Recent Trends in Natural Gas Spot Prices

John Herbert, James Thompson, and James Todaro

The unique conditions of one winter versus another have resulted in sharply different natural gas price patterns during the past three heating seasons. Weekly spot prices at the Henry Hub in November, December, and January have differed markedly between years with no discernible pattern. Perhaps the only common facet of prices in these months over the past several years has been their increased volatility compared with prices during the rest of the year. Further, wintertime price volatility is such that prices this January could vary from year-earlier levels by as much as $1.00 per million Btu (MMBtu). Based on recent trends in natural gas supply and consumption and current weather forecasts, however, it is likely that spot prices at the Henry Hub during January 1998 will be less than during the previous January, perhaps by as much as $0.40 per MMBtu.

This article focuses primarily on conditions and developments in the East Consuming Region and their connection to prices at the Henry Hub in the Producing Region.[1] The East Consuming Region is characterized by high gas consumption, particularly in the residential and commercial sectors, with much of the gas supplied from the Producing Region (although a fair amount is also imported from Canada). The Henry Hub in southern Louisiana is a major market center with interconnections for many of the pipelines that transport U.S.-produced gas to the eastern consuming States. Further, it is the preferred reference point for prices for most of the domestic gas destined for the East. Therefore, market conditions and developments in the East Consuming Region and price movements and trends at the Henry Hub are usually highly correlated.

The article discusses recent trends in Henry Hub spot prices, placing special emphasis on the relationship between prices and storage practices in both the East and Producing regions. It also highlights overall market trends in recent years and provides an indication of current market conditions in the East Consuming Region and expected price levels. Special attention is devoted to storage for several reasons. First, storage withdrawals are the swing source of supplies and satisfy a significant proportion of total demand during the heating season. Second, of the three supply components, storage information is the most current.[2] Also, in contrast to other sources of natural gas supply, working gas storage levels represent inventories ready for market.

Pre-Heating Season Prices: The Storm Before the Calm?

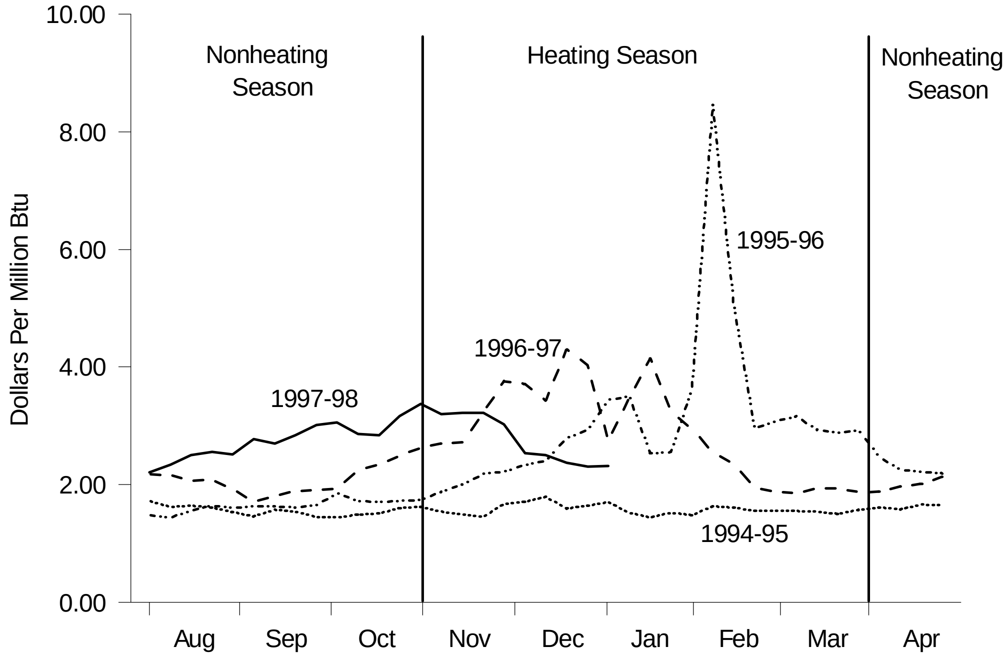
The 3-month period leading up to the beginning of the 1997-98 heating season witnessed quite different price behavior from that of the past 3 years (Figure FE1). Weekly average spot prices at the Henry Hub at the beginning of August 1997 were nearly identical to year-earlier levels and about $0.80 per MMBtu above those in August 1994 and 1995. From this point, spot prices climbed almost unremittingly through October. Weekly average prices during October ranged from $0.50 to $1.13 more than levels the previous year. For the 7 weeks between the beginning of October and the middle of November, prices greatly exceeded those in 1994 and 1995. For 4 of these weeks, prices were more than double the corresponding 1994 prices.

Not only were spot prices during this 3-month period much higher than in the past 3 years, but for much of this period spot and futures prices were very volatile, with futures prices consistently higher than spot prices in late September and throughout most of October. From the second week in September through the third week of October, prices often varied by $0.25 per MMBtu or more from one week to the next and futures settlement prices at the Henry Hub for month-ahead deliveries were often more than $0.25 per MMBtu higher than spot prices.

[1]The regions used in this analysis correspond to the three regions in the American Gas Association's weekly storage survey. The East Consuming Region includes all States east of the Mississippi River less MS, plus IA, NE, and MO. The Producing Region comprises TX, OK, KS, NM, LA, AR, and MS, while the West Consuming Region consists of all States west of the Mississippi River less the Producing Region and IA, NE, and MO.

[2]Since 1994, the American Gas Association has conducted a weekly survey of gas storage, presenting the results on a national level and separately within three regions of the country: the Producing Region, the East Consuming Region, and the West Consuming Region. The Energy Information Administration reports monthly survey data in the *National Gas Monthly* 2 months following the report month and preliminary estimates at the national level for the 2 most current months.

Figure FE1. Henry Hub Weekly Average Natural Gas Spot Prices



Source: Pasha Publications, Inc., *Gas Daily.*

This runup in prices prior to the heating season, accompanied by high price volatility and market premiums for future supplies (reflected by futures prices consistently higher than current spot prices), is attributable to a variety of factors. Some of these factors involve demonstrable market conditions, while others stem from various perceptions of market conditions or possible developments.

One reason for the elevated prices is that replacement costs for production are significantly more than year-ago values. Leasing rates for offshore rigs have doubled in the last year from slightly over $30,000 per day to almost $70,000.[3] Yet, the major problem facing drillers is having adequate crews to staff rigs.[4] The skilled workforce has been declining fairly steadily in the past 10 years. As late as the fall of 1995, when the conventional wisdom in the domestic oil and gas industry was that low prices would prevail at least though 1996, support was very much alive for continued aggressive costcutting, including few new hires.

The slowdown in the growth of imported gas from Canada in recent years is another factor in the higher prices. Canadian gas, even including the costs of transportation to various markets, is less expensive on average than domestically-produced gas. For example, the average price of gas for December 1997 delivery at the AECO-C Hub, the major hub in Canada, was $1.17 per MMBtu.[5] This compares with a price of $2.20 per MMBtu at the *Gas Daily* pricing point on the El Paso pipeline in New Mexico, which is near one of the least expensive producing areas in the United States. At Emerson, a popular pricing point for Canadian gas into the North Central United States, gas for December delivery was $2.33 per MMBtu. In comparison, the natural gas price at the Henry Hub in Louisiana, which also serves the North Central United States, the cost was $2.54 per MMBtu. However, the pipelines available to bring gas from Canada into the United States are becoming more fully utilized, thus dampening the growth of imported Canadian gas, even though about 230 million cubic feet per day of deliverability from Canada was added in 1997. Several new pipeline projects have been proposed, but until the new lines are in operation, the slowing growth of imports will continue to put upward pressure on prices if demand increases as expected.

[3]Ira Breskin, "Oil and Gas Drilling," *Investor's Business Daily* (November 10, 1997), p. 39.

[4]Martha M. Hamilton, "a Return to Success for Oil Services," *The Washington Post* (November 9, 1997), p. H2.

[5]The AECO-C Hub price was converted from joules to British thermal units (Btu) using a conversion factor of 1,055 joules per Btu. Canadian dollars were converted into U.S. dollars using an exchange rate of 0.7 U.S. dollars to 1 Canadian dollar. Pasha Publications, *Gas Daily Price Guide* (Arlington, VA, December 1997).

An unexpected increase in natural gas demand by electric utilities in the south central part of the United States as a result of coal deliverability problems also contributed to the higher prices. This past summer and fall, these utilities were using increased amounts of natural gas to substitute for the decline in rail shipments of coal (see Box, “Coal Deliveries to Texas Electric Utilities”).

Another reason for the relatively high prices is the perception that increased demand for gas by industrial customers may have significantly increased the average level of gas flowing on particular pipeline systems. These higher flow rates would increase the chance of constraints developing along these systems when demand shifts suddenly. This may encourage companies to pay more for guaranteed supplies of incremental gas along these systems. If customers purchase guaranteed supplies, they avoid the chance that congestion will preclude their access to supplies. If congestion develops, it could raise prices even higher. In short, there was increased concern in the late summer and early fall of 1997 that the chance of pipeline bottlenecks had grown in the past several years.

There was also much concern in the fall of 1997 as to the amount of working gas that would be held in inventory at the beginning of the heating season. This concern was a major factor in the elevated prices and great price volatility.[6] Industry participants and observers wanted to know: first, would storage levels this year reach or exceed those of last year—a year in which they had reached record low levels; and second, would these levels be sufficient to accommodate any increased demand over the previous year’s levels? (See the discussion under “Inventory Levels, Withdrawals, and Pre-/Early Heating Season Prices.”)

Storage: The Key to Prices

Of the factors discussed, perhaps the most important is that of natural gas storage. This is certainly true in the near term leading up to the heating season and throughout the heating season. In fact, in the view of many natural gas industry participants and observers, it would be difficult to overstate the importance of storage and information about storage levels and stock builds and drawdowns in influencing prices in both cash and futures markets. The reverse is also true with prices having a direct impact on storage practices.[7]

Storage withdrawals are the swing source of supplies and satisfy a significant proportion of total demand during the heating season, particularly in the East Consuming Region. During heating seasons, monthly withdrawals from the region’s storage facilities average about 27 percent of the region’s monthly consumption. During the past 7 years, this proportion has often been over 30 percent, and as high as 38 percent. The way the market perceives the adequacy of storage levels relative to expected demand in the East Consuming Region is likely to have a major influence on both current and future prices, because working gas levels, storage withdrawals, and consumption in this region typically average about 65 percent of the national total (Figure FE2).

Certainly some of the large incremental demand by commercial and residential customers during the winter is satisfied by an increase in production and imports, but still the largest proportion of this demand is satisfied with withdrawals of gas from storage (Figure FE3). The similar appearance of the lines for residential and commercial consumption and storage withdrawals in Figure FE3 illustrates visually the dependence of these sectors on storage withdrawals to satisfy heating season demand. In comparison, imports and dry gas production are relatively flat, although gas production increases modestly between November and December. Some of this production in November and December is stored as linepack when available supplies to market exceed actual deliveries.[8] All supply series tend to decline after January as the worst of winter is usually over by this time.

Of the three components of supply—production, imports, and storage withdrawals—storage is the only component for which there is reasonably current, comprehensive, and widely-disseminated information about its magnitude and availability. While there are undeniably myriad factors that influence gas prices, many are elements for which there are sparse, incomplete, or

[6]Volatility in daily futures prices can also influence volatility in spot prices when hedge funds open or close out futures position. This occurs because of the large position these companies take in the market.

[7]Some storage operators delay storage build ups in anticipation of lower prices or add to storage when prices are perceived to be low. For a further discussion of this and related issues, see J.H. Herbert, J.M. Thompson, and C. Ellsworth, “Gas Storage: What Moves the Market and What Doesn’t,” *Public Utilities Fortnightly* (December 1997), pp. 46-51.

[8]When the average amount of gas delivered to a pipeline exceeds the average amount taken, then the pipe can be considered as packed with gas and the gas designated as linepack.

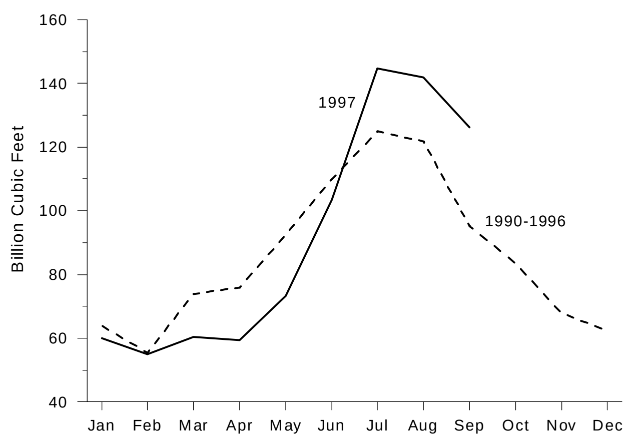
Coal Deliveries to Texas Electric Utilities

The merger of the two largest rail systems in the Southwest, the Southern Pacific and Union Pacific (UP) under the UP banner, has brought about severe logistical problems that have affected the delivery of goods and commodities throughout the region. Delay in the shipment of western coal to the region's electric utilities has been one of the more serious problems caused by this predicament and the situation seems most prevalent in Texas. The Texas Railroad Commission reported in October that several large electric utilities in the State had increased their consumption of natural gas in order to offset low coal stocks.

Texas is the largest consumer of natural gas in the country (3.5 trillion cubic feet in 1996), with electric utilities accounting for almost a third of the State's consumption. Based on Energy Information Administration data, most of the consumption by electric utilities occurs during the months of April to October to meet air-conditioning demand. In 1996, 70 percent or 722 billion cubic feet (Bcf) of the total 1,040 Bcf consumed by Texas electric utilities occurred in the April-to-October period. Energy Information Administration data also indicate that electricity demand in Texas during the winter months is, on average, about a third less than in the summer, again because of the reduction in the air-conditioning load.

The Department of Energy's Office of Emergency Management (EM) has reported that several electric utilities in Texas have instituted coal conservation plans and increased their consumption of natural gas. The most recent EIA data indicate that natural gas consumption at electric utilities in Texas increased in August and September by 18 percent and 40 percent, respectively, when compared with the same months last year. Coal consumption also increased during the same time period but at a much lower rate—3 percent in August and 1 percent in September. As shown in the following figure, natural gas consumption at Texas utilities during the period July through September is about 20 percent above the average for the previous 7 years.

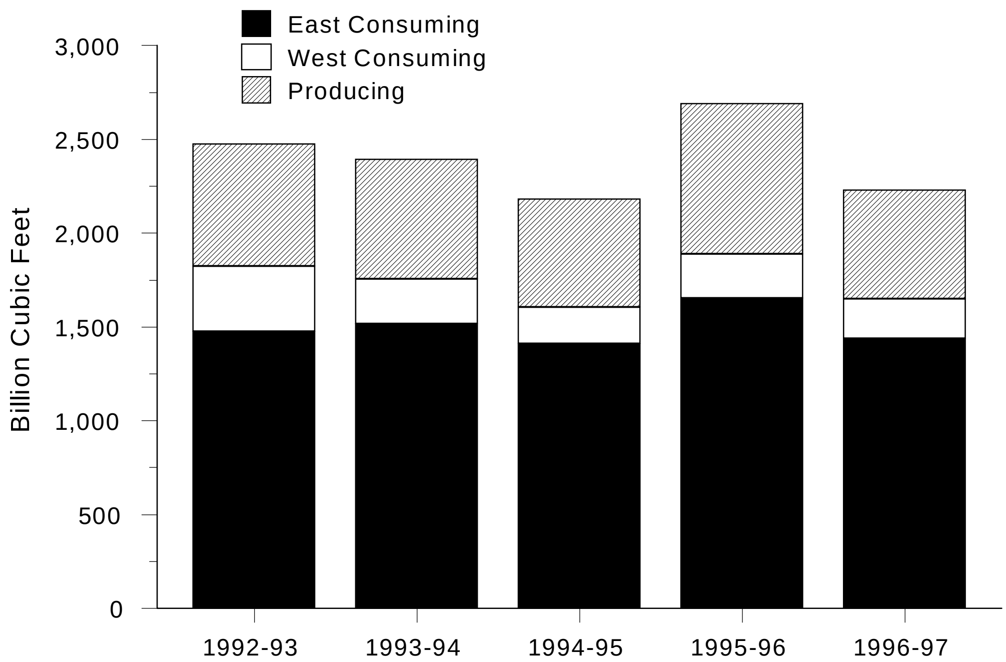
Natural Gas Consumption by Texas Electric Utilities



The weather in much of the Southwest and especially in Texas was quite hot in September, with cooling degree days for the month 21 percent higher than normal. In response to the high temperatures, electricity demand in Texas increased about 20 percent compared with the same month last year. These increases in gas consumption in Texas in recent months would indicate that the coal shipment problems in Texas have affected natural gas use and contributed to the price increase that began in August.

In late October, Union Pacific reported to the Surface Transportation Board, the successor to the Interstate Commerce Commission, that the situation has stabilized and is showing some improvement. The company reported that it is making progress in unclogging train movements into and out of Texas. The Office of Emergency Management reported in November that Union Pacific's overall car exchanges were increasing and unit coal car turnaround time had improved but average train speed still remained below normal. Based on recent price activity at major market hubs in Texas (prices have declined more than $1.00 per MMBtu since late October), it seems that supplies of natural gas are adequate to meet increased demand from electric utilities.

Figure FE2. Natural Gas Withdrawals from Storage in the East Consuming Region Make Up a Significant Portion of Total U.S. Withdrawals During the Heating Season



Source: Energy Information Administration, Office of Oil and Gas, *Natural Gas Monthly*.

untimely data; others are perceptions based on "guesstimates" or anecdotal information. In a way, storage information has become a proxy for industry conditions. Storage data, because they are relatively current and readily available, are viewed as the "bottom line" by the market in terms of current and near-term conditions, particularly leading up to and during the heating season.

In contrast to the other supply components, working gas storage represents gas readily available for markets. The other components of supply are generally upstream of markets and thus do not represent supplies readily available. Consequently, concerns about the adequacy of storage levels can put significant upward pressure on prices as the heating season approaches, while relatively large amounts of gas in storage throughout much of the heating season can depress prices even below levels experienced during the off-peak summer months.

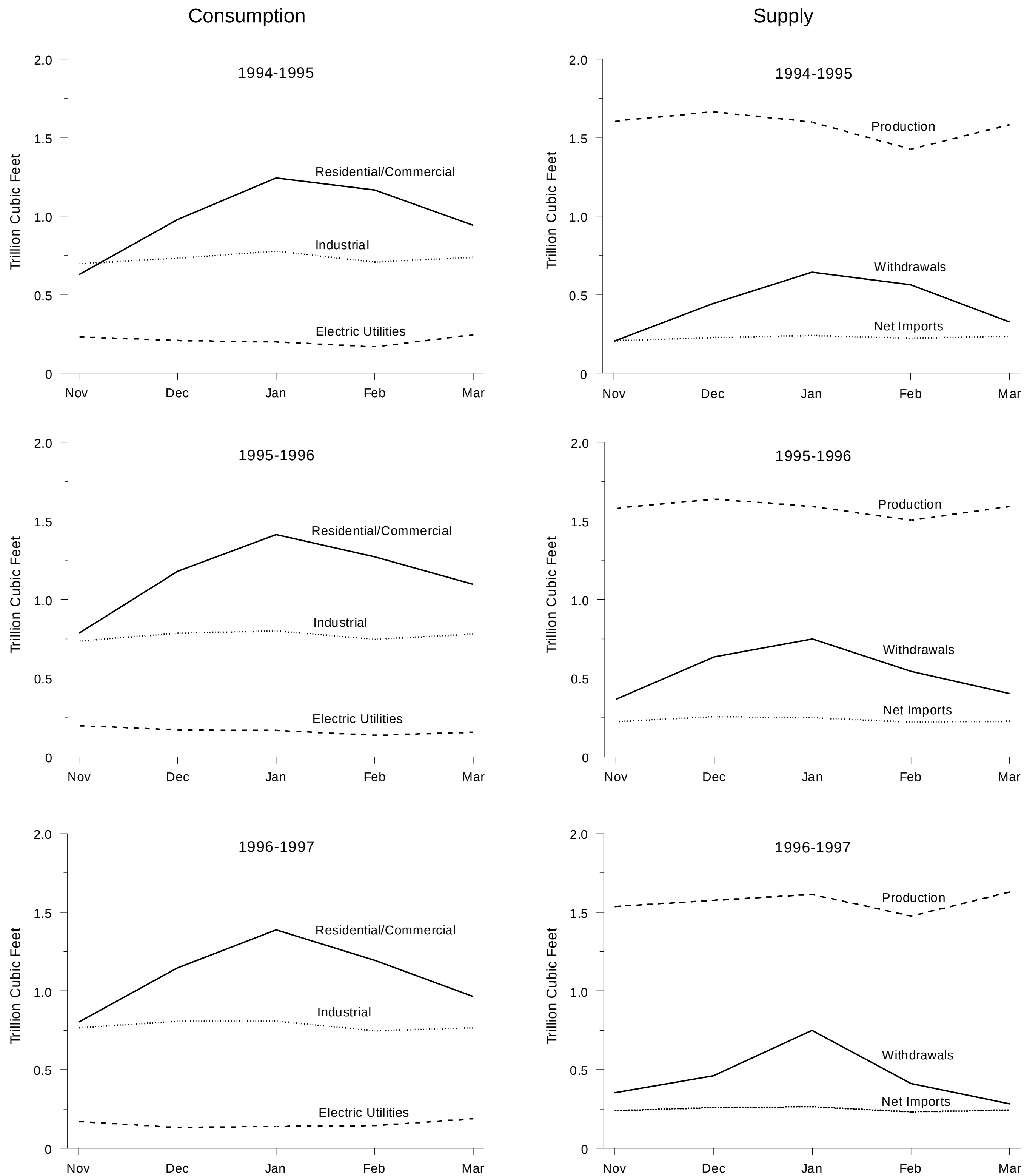
Heating Season Demand: The Key to Storage Utilization

Just as storage is the key to natural gas prices before and during the heating season, demand experienced during the heating season is the primary determinant of storage utilization. Demand, or consumption, during the winter months essentially has two components. One component is the more or less continuous demand for gas in the industrial sector. This demand represents gas used for a wide range of purposes and processes in industrial and manufacturing applications. This demand is more or less steady (but not constant) throughout the year.

Over the past 7 years, industrial sector consumption has grown steadily (Table FE1). This growth has been due to overall growth in the manufacturing sector and to reductions in natural gas prices to this sector as a result of industry restructuring. Consumption trends between years for this sector are easier to observe than for other end-use sectors because industrial demand is less influenced by weather.

A significant portion of the increase in industrial consumption since 1990 has been at cogeneration facilities, which allow companies to use natural gas not only for traditional applications of heating and manufacturing but also for electric power production. The increased use of natural gas for electric power production is expected to continue as a larger number of manufacturers increasingly use their own generators for the production of electricity instead of purchasing it from utilities.

Figure FE3. Natural Gas Residential/Commercial Consumption and Storage Withdrawals Vary Greatly During Heating Seasons
(Trillion Cubic Feet)



Source: Energy Information Administration, Office of Oil and Gas, *Natural Gas Monthly*.

Table FE1. Natural Gas Consumption and Supply During the Heating Season
(Billion Cubic Feet)

Heating Season	Consumption				Supply		
	Residential	Commercial	Industrial	Electric Utilities	Dry Gas Production	Withdrawals	Net Imports
1990-91	3,087	1,659	3,105	872	7,636	1,966	704
1991-92	3,173	1,697	3,311	915	7,584	2,213	784
1992-93	3,456	1,826	3,416	885	7,626	2,377	931
1993-94	3,588	1,884	3,601	887	7,858	2,394	1,035
1994-95	3,199	1,756	3,651	1,051	7,875	2,182	1,133
1995-96	3,717	2,027	3,850	831	7,906	2,698	1,176
1996-97	3,517	1,969	3,887	773	7,832	2,256	1,235

Source: Energy Information Administration, Office of Oil and Gas, *Natural Gas Monthly.*

The second major component of wintertime demand consists primarily of the space-heating requirements in the winter months in the commercial and residential sectors. While these sectors have some year-round consumption for such activities as cooking and water heating, this is far overshadowed by wintertime space-heating consumption, which can be substantial. During the heating season, combined consumption in the residential and commercial sectors exceeds consumption in the industrial sector (Table FE1).

Space-heating demand is also very temperature-sensitive: changes in combined residential and commercial consumption between heating seasons are more influenced by weather differences than by changes in the number of commercial establishments and households using natural gas. Because of this temperature-dependence, combined residential and commercial demand is highly variable and can change rapidly in a very short period. Storage plays the key, critical role during this time because it is the primary source of readily available incremental supplies to satisfy this temperature-driven "swing" demand. As shown in Figure FE3, combined residential and commercial consumption rise and fall more or less in tandem with storage withdrawals throughout the heating season, illustrating the close relationship between the two.

Thus, wintertime demand is dominated by: (1) the primarily industrial, somewhat steady base load; and (2) the temperature-sensitive, residential / commercial space-heating load, which can "swing" up or down, sometimes drastically, depending on the weather. In trying to plan for heating season requirements, the gas industry is faced with the uncertainty of weather-determined demand. If a winter is particularly cold, demand could grow significantly, while in a milder winter, much or perhaps all of the increased demand as a result of normal economic growth could be offset by less-than-expected demand for space heating.

Assessing Heating Season Demand

To analyze and attempt to quantify these two components of heating season demand in the important East Consuming Region, a multiple regression analysis was conducted (see Technical Appendix). The results of the analysis provide a method for estimating monthly consumption in the East Consuming Region during the current heating season, based on consumption trends over the past 7 heating seasons, and taking into account the effects of prevailing temperatures.

The results of this analysis indicate that, on average, consumption in the East region attributable to "normal" economic growth[9] can be expected to be about 28 billion cubic feet (Bcf) per month, or a total of about 140 Bcf greater in a particular heating season over the previous heating season. This corresponds to about 0.93 Bcf per day of increased consumption (i.e., 140 Bcf divided by 151 days in November through March). Further, for each 1 degree F. difference between the observed monthly

[9]This growth is attributable primarily to consistent increases in industrial activity throughout most of this period, plus the addition of new customers in all end-use sectors.

temperature during a heating season month and the "normal" temperature[10] for that month in the East Consuming Region, there is a corresponding change in consumption of about 19.6 Bcf. If the average temperature is 1 degree warmer than normal, consumption falls by 19.6 Bcf; conversely, if the temperature is 1 degree colder than normal, consumption increases by 19.6 Bcf. Likewise, this corresponds to a temperature-related "swing" factor of about 0.65 Bcf per day per 1 degree F. difference.

The ratio of the "trend" growth factor to the swing factor (i.e., 0.93 Bcf per day divided by 0.65 Bcf per day per 1 degree F. difference) is 1.43. In other words, for each month for which the observed temperature is 1.43 degrees above normal in the East Consuming Region, the expected drop in temperature-driven space-heating demand will just offset the expected increased demand from normal economic growth, and the resulting total demand will be expected to be unchanged from the previous year.

The ratio can be computed for each month of the heating season and for the entire heating season. If the January temperature is 1.5 degrees warmer than the previous January, then total demand during January would be expected to be similar to the previous January level. If instead, demand were much higher despite the 1.5 degree temperature increase, it would raise the question as to the cause of this "unexpected" increase.

Recent Trends in Storage Operations and Inventory Management

Until this year, working gas inventories at the beginning of the heating season had declined every year except one since 1990, even though consumption, particularly in the temperature-sensitive residential and commercial sectors, has generally increased. This trend toward lower inventory levels has occurred not just in the natural gas industry but in much of the energy industry serving space-heating demands. For example, between 1994 and 1996, stocks of natural gas, oil, and propane all declined from year-earlier levels (Figure FE4). At the same time, October spot prices at the Henry Hub have been higher than year-earlier levels for the past 3 years (Figure FE1), correlating with the decreased levels of working gas inventories.

Many feel that this trend of lower inventory levels reflects an increase in efficiency in the industry fostered by the implementation of Order 636, which brought partial deregulation and increased competition to industry structure and operations. Another factor is the increased ability that industry participants have to move gas around more easily—either among storage reservoirs accessible to a given pipeline system or even across different pipeline systems. This added flexibility of transporting gas was one of the major objectives of Order 636. The development of hubs, market centers, and liquid spot markets along portions of pipeline systems has made it easier to move the gas from a pipeline where demand has unexpectedly dropped to one where demand has unexpectedly increased. Because price discovery is usually good at market centers and hubs, their existence facilitates the trading of gas across pipeline systems and can also ease demand for storage inventories in certain situations.

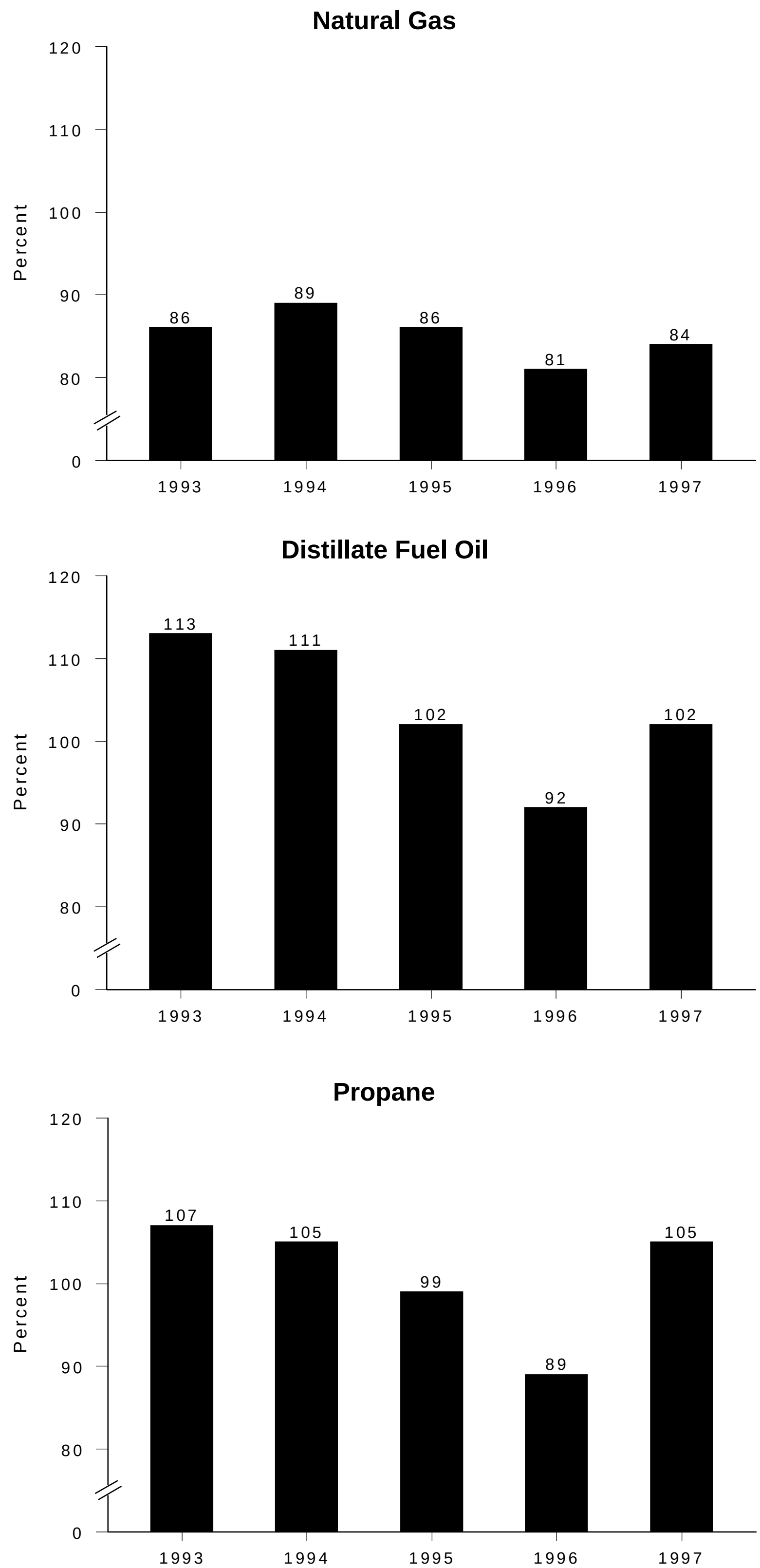
The decline in the amount of working gas in the face of increased gas demand can also be partly explained by the development and use of additional high-deliverability salt cavern storage facilities. Between 1993 and 1996, deliverability from storage increased by 8 percent, primarily because of increases in salt cavern storage capacity.[11] About 34 billion cubic feet (Bcf) of working gas capacity was added to salt cavern facilities, increasing daily deliverability by almost 4.1 Bcf which was almost 60 percent of total deliverability additions. Currently, 116 Bcf of working gas is stored in U.S. salt cavern reservoirs, which represents 11 Bcf of daily deliverability.

Unlike conventional storage reservoirs, a salt cavern storage facility is designed to be filled several times during the heating season. On average it takes about 10 days to withdraw all the gas from a salt cavern site and about 20 days to reinject to full capacity. The capability to inject during the heating season allows a company to increase the amount of withdrawals during the season. Thus the 34 Bcf increase in salt cavern storage capacity during the past few years represents an increase of more than 100 Bcf in the gas available for delivery from storage to market during the heating season. Withdrawals from salt cavern storage as a percentage of working gas capacity has also increased, from 16 percent in January 1992 to 35 percent in January 1997. Withdrawals from salt cavern facilities are at their highest level of the year during January.

[10]Normal temperature refers to the average temperature for major cities in the region over the 30 years from 1961 through 1990, as computed by the National Weather Service.

[11]Energy Information Administration, "U.S. Underground Storage of Natural Gas in 1997: Existing and Proposed," *Natural Gas Monthly*, DOE/EIA-0130(97/09) (Washington, DC, September 1997).

Figure FE4. Stocks of All Heating Fuels Have Behaved Similarly in the Past 5 Years
(Inventory Index Base-November 1, 1990)



Note: The reported numbers are values for November 1 as a percentage of the value on November 1, 1990.
Source: Energy Information Administration, Office of Oil and Gas, *Natural Gas Monthly* and *Petroleum 1996: Issues and Trends*.

Some salt storage facilities can inject and withdraw gas on the same day, which provides the flexibility to take advantage of arbitrage and other relatively risk-free commercial opportunities. In principle, large amounts of gas can be withdrawn from salt cavern storage facilities when demand and daily spot prices increase suddenly in late fall and early winter. When demand and daily spot prices subsequently decline, gas can be injected into storage as a replacement for the gas that was previously withdrawn from storage and sold at a relatively high price. Thus, producers or third parties acting for producers can withdraw gas from storage when demand and prices rise and then inject gas into storage when demand declines and prices fall.

Injections of gas into storage during the heating season in the Producing Region, where most of the salt cavern storage reservoirs are located, have exceeded the levels of 1992-93 in each succeeding heating season. In 1996-97, injections were 22 percent more than during the previous heating season and about 90 Bcf greater than in 1992-93 (Figure FE5) or an increase of almost 1 Bcf per day. There is still the possibility of larger increases since injections during the heating season can be several times as large as the working gas capacity in salt cavern storage facilities.

Utilization patterns for conventional storage sites in depleted gas and oil fields are very different from salt storage. In contrast to salt storage, there is a reluctance to withdraw increasing amounts of gas from storage early in the heating season. Companies often hold onto their gas as a form of insurance and as a means of maintaining deliverability at a relatively high level. Much of the stored gas, especially east of the Mississippi River, is owned by local distribution companies that may have regulatory disincentives that inhibit them from taking advantage of rising spot prices.

Finally, another possibly important factor in the continued reduction in underground working gas storage levels is any improvements in the use of linepack in anticipation of demand surges during forecasted cold snaps. As noted earlier, pipelines can be packed with extra gas when deliveries to the line exceed customer demand, which is generally the case in the fall and early winter. For the 5 years from 1992 through 1996, the average difference between supplies and deliveries was 80 Bcf, while the average difference in November, when linepack appears to be at its highest, was 212 Bcf.[12] Linepacking is often similarly high in December, and sometimes even higher.

[12]This information is published in *Natural Gas Monthly* tables as part of an imbalance item, which also includes losses from the pipe and measurement errors associated with counted supplies and deliveries from different respondents.

Inventory Levels, Withdrawals, and Pre-/Early Heating Season Prices

This year, stocks of all fuels for the current heating season are above year-earlier levels. While prices for propane and distillate oil are lower than a year ago, as noted earlier, this was not the case for natural gas at the start of the heating season. Although natural gas stocks on November 1 were above last year's level, October spot prices were much higher than last year and were roughly double their value in October 1994. Indeed, until the third week in November, natural gas prices were above year-earlier values. At first glance, this is contrary to what one might expect.

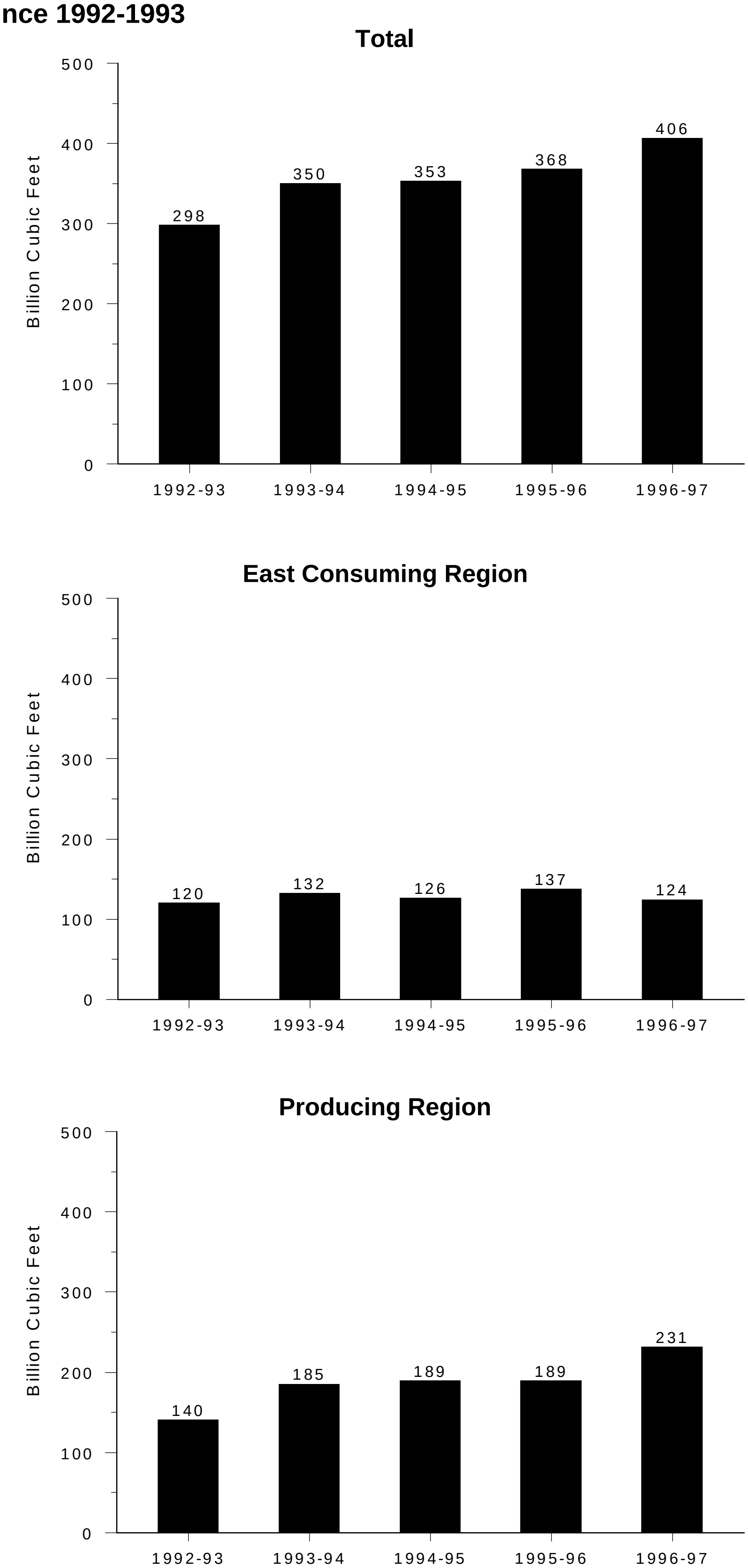
However, upon examining the situation with storage a little more deeply, it can be seen that even though total gas inventories at the beginning of the heating season were above year-earlier levels by about 82 Bcf according to American Gas Association estimates (2,807 Bcf vs. 2,725 Bcf), stocks in the important East Consuming Region were about 30 Bcf below last year's levels (1,691 Bcf vs. 1,721 Bcf). Further, as previously discussed, general economic growth in the region is expected to increase consumption by 140 Bcf during the heating season. Thus, not only were inventory levels in the East down from the previous year, but perhaps a more telling statistic—the ratio of inventory with respect to expected demand—was also lower (Figure FE6).

This situation provided support for higher prices at the beginning of the heating season. However, when storage withdrawals were modest during the first several weeks of the heating season, storage levels in the East Consuming Region equaled, and in some weeks actually exceeded, year-earlier values. By the end of November, inventories in the East Consuming Region were about 33 Bcf higher than the year before. Futures prices plummeted $0.50 per MMBtu between the third and fourth week in November, returning to levels of early September. This was the first time in 4 years that November futures prices were below those of the previous November.

Early-to-Mid-Winter Demand and Price Outlook

Throughout the early months of the heating season, the industry will closely watch storage data for indications of the shifting balance of supply and demand, and storage data will likewise have a great influence on prices. In turn, storage utilization will be driven largely by the the temperature-sensitive demand in the residential

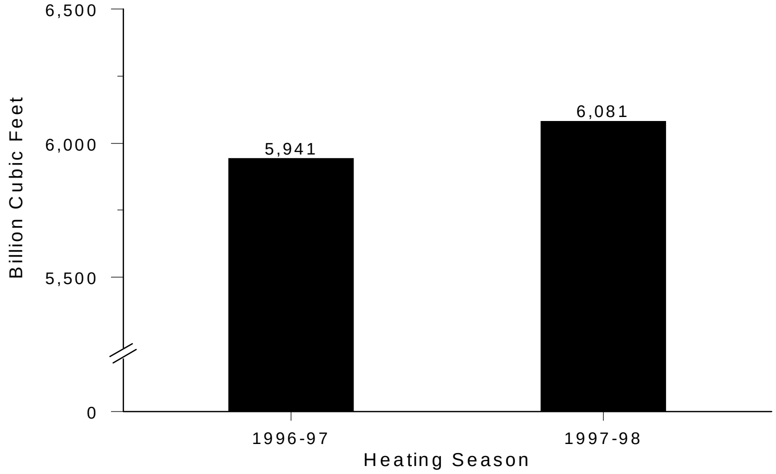
Figure FE5. Natural Gas Storage Injections During Heating Seasons Trend Upwards Since 1992-1993



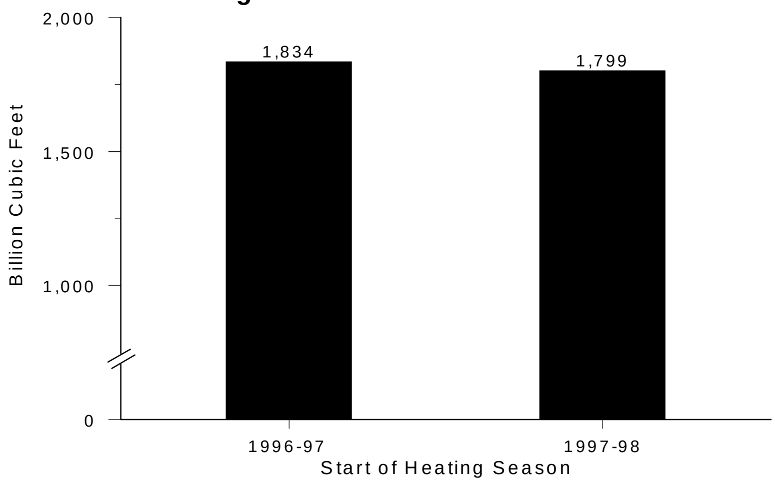
Source: Energy Information Administration, Office of Oil and Gas, *Natural Gas Monthly*.

Figure FE6. Expected Natural Gas Consumption in East Consuming Region Relative to Storage Inventories

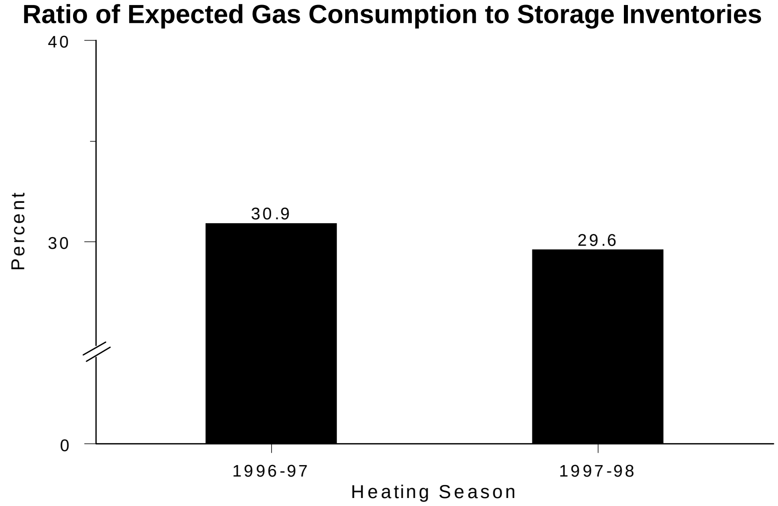
Expected Natural Gas Consumption



Storage Inventories on November 1



Ratio of Expected Gas Consumption to Storage Inventories



Note: Because vertical scales differ, graphs should not be directly compared.

Sources: **Storage Inventories:** Energy Information Administration (EIA), Office of Oil and Gas, *Natural Gas Monthly*. **Expected Natural Gas Consumption**: EIA estimates.

and commercial sectors, particularly in the East Consuming Region. Thus, during the heating season, storage utilization and natural gas prices, both spot market and futures, are heavily influenced by, and subject to the variability of, the weather.

The regression analysis (see Technical Appendix) of heating season consumption in the East Consuming Region provides a way of quantifying the effect of deviations from normal temperature on wintertime demand. As previously discussed, the analysis shows that, for each 1.43 degrees that the observed temperature is above normal over a given period of time, the decreased demand as a result of the warmer weather would just offset the increased demand resulting from normal economic activity and growth in customer base, etc. For example, last year the average temperatures for December and January were 2.16 degrees above and 0.82 degrees below, respectively, normal temperatures. The average of these temperature differences is about 1 degree F. above normal. Thus, if temperatures for this 2-month period are above normal levels this year by 2.43 degrees F. or more in the East Consuming Region, it is expected that reductions in consumption from this rise in temperatures will equal or exceed increases in consumption from normal growth trends.

What kind of weather patterns will occur during this heating season? Much has been made in the media about the "El Nino" climate event that is currently affecting weather on a worldwide scale. Current weather forecasts expect wetter-than-normal conditions to prevail in the southern States and warmer-than-normal temperatures in the northern States from the Rocky Mountains to the Great Lakes. To the extent that the Weather Service's predictions are correct, the reduced demand as a result of higher-than-normal temperatures will tend to put downward pressure on prices.

In addition to weather, a number of other factors could affect the supply-demand balance this heating season and influence price levels. These are:

- **Fuel switching.** Relatively high natural gas prices in the past several months may have encouraged some customers to seek out other sources of supply—oil by industrial customers and, in some instances, coal by electric generators as power from coal is increasingly traded to supply peak electricity needs in parts of the country not dependent on Union Pacific for coal shipments. To the extent that this has happened, some of the demand for natural gas will have eased, tending to soften prices.

- **Storage operations and production.** The ability to inject gas into salt cavern storage during the winter allows producers to produce at a relatively steady rate of production. The steady or optimal rate of production improves the economics of production. This will tend to put downward pressure on prices.

- **New pipeline capacity.** New pipeline builds added 3.3 Bcf of deliverability in 1997. This increase in deliverability will reduce the chance of bottlenecks, assuming that the pipeline grid is well connected in the Louisiana producing area. This should put downward pressure on prices.

- **Increased efficiency of utilization of storage and pipeline assets**. While total inventories at the beginning of this heating season were above year-earlier levels, part of the reason for higher-than-expected prices at the beginning of the heating season was that inventories in the East Consuming Region were below those of last year. However, in principle, if the system operates efficiently and with some foresight, gas from Producing Region inventories, particularly that held in high-deliverability salt cavern storage facilities, can be dispatched in such a way as to make up some of the temperature-driven increases in demand in the East Consuming Region. Expected increases in demand in the East, based on anticipation of colder temperatures, should result in a chain reaction of increasing flows of gas on pipelines, increased storage withdrawals, and rising prices at markets along the pipelines' systems. If the regions are well-connected, these actions should be communicated upstream to the Producing Region, resulting in increased storage withdrawals to substitute for or replace the additional demand being experienced throughout the downstream portions of the systems. This improved efficiency should tend to put downward pressure on prices.

Thus, gas demand this winter could begin to decline from year-earlier values because of milder weather and consumers' response to the high prices of the past several years. Milder temperatures should also reduce the rate of storage withdrawals. Thus, at the end of January, storage levels could be above year-earlier values, even in the East Consuming Region, which could put additional downward pressure on prices throughout late winter and early spring.

Conclusion

Natural gas spot prices are particularly volatile during the heating season, responding quickly to changes in weather and reported storage levels. Storage utilization and storage data are the industry's key indicators of conditions, and hence of price levels, especially early in the heating season. At that time, average weekly spot prices at the Henry Hub tend to rise or fall in direct reaction to reported weekly storage levels relative to expected demand.

Temperatures in many major residential gas markets are expected to be warmer than normal this winter. This could lead to less gas being consumed than last winter and to reduced demand for storage stocks, which are currently above last year's levels. The lower demand will likely lead to lower prices, with spot prices at the Henry Hub during January perhaps as much as $0.40 per MMBtu less than during the previous January.

Technical Appendix: Natural Gas Outlook, 1997-98 Winter

A multiple linear regression equation was used to estimate the expected consumption in the East Consuming Region for the 1997-98 winter heating season (i.e., November 1997 through March 1998). In specifying the equation, it was hypothesized that total consumption is a function of heating season temperatures as well as of annual growth in consumption not connected with or dependent upon weather. Thus, the equation took the form:

East Consuming Region heating season total consumption=constant+α*temperature+β*growth trend+error term

Defining Variables

The variables used in the regression are as follows:

- **East Consuming Region Heating Season Total Consumption**. The consumption variable represents the sum of end-use consumption during each month (November through March) of the past seven heating seasons, 1990-91 through 1996-97, for the 28 States plus the District of Columbia that comprise the American Gas Association-defined Consuming East Region (i.e., AL, CT, DC, DE, FL, GA, IA, IL, IN, KY, MA, MD, ME, MI, MO, NC, NE, NH, NJ, NY, OH, PA, RI, SC, TN, VA, VT, WI, and WV). End-use data are based on natural gas consumption in the residential, commercial, and industrial sectors reported to the Energy Information Administration (EIA) on Form EIA-857, "Monthly Report of Natural Gas Purchases and Deliveries to Consumers," and natural gas consumption by electric utilities reported on Form EIA-759, "Monthly Power Plant Report." The monthly sums for all States / District of Columbia were used to arrive at total consumption in the East Consuming Region for the heating season months November 1990 through March 1997.

- **Temperature.** Monthly average temperatures were computed for each of the heating season months in the series November 1990 through March 1997, based on daily high and low temperatures reported by the National Weather Service for four major cities in major gas-consuming areas of the East Consuming Region: Chicago, Kansas City, New York, and Pittsburgh. A daily four-city average temperature was computed by summing the eight observations and dividing by 8. Then a monthly average temperature was computed from these daily four-city average temperatures by summing the daily average temperatures for each day in a given month, divided by the number of days in that month.

- **Growth Trend.** To capture the effects of "normal," systematic, year-to-year growth[13] in natural gas consumption, a "growth trend" term was included in the equation. This is simply an integer assigned to each set of heating season months, beginning with the number "1" for the months November 1989 through March 1990, (even though these heating season months were not used for estimating the regression) incremented by 1 for each succeeding set of heating season months, through the number "8" assigned to November 1996 through March 1997.

Initial Results and Equation Modification

Upon examination of the error terms from this initial regression equation, it was noted that the residuals for the months of November and December were consistently negative, indicating that the equation consistently overestimated consumption in these months. To attempt to correct or compensate for this, the regression equation was modified to include a "dummy" term.

- **Dummy Variable.** To construct the dummy variable, the integer "1" was assigned as the dummy term for the months of November and December in the data file and "0" as the dummy term for all other months.

Final Regression Equation and Results

With the addition of the dummy variable, the new equation has the form:

CONSUMPTION(EAST)=k+α*AVG TEMP
+β*TREND+γ*DUMMY+error term

When the above equation was estimated, the following constant term and regression coefficients were obtained (standard errors are shown beneath each in parentheses):

k=1,679,322 α=-19,616.4 β=28,096.13 γ=-117,620

[13]This growth is attributable primarily to consistent increases in industrial activity throughout most of the period, plus the addition of new customers in all sectors.

(44,698.04) (1,359.098) (3,842.35) (16,768.22)

The R-squared of the regression is 0.942. The t-statistics for the regression coefficients are as follows:

k: 25.08 α: -14.43 β: 7.31 γ: -7.01

Computing Expected Consumption for the 1997-98 Heating Season

The regression results were used to compute expected consumption in the East Consuming Region. For this computation, it is assumed that temperatures will be "normal"[14] throughout the heating season for the four cities previously identified. Taking the simple average of the normal temperatures for these four cities for the heating season months results in the following combined normal temperatures:

November	=	43.23° F
December	=	32.25° F
January	=	26.06° F
February	=	29.69° F
March	=	40.24° F.

These temperatures can be substituted into the regression equation to estimate consumption in the East Consuming Region for each of the months November 1997 through March 1998. (Note that the integer for the growth trend is increased by 1 from the previous heating season, and therefore is "9" for the 1997-98 heating season.) The resulting estimates, measured in million cubic feet (MMcf), are as follows:

November 1997	=	966,587 MMcf
December 1997	=	1,201,514 MMcf
January 1998	=	1,421,081 MMcf
February 1998	=	1,349,775 MMcf
March 1998	=	1,142,821 MMcf
Total:	=	6,081,778 MMcf, or about 6,082 billion cubic feet.

Quantifying Changes in Consumption

It is useful to point out a way of interpreting the regression results that can serve as a "rule of thumb" to gauge the effect on consumption of patterns or events whose impacts can be expressed in terms of the number of degrees that temperatures are greater or less than normal.

First, the coefficient of the temperature variable in the regression equation (-19,616) means essentially that, for every 1 degree increase in monthly average temperature, consumption decreases by 19,616 MMcf. Second, because the Trend variable changes by an increment of 1 for each succeeding heating season, the coefficient of the Trend variable (28,096) is essentially an estimate of how much additional consumption in any given month of a heating season compared with the year-earlier level is due simply to systematic demand growth, namely 28,096 MMcf.

Further, the regression equation therefore predicts that total Trend demand growth from one heating season to the next is about five times 28,096 MMcf, or 140,480 MMcf. The ratio of the Trend coefficient to the temperature coefficient (28,096/-19,616), -1.43, is a measure of the amount of increase in average temperature required such that the decrease in temperature-driven demand just equals the rise from normal growth in demand. Thus, in this analysis, a temperature increase of about 1.4 degrees F. in any given month would result in consumption levels equal to those in the same month of the prior heating season.

Finally, this ratio can be used as a rule of thumb applied over any period of time. That is, on average, over any period of time (day, number of days, weeks, etc.), when the average temperature for the time period exceeds the normal temperature for the same period by 1.4 degrees F., the decline in demand as a result of warmer-than-normal temperatures offsets the increased demand resulting from Trend growth. Thus, this ratio can be used to gauge or estimate how consumption in the East Consuming Region is changing during the heating season with respect to the previous heating season.

Computing Expected Consumption During the 1996-97 Heating Season

Figure FE6 shows expected consumption for the 1996-97 heating season as well as the upcoming 1997-98 heating season. To make the data comparable in the graph, the value for expected consumption for the 1996-97 heating season was computed in the same way as was expected consumption for the 1997-98 heating season. That is, the 1996-97 value was derived using the same regression

[14] The National Weather Service (NWS) uses temperature observations over the 30-year period 1961-1990 to compute average temperatures for different time scales (i.e., daily, weekly, monthly, etc.) for thousands of locations throughout the country. These average temperatures are often cited as "normal" for these locations for the different time scales. For this analysis, the monthly 30-year NWS averages were used for the four subject cities.

equation, assuming normal temperatures for the 1996-97 heating season months (thus, using the 30-year average temperatures for these months), and using the trend integer of 8 along with the other regression coefficients. In other words, expected consumption for the 1996-97 heating season was computed as if that heating season had not already occurred. The value computed in this manner is approximately 5,941 billion cubic feet (Bcf).

An alternative method of computing an estimate for this value was also used. This method involved reestimating the regression equation after dropping the observations corresponding to the 1996-97 heating season, then using the regression coefficients thus obtained to compute estimated consumption for the 1996-97 heating season. The value thus obtained is approximately 5,997 Bcf—only 56 Bcf, or slightly less than 1 percent, greater than the above estimate. It was therefore decided to use the estimated value derived from the original regression, as described above.