) to as much as 2,261 Bcf (November 2010 - March 2011) during peak winter demand periods.

- For the aforementioned five-year period, storage accounted for about 17 percent of winter heating season consumption on average.
During the 2013-14 winter heating season, natural gas demand was higher as was utilization of underground storage assets. For the first time in history, more than 3 Tcf of gas was required from working gas inventories (net withdrawals being 3,012 Bcf to be precise), and storage accounted for 22 percent of the natural gas consumed. Figure 1 illustrates this recent growth in seasonal utilization of this supply asset.

Lesson # 3: Domestic natural gas production has grown, and this influences expectations regarding summer underground storage injections.

- Dry natural gas production in the lower-48 states averaged 52 Bcf per day in 2003.
- Domestic gas production will average over 67 Bcf per day in 2014—a 29 percent increase from 2003.
- This growth in domestic natural gas production serves not only as a flowing supply resource for growing end-user demand but also as additional supply for an increasing summer cooling power generation load and for storage injections during the summer refill months.
Lesson # 4: Natural gas-fired power generation surges during the same periods in which natural gas heating loads peak, so on a cold winter day underground storage in effect serves both natural gas and electric power loads.

- During January 2014 natural gas to power generation ranged from about 14 Bcf on a relatively warm winter day to 31 Bcf on January 7 (the coldest day of the past winter in many regions), according to Bentek Energy.

- Natural gas-fueled power production surges in concert with natural gas peak heating demand. While seasonal variability in natural gas demand continues to be dominated by residential and small commercial customer heating loads, winter demand for power generation is gaining prominence and is expected to continue to grow.

**Figure 2**

**NATURAL GAS INTO POWER GENERATION 2014**

Source: Energy Information Administration
Following the 2002-03 winter heating season, when domestic underground storage inventories dipped below 650 Bcf, many storage operators invested in facility improvements to enhance daily deliverability. For example, new wells were drilled in existing fields and compression and other upgrades were completed.

With the upgrades came capacity additions—via new facilities and expansions to existing ones—as well as reclassifications of base gas to working gas and vice versa, depending on the field. The impact of these improvements was a net increase in the design capacity of more than 400 Bcf over the ensuing 10 years.

The domestic underground storage system is now larger and more adaptable than a decade ago, recognizing that certain facility types, such as shallow aquifer facilities, are not as flexible in terms of cycling (or inventory turnover) capability as salt caverns or high permeability depleted reservoirs.

Traditional patterns of storage management appear to be giving way to newer trends.

Figure 3 represents daily net injection patterns for U.S. underground storage during calendar year 2007—the traditional view. Positive values are net winter heating season withdrawals and thus represent a supply source, while spring and summer injections are depicted as negative supply volumes, captured as working gas inventories for those days. The traditional storage management pattern is evident in this chart, where stronger seasonal injections are made in the May-June period, followed by brief storage withdrawals in the middle of summer due to draws from power generation (a relatively recent development at the time), and wrapping up the refill season with a declining injection slope in the September-October period, as facilities fill up and reservoir pressure builds.
A look at calendar year 2013 (Figure 4) shows at a minimum subtle changes to the traditional pattern of storage management, and at best, a shift to a new norm in injection practices. During 2013, the early to mid-injection season (May-August) was as expected—strong in May and June, followed by declining injections as natural gas to power generation competed with natural gas injection volumes.

However, the later injection season pattern was decidedly different than in 2007. In fact daily storage injections in September and October 2013 were as strong as those made during the early spring and summer. While many reasons drive injection decisions—particularly concerning discretionary volumes outside utility winter heating season planning—it is likely that cumulative improvements to underground storage facilities as well as capacity additions and expansions (mainly salt caverns and depleted reservoirs) have ultimately changed the industry mindset regarding underground storage utilization and management practices.
Lesson # 6: The 2013-14 winter heating season was the first real winter test of this new underground storage system and of the entire natural gas value chain.

- Sustained periods of frigid temperatures across a wide swath of the lower-48 states, framed by successive winter events, particularly in January and February 2014, challenged the durability and reliability of the natural gas delivery infrastructure. The degree to which natural gas system performance was tested is unprecedented.

- However, the natural gas system had evolved during the preceding decade, enabling it to withstand this test. Domestic production (bolstered by “shale gale”) increased significantly, storage infrastructure grew in capacity and flexibility, pipelines expanded in build-outs and capacity (although not equally in all regions), and regulatory structures evolved.
The following observations from AGA members regarding their individual underground storage utilization during the first quarter of 2014 reflect this winter’s experiences and the new realities of the underground storage system.

Highest seasonal volume withdrawal in fifteen years.

The extended extreme cold winter of 2013-14 resulted in a heavy demand for stored natural gas. A record single-day withdrawal was set on January 7, 2014, and the withdrawal season ended with a record low working gas inventory of 3 percent. This was a good test of our storage system, which performed as expected despite heavy demand.

Here is a short summary of some of the winter conditions. January 4th - 6th produced 17 inches of snow with drifts pushing 4 feet. The wind chill ranged from -20 to -40 degrees. During that time, Gas Control needed a maximum rate, resulting in three of us (field men) getting our trucks stuck within sight of each other. Some wells within range, we walked to, and then we shoveled our trucks out and were able to plow our way in. This scenario played out much of the harsh winter. The horizontal wells really made it possible to deliver gas in a short time.

Because of supply demands and shortages, storage supply was more critical for a longer time than in the recent past. Our operators worked almost double the normal overtime in order to address and prevent any developing issues in a timely manner and to ensure that storage field volumes were available.

Each of “lessons learned” identified in this narrative point to an understanding of the underground storage of natural gas and its impact on current markets, as well as service reliability to customers. As a natural gas supply asset within a portfolio of assets available to local gas utility planners, underground storage has evolved, has grown and has increased its value in sustaining system integrity, service to customers and even arbitrage opportunities in support of price discovery. It is a physical hedge for supply planning and, importantly, is a critical part of what makes the domestic natural gas system the most flexible and enduring in the world.

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Role of Interruptible Customers in Balancing System

Supply and Demand
Local gas utilities serve many customer classes under differing rate structures. In some cases, customers (often larger volume customers) choose an interruptible tariff, either for sales or transportation service. This choice allows the customer to pay a lower service rate, with the possibility that their natural gas service may be interrupted by the utility during critical demand days in order to ensure service to firm customers. Ideally, the interruptible customer has dual-fuel capability and is able to switch to another energy source during interruptions. In fact, a customer may be required to have this capability in order to qualify for interruptible rates. For example, a large industrial or commercial customer might have an oil tank and burner on site ready to be turned on, if gas service is interrupted.

For many utilities, interruptible service provides a valuable gas supply and operations management tool, allowing service curtailments on peak demand days to ensure reliable and safe gas service to core customers. During the winter on the coldest days, natural gas utilities may call upon customers designated for interruptible service to cease natural gas use temporarily, at which point these customers switch to a back-up fuel (such as heating oil) or simply choose to halt operations until the critical period passes, thereby reducing natural gas requirements on the distribution system. Natural gas utilities may choose to initiate interruptions with interruptible customers for a variety of reasons, though most often it is to maintain system integrity.

Natural gas utilities often provide tiered classes of service, based on a customer’s natural gas use and requirements. Some utilities do not have a set interruptible service tariff; however, they negotiate terms individually with their largest users that allow them to interrupt service if necessary. As with other elements of natural gas service, utilities operating in 50 different states develop with their regulators and customers varying mechanisms, which achieve the same purpose.

The fact that for the past decade or so winters were generally warmer than normal and the supply base was steadily growing means that many companies did not find it necessary to rely on interruptible customers to help balance their systems in response to critical demand levels. Put simply, interruptible customers have not been interrupted often in the past decade or so. This changed during the 2013-14 winter heating season. The following observations briefly describe the role of interruptible customers on natural gas utility systems and integrates this understanding into the experience of the 2013-14 winter.
ROLE OF INTERRUPTIBLE CUSTOMERS IN SYSTEM DESIGN

Natural gas distribution systems are designed to meet not only the average requirements of day-to-day service but also peak demand on the coldest day of the year. Utilities have a regulatory mandate or obligation serve firm, or core, customers (generally residential and small commercial), and supply portfolios and system deliverability are built to ensure reliable service to firm customers and others on a design day (or a forecasted peak day load based on historical weather conditions). The methodologies for design day determination vary among utilities but are based typically upon the principle of maintaining service on the coldest days of winter.

Numbering more than 66 million, residential consumers are by far the largest natural gas customer segment in the U.S., and they are mostly dependent on the local utility to manage all aspects of their gas service; however, they consume not more than 64 million Btu of natural gas on average annually. In contrast, the typical interruptible utility service customer is an industrial plant that consumes large volumes of gas each year. According to AGA’s Gas Facts, the average utility industrial customer (numbering about 180,000 in the U.S.) consumes 21,343 million Btu or 339 times more gas than the typical residential customer. Acknowledging that a temporary service interruption of a large volume customer can go a long way to balancing system needs during critical periods, a significant number of utilities have put in place interruptible service arrangements with their large volume customers.

As mentioned earlier, during periods of high usage and system constraints, prevalent on the coldest winter days, natural gas utilities may call upon customers that have contracted for interruptible gas service to cease gas usage temporarily, upon which these customers generally switch to a back-up fuel, such as fuel oil. The tradeoff for these customers is a discounted rate for the natural gas delivery service, compared with firm service rates. In brief, interruptible customers play an important role for many utilities on critical days, helping them maintain system integrity while delivering gas reliably to core customers.

SERVICE INTERRUPTIONS: OCCURRENCE AND UNDERLYING FACTORS

When overall system demand exceeds available capacity, natural gas utilities may opt to curtail service to interruptible customers on a temporary basis in order to maintain system integrity and service reliability to firm customers. Normally this event occurs on the coldest days of the year and does not last long, after which service is restored to these customers.

Gas distribution service interruptions result from a number of factors, including extreme weather conditions, upstream or on-system constraints or outages, and force majeure events. Companies in the AGA 2013-14 LDC Winter Heating Season Performance Survey cited all these reasons for curtailing service to interruptible customers; however, upstream system constraints played an important role, impacting local distribution systems in the form of operational flow orders and critical days. These orders are necessary to safe pipeline operation, particularly during system constraints, compression outages, maintenance, production freeze-offs, or force majeure events. Similar critical notices are issued for storage injections and withdrawals. Sixty-three percent of AGA survey companies (52 of 83) encountered upstream pipeline operational flow orders which impacted their own system operations (i.e. city gate deliveries). The median number of upstream OFO notices was eight, while the average duration was slightly above 3.5 days.
In addition to operational flow orders, 24 companies (29 percent) noted that pipeline critical transport days were issued during the winter heating season that impacted their operations, and 14 companies identified storage critical days. Median critical storage days issued for the companies was 5.5, while the median point of average durations was 8.4 days.

A number of companies found it necessary to curtail service to interruptible customers this past winter, predominantly due to upstream system constraints: 51 percent (43 of 84 reporting companies) halted service to interruptible customers temporarily, either on a peak day (40 companies) or on another day (27 companies). Significantly, 33 companies did not interrupt any customers, even during extreme winter conditions.

Based on AGA query of members, a significant portion of companies with interruptible arrangements reported a growing number of customers that were interrupted in the 2013-14 winter relative to prior winters, which is not surprising, given the exceptional weather conditions, particularly in January through March: 38 percent reported that the number of customers that were interrupted increased this past winter, compared with the prior winter (32 percent said they increased compared to the five year average from the 2008-09 to 2012-13 winters). However, the majority of companies reported that the number was unchanged (42 percent), decreased (9 percent), or that there were no interruptions at all (11 percent).

The median number of interruptions per local distribution company was five this past winter, and three fourths of companies initiated 10 or fewer interruptions. The median duration per interruption was two days, and nearly two thirds of companies reported average durations of two days or less. Overall, the median volume of gas not delivered due to interruption represented two percent of a utility’s total gas deliveries. While the median percentage of volumes appears small, it is not insignificant for the utility, where reliable service to core customers on critical days lies on the margin.
The proportion of gas that is interrupted can vary, depending on the number of interruptions, their duration, and the end user's gas requirements for that period. The median proportion of interrupted gas relative to total utility gas deliveries was two percent for the 36 reporting companies, ranging from less than 0.1 percent to 18 percent. Also 78 percent of the companies reported less than 8 percent of gas volumes interrupted.
Companies generally have a specific order in which customers are interrupted. In fact, based on an AGA Query, 81 percent (47 of 58) of companies with interruptible service arrangements initiate interruptions in a specific order, often based on rate class, tariffs, and zones. This winter, 23 percent (14 of 48) of reporting companies interrupted customers farther down the queue, and for eight of these companies, this was unique to the 2013-14 winter heating season, compared to the past five years.

The manner in which utilities manage interruptible customers varies. While the majority of companies (46 of 58 reporting) do not view interruption events as an opportunity to encourage interruptible customers to switch to firm service (perhaps because these customers provide operational and reliability benefits to the distribution system), 25 percent (13 of 52) indicated that their customers on an interruptible tariff elected to switch to a firm rate in response to service interruptions this past winter. Generally, utilities do not allow mid-season switches to firm service and defer such changes to the following year. Others limit switching opportunities (for example, once every few years). However, in some cases, in keeping with tariff provisions, a utility may decide to switch a customer to firm service when they fail to comply with multiple curtailment orders.

**Distribution System Operational Flow Orders**

An operational flow order (OFO) is a mechanism used to protect distribution system integrity, issued either to specific customers or system-wide, requiring them to rigorously balance customer gas usage with delivered quantities, usually within a specified tolerance band. As with upstream pipelines, these orders are necessary to safe and reliable operations (sustaining critical system pressure), particularly during capacity constraints, compression outages, maintenance, or force majeure events.

As stated earlier, upstream constraints impacted LDC operations. In fact 57 percent of survey companies (48 of 84) issued distribution system operational flow orders (OFOs) to non-core customers in order to protect distribution system integrity. For 58 percent of the 48 companies, the OFOs were issued system-wide, while 10 percent issued customer-specific OFOs, and 31 percent applied both. Customer-specific flow orders were based on usage, geographic area, or rate class. The factors that drove OFO issuances on utility distribution systems varies, ranging from upstream constraints to on-system issues; however upstream constraints were the predominant factor.
If customers take unauthorized volumes after the OFO is posted, a utility may enforce the flow order by either billing the customer for the unauthorized volumes and/or assess a non-compliance penalty or charge per unit of unauthorized gas usage. Eighty-eight percent of reporting companies (42 of 48) enforced OFO non-compliance this past winter.

Approaches to assessing OFO penalties to large volume customers vary: 63 percent of reporting companies (53 of 84) charge a penalty, and the median penalty is $20 per Dekatherm. Fifty percent of companies (28 of 56) assess the penalty at a prescribed tolerance threshold—the median tolerance band being 5 percent—and 14 percent (8 of 56 companies) have a pre-determined de minimus non-compliance level where no penalty applies.

### CONCLUSION

Natural gas distribution system schedulers use specific tools to maintain system balance and integrity. These include operational flow orders (OFOs), emergency flow orders (EFOs) and curtailments of interruptible service customers. Due to exceptional demand created by extreme winter conditions, upstream constraints, and force majeure events, natural gas utilities made use of these tools this past winter to a larger extent than recent winters. However, utilities are not limited to these actions and employ diligent planning and preparedness, which involve a mix of supply and operations management approaches. This affords them a degree of flexibility and serves as a buffer against such contingencies. Generally, the use of flow orders and service curtailments are a last resort.
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Energy Efficiency and the Customer Experience
Promise Delivered
PLANNING, PREPARATION, AND PERFORMANCE DURING THE 2013-2014 WINTER HEATING SEASON

ENERGY EFFICIENCY AND THE CUSTOMER EXPERIENCE

It is impossible to understand the evolution of natural gas usage in buildings without recognizing the efficiency gains achieved during the past 40 years. Since the 1970s, customers have used less natural gas on average to heat their homes and businesses. As more customers have been added to the natural gas distribution system, lower consumption on average has offset these additions, resulting in a largely flat growth profile.

As such energy efficiency may serve as a demand side management tool, and many natural gas utilities recognize this. From near-term winter demand forecasting to long-term integrated resource planning, natural gas efficiency is often a component of system design planning, meeting customer requirements, and helping reduce costs to consumers.

Improvements in energy efficiency had a substantive and positive effect on the natural gas distribution system and on customers this past winter. Clearly, had efficiency not been a factor, utility systems would have been pushed harder, and customers would have paid more. Instead, energy efficiency in combination with relatively low natural gas prices, buffered consumers from what would have been higher bills this past winter.

This paper begins by exploring the historical trends in average natural gas use per customer. Then it explores how efficiency has shaped natural gas utility supply and demand planning, and it concludes by estimating the direct effects of energy efficiency on natural gas consumption and consumer bills this past winter heating season.

DECLINES IN NATURAL GAS USE PER CUSTOMER

One critical feature of natural gas use in buildings has been the steady and inexorable improvement in efficiency as measured by use per customer. Reductions in use per customer can be attributed to a number of factors including the following:

- Increasingly efficient end use appliances;
- Tighter building envelopes;
- Growing utility investments in energy efficiency programs; and
- Consumer conservation.

RESIDENTIAL ENERGY EFFICIENCY GAINS

The natural gas residential customer has shown substantial gains in energy efficiency. In 2003 the average customer used 84.1 Mcf on a weather normalized basis. A decade later the average annual use for a gas home was 63.2 Mcf, roughly a 25 percent decline. Technology improvement was the prevalent factor behind this trend: customers replaced their older gas appliances—particularly space heating units—with more efficient models. Additionally, new homes were built to higher standards and featured better insulation, windows, and doors.
Also contributing to this sector’s enhanced efficiency are utility and government programs that encourage energy conservation. Through these programs, utilities offered consumers equipment rebates and other financial incentives for efficiency improvements. Tax deductions were also in effect on investments that met or exceeded regulated standards for appliances or buildings. These programs accelerated energy efficiency gains in homes.

Predicting customer conservation is not an exact science. An AGA survey\(^1\) asked its members if they under or over predicted normalized residential demand this past winter. Of 37 responses, nine (24 percent) overestimated residential customer use by one to five percent. On the other hand, 29 utilities (76 percent) underestimated customer usage by one to twelve percent, with an average of five percent.

If utility underestimation of normalized demand was representative of the nation, it could indicate that the households did not conserve as expected, which would have required utilities to acquire more natural gas than planned. However, utilities were able to meet demand even when they under-forecasted. Based on this limited sample, it appears that residential market behavior may be in flux.

\(^1\) American Gas Association Bill Comparison Survey for March 2014, Question of the Quarter
**Commercial Energy Efficiency Gains**

Similar improvements in energy efficiency can be seen in commercial buildings. The decline in natural gas use per customer in the commercial sector has been steady since the late 1970s-early 1980s.

Demand in the commercial sector is much higher than the residential sector on average. However, the heating portion of a commercial customer’s natural gas consumption is typically lower than that of a residential customer, which would explain why conservation impacts are lower for business customers. These businesses exhibited a reduction in use per customer of 13 percent, from 630 Mcf of annual per customer demand in 2003 to 546 Mcf in 2013.

Source: American Gas Association, *Gas Facts*
Efficiency-Directed Gas Utility Investments

As mentioned earlier, utility programs played a role in efficiency gains and reduced costs to customers. A number of these programs have existed for decades; however, the pace of utility investments in efficiency programs has accelerated in recent years—having more than tripled, from $320 million in 2007 to $1.1 billion in 2012. Energy savings more than doubled as a result of these investments—from 48.4 trillion Btu of saved energy in 2008 to 135.9 trillion Btu in 2012. Also for 2013, Utilities budgeted nearly $1.5 billion (projecting a 30 percent increase in spending). This helped residential program participants save 16 percent of household gas usage on average or about 112 Therms per year, averaging $117 in cost saving on their annual energy bill.

Natural Gas Efficiency Program Expenditures
United States

<table>
<thead>
<tr>
<th>Year</th>
<th>Expenditures (US Dollars million $)</th>
<th>Programs</th>
</tr>
</thead>
<tbody>
<tr>
<td>2007</td>
<td>$320 million</td>
<td>52</td>
</tr>
<tr>
<td>2008</td>
<td>$565 million</td>
<td>85</td>
</tr>
<tr>
<td>2009</td>
<td>$803 million</td>
<td>104</td>
</tr>
<tr>
<td>2010</td>
<td>$838 million</td>
<td>125</td>
</tr>
<tr>
<td>2011</td>
<td>$958 million</td>
<td>126</td>
</tr>
<tr>
<td>2012</td>
<td>$1.13 billion</td>
<td>120</td>
</tr>
<tr>
<td>2013</td>
<td>$1.46 billion</td>
<td>118</td>
</tr>
</tbody>
</table>

Source: AGA Natural Gas Efficiency programs Survey – 2008 through 2013

Natural Gas Efficiency and Distribution System Planning

Energy efficiency has also affected gas utility supply planning, design day requirements, and integrated resource planning. For many utilities, energy efficiency gains—both the declines in use per customer and the long-term flattened or lower natural gas consumption—form a part of peak natural gas demand day forecasts and overall supply planning. For others, the inclusion of use per customer is more implicit: These companies forecast design day requirements using usage data from prior years.
According to a recent informal survey² of AGA member natural gas utilities, most respondent companies incorporate energy efficiency into gas supply planning and design day requirements. Also companies integrate energy efficiency to a lesser extent into their integrated resource planning (IRP). Not all natural gas utilities go through the IRP exercise, which may explain the lower incidence of positive responses.

### HAVE ENERGY EFFICIENCY GAINS IMPACTED THE FOLLOWING ACTIVITIES?

<table>
<thead>
<tr>
<th></th>
<th>OVERALL</th>
<th>GAS SUPPLY PLANNING</th>
<th>DESIGN DAY REQUIREMENT</th>
<th>IRP</th>
<th>OTHER</th>
</tr>
</thead>
<tbody>
<tr>
<td>Yes</td>
<td>48</td>
<td>42</td>
<td>42</td>
<td>20</td>
<td>4</td>
</tr>
<tr>
<td>No</td>
<td>13</td>
<td>6</td>
<td>6</td>
<td>28</td>
<td>44</td>
</tr>
<tr>
<td>TOTAL</td>
<td>61</td>
<td>48</td>
<td>48</td>
<td>48</td>
<td>48</td>
</tr>
</tbody>
</table>

Source: AGA Query on Interruptible Service and Energy Efficiency in the Context of 2013-14 Winter Heating Season

In response to a separate question on the survey, 20 of 60 companies indicated that the utility calculates *use per customer* into an integrated resource plan. Another 14 companies noted that they integrate “use per customer” in their overall planning, but they don’t have an IRP. Sixteen respondents replied that use per customer was not a part of their forecasting process.

Based on utility data, it is clear that energy efficiency reduces average consumption over time. There is also anecdotal evidence from some companies that the effects of energy efficiency (i.e. lower consumption) tend to be muted on peak demand days. The reasons cited for this are that heating equipment may be running at full capacity or that customers may disregard conservation measures on the coldest day(s) of the year. This suggests that energy efficiency appears to reduce average energy consumption over time but may have less of an impact proportionally on peak day consumption. Nevertheless, energy efficiency remains a critical aspect of natural gas utility planning and helped shape the customer experience this past winter.

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² SOS Query Results on Interruptible Service and Energy Efficiency –07/21/14
**How Were Customers Impacted and How Did They Respond to the Harsh Winter?**

Customer bills increased primarily due to increased demand. Despite natural gas demand reaching record levels this past winter, residential gas prices rose only 3.1 percent. The winter 2013-14 natural gas price was still lower than what the average household paid during the winters of 2004 to 2012. Overall residential customer bills increased by ten percent from the previous winter, and natural gas continues to be the low cost option for households.

In spite of the bill increase, by spring 2014 the percentage of customers disconnected from utility service due to nonpayment hardly changed compared to the prior year, as many were able pay at least a portion of what they owed. However, the challenge to pay utility winter bills persists for some customers.

- The number of customers disconnected was 2.2 percent, an increase of less than one percentage point from the previous year.
- The number of customers in arrears rose to 21.5 percent of small volume customers for those companies surveyed.
- The amount owed by customers in arrears increased 9.6 percent.

For those that continued to have difficulties paying their heating bills, assistance from federal, state, and utility energy efficiency and bill payment assistance programs were available to help them stay current on their bills. But not all those that require assistance obtain it: 22 percent of such customers are at least 30 days late in arrears on their bills, and a little over two percent were disconnected from utility service at the end of the winter heating season. Survey results are presented in the table below.
EFFICIENCY GAINS AND AVOIDED COSTS ON RESIDENTIAL AND COMMERCIAL CUSTOMERS

As mentioned earlier, the use per residential customer declined 25 percent from 2003 to 2013. If consumers had not implemented such efficiency measures over the past decade, natural gas consumption would have been 965 Bcf higher during the winter of 2013-14, adding $9.7 billion more to consumers’ natural gas heating bills—keeping price constant (i.e., assuming no upward pressure on natural gas price due to heightened demand).

Commercial customers also reduced energy consumption over the past decade. Had commercial customers not conserved, the increased natural gas usage for commercial space heating this past winter would have resulted in about 325 Bcf of additional natural gas for the commercial sector.

Predicting customer conservation is not an exact science, however. A recent informal AGA survey(3) asked natural gas utilities to assess their weather-normalized residential demand forecasts for this past winter heating season. Of 37 companies, nine (24 percent) overestimated residential customer use by one to five percent. On the other hand, 29 utilities (76 percent) underestimated customer usage by one to twelve percent or an average five percent. If this underestimation of normalized demand by 76 percent of the survey utilities is representative of the nation, one could infer that households did not conserve energy as expected, which would require utilities to acquire more natural gas than planned. This said, utilities did meet their load requirements even though demand forecasts in many instances were not 100 percent on target.

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(3) American Gas Association Bill Comparison Survey: Question of the Quarter, March 2014
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A Decade of Growth
Measuring the U.S. Natural Gas Industry from 2002-03 to 2013-14
## A Decade of Growth: Measuring the U.S. Natural Gas Industry from 2002-03 to 2013-14

<table>
<thead>
<tr>
<th></th>
<th>2002/2003 WHS</th>
<th>2013/2014 WHS</th>
</tr>
</thead>
<tbody>
<tr>
<td>(1) Number of Heating Degree Days</td>
<td>3,709</td>
<td>4,217</td>
</tr>
<tr>
<td><strong>Customers</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Consumption</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>(6) Residential</td>
<td>3,759,621 Mcf</td>
<td>3,973,140 Mcf</td>
</tr>
<tr>
<td>(7) Commercial</td>
<td>2,103,069 Mcf</td>
<td>2,299,497 Mcf</td>
</tr>
<tr>
<td>(8) Industrial</td>
<td>3,241,498 Mcf</td>
<td>3,395,905 Mcf</td>
</tr>
<tr>
<td>(9) Electric Generation</td>
<td>1,790,119 Mcf</td>
<td>3,033,146 Mcf</td>
</tr>
<tr>
<td>(10) Total Consumption</td>
<td>10,894,307 Mcf</td>
<td>12,701,688 Mcf</td>
</tr>
<tr>
<td><strong>Efficiency (Consumption per Customer)</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>(11) Residential</td>
<td>60.76 cubic feet</td>
<td>59.63 cubic feet</td>
</tr>
<tr>
<td></td>
<td>(1.9% less even though there were 13.7% more HDDs)</td>
<td></td>
</tr>
<tr>
<td><strong>Prices (Average Residential Price for WHS)</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>(12) Residential</td>
<td>$8.48 ($/Mcf)</td>
<td>$9.79 ($/Mcf)</td>
</tr>
<tr>
<td>(13) Commercial</td>
<td>$7.74 ($/Mcf)</td>
<td>$8.41 ($/Mcf)</td>
</tr>
<tr>
<td>(14) Industrial</td>
<td>$5.99 ($/Mcf)</td>
<td>$5.62 ($/Mcf)</td>
</tr>
<tr>
<td>(15) Electric Generation</td>
<td>$5.58 ($/Mcf)</td>
<td>$6.20 ($/Mcf)</td>
</tr>
<tr>
<td><strong>Infrastructure</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>(16) Storage Withdrawal Total US</td>
<td>2,530 Bcf</td>
<td>3,012 Bcf</td>
</tr>
<tr>
<td>(17) Storage Working Gas Capacity</td>
<td>3,568 Bcf</td>
<td>4,216 Bcf</td>
</tr>
<tr>
<td>(18) Miles of Main</td>
<td>1,097,900</td>
<td>1,246,300 (2012)</td>
</tr>
<tr>
<td>(19) Services</td>
<td>59,812,688</td>
<td>67,104,711</td>
</tr>
<tr>
<td>(20) Emissions</td>
<td>154.8 (Tg CO2 eq) (2003)</td>
<td>129.9 (Tg CO2 eq) (2012)</td>
</tr>
</tbody>
</table>

Winter Heating Season

Energy Analysis
LDC SUPPLY PORTFOLIO MANAGEMENT DURING THE 2013-14 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 2013-14 winter heating season (November 2013 through March 2014), no one could have anticipated the sustained weather impacts of a polar vortex after January 1, 2014 and the record volumes of natural gas supplied and consumed during the first quarter of 2014. In fact, in 2013 market acquisition prices averaged about $3.75 per MMBtu—one dollar higher than in 2012. At the start of this winter heating season, storage inventories were strong at 3.8 trillion cubic feet (Tcf), and natural gas reserves and production volumes were at or near all-time highs. Domestic natural gas demand per annum was reaching 25 Tcf, and the natural gas system from wellhead to burner tip was poised for a real winter test—a test that materialized with a vengeance for much of the country.

Given this backdrop, the analysis in this paper regarding critical elements of the 2013-14 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 focused on peak-day and peak-month supply practices, pricing mechanisms, regulatory frameworks, and market hedging practices—acknowledging that the winter in question was exceptional in many ways.

This year responses (whole or subsets) were received from 84 local gas utilities with service territories in 49 states. The sample companies had an aggregate peak-day send out of 63.4 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 72.4 million Dth in
aggregate, which means that about 88 percent of the planned peak send out volume was actually required during the 2013-14 WHS. Even though aggregate actual peak-day send out fell short of aggregate design peak-day volumes for responding companies, an 88 percent utilization factor is the highest in more than a 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 past 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 2013-14 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 84 AGA member local gas utilities in 49 states. These companies had a cumulative, non-coincident, peak-day send out of 63.4 million Dth and an average peak-day send out of 754,853 Dth, which was nearly three percent higher than the sample of companies for the previous winter heating season (2012-13). The coldest day of the 2013-14 winter heating season, as reported by respondents, occurred predominantly in January (70 of 84 respondents), with 51 companies reporting January 6 or 7, 2014 as their coldest day.

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 above 70 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. The January 7 consumption volume was a single day record for natural gas in the United States. Single day (winter month) consumption by the residential, commercial, and power generation sectors were also all-time records.

- The residential and commercial segments of the market were most responsible for the dramatic swings in load requirements during the past winter heating season, ranging from over 78 Bcf per day on a cold January day in 2014 to a winter heating season low of about 27 Bcf per day in late March.
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 of the coldest months.

➢ The United States compiled 4,217 heating degree days (HDD) over the five month period November 2013-March 2014. This HDD total is 35.5 percent higher than the norm for the past 29 winter heating seasons (from 1985-86 to the present) and makes up the coldest winter since 1995-96. The 2013-2014 WHS was second coldest for the nation as a whole during that 29 year period.

➢ Although the month of October 2013 was warmer than normal for the country as a whole, the next five consecutive months comprising the 2013-14 winter heating season were all colder than normal, according to data from the National Oceanographic and Atmospheric Administration (NOAA). In fact, February and March 2014 were 13 percent and 15 percent colder than normal, respectively. The continuation of cold temperature patterns even late into the winter for much of the country east of the Rocky Mountains is important from the standpoint that supply portfolio planning and specific supply sources, such as underground storage, did not get a reprieve. The pressure to continue to perform was exceptional and continuous.

➢ Even though February and March were colder than normal, the peak consumption day occurred in January for 70 of the 84 surveyed companies, while six identified December and eight selected February or March as the month in which their peak day load occurred.

➢ For the previous WHS period of October 1, 2012 through March 31, 2013, cumulative heating degree days were 3.5 percent fewer than normal on a national basis (meaning warmer than normal), and prior to that, the 2011-12 winter season was even warmer (17.5 percent warmer than normal) for the nation as a whole. In general, temperature conditions during the 2013-2014 winter were a sharp departure from recent winter events.

This past winter was indeed exceptional. For an example of a similar winter with cumulative weather resulting in a consistently colder-than-normal winter, one must look back to 2000-01, when sustained cold temperatures and concerns regarding a tight supply market resulted in significant natural gas price leaps. However, generally winter weather has been decidedly warmer than normal on average compared to the 30-year norm since that remarkable winter.

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. This relationship between design peak day and actual peak day usage was typical for the past decade. As noted previously, this ratio of actual to planned peak day requirement was 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.
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 2013-14 WHS survey, twenty-seven companies noted using a 1-in-30 year risk or probability of occurrence, and ten used a 1-in-20 year probability. Thirty companies used other methodologies including a historical peak, severe weather event from specific year, 20-year peak times 1.05, Monte Carlo statistical simulation, and coldest effective degree day in a 30-year period—to name a few.

- 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. Seventy-three of 84 companies indicated that firm supplies were a part of their gas supply portfolio, including 57 companies that used firm supplies to meet between 25 and 76 percent of their peak-day volume requirements. Twenty 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-seven companies indicated that up to 50 percent of peak-day supplies originated from pipeline or other storage, 63 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 34 companies said that up to 50 percent of their peak-day volumes were city gate purchases for sales customers. Eighteen 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 2013-14 winter heating season are broken down as follows: 35 percent of the 63.4 million Dekatherm delivered arrived at LDC city gates via firm pipeline transportation, 21 percent from pipeline or other storage, 18 percent as shipments for transportation customers, and 14 percent from on-system underground storage, adding up to 88 percent of peak day supplies. Also those same four sources of gas supply accounted for 91 percent of peak-month gas supply.

- Mid-term agreements (more than one month and up to one year) were the most utilized for 2013-14 peak-day purchases, with 71 of 84 companies having such contract terms. Moreover, 34 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 40 of 84 reporting companies within their peak-day gas supply portfolio (compared to 36 of 61 companies two years prior); however, only nine companies used long-term contracts for more than 50 percent of purchased gas on a peak day (comparable to the 9 of 72 companies in the 2012-13 WHS).

- When asked to describe the distribution of gas supply purchases among suppliers, respondents cited independent marketers, producers, producing company affiliates, and LDC 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 2013-14 winter, 36 companies (43 percent) answered “yes;” however, 48 said “no.”

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 managing supply and price risk, 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), and call and swing options.
For long-term supplies (greater than one year), 31 of the 41 companies that have 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 winter supply, while eight used some form of fixed pricing.

Of the 72 companies that have mid-term purchases (more than one month, less than one year), 62 reported these purchases as most often tied to FOM indices, of which 40 companies used this pricing for significant volumes of gas. Also included in the mid-term pricing basket were daily mechanisms (for 39 companies), fixed prices (28 companies) and NYMEX indices (21 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 this past winter of 2013-14, the percentage of companies hedging with financial instruments decreased to 79 percent (or 66 of 84 companies). This contrasts with three years prior, when 92 percent (of a different sample of companies) indicated using financial hedging tools. On the other hand, during the 2004-05 winter 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 2013-14 WHS companies hedged as little as two percent and as much as 83 percent of winter heating season supply using financial instruments. The median supply volume hedged for the 2013-14 sample of companies was 32 percent.

Options and fixed-price contracts were most often cited (by 39 and 28 companies, respectively) as tools used to hedge a portion of gas purchases. Other regularly used financial tools include swaps (26 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, 56 of 66 companies (85 percent) indicated that they hedge 7-13 month forward for a portion of their supplies, while 53 of 66 companies employed a six-month-or-less timeframe. In addition, 33 companies hedged forward more than 13 months for a portion of their supplies. Of these 66 companies that hedged supplies, 28 employed all three timing strategies.

On the physical side in preparation for the 2013-14 WHS, 79 of 84 respondents (94 percent) reported using storage as a natural hedging tool. Thirty-seven of those companies hedged between 25 and 51 percent of winter heating season supplies using underground storage, compared with 39 companies last year. Another 35 companies employed this physical hedge for 1 to 25 percent of their supply portfolio.

Only three of 84 survey respondents indicated that they used weather derivatives during the 2013-14 winter heating season. This compares with two of 51 companies three winter heating seasons prior.

When asked about their own regulatory environment, 63 of the 63 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, 45 of the 72 respondents that knew the answer indicated that their regulator was equally interested in
stable prices and the lowest price possible. Twelve said that a lowest price was the only focus, while 15 tagged stable prices as the regulator's concern.

- Only one of 81 companies indicated that regulators overseeing their services and activities in preparation for the 2013-14 winter heating season were less receptive to hedging than in the prior year. Eleven companies perceived regulators as more receptive to hedging strategies, while 69 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-seven of 79 companies answering the question (97 percent) indicated that weather-induced demand compelled them to utilize storage services during the 2013-14 winter heating season, which is not a surprise. Respondents also cited no-notice requirements (67 companies), "must turn" contract provisions (50 companies), pipeline operational flow orders (42 companies), and arbitrage opportunities (27 companies) as reasons to maintain storage services within their gas supply portfolio. Among these companies, 13 noted all of these influences in their use of storage assets.

- When asked whether the extraordinary weather events of the first quarter of 2014 would influence future storage-related supply planning, 65 of 79 companies (82 percent) said no, while only 14 companies said yes.

- Ninety-four percent of respondents (79 of 84 companies) indicated that they used underground storage (on-system or pipeline) for a portion of their 2013-14 winter heating season supply. That portion tended to be one to 50 percent—only seven companies indicated that more than 50 percent of their WHS supply originated from underground storage.

- Seventy of the 79 companies that have storage assets used first-of-month index pricing to purchase gas for injection into storage, and 44 percent (or 31 companies) of those companies used FOM prices for 76-100 percent of gas injected into storage. Fifty-two 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 79 companies (38 percent) used fixed-price schedules for some portion of their storage purchases, compared to 48 percent two years prior.

- Twelve of 84 companies indicated that they were either constructing or studying the potential for adding underground storage during the next five years, while ten were considering adding market-area LNG or propane peak-shaving capacity to their gas supply assets.

- Companies were asked whether they employed non-traditional methods to strategically manage their storage assets during the past winter. Seventy-five of 84 companies said no. However, nine companies identified the purchase of additional flowing gas on the daily market as a primary tool for relieving strains on storage assets. Although simple in concept, just the fact that flowing gas was available—given the demand levels and persistent cold—is an extraordinary turn of events, considering past perceptions of the U.S. gas supply market.


**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 2013 to March 2014, 32 to 47 of the survey companies (varying with the month) released their unneeded pipeline capacity to the secondary market. Of those, 26 to 33 companies (depending on the month) released up to 25 percent of their pipeline capacity. During the spring-summer of 2013 (April through August), from 10 to 15 surveyed companies per month released 26 to 50 percent of their capacity.

- Fifty-two of 83 companies indicated that operational flow orders impacted their systems during the 2013-14 winter. The previous winter 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 8 and the median point of reported average durations was 3.65 days.

- In addition to operational flow orders, twenty-four companies (29 percent of those reporting) noted that pipeline critical transport days were issued during the winter heating season that impacted their operations, and 14 companies identified storage critical days. Median critical storage days issued for the companies was 5.5, while the median point of average durations was 8.4 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. Five and a half months earlier, peak day consumption in the United States reached 139 Bcf—148 percent higher than the more conventional June period. 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. 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 above 70 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 into June 2014. Clearly, winter heating season daily consumption does not necessarily correspond to annual or monthly averages.
For example, from January 1 through March 31, 2014 daily natural gas consumption ranged from as little as 65 Bcf to over 135 Bcf. The graph also shows that consumption fell to below 60 Bcf per day for much of May 2014, but history tells us it may surge again in July and August to meet natural gas-fired power generation requirements.

FIGURE 1

U.S. Daily Natural Gas Consumption 2014


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.
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 (on the following page) graphs residential and commercial natural gas consumption data from January 1 through June 16, 2014. Here we see daily sector consumption as low as 25 Bcf for a relatively warm winter day in March sharply contrasted with close to 80 Bcf consumption day in January. On a national basis, this represents a 200 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.
IV. Weather 2013-14 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. The following attempts to quantify and place in context the critical metrics describing the temperature-related events of November 2013 - March 2014.

- The United States compiled 4,217 heating degree days (HDD) over the five month period of November 2013 - March 2014. This total is 35.5 percent more than the norm for the winter heating season periods or 1985-86 to the present (29 seasons). The 2013-14 WHS was the second coldest for the nation as a whole during that 29 year period.
The East North Central portion of the country (essentially the upper Midwest) experienced 45.7 percent more HDDs than normal and as such recorded the coldest winter in 29 years.

The East South Central region recorded 41.6 more HDDs and was the second coldest by that measure in the 29 year period.

The Middle Atlantic region experienced its third coldest winter in 29 years and was 55 percent colder than normal based on HDD totals.

Likewise, New England was the third coldest it has been in 29 years with a HDD 36.9 percent above the norm.

The South Atlantic region completed the east coast trifecta with temperatures resulting in 36.6 percent more heating degree days than normal— the second coldest winter in 29 years.

Further west, it was also cold in the West North Central and West South Central regions—40.4 percent and 15.9 percent colder than normal, respectively, as measured by HDDs. For the WNC region, it was the coldest in 29 years, and for the WSC, the second coldest.

Only until you look at the Mountain West and Pacific coast do you see more normal or even warmer conditions for the just past winter. The Mountain region was 13.7 percent colder, but this was only its twenty-third coldest winter in 29 years.

The Pacific region was the clear exception for the country as the polar vortex that settled over the mid-continent and East Coast actually pulled the jet stream further north in the Pacific bringing dry and warmer conditions. The Pacific region registered 1.1 percent fewer heating degree days and was thus warmer than normal this winter. It was actually the second warmest winter heating season for the Pacific Coast in 29 years, according to data from the National Oceanographic and Atmospheric Administration (NOAA).

According to data from the National Oceanographic and Atmospheric Administration (NOAA), the 2013-14 winter months were about 6.6 percent colder than normal (Table 1), following two consecutive winters that were warmer than normal. The five-month winter season is unpredictable and can often demonstrate different patterns—cold early and warm during its core or warm early and colder than normal in March, for example. For the 2013-14 WHS, however, all months November 2013 through March 2014 were colder than normal—a relatively rare occurrence.
### TABLE 1

**MONTHLY COMPARISON OF NATIONAL HEATING DEGREE DATA**  
**OCTOBER 2012 – MARCH 2014**

<table>
<thead>
<tr>
<th>MONTH</th>
<th>PERCENT CHANGE FROM NORMAL</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2012-13</td>
</tr>
<tr>
<td>October</td>
<td>3.2%</td>
</tr>
<tr>
<td>November</td>
<td>1.5%</td>
</tr>
<tr>
<td>December</td>
<td>14.4%</td>
</tr>
<tr>
<td>January</td>
<td>8.8%</td>
</tr>
<tr>
<td>February</td>
<td>2.0%</td>
</tr>
<tr>
<td>March</td>
<td>10.5%</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td><strong>3.5%</strong></td>
</tr>
</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 2013-14 WHS survey, companies described their methodology for determining their design day calculation as follows: 27 employed a 1-in-30 year risk of occurrence, 10 used a 1-in-20, three used a 1-in-15, three a 1-in-10, and two used a 1-in-5 year occurrence probability. Eight companies utilized an alternative time period criteria, ranging from 25 years to 1-in-100 years. In addition, 30 companies used other methodologies including a historical peak, severe weather event from specific year, 20-year peak times 1.05, Monte Carlo statistical simulation, coldest effective degree day in a 30-year period, and other econometric models and statistical methodologies—to name a few.

Peak-day consumption predominantly occurred in January for survey respondents (70 of 84 companies). For these 84 companies, the aggregate peak-day send out was 63.4 million Dekatherms during the 2013-14 WHS, making up 88 percent of the 72.4 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 2013-14 WHS. Seventy-three of 84 companies indicated that firm pipeline supplies formed a part of their peak day gas supply portfolio, including 41 companies that showed 26 to 50 percent of their required peak-day volumes coming from firm supplies. Another 20 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 |
| SOURCES OF LDC PEAK GAS SUPPLIES |
| 2013-14 WINTER HEATING SEASON |
| (84 Companies) |

<table>
<thead>
<tr>
<th>SUPPLY VOLUME PERCENTAGE RANGES</th>
<th>CITY GATE PURCHASES FOR SALES</th>
<th>CITY GATE SUPPLIES FOR TRANSPORTATION</th>
<th>LNG/PROPANE AIR/SNG</th>
<th>LOCAL PRODUCTION</th>
<th>ON-SYSTEM UNDERGROUND STORAGE</th>
<th>PIPELINE OR OTHER STORAGE</th>
<th>PURCHASES MOVED VIA FIRM PIPELINE TRANSPORTATION</th>
<th>PURCHASES MOVED VIA INTERRUPTIBLE TRANSPORTATION</th>
<th>OTHER</th>
</tr>
</thead>
<tbody>
<tr>
<td>PEAK DAY</td>
<td></td>
<td></td>
<td></td>
<td></td>
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<td></td>
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<tr>
<td>1–25%</td>
<td>30</td>
<td>43</td>
<td>28</td>
<td>13</td>
<td>6</td>
<td>30</td>
<td>12</td>
<td>0</td>
<td>15</td>
</tr>
<tr>
<td>26–50</td>
<td>4</td>
<td>20</td>
<td>3</td>
<td>0</td>
<td>12</td>
<td>37</td>
<td>41</td>
<td>2</td>
<td>1</td>
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<tr>
<td>51–75</td>
<td>1</td>
<td>1</td>
<td>0</td>
<td>0</td>
<td>1</td>
<td>4</td>
<td>16</td>
<td>1</td>
<td>0</td>
</tr>
<tr>
<td>76–100</td>
<td>3</td>
<td>20</td>
<td>0</td>
<td>0</td>
<td>1</td>
<td>0</td>
<td>4</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>0</td>
<td>46</td>
<td>20</td>
<td>53</td>
<td>71</td>
<td>64</td>
<td>13</td>
<td>11</td>
<td>82</td>
<td>68</td>
</tr>
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<td>PEAK MONTH</td>
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<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1–25%</td>
<td>29</td>
<td>30</td>
<td>26</td>
<td>11</td>
<td>12</td>
<td>44</td>
<td>12</td>
<td>1</td>
<td>11</td>
</tr>
<tr>
<td>26–50</td>
<td>5</td>
<td>29</td>
<td>0</td>
<td>4</td>
<td>7</td>
<td>25</td>
<td>34</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>51–75</td>
<td>1</td>
<td>4</td>
<td>0</td>
<td>0</td>
<td>1</td>
<td>1</td>
<td>23</td>
<td>2</td>
<td>0</td>
</tr>
<tr>
<td>76–100</td>
<td>4</td>
<td>1</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>1</td>
<td>4</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>0</td>
<td>45</td>
<td>20</td>
<td>58</td>
<td>69</td>
<td>64</td>
<td>13</td>
<td>11</td>
<td>80</td>
<td>73</td>
</tr>
</tbody>
</table>

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: 67 of 84 companies indicated that up to 50 percent of peak-day supplies originated from pipeline or other storage, while 63 companies indicated that up to 50 percent of their peak-day supplies were city gate supplies for transportation customers. Thirty-eight companies made city gate purchases, 31 used LNG or propane air as a supply source (compared to only 16 last year), 20 used on-system storage, and 13 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. Two years ago, no company reported interruptible transportation as a peak day or peak month supply source. The peak day “Other” category, reported by 16 companies most consistently included purchases to supplement gas supplies, mainly for on-system balancing.
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.
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 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 2013-14 data show a relative balance among contract lengths of peak-day and peak-month supply volumes (see Table 3). 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. Table 4 includes contract terms for winter heating season supplies, and it shows a similar pattern as for peak month supplies, with a slight decrease for mid-term supplies in the case of volumes making up 50 percent or more of gas requirements.

<table>
<thead>
<tr>
<th>SUPPLY SOURCES</th>
<th>PEAK DAY</th>
<th>PEAK MONTH</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>VOLUME</td>
<td>%</td>
</tr>
<tr>
<td>Citygate purchases for sales customers</td>
<td>4,069,201</td>
<td>6%</td>
</tr>
<tr>
<td>Citygate supplies for transportation customers</td>
<td>11,521,082</td>
<td>18%</td>
</tr>
<tr>
<td>LNG / Propane-air / SNG</td>
<td>2,131,155</td>
<td>3%</td>
</tr>
<tr>
<td>Local production</td>
<td>678,067</td>
<td>1%</td>
</tr>
<tr>
<td>On-system underground storage</td>
<td>8,885,028</td>
<td>14%</td>
</tr>
<tr>
<td>Pipeline or other storage</td>
<td>13,065,121</td>
<td>21%</td>
</tr>
<tr>
<td>Purchases moved via firm transportation</td>
<td>22,100,065</td>
<td>35%</td>
</tr>
<tr>
<td>Purchases moved via interruptible transportation</td>
<td>118,436</td>
<td>0%</td>
</tr>
<tr>
<td>Other</td>
<td>838,248</td>
<td>1%</td>
</tr>
<tr>
<td>TOTAL</td>
<td>63,406,403</td>
<td>100%</td>
</tr>
</tbody>
</table>
Mid-term deals for peak-day purchases were made by 71 of 84 companies reporting LDCs—more companies than those using daily (63 companies), monthly arrangements (50 companies), or long-term contracts (40 companies). A similar pattern emerges for peak month and winter season purchases although for peak month supplies mid-term deals tend to represent a higher percentage (50 percent or more) of gas supplies than peak day or winter season. Also, during the entire 2013-14 winter heating season many companies needed to go to the well more often than usual for daily purchases, given cold and persistent winter temperatures.

### Table 4
**Contract Terms for Gas Purchases**
**2013-14 Winter Heating Season**
(84 Companies)

<table>
<thead>
<tr>
<th>Supply Volume Percentage Ranges</th>
<th>Daily</th>
<th>Long-term (&gt; 1 Year)</th>
<th>Mid-Term (1 Month ≤ 1 Yr)</th>
<th>Monthly</th>
<th>Other</th>
</tr>
</thead>
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<tr>
<td><strong>Peak Day</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1 – 25%</td>
<td>31</td>
<td>24</td>
<td>19</td>
<td>32</td>
<td>1</td>
</tr>
<tr>
<td>26 – 50</td>
<td>17</td>
<td>7</td>
<td>18</td>
<td>13</td>
<td>5</td>
</tr>
<tr>
<td>51 – 75</td>
<td>9</td>
<td>3</td>
<td>17</td>
<td>2</td>
<td>1</td>
</tr>
<tr>
<td>76 – 100</td>
<td>6</td>
<td>6</td>
<td>17</td>
<td>3</td>
<td>0</td>
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<tr>
<td>0</td>
<td>21</td>
<td>44</td>
<td>13</td>
<td>34</td>
<td>77</td>
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<tr>
<td><strong>Peak Month</strong></td>
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<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1 – 25%</td>
<td>32</td>
<td>26</td>
<td>16</td>
<td>31</td>
<td>4</td>
</tr>
<tr>
<td>26 – 50</td>
<td>21</td>
<td>6</td>
<td>17</td>
<td>13</td>
<td>3</td>
</tr>
<tr>
<td>51 – 75</td>
<td>9</td>
<td>2</td>
<td>23</td>
<td>4</td>
<td>0</td>
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<tr>
<td>76 – 100</td>
<td>3</td>
<td>7</td>
<td>15</td>
<td>3</td>
<td>0</td>
</tr>
<tr>
<td>0</td>
<td>19</td>
<td>43</td>
<td>13</td>
<td>33</td>
<td>77</td>
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<tr>
<td><strong>Winter Season</strong></td>
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<tr>
<td>1 – 25%</td>
<td>39</td>
<td>26</td>
<td>18</td>
<td>33</td>
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<tr>
<td>26 – 50</td>
<td>20</td>
<td>6</td>
<td>16</td>
<td>16</td>
<td>4</td>
</tr>
<tr>
<td>51 – 75</td>
<td>5</td>
<td>3</td>
<td>21</td>
<td>3</td>
<td>0</td>
</tr>
<tr>
<td>76 – 100</td>
<td>3</td>
<td>6</td>
<td>17</td>
<td>2</td>
<td>0</td>
</tr>
<tr>
<td>0</td>
<td>17</td>
<td>43</td>
<td>12</td>
<td>30</td>
<td>77</td>
</tr>
</tbody>
</table>
As to supply providers, as shown in Table 5, when asked to describe the distribution of peak-day gas purchases among suppliers, 68 LDCs identified independent marketers as their supply provider. The balance of supplies acquired by LDCs were distributed among producers (51 companies), producing company marketing affiliates (37 companies), LDC energy marketing affiliates (21 companies), pipeline energy marketing affiliates (13 companies), customer owned gas (five companies), and LDC-owned production (four companies). The other category includes financial marketing affiliates, asset managers, imported LNG, storage operators and other supply aggregators.

<table>
<thead>
<tr>
<th>SUPPLY VOLUME PERCENTAGE RANGES</th>
<th>INDEPENDENT MARKETER</th>
<th>LDC ENERGY MARKETING AFFILIATE</th>
<th>LDC OWNED PRODUCTION</th>
<th>CUSTOMER OWNED</th>
<th>PIPELINE ENERGY MARKETING AFFILIATE</th>
<th>PRODUCER</th>
<th>PRODUCER MARKETING AFFILIATE</th>
<th>OTHER</th>
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<tr>
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<td></td>
</tr>
<tr>
<td>1 – 25%</td>
<td>13</td>
<td>18</td>
<td>2</td>
<td>3</td>
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<td>9</td>
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<tr>
<td>26 – 50</td>
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<td>1</td>
<td>2</td>
<td>1</td>
<td>16</td>
<td>16</td>
<td>4</td>
</tr>
<tr>
<td>51 – 75</td>
<td>18</td>
<td>0</td>
<td>1</td>
<td>0</td>
<td>1</td>
<td>8</td>
<td>5</td>
<td>2</td>
</tr>
<tr>
<td>76 – 100</td>
<td>19</td>
<td>1</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>9</td>
<td>1</td>
<td>3</td>
</tr>
<tr>
<td>0</td>
<td>16</td>
<td>63</td>
<td>80</td>
<td>79</td>
<td>71</td>
<td>33</td>
<td>47</td>
<td>66</td>
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<td>PEAK MONTH</td>
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<td></td>
<td></td>
<td></td>
<td></td>
</tr>
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<td>1 – 25%</td>
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<td>19</td>
<td>2</td>
<td>1</td>
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<td>23</td>
<td>16</td>
<td>12</td>
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<td>64</td>
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</table>

When asked whether their company used asset management agreements for any portion of their gas supply purchases during the 2013-14 winter heating season, 36 of 84 companies (43 percent) said yes—slightly more than the prior winter heating season. Of these 36 companies, 20 used asset management for 25 percent or less of their winter heating season supplies, while nine companies actually used asset management agreements for 100 percent of 2013-14 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. 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, 14 of 83 responding companies (17 percent) said “yes,” and 43 said “maybe.” Responses possibly reflect a general feeling that Henry Hub prices will likely remain stable overall but at even lower levels than previously anticipated. Of the 14 companies that answered “yes” to the hypothetical question regarding fixed-price longer-term contracts, 12 said they would consider building fixed price arrangements for less than or equal to 30 percent of their total supply. One opted for 71-80 percent, and one selected 91-100 percent. With respect to preferred contract durations for such deals, seven of the 14 companies found 5-year and greater terms as optimal, while five others favored terms of three years or less.

Thirty-four of the 43 companies that answered “maybe” regarding longer-term fixed price arrangements said they would consider gas supply ranges of up to 30 percent of their purchases for such deals. With regard to contract durations, 15 of the “maybe” companies viewed 3-5 years as optimum.

<table>
<thead>
<tr>
<th>Supply Volume Percentage Ranges</th>
<th>Number of Companies</th>
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<tr>
<td>1 – 25%</td>
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<td>3</td>
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<td>76 – 100</td>
<td>10 (9 = 100%)</td>
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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 dominates the market for the largest portion of supply agreements, whether short, long or mid-term. Table 7 provides a closer look at the balance of pricing mechanisms among survey respondents during the 2013-14 winter heating season.

<table>
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<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>
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<tr>
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<td>6</td>
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<td>17</td>
<td>16</td>
<td>4</td>
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<td>1 – 25%</td>
<td>0</td>
<td>12</td>
<td>21</td>
<td>18</td>
<td>8</td>
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<tr>
<td>26 – 50</td>
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<td>13</td>
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<tr>
<td>51 – 75</td>
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<td>7</td>
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<td>1</td>
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<td>29</td>
<td>45</td>
<td>60</td>
<td>75</td>
<td>74</td>
</tr>
</tbody>
</table>
As shown in Table 7 and Figure 5, 31 of the 41 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 50 percent or more of recent purchases. Sixteen companies used daily pricing mechanisms for long-term supplies spread evenly among volume ranges. Also 15 companies utilized some form of fixed pricing (compared to 16 of 42 the prior year). By way of comparison, for the 2007-08 WHS 15 of 47 companies used fixed pricing, while eleven years ago, only 10 of 40 companies cited fixed deals.

Figure 5

![LDC Long-Term Gas Supply Pricing Mechanisms](image)

Figures 5, 7 and 8 show the pricing mechanisms employed by this year’s 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 2013-14 just as they were for the 2012-13 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—given the strong calls on flowing gas during the extraordinary first quarter of 2014—and fixed pricing also played a somewhat prominent role for larger long-term volumes relative to other mechanisms. The relative prevalence of these two pricing mechanisms 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 six consecutive years of growth in domestic production. Weekly and average three-day pricing played no role in long-term gas purchases during the 2013-14 WHS.
According to the 72 companies that reported mid-term supplies (of more than one month and up to one year) during the 2013-14 WHS, much of these natural gas purchases were tied to FOM indices (62 companies, including 40 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-eight companies reported using fixed pricing mechanisms for mid-term purchases, compared with 15 for long-term purchases. Also 398 of 72 reporting companies used daily prices for mid-term purchases.

As would be expected, more companies (65 of 75) used daily pricing for short-term purchases (one month or less) than for mid-term or long-term purchases during the 2013-14 WHS; however, these short-term purchases were also heavily dependent on first-of-month indices (46 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.
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-nine percent of responding companies (66 of 84) said they used financial instruments to hedge a portion of their 2013-14 winter heating season gas supply purchases. This percentage is slightly lower than last year (when 84 percent of companies indicated using financial hedges) and generally lower than for prior 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, 53 of 66 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 2013-14 WHS gas supply purchases: options (39 companies), fixed price contracts (28 companies), swaps (26 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 this year, 28 percent of the gas delivered by the companies in the survey during the 2013-14 winter heating season was hedged—exactly the same as last year and five points less than two years ago.

Only one company reported using weather derivatives during the 2013-14 winter heating season. This compares with 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, 53 of 66 companies with hedging programs (81 percent) indicated that they applied a six-month or less strategy for a portion of their hedges for the 2013-14 winter heating season. Fifty-six companies used a 7-13 month strategy, and 33 companies employed a greater than 13-month strategy. Of course, a single company may use one or all strategies simultaneously. In fact, 28 of the respondents did just that, compared with 24 the prior year and 19 for the 2011-12 WHS.

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 2013-14 winter heating season, 79 of the 84 reporting companies (94 percent) used storage as a physical hedge. Seventy-two 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. Thirty of 83 responding companies said that they are required to secure pre-approval from their regulator, and 29 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 (74 of 81) reported no change in their regulator’s receptivity to financial hedging during the 2013-14 winter heating season compared to the prior year, and four reported increased receptivity on the part of their regulator or public utility commission (PUC). Three companies indicated that their PUC was less receptive this past winter heating season. Sixty-nine of 81 companies did not believe that the events of the just past winter would influence regulatory views of hedging strategies.

All 63 responding companies reported that their regulator treated the financial losses and the gains related to hedging equally. This 100 percent response compares with 88 percent (or 45 of 51 companies) three years ago, 81 percent the year prior, and 78 percent the year before that. Additionally, 65 of 67 companies that answered the question said yes when asked if costs associated with their financial hedging programs were fully recoverable, while one responded no, and another said that it varies.

When asked about the focus of their regulator with respect to natural gas purchases, twelve respondents indicated that their regulator was primarily interested in the lowest possible price, fifteen said that the focus was on stable prices, and 45 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, 28 of 67 companies cited regulatory requirements, 37 said it was a voluntary decision (in certain cases influenced by customers), and 15 identified other or additional reasons or goals, such as price stability. Several of these companies noted more than one motivation.

When asked how customers benefited from their financial hedging compared with no hedging, 65 of 67 companies (97 percent) noted the reduced price volatility as a benefit to customers, while 42 companies identified reduced gas costs as valuable to customers. Of the 67 respondents, 40 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 2013 compared to the same period in 2014. It is plain to see that there were considerable differences.

For the nation as a whole, working gas inventories by April 2013 were not particularly strained (above 1,600 Bcf). However, by the time net injections began in earnest in April 2014 working gas levels were at half the prior year level and at their lowest in 10 years—only slightly above 800 Bcf. This stark difference is attributable to the severity and persistence of the 2013-14 winter, particularly during the first three months of 2014. A record for net underground storage withdrawals 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.

Ninety-four percent of survey companies (79 of 84) used underground (on-system or pipeline) storage for a portion of their gas supply during the 2013-14 winter heating season, of which 37 reported that up to 50 percent of their 2013-14 winter supplies were derived from storage. In preparation for that winter, the spring-summer 2013 storage refill season competed with gas flowing to power generation. In fact, 19 of 73 companies that answered the question indicated flowing
volumes of gas from storage during the injection season to serve summer power generation loads. Nevertheless, storage volumes still reached 3.8 Tcf at the start of winter. It was a good thing, because most of it was ultimately needed.

### Table 8

<table>
<thead>
<tr>
<th>Date</th>
<th>Total (Bcf)</th>
<th>Producing (Bcf)</th>
<th>East (Bcf)</th>
<th>West (Bcf)</th>
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</thead>
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<td>1799</td>
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Source: Energy Information Administration.

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 66 of the 79 companies that used storage. Price considerations also influenced the decisions of 52 companies, and regulatory plans or mandates impacted the storage strategy for 40 companies. Of course, more than one variable may influence injections of gas supplies into storage: In fact, 30 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 97 percent of respondents (77 of 79) to make use of their storage services during the 2013-14 winter heating season. Other factors cited by companies were no-notice requirements (67 companies), “must turn” contract provisions (50 companies), pipeline operational flow orders (42 companies), and arbitrage opportunities (27 companies). Again more than one variable moved companies to use storage: thirteen 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 2013 refill season, in preparation for the 2013-14 winter heating season, were based primarily on first-of-month indices (70 companies) and daily spot pricing, although primarily for smaller volumes, (52 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 21 companies, respectively.

<table>
<thead>
<tr>
<th>SUPPLY VOLUME PERCENTAGE RANGES</th>
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<th>FIRST-OF-MONTH INDEX</th>
<th>FIXED</th>
<th>NYMEX</th>
<th>WEEKLY</th>
<th>OTHER</th>
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<td>1 – 25%</td>
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<td>6</td>
<td>15</td>
<td>10</td>
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<tr>
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<td>7</td>
<td>3</td>
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<tr>
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The pricing mechanisms used for the 2012 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.

Looking at other pricing mechanism used for gas intended for storage refill, in 2010 fixed price schedules were used for a portion of injected volumes by 26 reporting companies, while daily pricing was applied by 30 surveyed companies. Daily pricing was more regularly applied to smaller volume purchases in 2009 (up to 25 percent of purchased gas for storage) and in 2010 (up to 50 percent of purchased volumes). As mentioned earlier, during the 2013 injection season, the daily market was of course very active.

When asked about their future plans at the end of the 2013-14 winter heating season, twelve 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 the implementation phase. In addition, ten companies were considering expanding market-area LNG or propane air peak-shaving facilities, but again none were in the building phase at that point.
Management of storage assets during the 2013-14 winter was stressed in many locations around the country given the conditions of the extended polar vortex that impacted wide swaths of the country east of the Rockies front. Seventeen percent of the 83 responding companies indicated that they experienced Storage Critical Days (SCD) during the 2013-14 winter heating season, in many cases due to the continuous draw on facilities during January, February and March 2014. The median number of SCDs issued per company was 5.5, lasting from 1 to 14 days on average.

Factors impacting the storage market of course vary year to year, so it may be useful to contrast storage conditions with prior years. For example, storage assets during the 2011-12 winter heating season presented a markedly different experience, given that it was 17 percent warmer than normal nationally and working gas in storage was 60 percent higher than the 5-year average at the end of that year’s withdrawal season. During that period, twelve of 63 respondents indicated that they employed non-traditional methods to strategically manage storage assets, including 1) conducting an economic review of must turn provisions and selling base winter supply to meet storage withdrawal requirements; 2) optimizing storage to reduce Weighted Average Cost of Gas and prioritizing all ratchet based storage over other options; 3) relaxing late season ratching by interstate pipeline; 4) acquiring short-term interruptible storage; 5) purchasing less flowing supplies each month; and 6) continuing injections of flowing gas sources into the standard storage withdrawal period. It is remarkable how quickly local gas utilities must adjust strategies given market and other conditions.

For the 2013-14 WHS, 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 shale gale.

Perhaps because of this current gas supply picture, when asked whether the events of the 2013-14 winter heating season will cause them to modify storage-related supply planning for the next winter, 82 percent of respondents (65 of 79) said that it will not have an impact on their storage-related decisions for the 2014-15 WHS. In fact, when asked to describe the most effective tool for managing supply availability and price risk (even if a small part of the supply portfolio), the majority of respondents named underground storage as the most effective gas acquisition and price management this past (2013-14) winter heating season. Other tools included financial hedging options, fixed price contracts, and specific pricing mechanisms.

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 2013 to March 2014. 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.
TABLE 10
PERCENT OF PIPELINE CAPACITY RELEASED BY LDCs
APRIL 2013 – MARCH 14

| CAPACITY PERCENTAGE RANGE | INJECTION SEASON | | | | | WINTER HEATING SEASON | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | APR | MAY | JUN | JUL | AUG | SEP | OCT | NOV | DEC | JAN | FEB | MAR |
| 1 – 25% | 29 | 33 | 30 | 30 | 27 | 29 | 29 | 26 | 26 | 30 | 31 | 30 |
| 26 – 50 | 10 | 10 | 13 | 13 | 15 | 13 | 12 | 6 | 5 | 3 | 3 | 4 |
| 51 – 75 | 2 | 1 | 2 | 2 | 2 | 1 | 1 | 1 | 1 | 1 | 0 | 0 |
| 76 - 100 | 0 | 1 | 1 | 2 | 2 | 2 | 1 | 0 | 0 | 0 | 0 | 0 |
| 0 | 9 | 5 | 4 | 3 | 4 | 5 | 7 | 4 | 5 | 3 | 3 | 2 |

Regarding system operations, 63 percent of survey respondents (52 of 83 companies) indicated that their operations and/or system had been impacted by the issuance of pipeline operational flow orders (OFOs) during the 2013-14 winter heating season—a much higher rate compared to the prior year percentage-wise. Companies (24 of 83) also encountered pipeline Transport Critical Days and Storage Critical Days (14 companies).

The median for the number of OFO issuances was eight, and for OFO durations was 3.7 days (respondents being asked for average duration per event). Transport Critical Days (TCD) tended to last a little longer (median of 3.9 days per event) and were encountered seven times per LDC (median value) over the course of the winter heating season. Several companies reported that many OFOs were issued, but that they had no real impact on their system operations. The main reasons for the OFOs and TCDs cited by upstream pipelines had to do with protecting system integrity, maintaining pipeline physical flow requirements, and preserving storage deliverability, and they were 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 nominations that exceeded capacity to deliver.

Of the 84 respondents, 6 percent used capacity held on an affiliated interstate pipeline to make off-system wholesale natural gas sales, while 39 percent used capacity held on non-affiliated pipelines for the same purpose.

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 2013-14 winter heating season. Exactly half of the 84 surveyed companies said yes; however, all but one described the investigations as routine. One company described the regulatory scrutiny as routine in some case, but not in all. In addition, when asked whether regulators had significantly delayed the full recovery of gas sales costs incurred during the 2013-14 winter, 82 of 84 companies said “no.”
The method for recovering gas costs was further described: 39 of 84 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. For some companies, recovery is subject to a prudence review. Twenty-nine 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 five other companies the treatment of interest varies by service territory or jurisdiction. Five companies mentioned other PUC-approved recovery mechanisms, such as regulator-approved incentive mechanisms and customer-shareholder sharing mechanisms.

When asked whether permitted to retain some or all revenues from off-system wholesale natural transactions, 32 of the 53 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 14 of the 84 companies (17 percent) said that they offered fixed-price options to their customers.

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