AGA American Gas Association

February 20, 2012

Honorable Scott D. O'Malia
Commodity Futures Trading Commission
Three Lafayette Center
1155 21st Street, NW
Washington, DC 20581

Dear Commissioner O'Malia:

Thank you for meeting with members of the American Gas Association on February 2. We are writing to follow up on some of the questions that you asked and to provide some of the information requested.

By way of background, the American Gas Association represents more than 200 local energy companies committed to the safe and reliable distribution of clean natural gas to more than 65 million customers throughout the United States. More than 622,000 people are directly involved in exploring for, producing, transporting, and distributing natural gas, of which approximately 120,000 AGA member company employees are directly involved in the distribution of natural gas.

The wholesale sale and transportation of natural gas in interstate commerce is regulated by the Federal Energy Regulatory Commission ("FERC") under the Natural Gas Act, 15 U.S.C. §§ 717 – 717z. However, under section 1(b) of the Act (§717(b)), the provisions of the Act do not apply to "the local distribution of natural gas or to the facilities used for such distribution . . . ." In addition, in 1954, the Act was further amended to make clear that when local distribution companies own high pressure transmission lines that would normally be subject to FERC regulation under the Act, the provisions of the Act do not apply if the natural gas is received within or at the boundary of the state and all of the gas is ultimately consumed within that state, provided that the rates, services and facilities of the company are regulated by that state's utility commission. Natural Gas Act §1(c), 15 U.S.C. § 717(c). In other words, natural gas utilities are "local distribution companies" exempt from FERC regulation under sections 1(b) and 1(c) of the Natural Gas Act, 15 U.S.C. §§ 717(b), 717(c), but are subject to state utility regulation for their rates, services and facilities.

As we discussed at our meetings, our members use a variety of products to hedge price risk, including financial and physical transactions. We fully expect that financial transactions will be regulated under the new swaps regulatory regime but expressed concern in our meetings about the treatment of some of our physical transactions, including those with flexible delivery terms. We understood that you had questions regarding the hedging practices of gas utilities generally, and so have provided the attached analysis conducted by AGA's Policy Analysis Group entitled, "LDC Supply Portfolio Management during the 2010-2011 Winter Heating Season," dated June 29, 2011. Each year, AGA surveys its members on a variety of topics related to how gas utilities meet the peak winter requirements of their customers. Among the topics are how gas supplies are priced and whether and how gas utilities use hedging mechanisms to address price volatility. Based on the survey, 92 percent of the utilities responding to the survey said they used financial instruments to hedge a portion of their gas supply purchases during the 2010-2011 winter. (See page 18). While this report and the highlighted statistics focus somewhat on financial transactions, we thought it would be useful to include it with respect to hedging programs at our member companies generally. Please understand that we are not able to provide explicit statistics about the use of physical transactions – those we are most concerned about with respect to the swap definition – by our member companies in their hedging programs.

With regard to regulation of hedging programs, the analysis noted variations in the motivations for hedging programs. "In some jurisdictions, there are no formal standing plans. In others, LDCs may actually be required to hedge portions of future gas supplies with those hedges required to be in place by predetermined dates. Variations on these themes are many and are geared to fit the interplay among a local distribution company, the regulator and market conditions in a given area." (See page 19).

A follow-up to the survey revealed that most of AGA's members responding to the survey do not receive pre-approval of their hedging programs from their regulators, with some members mentioning that pre-approval is statutorily not allowed. However, gas utility hedging programs are discussed, monitored and reviewed by the applicable state regulators. In this regard, all members that responded to the follow-up survey reported that they preview their hedging plans with their regulators, and some companies come in for periodic reviews during the hedging year.

We hope you find this information helpful. If you have any questions regarding the information provided, please feel free to contact us.

Sincerely,

/s/ Andrew K. Soto

Andrew K. Soto
Arushi Sharma
American Gas Association

cc: Allison Lurton

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EA 2011-07 **June 29, 2011**

LDC SUPPLY PORTFOLIO MANAGEMENT DURING THE 2010-11 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 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 up to 78 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. 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 2010-11 winter heating season, they were met with market conditions that had stabilized following the tumultuous economic downturn in 2009. Some large volume natural gas customers, particularly in the industrial sector were consuming less. However, because natural gas supplies remained strong, even a record overall consumption year in 2010 (24.1 trillion cubic feet according to the *Energy Information Administration*) did not change the outlook for price stability during the 2010-11 winter heating season. Domestic natural gas production was in the midst of another year-over-year growth cycle, which left increases in liquefied natural gas imports languishing and reduced requirements for pipeline gas from Canada. In addition, underground storage working gas volumes built to over 3.8 Tcf prior to the change over from weekly net injections to weekly net withdrawals and were, therefore, very strong. Regarding natural gas acquisition prices, according to the *Energy Information Administration,* average domestic wellhead prices fell from $5.14 per Mcf (thousand cubic feet) in January 2010 to $3.34 in November just as the winter heating season began – another extraordinary year for natural gas markets!

Many of the changes in natural gas markets were good news for gas customers. The six-month period October 2010 through March 2011 turned out to be about 1.2 percent colder than normal for the nation as a whole. That doesn't seem particularly important except that most winter heating seasons for the previous decade had been warmer than normal. In addition, the coldest part of the 2010-11 winter came during December through mid-February (10 of 11 colder than normal weeks) and yet – except for the occasional transportation basis blow out in a supply constrained region – there were no significant natural gas commodity pricing events during the 2010-11 winter.

Beyond price considerations, of course, winter temperatures play a significant role in supply planning as well as consumer bills. The coldest periods during the 2010-11 winter heating season were in December 2010 and January through mid-February 2011. November 2010 and March 2011 were warmer than normal, according to nationwide heating degree day statistics from the *National Oceanographic and Atmospheric Administration*. On a weekly basis, 14 of 22 weeks from November 1, 2010 through April 2, 2011 were colder than normal nationwide.

With this background, this analysis describes critical elements of the 2010-11 winter heating season (WHS) and summarizes data acquired from AGA member local distribution companies (LDCs) via the AGA *Winter Heating Season Performance Survey*. For this year's survey, questions focused on peak-day and peak-month supply practices, pricing mechanisms, as well as regulatory and market hedging practices.

This year responses (whole or subsets) were received from 51 local gas utilities with service territories in 31 states. The sample companies had an aggregate peak-day sendout of 47.3 million Dekatherms (Dth), acknowledging 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 60.8 million Dth in aggregate, which means that only about 78 percent of the planned peak sendout volume was actually required during the 2010-11 WHS. This makes this the eighth year consecutively that aggregate actual peak-day sendout fell short of aggregate design peak-day volumes for respondent companies.

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 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. In some cases, the report compares survey results for the 2010-11 winter heating season with those reported in prior years. 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 41 corporate entities, representing 51 AGA member local gas utilities. These companies had a cumulative, non-coincident, peak-day sendout of 47.3 million Dth and an average peak-day sendout of 927,037 Dth. Unlike the previous winter heating season when 44 (of 56 companies providing data) reported January 2010 as the month in which their peak day occurred, the coldest day of the 2010-11 winter heating season was nearly equally distributed for the companies, reporting the peak day between December 2010 and January-February 2011 with 13, 18 and 15 companies, respectively. Results of the winter heating season survey are generally presented as counts of companies that fit into percentage ranges (1-25 %, 26-50 %, and so forth) of supply volumes. 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 demand at something greater than 66 Bcf per day "on average." However, and particularly during the winter heating season, requirements for natural gas by consumers are not average.

- During the period of November 1, 2010 through March 31, 2011, total consumption of natural gas in the U.S. ranged from 62 Bcf per day on a warm November or March day to about 110 Bcf (including net exports to Mexico) on the coldest winter day in February, according to *Bentek Energy LLC* – a huge swing in daily winter heating season demand.

- In fact, the residential and commercial sectors of the market were most responsible for the dramatic swings in customer requirements, rising to more than 60 Bcf per day on February 8-9, 2011 from a winter heating season low of 17 Bcf per day on November 9, 2010.

Weather

- For two months (October-November) leading to the heart of the 2010-11 winter heating season conditions were warmer than normal – 15.5 and 3.4 percent warmer, respectively – but flipped completely when December 2010 through February 2011 recorded colder than normal temperatures for the nation as a whole. Only in March did conditions return to warmer than normal.

- This correlates with 13 companies identifying December as the month containing their *peak* consumption day, 18 companies identifying January and 15 pointing to February. Simply stated temperatures around the country were generally colder than normal for the core winter heating season months, even though the winter began and ended slightly warmer than normal.

- For the period of October 1, 2010 through March 31, 2011, cumulative heating degree days were 1.3 percent larger than the previous year and 1.2 percent more than normal (meaning colder than normal) on a national basis. However, cumulative regional conditions varied from about 5.1 percent colder than normal in the South Atlantic to 5.4 percent warmer than normal in the Mountain region.

- To find an example of cumulative weather that also resulted in a colder-than-normal winter heating season, one must search as far back as 2000-01. Compared to the 30-year norm, winter weather has been on average decidedly warmer than normal since that remarkable winter, when sustained cold temperatures and concerns regarding a tight supply market resulted in significant natural gas price leaps.

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. For the 2010-11 winter heating season, survey companies planned for 60.8 million Dth of peak-day gas sendout, but only 78 percent (47.3 million Dth) of the volume was actually required because of the lower than projected peak consumption levels nationwide. As a point of reference, last year's sample of 56 companies planned to deliver about 66 million Dth of peak-day gas requirements but in fact delivered only about 49 million Dth (about 74 percent). In addition, twenty-six of 51 companies indicated that their design day forecast includes a margin for error and 21 of those companies noted that the forecast error had been approved by the appropriate state oversight agency.

In addition, local gas utilities apply a standard or methodology for determining a design peak day temperature calculation and, of course, that influences the construct of their gas supply portfolio. For the 2010-11 WHS survey, thirteen companies noted using a 1-in-30 year risk or probability of occurrence, while 18 companies choose "other," which included using a historical peak adjusted for current and known changes, the use of a settlement conference to determine criteria, Monte Carlo statistical simulation and even up to 1-in-100 year considerations with additional statistical overlays.

- 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. Forty- five of 51 companies indicated that firm supplies were a part of their gas supply portfolio, including 35 companies that used firm supplies to meet between 26 and 75 percent of their peak-day volume requirements.

- Thirty-nine companies indicated that up to 50 percent of peak-day supplies originated from pipeline or other storage; 36 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 19 companies flagged on-system storage as the source of up to 50 percent of peak-day supplies.

- Long-term agreements, defined as one year or longer, were used by 29 of 49 reporting companies within their peak-day gas supply portfolio (compared to 31 of 55 companies the previous year), but only 6 accounted for more than 50 percent of purchased gas on a peak day (compared to 7 companies the previous year). Mid-term (more than one month, less than one year) agreements were the most utilized for 2010-11 peak-day purchases, with 43 of 49 companies having such contract terms. In fact, 26 companies indicated that more than 50 percent of their peak-day natural gas supplies were acquired utilizing mid-term agreements.

- When asked to describe the distribution of gas supply purchases among suppliers, respondents cited independent marketers, producer marketing affiliates and producers 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 2010-11 winter, 22 companies answered yes, while 29 answered 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 pointed to storage, swaps and call options, fixed pricing and advanced purchases at fixed prices.

- For long-term supplies (one year or more), 28 of the 39 companies that had such supplies used first-of-the-month (FOM) pricing for a portion of their supplies, including 21 companies that used FOM for 51-100 percent of long-term gas purchases. Thirteen companies utilized daily pricing, and 15 made use of fixed long-term pricing.

- Mid-term purchases (more than one month, less than one year) were reported by 39 of 50 companies as most often tied to FOM indices for significant volumes of gas. In addition, fixed-price (22 companies) and daily mechanisms (21 companies) were included in the mid-term pricing basket.

- Ninety-two percent of companies responding to the AGA survey (47 of 51 companies responding) indicated that they used financial instruments to hedge at least a portion of their supply purchases for the 2010-11 winter heating season. One year prior (with a different sample of companies) 90 percent used financial hedging tools. For the 2004-05 winter 70 percent had indicated using financial tools, while three years prior to that (2001-02) only 55 percent of the companies responding had indicated the same.

- Fixed-price contracts (27 companies), options (26 companies), swaps (20 companies) and futures (14 companies) were most often cited as financial tools used to hedge a portion of gas volumes delivered on a peak day. 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 or customer and may have been excluded from the LDC hedging calculation.

- On the physical side in preparation for the 2010-11 WHS, all 51 respondents reported using storage as a natural hedging tool. Twenty-seven of those companies hedged between 26 and 50 percent of winter heating season supplies using underground storage, compared to 28 companies last year. Another 19 companies provided this physical hedge for 1 to 25 percent of their supply portfolio.

- Companies use a portfolio of timed hedges to balance their approach to strategic price planning. When asked about the timing of hedging strategies, 37 of 51 companies (73 percent) indicated that they employ a six-month or less strategy for a portion of their hedges, while 38 of 51 companies also utilized a 7-12 month strategy for a portion of their hedges. Twenty-five companies pointed to hedges designed to include a greater than 12-month strategy.

- Only two survey respondents out of 51 indicated that they used weather derivatives during the 2010-11 winter heating season. This compares to four of 61 companies in 2007-08.

- When asked about their own regulatory environment, 45 of the 46 companies responding to the question (with an answer other than not applicable) indicated that financial losses and gains were treated equally within their hedging plans.

- When asked whether their regulator was more focused on gas purchases at the lowest possible price, at a stable price or interested in both equally, 32 companies indicated that there was an interest in both (equally), while eight said a stable price was the focus, and nine tagged the lowest price.

- Thirty-four of the 51 companies answering the question noted that they planned to hedge at the same level during the upcoming winter heating season (2011-12) as they did in the past winter. Two companies plan to hedge even more, while six plan to hedge less.

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 only by local utility requirements to serve winter peaking loads. Storage services now support natural gas parking, loaning, balancing and other commercial arbitrage opportunities that take place at market hubs and city gates.

- All 51 companies indicated that weather-induced demand, among other factors, compelled them to utilize storage services. Respondents also singled out no-notice requirements (42 companies), "must turn" contract provisions (32 companies), pipeline operational flow orders (24 companies) and arbitrage opportunities (23 companies) as reasons to maintain storage services within their gas supply portfolio during the 2010-11 winter heating season.

- Must turn provisions may be in place for some storage contracts as a way of maintaining facility integrity through an optimal pattern of injection and withdrawal into and from a storage field. During the 2010-11 winter heating season, storage inventories finished lower than the prior five-year average and the prior year. Sixty-three percent (32 of 51) of responding companies cited must-turn provisions as influencing their use of storage during the 2010-11 winter.

- Forty-three of the 50 companies that answered the question used first-of-the-month index pricing to purchase gas for injection into storage, and 42 percent of those companies (18) indicated that 76-100 percent of gas injected into storage was based on FOM prices. Thirty companies indicated that they purchased a portion of their stored gas in the daily market, however, the daily pricing tended to be used for less than 50 percent of purchased storage volumes. Twenty-six of 50 companies (just over 50 percent) used fixed-price schedules for some portion of their storage purchases, compared to 49 percent the prior year.

- Eleven of 51 companies indicated that they were either constructing or studying the potential for adding underground storage during the next five years, while eight were examining the possibility of adding peak shaving to their gas supply assets.

LDC Transportation and Capacity Issues

Transportation-only customers have assumed a high profile among all customers served by local gas utilities. Managing pipeline capacity efficiently is a challenge for many utilities and can involve the release of capacity to the secondary transportation market.

- From April 2010 to March 2011, 31 to 35 of the survey companies (varying with the month) released their unneeded pipeline capacity on a monthly basis to the secondary market. Twenty-two to 26 companies (depending on the month) released up to 25 percent of their capacity. During the spring-summer of 2010, from four to eight companies (per month) released 26 to 50 percent of their capacity.

- Only 19 of 51 companies that answered the questions reported that operational flow orders (OFO), which impacted their service territory, were issued by pipeline companies during the 2010-11 winter heating season. The median number of OFOs reported was four with a median duration of three days.

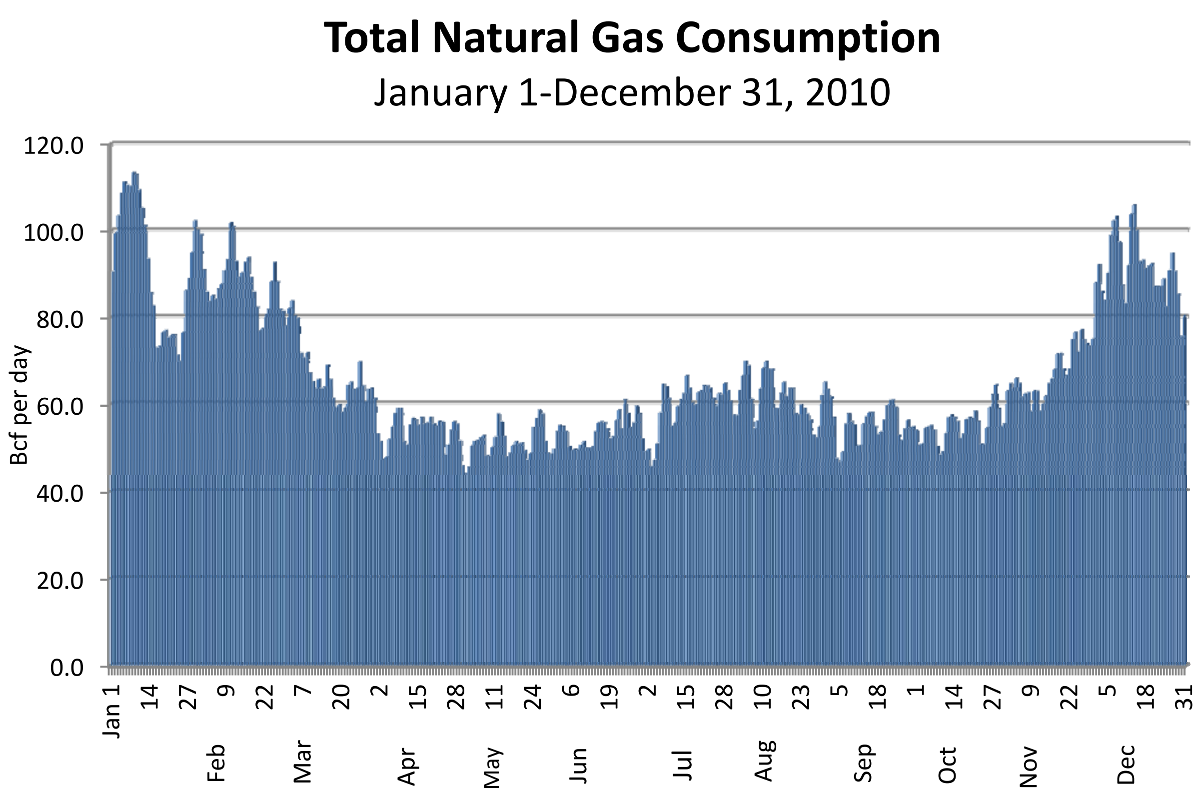
III. Natural Gas Market Overview

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 motivation is that of mitigating market uncertainty. Of course it is often weather that introduces an element of the unknown for gas supply planners throughout the country.

As a national trade association, AGA often describes national natural gas markets, based on annual or monthly data. Since 1995 and up to 2009, U.S. natural gas consumption had been about 22-23 Tcf annually, while U.S. natural gas production has been about 18-19 Tcf annually. In 2010, domestic natural gas consumption exceeded 24 Tcf for the first time on record and U.S. natural gas production reached 21.6 Tcf. Even though these data indicate a level of stability in the gas market, gas supply planners at local utilities face a very different picture – one that varies daily with fluctuating conditions that can become extreme during winter heating season months.

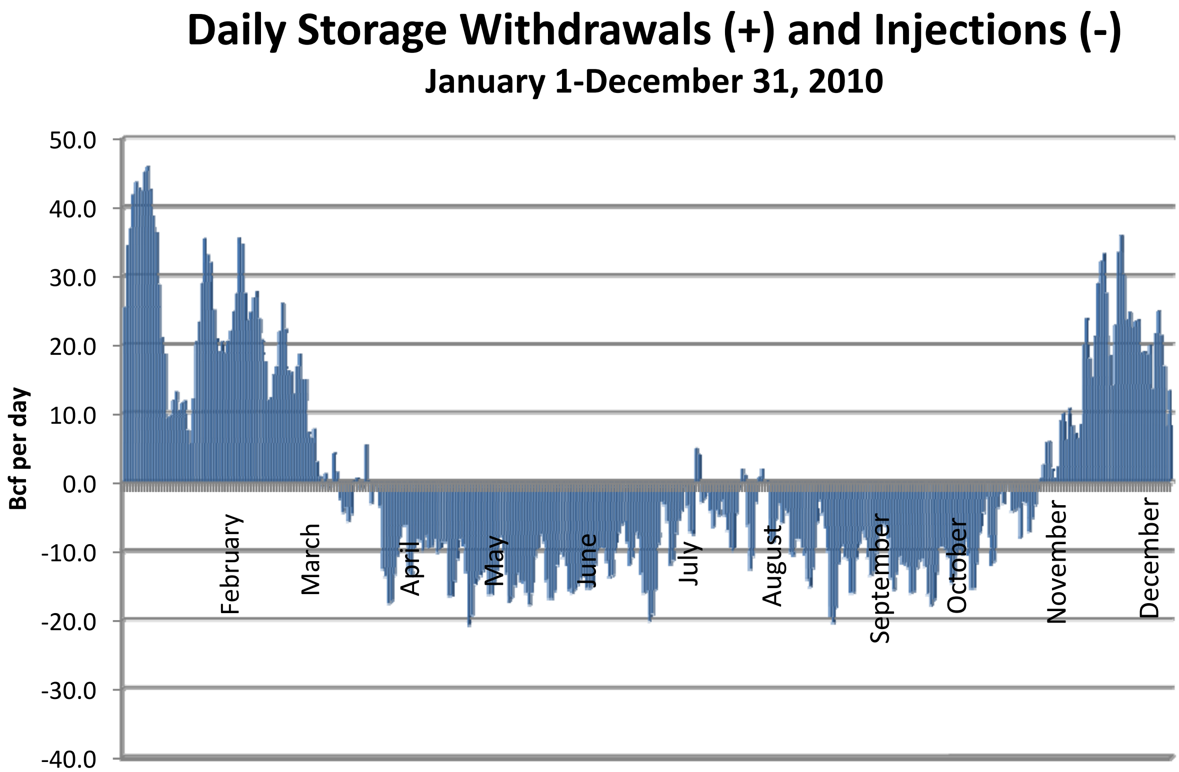
It is a known fact that a balanced natural gas market means supply equals demand. Today's U.S. natural gas market balances consumption with domestic and international supplies at about 66 Bcf per day on average. However, on a daily basis during the course of a winter heating season natural gas consumption can fluctuate significantly. Figure 1 represents a graph of daily natural gas consumption, from January through December 2010, and illustrates that winter heating season daily consumption does not necessarily correspond to the annual or monthly averages. For example, from January 1 through March 31, 2010, daily natural gas consumption ranged from about 60 Bcf to over 100 Bcf. The graph also shows that consumption fell to as little as 45 Bcf per day in May, leaving some gas in the 66 Bcf-per-day supply market as a source to begin underground storage replenishment.

FIGURE 1



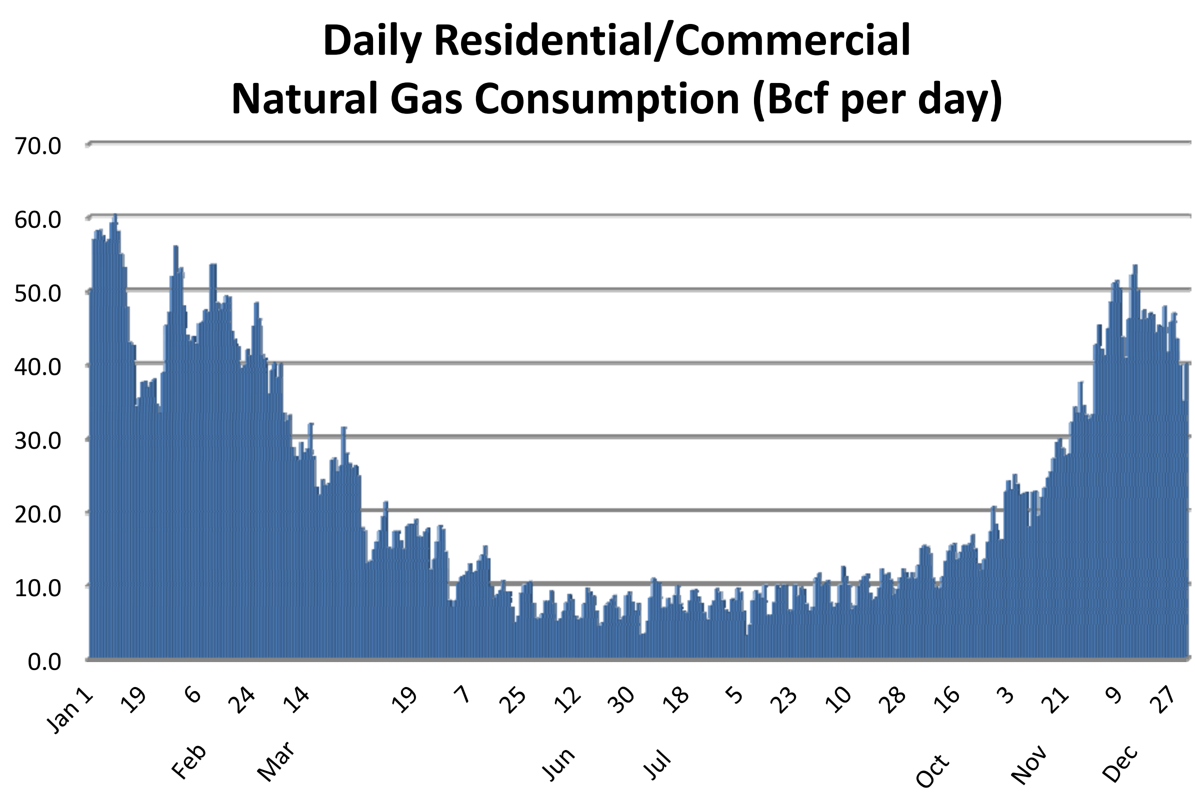
Source: Bentek Energy, LLC, *Energy Market Fundamentals*, December 31, 2010.

FIGURE 2



Source: Bentek Energy, LLC, *Energy Market Fundamentals*, December 31, 2010.

FIGURE 3



Source: Bentek Energy, LLC, *Energy Market Fundamentals*, December 31, 2010.

Figure 2 shows the net withdrawals from storage as a positive supply source and the net injections as a demand requirement (below the zero line). A look at only the residential and small commercial sectors provides an even starker example of daily demand fluctuations. Figure 3 graphs residential and commercial natural gas consumption data from January 1 through December 31, 2010. Here we see daily sector consumption as low as 24 Bcf for a warm winter day in March sharply contrasted with a nearly 60 Bcf consumption day in early January. On a national basis, this represents more than a 100 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 is an ongoing challenge in meeting customer requirements every winter, every day, and it is the starting point for developing a portfolio of tools geared toward meeting this challenge.

IV. Weather 2010-11 Winter Heating Season

Both the 2008-09 and 2009-10 winter heating seasons were warmer than normal based on heating degree day measures from October through March – 0.2 percent and 1.5 percent, respectively. That changed for the 2010-11 winter as cumulative data points to 1.2 percent colder than normal conditions for October 2010 through March 2011. The core winter months of December-January-February were all colder than the norm, while November and March were slightly warmer, according to data from the *National Oceanographic and Atmospheric Administration*. Heating degree day totals varied by as much as 8.0 percent colder (December 2010) to 3.4 percent warmer (November 2010).

For the 22-week period October 30, 2010 to April 2, 2011, only eight weeks were warmer than normal, while the remaining 14 weeks were colder than normal on a national basis. On a regional basis, cumulative conditions were colder than normal in every area of the country – October 2010 through March 2011 – except in the west south central and mountain regions where temperatures were slightly warmer. For the various regions of the country, deviations from temperature norms were cumulatively as much as 5.4 percent warmer (Mountain region) and 5.1 percent colder (South Atlantic region).

TABLE 1
MONTHLY COMPARISON OF NATIONAL HEATING DEGREE DATA
OCTOBER 2009 – MARCH 2011

MONTH	PERCENT CHANGE FROM NORMAL			
	2009-10		**2010-11**	
October	19.0%	Colder	15.5%	Warmer
November	19.0%	Warmer	3.4%	Warmer
December	6.0%	Colder	8.0%	Colder
January	0.7%	Colder	3.9%	Colder
February	9.1%	Colder	2.5%	Colder
March	10.5%	Warmer	0.3%	Warmer
TOTAL	1.5%	Warmer	1.2%	Colder

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

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), volatility in commodity prices, 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 standard or methodology for determining a design peak day temperature calculation and, of course, that influences the construct of their gas supply portfolio. For the 2010-11 WHS survey, two companies noted using a 1-in-10 year risk or probability of occurrence; four companies, 1-in-15; three companies, 1-in-20; 13 companies, a 1-in-30 year approach and 11 companies a coldest recorded temperature in a specific time period criteria. Eighteen companies choose "other," which included using a historical peak adjusted for current and known changes, the use of a settlement conference to determine criteria, Monte Carlo statistical simulation and even up to 1-in-100 year considerations with additional statistical overlays.

TABLE 2
SOURCES OF LDC GAS SUPPLY
2010-11 WINTER HEATING SEASON
(51 Companies)

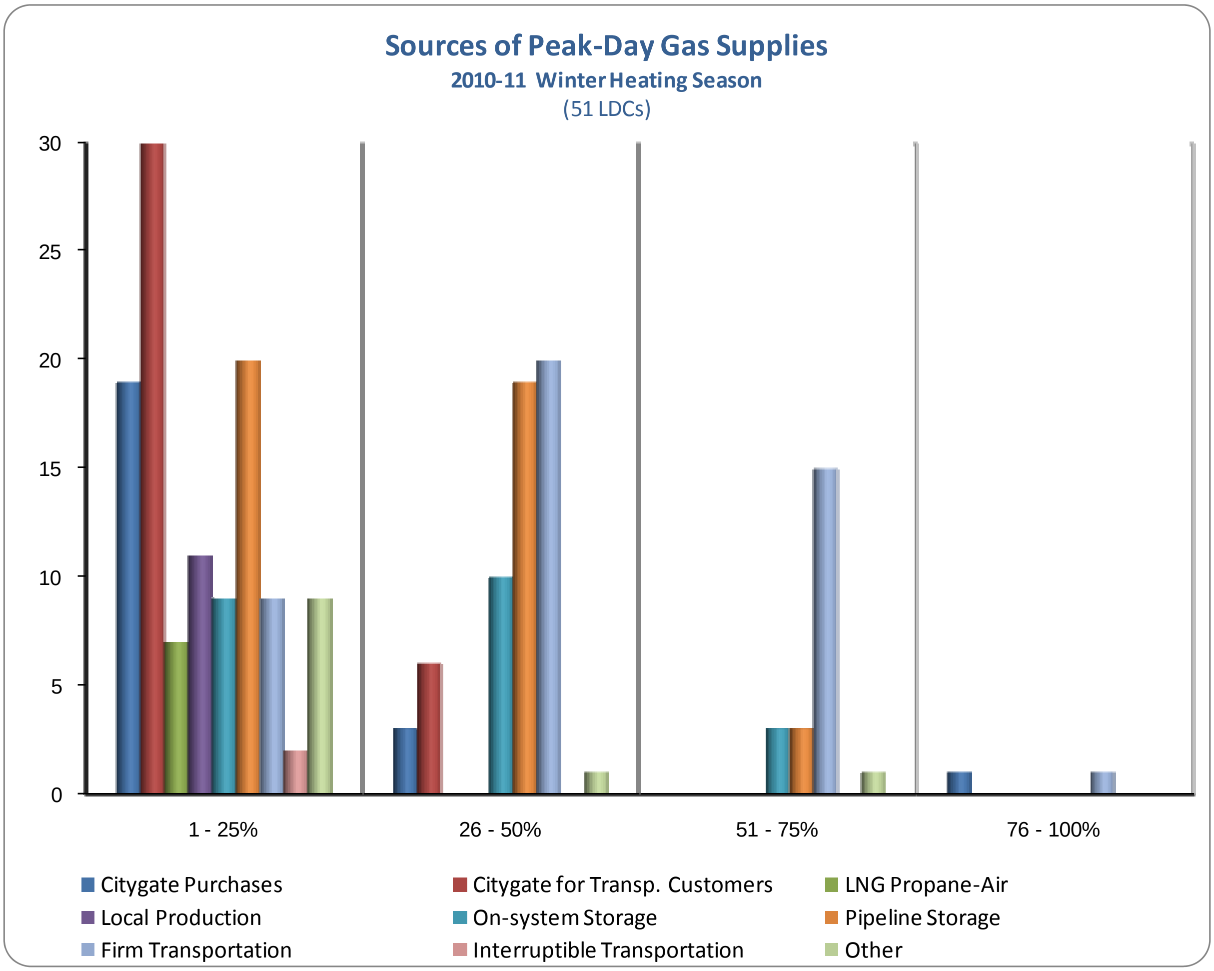
Percentage Ranges Peak Gas Supplies	City Gate Purchases	City Gate Supplies for Transportation	LNG Propane Air	Local Production	On-system Storage	Pipeline or Other Storage	Purchases via Firm Pipeline Transportation	Purchases via Interruptible Transportation	Other
Peak Day									
1 – 25%	19	30	7	11	9	20	9	2	9
26 – 50	3	6	0	0	10	19	20	0	1
51 – 75	0	0	0	0	3	3	15	0	1
76 – 100	1	0	0	0	0	0	1	0	0
0	28	15	44	40	29	9	6	49	40
Peak Month									
1 – 25%	14	22	4	9	13	26	4	3	5
26 – 50	2	15	0	2	8	15	17	0	1
51 – 75	1	0	0	0	1	1	21	0	0
76 – 100	1	0	0	0	0	0	3	0	1
0	33	14	47	40	29	9	6	48	44

Source: *2010-11 AGA LDC Winter Heating Season Performance Survey.*

Table 2 and Figure 4 illustrate some of the diversity of gas supply sources available to LDCs. It is not surprising that purchases moved by firm transportation provided much of the gas to consumers for the peak day and peak month during the 2010-11 WHS. Forty-five of 51 companies indicated that firm pipeline supplies were a part of their gas supply portfolio, including 20 companies that showed 26 to 50 percent of their required peak-day volumes coming from firm supplies. Additionally 15 companies indicated 51-75 percent of peak-day supplies to be firm.

Also according to Table 2, peak-month supplies were heavily weighted toward purchases via firm transportation. As with peak-day supplies, peak-month supplies tended to be supplemented with pipeline or other storage, city gate deliveries for transportation customers, city gate purchases, on-system storage, LNG or propane-air and some local production and interruptible transportation.

FIGURE 4



Other categories of gas supply for peak-day deliveries were also important to the sample of companies. For example, 39 of 51 companies indicated that up to 50 percent of peak-day supplies originated from pipeline or other storage, and 30 companies indicated that up to 25 percent of their city gate peak-day supplies were earmarked for transportation customers. Twenty-two companies chose on-system storage as a supply source. LNG or propane-air, city gate purchases and local production provided up to 25 percent of peak-day supplies for 7, 19 and 11 of the 51 companies, respectively. Only two companies used interruptible transportation to meet their peak-day needs (primarily for between 1 and 25 percent of peak-day volumes). Table 2 and Figure 4 demonstrate that the largest number of companies tend to employ a multiple-source supply strategy in increments often amounting to 50 percent or less of their total supply package.

TABLE 3

CONTRACT TERMS FOR GAS PURCHASED
2010-11 WINTER HEATING SEASON
(49 COMPANIES)

PERCENTAGE RANGES PEAK GAS SUPPLIES	DAILY	LONG-TERM	MID-TERM	MONTHLY
PEAK DAY				
1 – 25%	13	16	9	14
26 – 50	10	7	8	6
51 – 75	5	3	9	2
76 – 100	2	3	17	0
0	19	20	6	27
PEAK MONTH				
1 – 25%	18	16	5	15
26 – 50	8	8	11	7
51 – 75	5	4	10	2
76 – 100	0	2	17	0
0	18	19	6	25
WINTER SEASON				
1 – 25%	20	16	6	19
26 – 50	9	8	7	7
51 – 75	3	4	15	2
76 – 100	0	2	15	0
0	17	19	6	21

Source: *2010-11 AGA LDC Winter Heating Season Performance Survey.*

Supply diversity is not limited to sources of gas. 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, recent developments in reduced market volatility, particularly as they apply to natural gas acquisition prices, are resulting in a reexamination by consumers 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 2010-11 data, as shown in Table 3, show a balance of contract lengths among all peak-day and peak-month supply volumes, particularly for volumes up to 50 percent of requirements. However the use of mid-term deals (defined as more than one month but less than one year) is becoming more prominent for gas volumes representative of 51 to 75 percent and 76 to 100 percent of gas requirements. Since the table also includes reference to the whole winter heating season, one can see the increased use of monthly agreements for the five-month period.

Table 3 also shows that long-term agreements, defined as one year or longer, were used by 29 of 49 companies answering the question for peak day supplies (compared to 31 of 55 companies last year), but they accounted for 51 percent or more of purchased gas for only 6 companies on a peak day. In comparison, the 2007-08 WHS results has produced 14 companies that used long-term deals for more than 50 percent of their purchased gas on the peak day. Forty-three companies utilized mid-term deals (defined above) for peak-day purchases—more companies than those using one-month (22 companies) and daily agreements (30 companies). However, shorter-term deals were well represented for peak-day and peak-month purchases, particularly for volumes less than 25 percent of gas purchase requirements.

As shown in Table 4, when asked to describe the distribution of gas supply purchases among suppliers on a peak day, 42 LDCs identified independent marketers. The balance of supplies to LDCs were distributed among producer marketing affiliates (30 companies), producers (30 companies), pipeline marketing affiliates (8 companies), LDC marketing affiliates (15 companies) and other supply providers (14 companies). Also, pipeline purchases and LDC-owned production made up a smaller part of peak-day natural gas supplies for LDC customers.

TABLE 4

DISTRIBUTION OF PEAK-DAY GAS PURCHASES AMONG SUPPLY PROVIDERS

2010-11 WINTER HEATING SEASON

(49 COMPANIES)

PERCENTAGE RANGES PEAK-DAY VOLUMES	INDEPENDENT MARKETER	LDC MARKETING AFFILIATE	LDC OWNED PRODUCTION	PIPELINE	PIPELINE MARKETING AFFILIATE	PRODUCER	PRODUCER MARKETING AFFILIATE	OTHER
1 – 25%	8	11	2	4	7	11	16	10
26 – 50	18	3	0	0	1	9	8	1
51 – 75	8	0	0	0	0	8	6	0
76 - 100	8	1	0	0	0	2	0	3
0	7	34	47	45	41	19	19	35

Source: *2010-11 LDC Winter Heating Season Performance Survey.*

When asked if their company used asset management agreements for any portion of its gas supply purchases during the 2010-11 winter heating season, 29 of 51 companies answered no, while 22 companies answered yes.

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 functioning financial markets. The market fundamentals that impact price have also expanded to include interest rates, other investment opportunities and the price of other commodities and even currency exchange rates. Such broad market influences impact LDCs and other gas suppliers, making it difficult for all stakeholders to plan. In order to deal with the inherent uncertainty of the market, supply planners use a portfolio approach to pricing gas supplies just as they do for supply providers and transportation options.

Along with the variety of pricing mechanisms and contract terms noted below, the notion of adding fixed-price longer-term supply contracts to company portfolio management has resurfaced as a tool for price stability in today's volatile market. Even some key future gas supply projects, such as the Alaska Natural Gas Pipeline, would seem to beg for longer-term demand pull contract arrangements in order to be successful. When asked if a company would include fixed-price supply deals in their acquisition portfolio (1-3 year terms in the $5-6 per MMBtu range), 25 of 50 companies answered yes, if regulators approved the action, and 13 said maybe. Likewise, over half (38 of 55 companies) answered yes to the same question one year prior. For the 2010-11 winter heating season, 11 of the 29 companies that answered yes or maybe chose an optimum percentage of 11-20 percent of their total supply portfolio for these longer-term deals, while eight companies selected 1-10 percent and three companies opted for 21-30 percent and three chose 31-40 percent. Only two companies indicated that they would consider over 50 percent of their total supply portfolio for long-term, fixed-price deals. In addition, 17 of the 28 companies responding indicated a preference for 1-2 years duration on the deal's term.

When examining the natural gas purchasing practices of companies during the past several winter heating seasons, it is clear that first-of-the-month (FOM) index pricing dominates the market for the largest portion of supply agreements, whether short, long or mid-term. Table 5 provides a closer look at the balance of pricing mechanisms among survey respondents during the 2010-11 winter heating season.

As shown in Table 5 and Figure 5, for long-term supplies (one year or more), 28 of the 39 companies with such supplies used FOM pricing for a portion of these supplies, including 21 companies that used FOM for 51-100 percent of purchases. Thirteen companies used daily pricing mechanisms for a portion of their long-term arrangements, and 15 companies utilized some form of fixed pricing (compared to 9 and 15, respectively, for the 2007-08 WHS). Seven years ago, when the survey included 65 respondents, the number of companies citing fixed deals was only 10.

Figures 5 through 8 show pricing mechanisms employed by this year's survey participants, and Figures 5 and 6 provide a comparison of long-term pricing arrangements of this year's with last year's sample of companies. Comparing Figures 5 and 6 (2010-11 and 2009-10 WHSs, respectively) indicates that for the winter heating season just past, daily and fixed pricing played a slightly more prominent role for large volumes of long-term gas relative to other pricing mechanisms and perhaps that is understandable with the apparent development of relative price stability in the natural gas market given the overall strong position of natural gas supply demonstrated by year-over-year growth in domestic production for five straight years.

With that said, the graphs again clearly show that for larger volumes of gas purchased under long-term arrangements, first-of-the-month indices were the predominant pricing mechanism during 2010-11 just as they were for the 2009-10 winter. This isn't surprising since that first-of-the-month index is not only a measure of market movements but is often a baseline from which hedging strategies can be measured.

According to the 44 companies that had mid-term supplies (more than one month, less than one year) during the 2010-11 WHS, these natural gas purchases were tied to FOM indices for much of the supply volume arranged. However, as Table 5 and Figure 7 indicate, daily, fixed and NYMEX pricing mechanisms were used for smaller-volume mid-term purchases. Twenty companies reported using fixed pricing mechanisms for mid-term purchases, compared to 15 for long-term purchases. Twenty companies also used daily prices for mid-term purchases, compared to 13 for long-term purchases.

TABLE 5

GAS SUPPLY PRICING MECHANISMS – WINTER HEATING SEASON 2010-11

PERCENTAGE RANGES PEAK-DAY VOLUMES	AVERAGE LAST 3 DAYS	DAILY	FIRST-OF-THE-MONTH INDEX	FIXED	NYMEX	WEEKLY	OTHER
LONG TERM ONE YEAR OR GREATER (39 LDCS; 11 N/A)							
1 – 25%	0	7	3	3	3	0	1
26 – 50	0	3	4	1	1	0	0
51 – 75	0	1	3	0	0	0	0
76 – 100	0	2	18	11	1	0	0
0	39	26	11	24	34	39	38
MID TERM GREATER THAN ONE MONTH, LESS THAN ONE YEAR (44 LDCS; 6 N/A)							
1 – 25	1	10	7	11	4	0	0
26 – 50	0	7	9	4	4	0	0
51 – 75	0	3	7	2	0	0	0
76 – 100	0	1	16	5	1	0	0
0	43	23	5	22	35	44	44
SHORT TERM ONE MONTH OR LESS (44 LDCS; 6 N/A)							
1 – 25	0	9	14	5	4	0	0
26 – 50	1	10	4	4	0	0	0
51 – 75	0	5	4	6	2	0	0
76 – 100	0	11	6	5	1	0	0
0	43	9	16	24	37	44	44

FIGURE 5

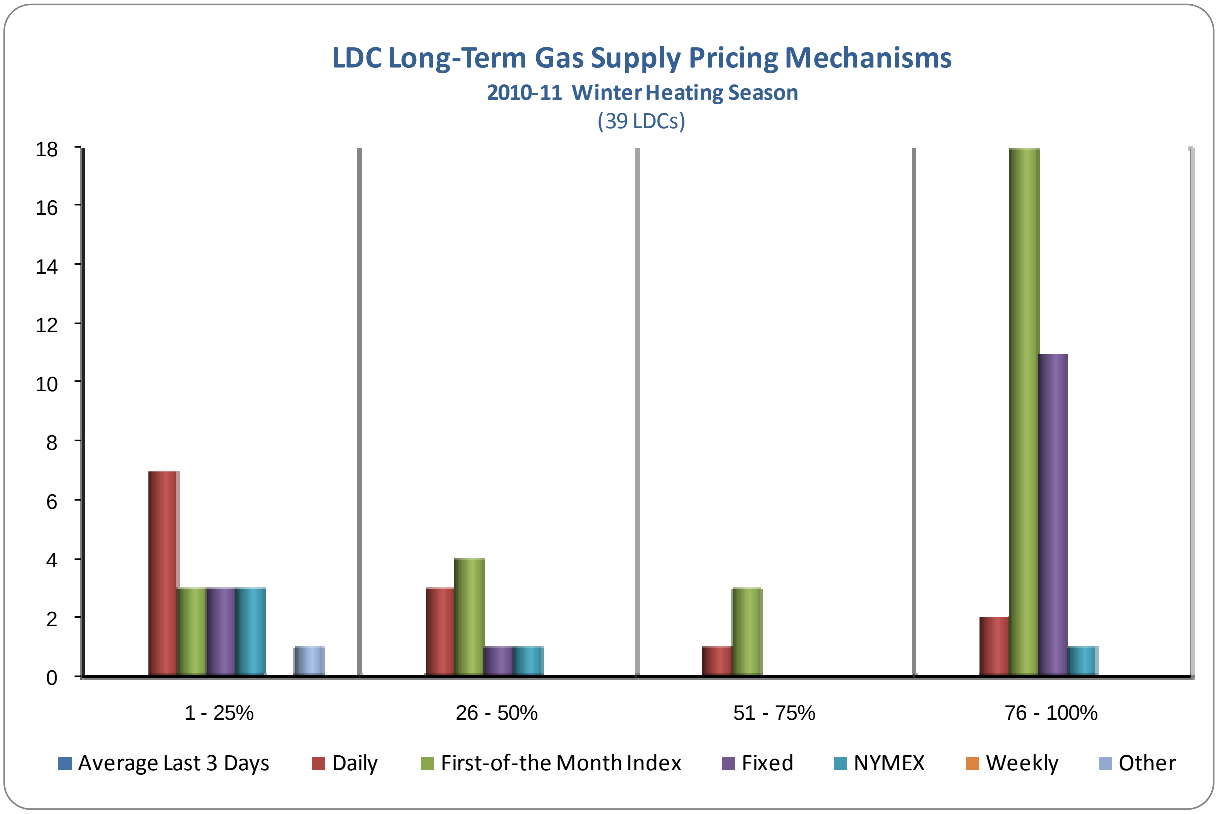


FIGURE 6

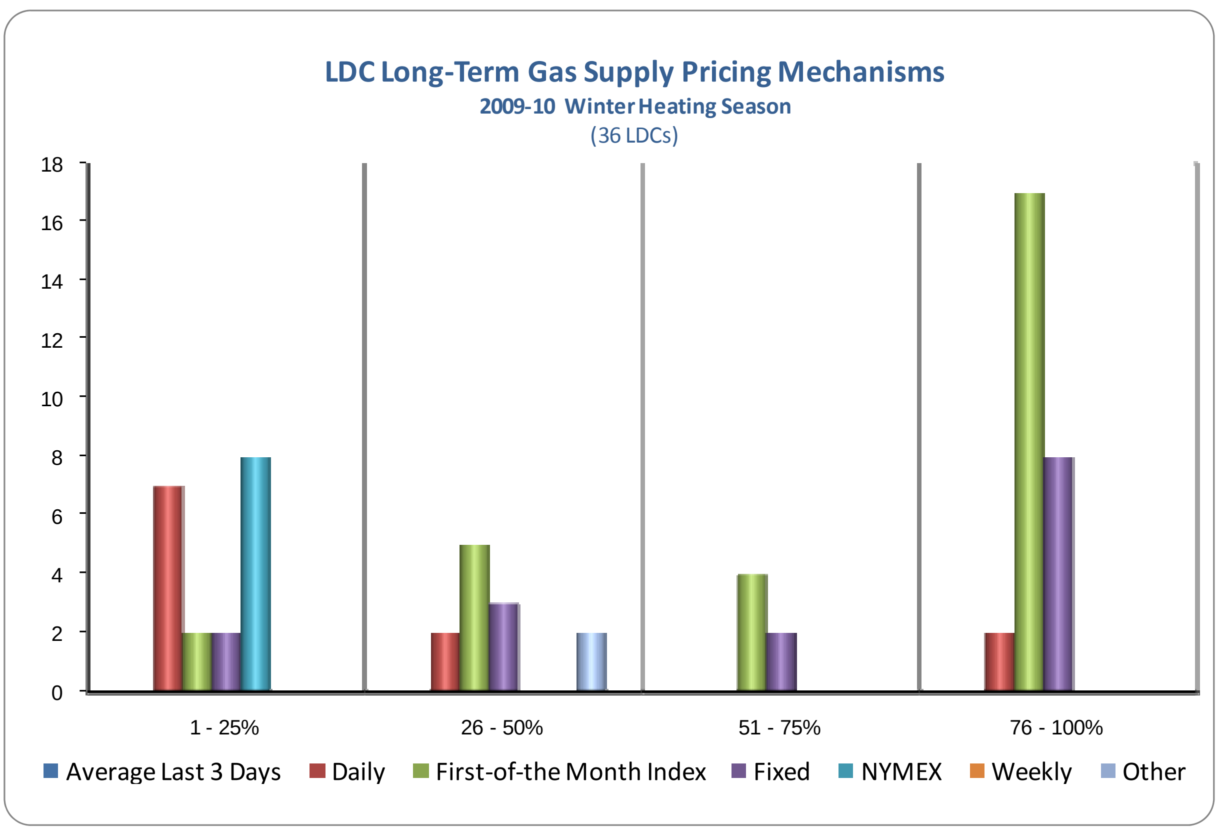
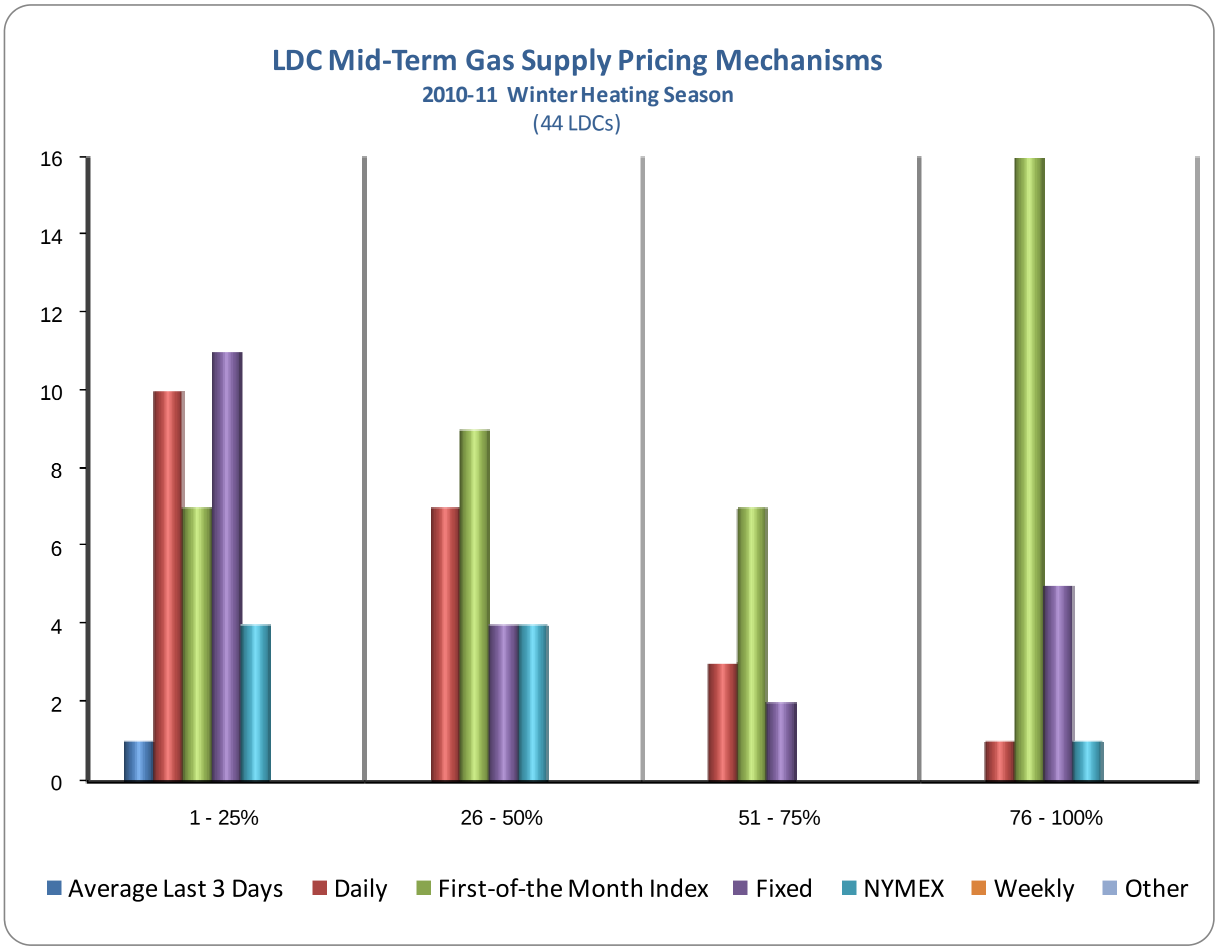
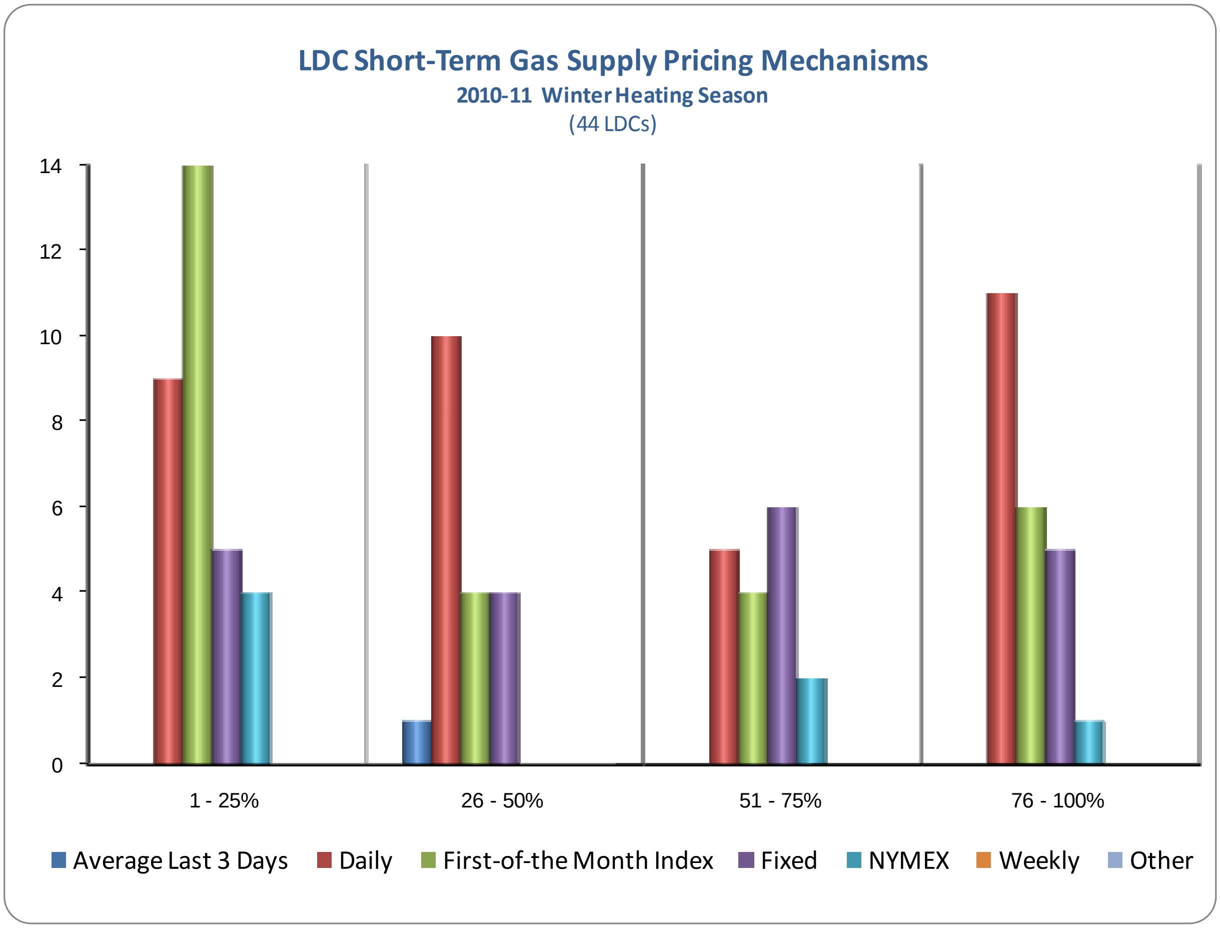


FIGURE 7



As would be logical, short-term purchases (one month or less), for the 44 companies identifying such supplies during the 2010-11 WHS, included more daily pricing (35 of 44 companies) than mid-term and long-term purchases; however, these short-term purchases were also heavily dependent on first-of-the-month indices (28 companies). They were also tied to fixed prices and NYMEX indices (see Table 5 and Figure 8). It should be noted that LDCs build gas supply portfolios and pricing strategies based on prior and 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 impact on the delivery of natural gas and services to customers at the lowest possible cost.

FIGURE 8



Hedging Mechanisms

Market developments during and since the 1990s have expanded the options available for acquiring gas supply, trading transportation capacity and the use of financial instruments. Today, industry players use futures contracts and other tools to offset the risk of commodity price movements. These financial instruments, which to some extent include fixed-price gas purchase contracts, futures, swaps and options, allow gas supply portfolio managers to hedge or lock in a portion of the gas cost component of gas supplies. This is achieved particularly 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.

Ninety-two percent of the companies responding to the AGA WHS survey said they used financial instruments to hedge a portion of their gas supply purchases during the 2010-11 winter. This number is close to the percentage of respondents using financial tools in the two preceding surveys (90 percent and 89 percent in 2009-10 and 2008-09, respectively). The 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 sample companies and sample size were different each year.

For this past winter, 34 of 51 responding companies hedged up to 50 percent of their gas supply purchases compared to 35 companies the prior winter. Fixed price contracts (27 companies), options (26 companies), swaps (20 companies) and futures (14 companies) were most often cited as tools used to hedge a portion of peak-day gas volumes. Although any one company can use more than one instrument, the use of financial instruments may be understated in this report inasmuch as some volumes delivered to LDCs from marketers and other suppliers are hedged by a third-party rather than the LDC or customer and may have been excluded from the LDC hedging calculation.

Only two out of 51 companies indicated that they used weather derivatives during the 2010-11 winter heating season. This compares to five companies out of 76 in 2006-07 and seven companies out of 54 in the 2004-05 survey.

When asked about the timing of hedging strategies, 37 of 51 responding companies (73 percent) indicated that they applied a six-month or less strategy for a portion of their hedges for the 2010-11 winter heating season. During the 2010-11 WHS, 38 companies used a 7-12 month strategy and 25 employed a greater than 12-month strategy. Of course, a single company may use one or all strategies simultaneously. In fact, 19 of the respondents did just that compared to the 2009-10 WHS which 44 companies used all three timing strategies.

Thirty-four of 51 responding companies indicated that for the upcoming (2011-12) winter heating season they planned to hedge at the same level as in the 2010-11 season. Two companies plan to hedge more of their purchased gas volumes (compared to three companies in 2009-10), and six intend to hedge less than in 2010-11. One of 51 companies reported that their public utility commission (PUC) was more receptive to hedging strategies than in the past, while the majority (42) indicated PUC receptivity to be the same compared to last year. In addition, among the 51 companies reporting, seventeen indicated that state regulators place restrictions on the use of financial tools for hedging (e.g., choice of tools, date ranges and volumes); while 12 companies noted that hedging programs required that plans be filed for approval.

On the physical side, companies view gas delivered to storage during the summer refill season as a price hedge against potential winter run-ups. In preparation for the 2010-11 winter heating season, all 51 reporting companies used storage as a physical hedge (just as all 56 companies in last year's survey had indicated). Forty-six companies reported using storage for 1 to 50 percent of winter heating season supplies compared to 52 companies in 2009-10.

When asked about their own regulatory environment, 88 percent (45 of 51 responding companies) indicated that financial losses and gains were treated equally within their hedging plans, compared to 81 percent one year ago and 78 percent the year before that. Additionally, 46 of 51 companies answered yes when asked if costs associated with their financial hedging programs were fully recoverable (the one respondent answering *no* to the question reported that 80 percent of hedging costs were recoverable). When asked whether their PUC was focused more on natural gas being purchased at the lowest possible price, a stable price or both, thirty-two companies said the focus was equally on both; nine felt their commission to be more focused on lowest price; while eight indicated that regulators were more concerned with price stability.

Motivations behind hedging programs are varied among survey respondents. In some jurisdictions there are no formal standing plans. In others, LDCs may actually be required to hedge portions of future gas supplies with those hedges required to be in place by predetermined dates. Variations on these themes are many and are geared to fit the interplay among a local distribution company, the regulator and market conditions in a given area.

VII. Gas Storage

As noted earlier, LDCs are concerned with managing gas supply and transportation portfolios efficiently and to reduce costs. Production area storage and market area storage can help LDCs meet such goals. The use of storage facilities helps LDCs to both meet short-term swing opportunities and satisfy peaking needs.

Table 6 shows storage levels as estimated by the Energy Information Administration for January- April 2010 compared to the same period in 2011. For the nation as a whole, working gas inventories in both years were not particularly strained, even though by the time net injections began in earnest in mid-April 2011 working gas levels were about 175 Bcf behind that of April 2010. During 2008-09, underground storage exceeded 2007-08 levels by 25-440 Bcf for most of the winter. In fact, at the end of the winter heating season on March 31, 2009 about 1.65 Tcf remained in storage identified as working gas compared to 1.24 Tcf at the end of March 2008. For the 2009-2010 winter, working gas inventories in November were over 3.8 Tcf (a working gas record) and ended the following March 31 at about 1.6 Tcf – essentially the same remaining inventory as in March 2009.

TABLE 6

AMERICAN GAS STORAGE SURVEY
WORKING GAS IN STORAGE

	2010 (Bcf)					**2011** (Bcf)			
	Total	**Prod**	**East**	**West**		**Total**	**Prod**	**East**	**West**
Jan 1, 2010	3118	1006	1678	434	Dec 31, 2010	3097	1079	1590	428
	2852	906	1532	414		2959	1059	1510	390
	2607	810	1401	396		2716	968	1384	364
	2521	807	1334	380		2524	912	1280	350
	2406	796	1251	359		2353	856	1165	332
Feb 5	2215	736	1135	344	Feb 4	2144	789	1055	300
	2025	673	1030	322		1911	698	937	276
	1853	607	935	311		1830	687	880	263
	1737	580	861	296		1745	696	809	240
Mar 5	1626	548	789	289	Mar 4	1674	703	748	223
	1615	562	770	283		1618	700	697	221
	1626	581	760	285		1612	715	675	222
	1638	596	753	289		1624	740	668	216
Apr 2	1669	627	750	292	Apr 2	1579	742	616	221
	1756	665	795	296		1607	763	623	221
	1829	696	829	304		1654	780	652	222

Source: Energy Information Administration.

With the 2010-11 winter colder than normal for the country, working gas levels ended the traditional withdrawal season on March 31 slightly lower at about 1.58 Tcf compared to the prior year. Even though the producing region had more remaining in storage than the previous year at season's end, the consuming regions west and east were lower reflecting the colder than normal conditions particularly in December, January and the first half of February 2011.

Fifty-one responding companies (100 percent) indicated that weather-induced demand compelled them to utilize storage services. However, respondents also singled out no-notice requirements (42 companies), “must turn” provisions (32 companies) and pipeline operational flow orders (24 companies) as reasons to maintain storage services within their gas supply portfolio. Twenty-three companies also stated that arbitrage opportunities influenced their storage decisions during the 2010-11 winter heating season – one less than noted the prior winter heating season. More than one factor often influenced LDCs to use storage. For example, 14 companies noted that they were influenced by all of the above-mentioned reasons.

Many reasons underlay decisions for injecting gas into storage during the spring-summer storage refill season in 2010. Price considerations were noted by 44 of 51 companies, and supply reliability considerations influenced 46 companies. In addition, 48 companies (94 percent) cited operational issues as influencing storage injection patterns in 2010, while 25 companies indicated that regulatory plans and mandates impacted their storage strategies. Of course, more than one influence may underlie a company’s decision to use storage. In fact, 21 of the 51 companies said that all of the above factors influenced storage injection decisions.

TABLE 7

PRICING MECHANISMS FOR GAS INJECTED INTO UNDERGROUND STORAGE
2010 STORAGE REFILL SEASON

(51 Companies)

PERCENTAGE RANGES STORAGE VOLUMES	AVERAGE LAST 3 DAYS	DAILY	FIRST-OF-THE-MONTH INDEX	FIXED	NYMEX	WEEKLY	OTHER
1 – 25%	1	14	8	13	4	0	0
26 – 50	0	12	7	5	4	0	0
51 – 75	1	0	10	4	1	0	0
76 – 100	0	4	18	4	0	0	0
0	48	20	7	24	41	50	50

Source: *2010-11 AGA LDC Winter Heating Season Performance Survey.*

Table 7 and Figure 9 show that many of the gas purchases made during 2010 for storage injections (in preparation for the 2010-11 winter heating season) were made based on first-of-the-month indices (43 companies), although daily, fixed price and even NYMEX-based gas pricing were also prevalent, particularly for small volumes of gas destined for underground storage. The same is reflected in Figure 10 for the refill period in 2009. Looking back to 2007, 27 of 57 companies indicated that more than 75 percent of the supplies purchased for storage injections were FOM priced. Twenty-three of 53 companies did the same in 2008 and 19 of 55 did so in 2009. Fixed price schedules accounted for storage volumes injected by 26 companies reporting for 2010, while daily pricing applied to 30 of the surveyed companies. Daily pricing was generally applied to 1-25 percent of gas purchased for underground storage in 2009 but also up to 50 percent in 2010.

FIGURE 9

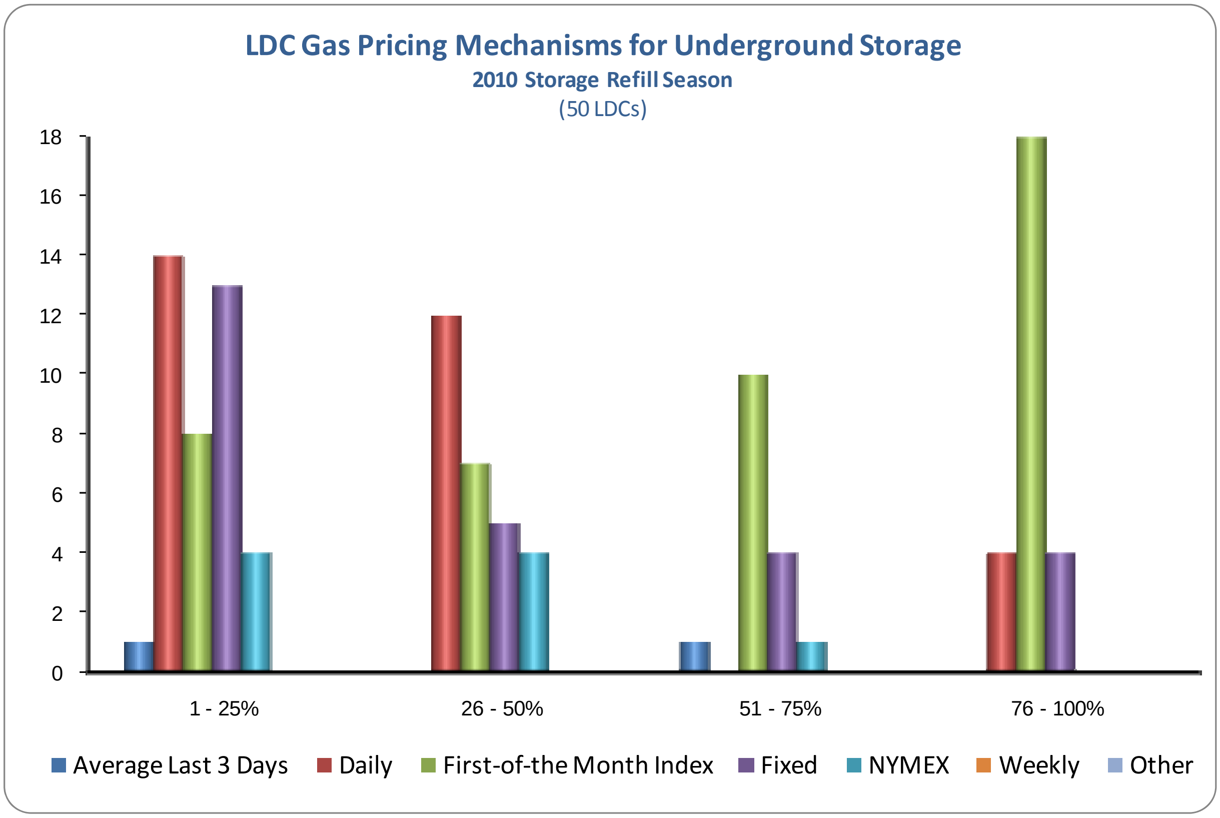
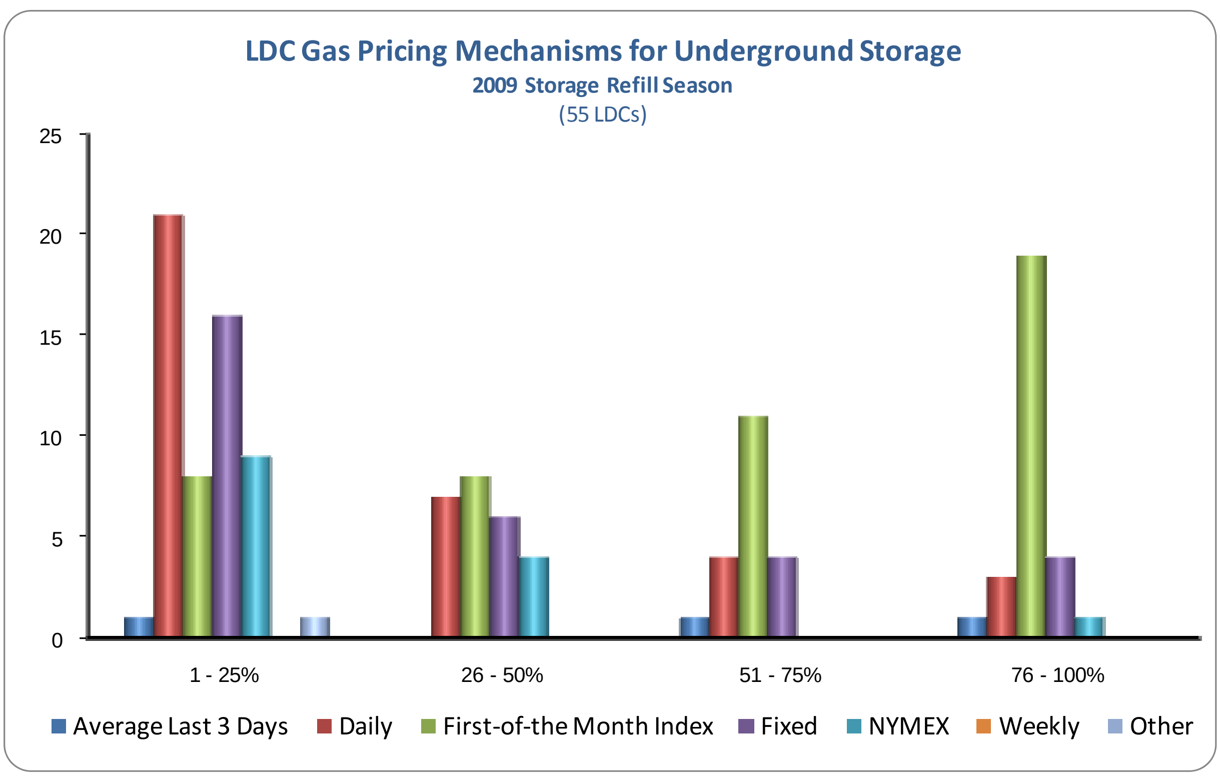


FIGURE 10



Eleven companies indicated that they were building or examining options to build underground storage additions during the next five years. In addition, eight companies were building or considering additions or expansions of peak-shaving facilities. Regarding contracted storage capacity, only four companies plan to increase underground storage for the 2011-12 winter heating season, while 47 companies intend to keep the same capacity as this past year. Additionally, one company plans to contract for additional peak-shaving capacity for 2011-12, while 49 expect to remain the same. Of 51 responding companies, 15 indicated that they had flowed gas from storage to serve gas-fired electric generation load during the 2010 storage injection season – the same as one year prior.

VIII. LDC Transportation and Capacity Issues

Transportation-only customers have assumed a higher profile among customers served by LDCs. As stated before, planning for transportation capacity and supply is generally held hostage to weather, economic activity and other factors that influence gas consumption. Managing pipeline capacity efficiently is a challenge for LDC's and can involve the release of capacity to the secondary transportation market, if events allow it.

TABLE 8

PERCENTAGE OF LDC PIPELINE CAPACITY RELEASED
2010-11

	2010 (38 LDCs; 13 N/A)									**2011** (34 LDCs; 17 N/A)		
PERCENTAGE RANGE RELEASE PIPELINE CAPACITY	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR
1 – 25%	26	22	23	22	22	22	24	24	26	26	25	22
26 – 50	4	8	5	5	7	6	3	6	3	3	4	6
51 – 75	2	2	2	2	2	2	2	0	1	1	0	1
76 - 100	3	3	3	3	3	3	3	3	2	2	3	2
0	3	3	5	6	4	5	6	1	2	2	2	3

Source: 2010-11 LDC Winter Heating Season Performance Survey.

Table 8 presents a brief view of this topic. LDCs were asked to identify the percentage of pipeline capacity they held and released to the secondary market each month from April 2010 to March 2011. This table highlights some interesting elements. Most of the responding companies released less than 25 percent of their capacity throughout the year. During the spring-summer months, and as might be expected, more companies made up to 50 percent of their releasable capacity available to the secondary market. This makes sense, assuming that LDCs, trying to meet seasonal heating loads, are less likely to have a large excess of capacity during the winter heating season months.

In addition to the data above, 20 of 51 companies used capacity held on *non-affiliated* interstate pipelines to make off-system wholesale natural gas sales. Only two companies used capacity held on *affiliated* interstate pipelines to conduct wholesale natural gas transactions.

Regarding system operations, 37 percent of the companies in the 2010-11 Winter Heating Season survey indicated that they had been impacted by the issuance of operational flow orders (OFOs). During the 2009-10 WHS, 41 percent of the companies experienced OFOs. This compares 74 percent (48 of 65 companies) during the 2002-03 WHS and 51 percent during the 2003-04 winter. For the 19 companies reporting OFOs during 2010-11, the median number of OFOs issued was four. Duration for the OFOs ranged from 1 to 130 days; however, the median duration was only three days.

IX. Local Gas Utility Regulatory, Rates and Other Issues

Examining other regulatory issues, survey participants were asked if regulators in their state or states of operation were formally investigating their gas acquisition prices for the 2010-11 winter heating season. Thirty-two of 51 companies indicated to the affirmative, however, all described the investigations as *routine*. In addition, when asked if regulators were delaying full cost recovery for gas sales incurred during the 2010-11 winter, all 51 companies replied no.

Recovery of gas costs was further described in terms of method of recovery. Twenty-six of the 51 companies responding indicated that gas costs incurred over a period of time were passed through to customers with over-or under-recovery deferred with interest and collected or distributed during a subsequent period subject to prudence review. An additional 19 companies agreed but without the interest component.

Given a portfolio approach to gas acquisition and price management during the past winter heating season, companies were asked to identify the most effective supply and price management tools that they employed. Those noted included physical storage, fixed price contracts and physical call options. When asked if there were products they would have liked to use more, for the most part the companies indicated none or not applicable. When cited companies most often including more hedging overall and the use of additional fixed price arrangements.

When asked if the gas utility offered a fixed price option to customers, eight of 51 answered yes and 43 answered no. However, 41 of 51 companies noted that customers benefited from financial hedging as a tool for reducing price volatility. Others cited overall reduced gas costs, while nine companies pointed to both as significant contributors to customer benefits when interacting with regulators. In addition, weather normalization clauses were used within rate structures by 26 of 51 companies. And finally, 19 of 51 companies were permitted by regulators to retain part or all of their off-system wholesale gas revenues. Fourteen companies were not and 18 viewed the issue as not applicable.

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