Natural Gas Residential Pricing Developments During the 1996-97 Winter

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Many residential consumers were shocked by their high natural gas bills this past winter.[1] Monthly residential prices from November 1996 through March 1997 were between 10 and 19 percent higher than year-earlier levels (Figure FE1) despite a 4.1 percent decline in consumption. Overall, residential consumers paid $23.2 billion for natural gas during the 1996-97 heating season, compared with $21.1 billion in 1995-96—an increase of more than 10 percent.

Gas prices during the 1996-97 heating season were shaped to a considerable extent by the events of the prior winter. The 1995-96 heating season began with colder-than-normal temperatures over an extensive portion of the United States, including the heavy gas-consuming regions of the Midwest and Northeast. The resulting high levels of consumption were met with early drawdowns of storage gas. These storage volumes could not be replaced readily because the temperature pattern persisted, causing concern about future supply availability. By the end of the winter, storage levels had reached record lows.

When the 1996-97 heating season began with even more severe temperatures than in November 1995 and even lower storage inventories than the previous year, many distribution companies preferred to purchase gas on the spot market rather than draw down storage volumes early. This placed significant pressure on gas prices, which were already higher than last year in large part because of higher demands in mid-1996 to refill storage stocks. The average wellhead prices increased from $1.93 per thousand cubic feet (Mcf) in October 1996 to $3.53 in December 1996 and reached $3.69 in January 1997.The December 1996 price was almost double that of December 1995.

The higher prices have raised concerns about the performance of the industry. Individuals and organizations have questioned the capacity of the industry to deal with extreme conditions, and even the possibility of market abuses. Price levels reflect a complex set of influences, with storage operations being only one part of an extensive chain of services involved in producing, transporting, and distributing gas to consumers. The industry response to market conditions, pricing mechanisms, and the institutional and regulatory structure contributed to the developments of last winter. Some locations, such as New Mexico with residential price increases of almost 70 percent, were especially hard hit by circumstances that were specific to the particular State.

This article is intended to provide an understanding of the reasons behind the sharp rise in residential gas bills this past winter. It discusses the key factors that affect pricing patterns, highlighting the effects of weather, utilization patterns of natural gas storage, and pricing mechanisms used in natural gas markets. It also considers market power issues and some insights into the future that can be gained from the events of the 1996-97 heating season.

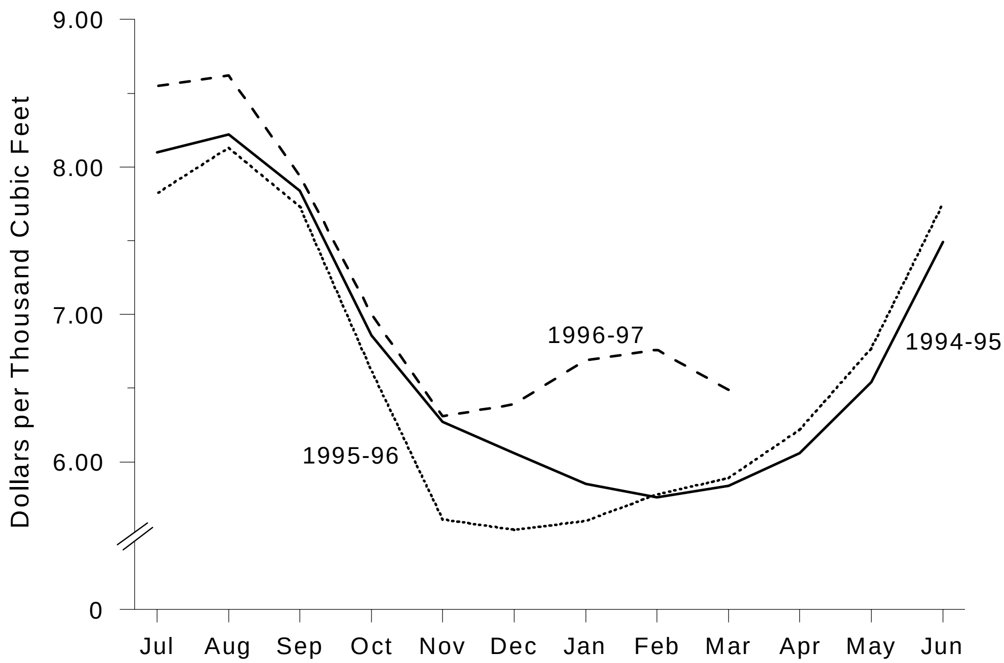
Weather Effects

Weather is a key factor in natural gas markets and played an important role in the exceptional rise in prices in 1996-97. Weather can affect both supply and demand. In the heating season, temperatures directly affect residential consumers as they primarily use gas for space heating.[2] Temperature extremes may affect gas field production by interrupting flow through well freezeoffs, but such disruptions tend to be limited in impact and of short duration.

[1]The *heating season* refers to the period from the first of November through the end of March. For ease of exposition, the terms *heating season* and *winter* are used interchangeably in this article.

[2]A discussion of this and other demand-related factors appears in *Load Forecasting Methods*, American Gas Association (1995). This study includes an analysis of Canadian residential consumption data that yields demand elasticity coefficients with respect to temperature of 0.17 and 0.24 for the fourth and first quarters of the year, which indicate that a 10 percent rise in heating degree days (HDD) will increase gas consumption about 2 percent. HDD are calculated as the deviation of average temperature from 65 degrees Fahrenheit, so successive temperature drops of equal size represent decreasing percentage increases in HDD. The corresponding decline in consumption response is consistent with the findings of "An Examination of Bend-Over in the Natural Gas Sendout Curve," *A.G.A. Forecasting Review*. This phenomenon arises as temperatures become extreme (perhaps below 20 degrees), causing heating appliances to approach maximum usage at which point consumption cannot increase with further reductions in temperature.

Figure FE1. Average Residential Gas Prices, July 1994 - March 1997



Source: Energy Information Administration, *Natural Gas Monthly* (June 1997).

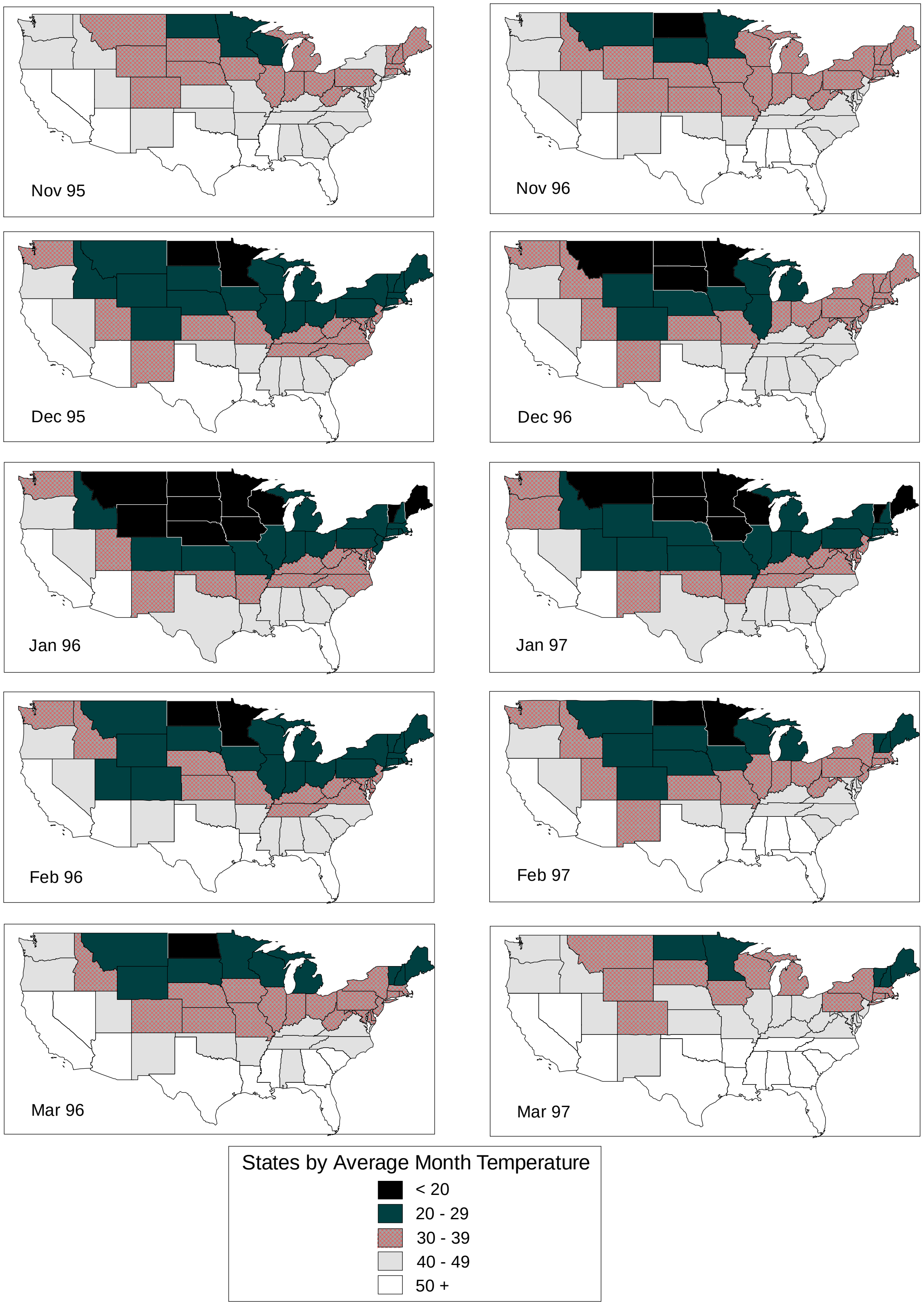
Gas consumption patterns during the past two heating seasons showed the strong effects of weather and differences in weather patterns. The 1995-96 heating season began with an unusually cold November and low temperatures persisted through subsequent months. The low temperatures were widespread, covering both the northern central area and the top tier of the eastern portion of the country (Figure FE2). The eastern portion in particular includes large residential gas markets with very high gas requirements during severe weather. Residential gas consumption in 1995 in Illinois, Michigan, New York, Ohio, and Pennsylvania was at least one-third of total gas consumption for the year.

The widespread low temperatures through much of the 1995-96 heating season caused large incremental demand overall that imposed stresses on the supply system and led to high price peaks. Storage supply was particularly important in meeting the additional demand as the eastern States have relatively limited amounts of indigenous production and rely primarily on domestic production from the South and Southwest and western Canadian supplies. Small amounts of liquefied natural gas (LNG) are imported but cannot be accessed quickly because of the extensive distance from the originating point.

Temperatures at the beginning of the 1996-97 heating season were even more severe than in November 1995. However, for the rest of the 1996-97 season, the severe temperatures tended to be more geographically focused and in smaller gas markets. The unusually cold November was followed by a month of considerably milder temperatures in the Northeast than those of December 1995. The January temperatures were similar in both years, although the average temperature in the northernmost States was slightly lower in 1997. February 1997 weather was much less severe, with freezing temperatures prevailing only in the Rocky Mountain States and the North Central area. March 1997 had above-freezing temperatures in all but five States (Figure FE2). The peak demand in 1996-97 was more centralized in the North Central States, which have access to potential supplies from all directions.

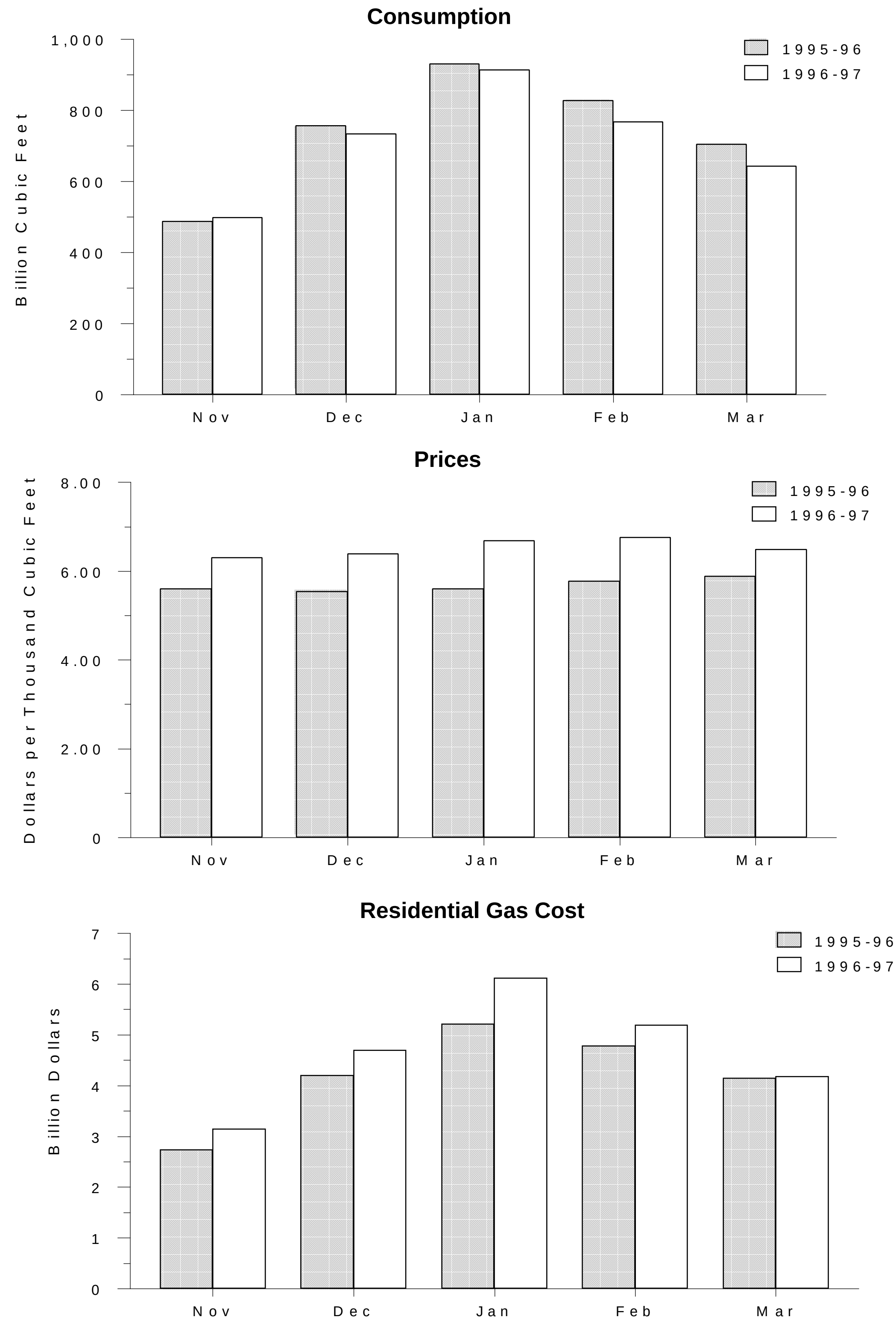
The generally milder weather in regions with major residential markets in the 1996-97 heating season compared with 1995-96 resulted in lower residential and total consumption. Residential consumption was 4.1 percent less than in the previous winter. Monthly residential consumption was 2.3 percent higher in November 1996 than in November 1995 but lower than year-earlier levels in all other months of the 1996-97 heating season. Residential gas use in March 1997 was 8.7 percent less than in March 1996 (Figure FE3). Total

Figure FE2. U.S. Winter Weather, 1995-96 and 1996-97



Sources: Energy Information Administration, Office of Oil and Gas, derived from National Oceanic and Atmospheric Administration, National Climatic Data Center.

Figure FE3. Monthly Residential Gas Consumption, Prices, and Total Expenditure for the Past Two Heating Seasons



Source: Energy Information Administration, *Natural Gas Monthly* (June 1997).

end-use consumption displayed a similar pattern, increasing slightly (0.6 percent) between November 1996 and November 1997 and falling in the other months. Total consumption by all end users this past winter was 2.3 percent less than in 1995-96.

The lower consumption suggests less demand, which would have lessened upward pressure on natural gas prices. Instead, as previously noted, monthly delivered residential prices during the period from November 1996 through March 1997 ranged from 10 to 19 percent more than prices in the corresponding months of a year earlier. The higher average residential gas prices drove January 1997 gas costs up 17 percent over the 1996 value, despite the lower consumption. Higher prices in the 1996-97 winter with lower consumption indicate that the market response was dominated by reduced supplies rather than demand changes. The market reacted to the low temperatures and high demand early in the 1996-97 winter, basing many of its decisions upon the weather patterns of the previous winter.

Supplies for End-Use Markets

Delivery of natural gas to the end user consists of a chain of services: field production, storage, transportation, and distribution. The availability of gas from these sources has a direct bearing on end-use gas prices. Natural gas production and import supplies in the Lower 48 States during the 1996-97 heating season were comparable or greater than in previous years. These abundant supplies served to mitigate the surge in prices, and they were to some extent a response to those higher prices.

U.S. gas production has been growing for a number of years and this trend continued in 1996 and into the heating season (Figure FE4). The increased production was achieved despite some difficulties in the field. For example, during cold weather in December 1996, freeze-offs occurred in the Gulf of Mexico, which affected nearly 1 billion cubic feet per day of gas production.[3] Greater losses were averted because producers conducted overtime operations to maintain flow and take advantage of the higher gas prices.

The growing production trend resulted from various factors including improved transportation. Twenty-six pipeline expansion projects were completed and placed in service during 1996 that either added capacity directly to the interstate network, improved intrastate service, or expanded access to producing fields or natural gas market centers.[4] These system enhancements provide access to new producing areas, such as the deep water regions of the Gulf of Mexico, and help reduce some bottlenecks that have hindered production growth in areas such as the San Juan basin in northwest New Mexico and southwest Colorado.

Similar to domestic production, natural gas imports increased this past year. Gas from foreign sources is an important element of total U.S. supply, providing 13 percent of 1996 consumption. Imports have even greater importance on a regional basis, with a major impact on gas availability and prices in large consuming markets, especially in the upper Midwest and Northeastern United States.

Net gas imports were higher in each month of the 1996-97 heating season compared with the previous winter (Figure FE4). The higher net imports reflect the impact of the higher price stimulus and the availability of new crossborder pipeline capacity between the United States and Canada. Monthly imports from Mexico continued through 1996 and into the heating season without interruption, as in 1995. Larger shipments of Algerian LNG were received in each month of the heating season, as the Algerian refurbishment project is finishing and more capacity comes on line. Also, LNG shipments from the United Arab Emirates (UAE) were received in December and January. (Gas from the UAE was received for the first time in September 1996.)

Thus, with domestic production and import levels all higher than the year before, a very different pattern was evident in the use of storage. Net gas volumes drawn from storage during November 1996 were comparable to those in November 1995, yet net withdrawals in all other months of the heating season fell short of year-earlier levels. Net storage withdrawals equaled 21 percent of gas consumption in the 1995-96 heating season, but only 17 percent in the most recent one. The significant deficiency in December 1996 storage withdrawals, relative to the prior year, resulted in lesser total gas supplies for the month, despite the larger quantities of domestic production and net imports (Figure FE4). Storage utilization in the past winter was influenced by a set of diverse factors including initial stock levels, the experience of the 1995-96 heating season, and spot prices in cash markets.

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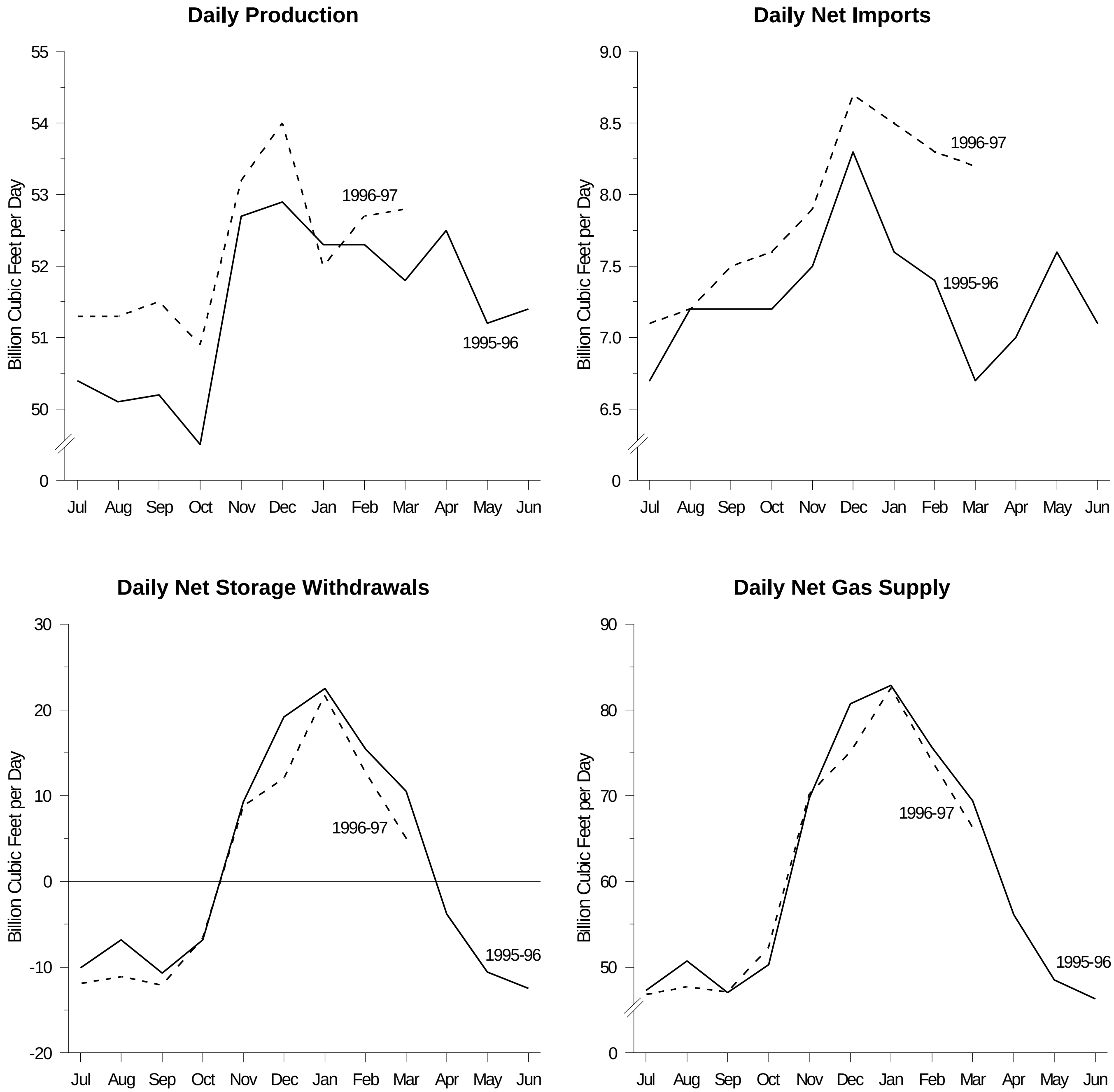
[3] "Cold Weather and High Prices Prompt Stellar Explanation," *World Gas Intelligence* (January 24, 1997).

[4] More detailed information on these projects is available in the Energy Information Administration's *Natural Gas Monthly* (Washington, DC, April 1997).

Figure FE4. Daily Average Gas Supplies by Month, July 1995 - March 1997



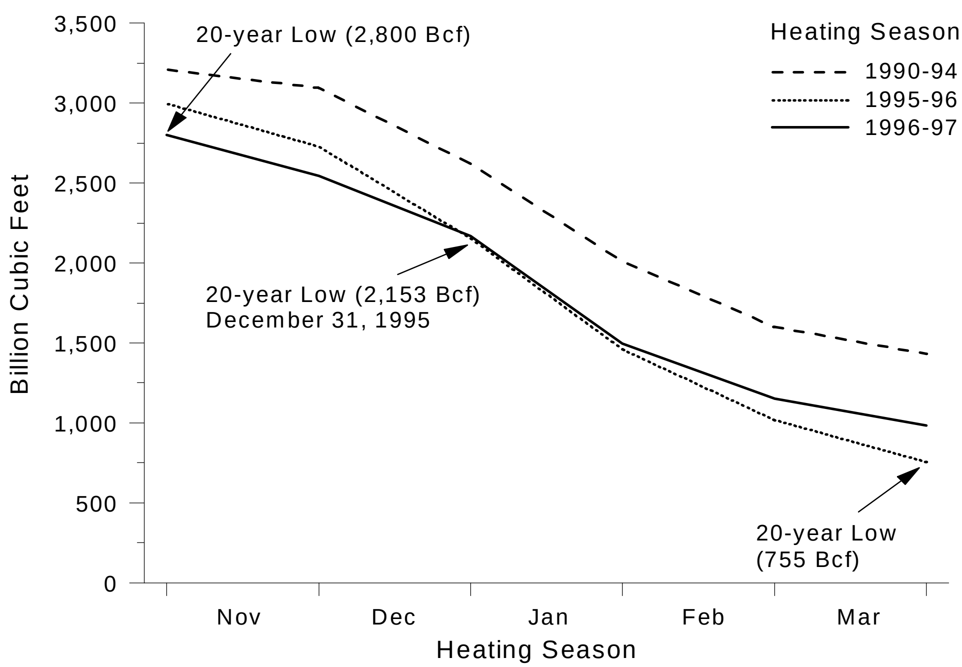
Source: Energy Information Administration, *Natural Gas Monthly* (June 1997). **Production:** Table 1. **Imports:** Table 2. **Storage Withdrawals:** Table 9. **Net Supply:** Table 2.

Storage Practices

Storage gas utilization practices appear to have been a major factor in determining prices in 1996-97. Storage is a key source of natural gas during peak demand periods because it can be located in the area of major consuming markets.[5] Additionally, the high drawdown rates provide deliverability to meet sudden demand surges that often are quite unexpected either in timing or intensity. Storage net withdrawals on average comprise about 20 percent or more of total U.S. consumption during the winter period, however reliance on storage varies widely for shorter periods. For example, on a typical winter day, storage gas meets 60 to 80 percent of natural gas requirements in Ohio.[6]

Working gas stocks of 2.8 trillion cubic feet (Tcf) on November 1, 1996, were slightly below the 3.0 Tcf available at the beginning of the 1995-96 heating season. These volumes are low relative to the more typical historical volumes (Figure FE5). Changes in inventory management, which have been motivated by new technology and the increased competition resulting from regulatory reform, are leading operators to maintain lower storage volumes. Without increases in other supply costs to compensate for less storage, overall system supply costs are reduced. New technology has improved performance of older underground storage units and allowed the use of salt caverns, both of which have higher delivery potential than depleted reservoirs using older technology. Increased deliverability despite lower quantities of gas in storage allows operators to reduce stocks without sacrificing the ability to meet target levels of gas deliveries.[7]

Figure FE5. Working Gas Levels



Sources: Energy Information Administration (EIA). **1990-1992:** *Historical Monthly Energy Review*. **1993-1994:** *Natural Gas Monthly* (June 1994). **1995-1997:** *Natural Gas Monthly* (June 1997).

[5] Storage is also a useful service in producing areas, although its role differs as a reflection of the difference in ownership. Producers prefer smooth production flows, and storage sites provide the option that compensates for the vagaries in takes for the market. Producers also maintain gas in storage to exploit arbitrage opportunities.

[6] Public Utility Commission of Ohio, *Weather Impacts on Gas Cost and Residential Winter Heating Bills, 1996-1997* (January 31, 1997), p. 6.

[7] High deliverability sites (salt caverns and refurbished depleted reservoirs) help to lessen the consequences of offpeak injection decisions. The ability to inject and withdraw gas rapidly allows for multiple "cycling" of the gas in a storage site. Gas is injected into storage even during periods of generally high consumption, such as the heating season. One advantage to owners of stored gas in high deliverability sites is the enhanced ability to capture monetary gains from transitory price changes. Another, arguably greater, advantage is the ability to restore at least some portion of storage volumes during the heating season, which reduces the burden of trying to anticipate months in advance the entire requirement for storage gas during the heating season.

Storage levels at the beginning of the winter showed some regional variation, with lower levels in production areas, but stocks in the East were close to last year's levels (Figure FE6). Higher mid-year prices in 1996 raised the cost of storage replenishment, but apparently did not discourage operators in the East from restoring stocks. For example, the Public Utility Commission of Ohio (PUCO) reports that storage facilities in that State were at 93 percent or more of capacity on November 1, 1996. Storage in the production areas, however, may have fallen somewhat short of the targets, not only because of the higher costs but also because of the greater opportunity cost of storing production rather than selling it at the higher prices. The high prices in cash markets were a signal of increased need for produced gas, and they would have motivated producer/operators to capture the higher revenue during mid 1996 while the opportunity was present.

Stocks of gas in storage are important because they constitute potential supplies of gas to the market. Storage drawdowns during November 1996 were about the same as in November 1995 (264 billion cubic feet (Bcf) vs. 278 Bcf). In contrast, storage withdrawals in December 1996 (276 Bcf) were only 63 percent of the 595 Bcf taken in December 1995. This level of drawdown is striking because working gas in storage entering December 1996 at 2,544 Bcf was 93 percent of the prior year level. Net withdrawals in January of both years were comparable. The 1997 February and March net withdrawals, however, exhibited considerably less reliance on storage, with gas supplied from storage at 80 and 48 percent of the 1996 levels.

Storage utilization decisions are considerably more complex than those associated with acquisition of other supplies. Storage decisions involve consumption expectations for a given day and succeeding ones, and the expected availability and price for replacement volumes. Decisions for storage gas use today, whether prudent or not, have implications for supply availability thereafter.

The reduced withdrawals of gas from storage in the first half of the heating season may have been a reaction to the industry experience in 1995-96. The heavy reliance on storage gas in late 1995 removed gas from inventories that was not replenished because of continued demands resulting from the persistent, widespread cold temperatures. Sporadic transmission bottlenecks during later winter months further jeopardized the ability of local distribution companies (LDCs) to deliver gas to their customers as needed.[8] Despite the low probability that weather will replicate itself in successive years, it seems operators in 1996-97 generally were reacting to experiences of the previous winter—especially in light of the low drawdowns in December 1996 when spot prices were quite high, providing lucrative arbitrage opportunities. Average weekly prices as measured at the Henry Hub ranged between $3.40 and $4.43 per million Btu (MMBtu) for the month, yet storage withdrawals were limited in all regions. In contrast, the much larger storage withdrawals in December 1995 were at a time when prices were no more than $2.42 per MMBtu in any week.

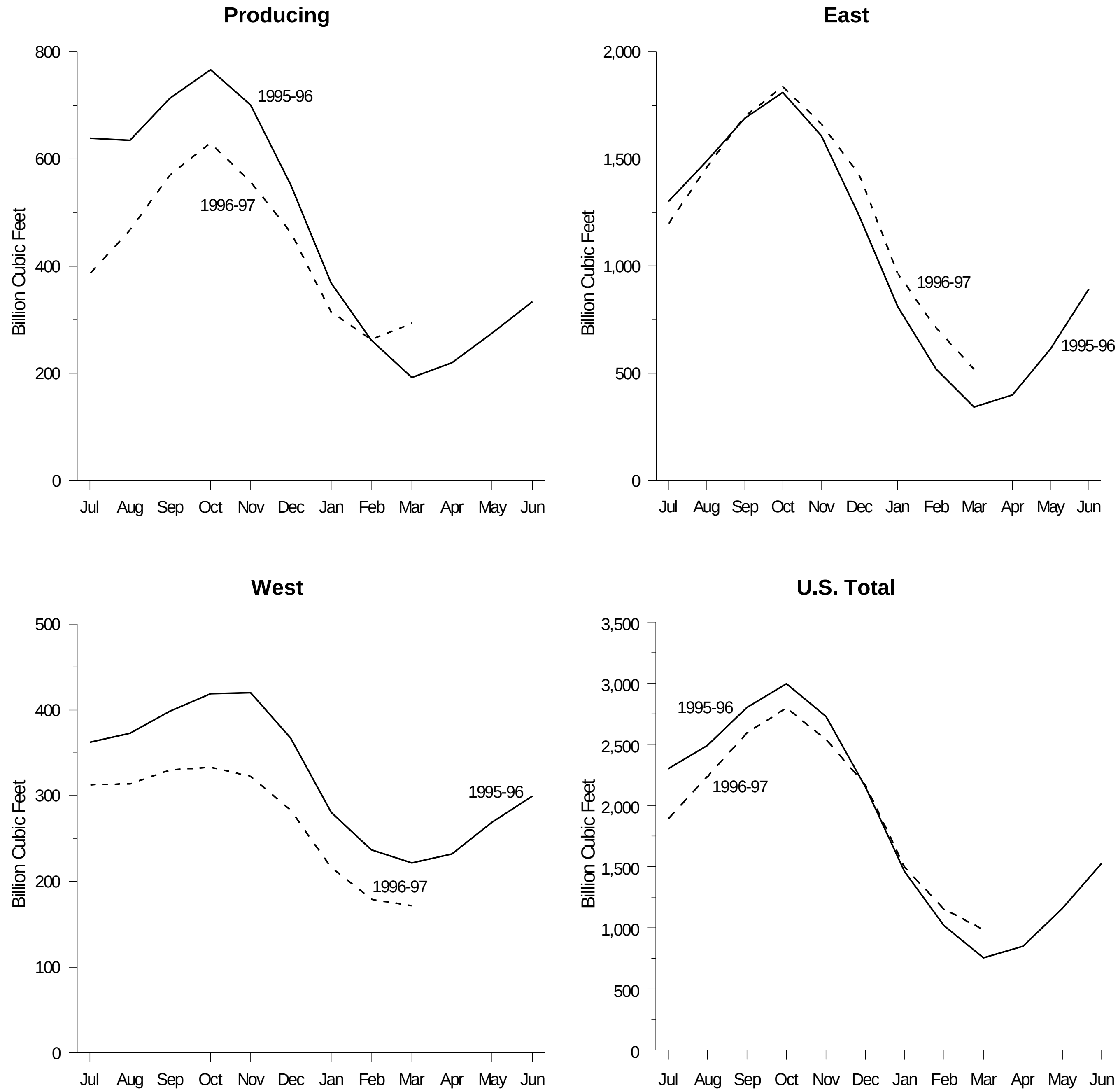
Low net storage withdrawals in February and March 1997 reflect the relative prices of gas supplies (Figure FE7). The Henry Hub price averaged $3.00 per MMBtu in the last week of January, but fell below $2.50 in the first week of February and continued to decline in successive weeks, reaching $1.85 in the final week of the month. The average weekly prices in March did not exceed $1.95. At such prices, spot gas purchases were the preferred, low-cost supply option, since gas from storage would have to be replaced with gas likely to be at higher prices, given the then-expectation of mid-1997 prices at approximately $2.00 per MMBtu.[9] The full cost of using storage gas includes not only the replacement cost, but the associated costs of withdrawal (of gas now) and injection (for replacement gas). Further, use of storage gas exposes the firm to the risk of future price increases, such as last year when prices rose from the end of the heating season into the summer.

Indefinite retention of gas in some storage facilities is discouraged by penalties that may be imposed when sufficient gas is not withdrawn by specified dates. Penalties are established on the basis of monetary charges, in-kind gas charges, or confiscated gas. However, these penalties are not in all storage arrangements. In a sample of 25 major storage operators,

[8]Bottlenecks or other difficulties in the chain of supply services may manifest themselves in severe price movements, which can prove disruptive to market suppliers and producers. The spot market showed a remarkable degree of price volatility in 1995-96. For example, after 2 weeks of daily prices ranging between $2.13 and $2.83 per million Btu, the spot price at the Henry Hub surged from $2.58 to $14.00 when a sudden cold snap occurred in the week of January 29 to February 2, 1996. The daily prices fluctuated between $4.00 and $8.75 during the succeeding 2 weeks. Thereafter, daily prices at the Henry Hub averaged $2.90 per million Btu with reduced variability ($2.43 to $3.65). Elsewhere, prices closer to end-use markets also swung dramatically in early February. For example, local utilities in Chicago were reported to have paid as much as $46.00 per million Btu for some transactions.

[9]Pasha Publications, Inc., *Gas Transportation Report* (March 19, 1997).

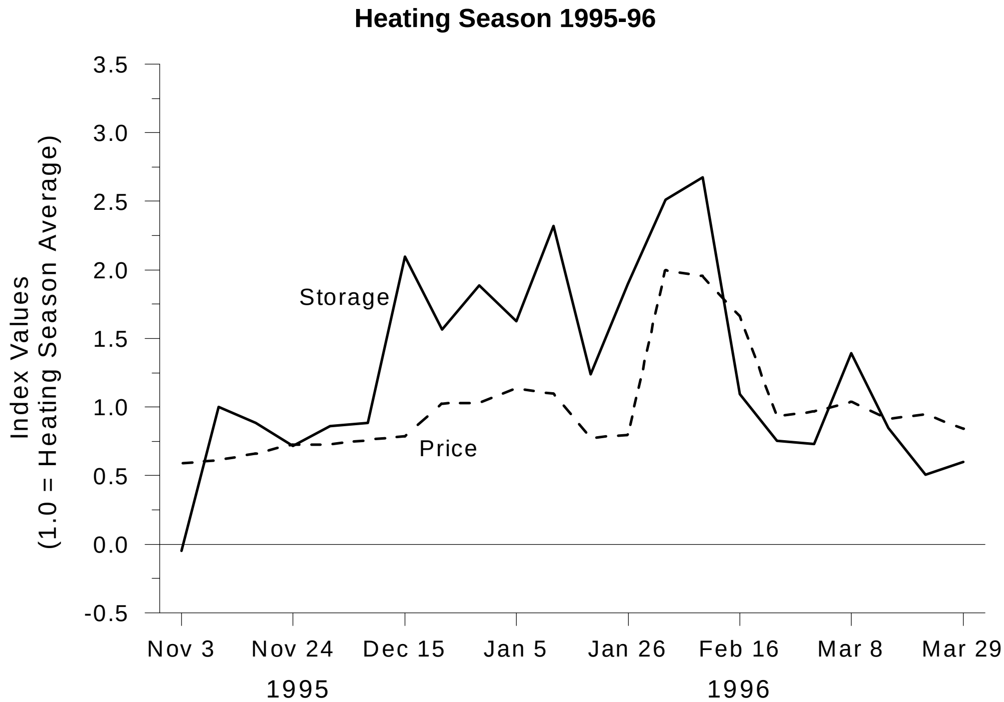
Figure FE6. Storage by Region, July 1995 - March 1997

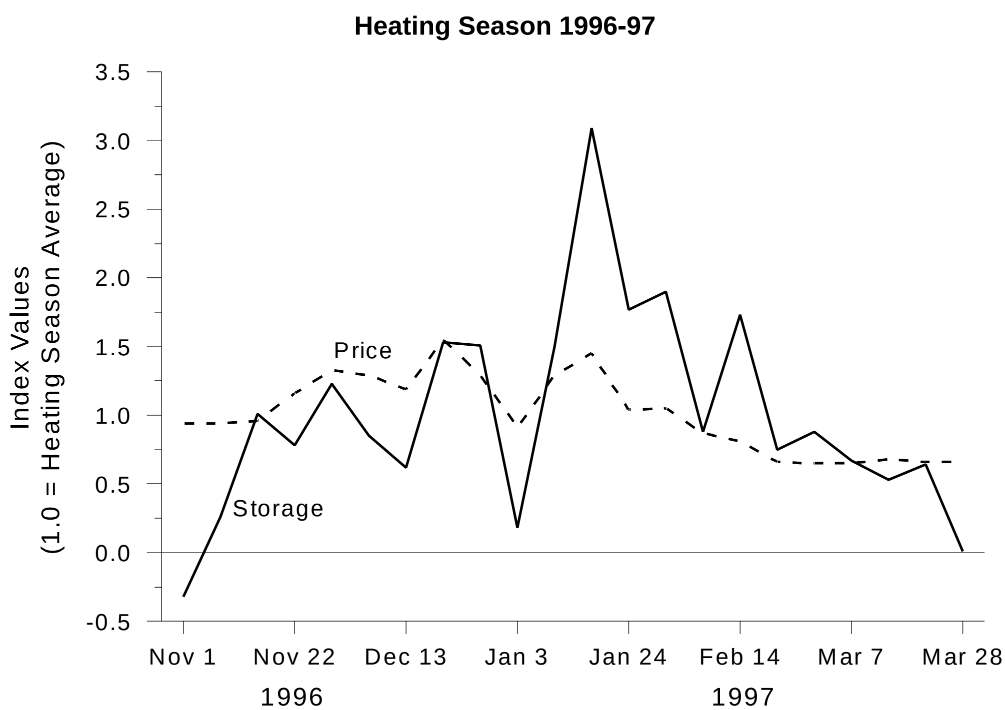


Note: Regions are comparable to those used by the American Gas Association in its *Weekly Survey of Working Gas in Storage*. Because vertical scales differ, graphs should not be directly compared.

Source: Energy Information Administration, *Natural Gas Monthly* (June 1997).

Figure FE7. Comparison of Net Storage Withdrawals and Spot Prices





Sources: **Storage Withdrawals:** American Gas Association, *Weekly Survey of Working Gas in Storage* (November 1995-March 1996). **Spot Prices:** Pasha Publications, Inc., *Gas Daily*.

10 of the companies did not have any requirement to remove gas from the facility. Only two storage operators required 100 percent removal of customer gas, and that applied only to certain classes of customers. Most withdrawal requirements allow for a portion of gas to remain in storage—generally about 20 to 25 percent of maximum. Further, the reported penalties for noncompliance with the withdrawal requirement frequently represent a rather moderate cost. For example, the 1.2 percent fuel charge imposed by ANR Pipeline is the equivalent of 2.4 cents for gas costing $2.00 per MMBtu. Such a nominal fee for not withdrawing gas is not sufficient incentive to withdraw the gas, replace it with gas expected to cost $2.00 or more, and then also pay the injection fees. Gas on the cash market priced at below $2.00 in February and March was a far superior choice.

Despite the market outcome based on limited early use of storage during the past winter, some operators remain reluctant to change significantly because of their concerns regarding supply security, which is vulnerable to the uncertain changes in weather. A conservative withdrawal strategy in the early part of the heating season positions the utilities well in the event of a late season cold snap. Storage utilization practices also are established on the basis of technical factors. For example, the physical attributes of the aquifer storage facilities of Northern Illinois Gas (NIGas) affect delivery in such a way that NIGas adheres to a previously established schedule more than it allows variation in response to fluctuating economic incentives.[10]

Institutional Factors

Marketing gas to residential customers has been conducted for many years in a framework of regulated franchises. Although some regulatory reform is underway on an individual State basis, operational practices did not change greatly between the two heating seasons. For example, local utilities generally did not pass along the increased supply prices any faster this year than in the past (Table FE1). Billings from some utilities included adjustments for cost discrepancies from the 1995-96 winter because the payments that were estimated under a levelized plan differed from the actual costs. Residential customers in Iowa, Minnesota, Ohio, and Wisconsin had bills affected by these adjustments. However, at least in the case of one utility in Minnesota, the adjustment was a reduction to compensate ratepayers for charges that had exceeded necessary cost recovery.

Gas supply acquisition strategies by local distributors also have remained largely unchanged. A small utility in New Mexico did attempt to arrange for longer term supplies, but was not successful prior to last winter. LDCs generally maintained their approach to gas storage utilization practices between years. The pattern of net storage withdrawals, however, does seem to reflect a shift in how storage supplies are viewed during the heating season months.

The level of residential billings is affected by the billing mechanisms themselves, many of which do not promote efficient consumer behavior. The surge in consumption during the heating season might be tempered somewhat if consumers were more aware of current gas prices and the impact of their decisions on their monthly gas costs. Bills arrive after the billing period during which consumption decisions have been made, and the bill is stated in terms of totals or averages for the period. It is difficult at best for consumers to ascertain their marginal costs for decisions within the period.

Some public utility commissions (PUCs), such as that of New Mexico, have proposed the incorporation of "signal prices" into monthly billings. The signal prices would be a projection for one or two months that are intended to inform the customer. This proposal is unclear on a number of key issues. It is unlikely that the signal price would be the actual price charged without subsequent adjustments. If so, its motivational strength is open to question. Another issue is the consequence of incorrect price projections, which are inevitable. One example of the difficulty in projecting prices occurred in Ohio last winter, when LDCs twice filed applications to amend the Gas Cost Recovery (GCR) rates. Initially the LDCs filed applications to amend upward the rates that were in effect during November and December 1996. The same companies later filed applications to reduce their GCR rates to reflect the prevailing price of gas. Given the uncertainty surrounding price projections, unless signal price projections were produced by a mutually acceptable third party, there may be continual challenges to their reliability.

Effective price signals to residential customers also are masked by specialized residential billing procedures, such as levelized billings, that are designed to avoid unexpected large increases in the monthly cost when possible. This objective has resulted in the availability of

[10]Yet NIGas is reviewing the performance of its storage operation during the past winter to refine its storage utilization, although no major changes are anticipated. "Lessons Shape Utilities' Storage Philosophies," *Gas Storage Report* (March 1997).

Table FE1. Activities in Various States in the 1996-97 Heating Season

Activity	Illinois	Iowa	Minnesota	New Mexico	Ohio	Virginia	Wisconsin
			Change Between 1995-96 and 1996-97 Heating Seasons				
Percentage Increase in Natural Gas Costs to Residential Consumers, Jan. 1996 vs. Jan. 1997	45	25	35	70	35	27	20
LDC Cost Passthrough Method	No	No	No	No	No	No	No
LDC Use of Storage	No	No	No	No	No	No	No
LDC Acquisition Strategy for Natural Gas Supply	No	No	No	No	Yes	No	No
			1996-97 Heating Season				
Leftover Costs from 1996 in 1997	No	Yes	Yes	No	Yes	No	Yes
LDC Use of Futures Market	No	No	No	No	Yes	No	No

LDC = Local distribution company.
Source: **Price Change:** *Natural Gas Monthly* (June 1997), Table 20. **Other:** State public utility commissions.

consumer options such as budget-payment plans,[11] in which the consumer is charged a uniform rate for 11 months and discrepancies between the cumulative payments and costs are addressed in the 12th month.[12] Budget-payment plans obscure not only the marginal cost of additional gas units consumed on any day, but also the average cost for the month or season.

Natural Gas Markets

A factor that would lessen competition and cause prices to be unnecessarily high is undue market power. Some analysts suspect that the generally higher prices in 1996-97 are due to growing monopoly power of gas marketers. However, the data do not support such a finding. The Herfindahl-Hirschman Index (HHI),[13] as a measure of market concentration, does not show concentration among gas marketers that would be consistent with undue market power. Also, analysis of price differentials between stages in the supply chain finds no evidence of improper market performance.

The HHI based on the annual sales volumes for recognized gas marketing firms is 243 for 1996, indicating an unconcentrated market.[14] Naturally, the concentration estimates on a regional level would be higher in some cases. However, even an indication of regional concentration is not compelling evidence of undue market power unless there are contractual, physical, or regulatory obstacles that can impede effective interregional competition or constitute a barrier to entry. Transitory conditions may cause price surges that create short-term opportunities for additional revenues and profits. Sporadic events of this type can be viewed as a reward to risk taking (e.g., returns to a firm for maintaining speculative gas volumes in storage). It becomes a problem when it is systematic in occurrence, or industry participants can influence its intensity or duration. The industry structure as gauged by the HHI lacks strong firm concentration that would lead to market power.

The chief concern about market power is the ability of firms in an industry to sway prices unduly and thereby

[11]Information on the number of customers relying on this or other options tends to be nonsystematic, but anecdotal evidence indicates that roughly 33 to 50 percent of residential customers are on some type of specialized billing option.

[12]Complete reconciliation is not necessarily attained in a single month, often depending on the amount owed by the consumer. In fact, the objective of these plans is to "smooth" the amounts owed by the customer, and in practice, ad hoc adjustments are introduced to achieve this goal. For example, payments under a budget-payment plan may be adjusted upward, even when out of cycle, if costs have risen so much that further delays in cost recovery are likely to result in a substantial "shock" if allowed to accumulate until the next reconciliation month. Thus, even customers under a plan for payment smoothing are open to the impact of a sudden, large increase in upstream gas prices.

[13]A *Herfindahl-Hirschman Index (HHI)* is a measure of market concentration. The HHI for a market is the sum of the squares of each company's market share. The lower the HHI, the less market concentration and the greater likelihood of a competitive market.

[14]The calculated HHI is based on 1996 gas marketer data obtained from Benjamin Schlesinger and Associates, Inc., *Directory of Natural Gas Marketing Companies*, 11th Edition (May 1997). The Federal Trade Commission divides market concentration as measured by the HHI into three broad categories: (1) unconcentrated—HHI below 1000, (2) moderately concentrated—1000 to 1800; and (3) highly concentrated—above 1800. *Department of Justice and Federal Trade Commission Horizontal Merger Guidelines* (April 2, 1992), http://www.antitrust.org/law/mg.html#14.

create or sustain unfair economic advantages for themselves. Price is a key performance characteristic of the industry, and it can indicate the successful use of market power. Natural gas prices are measured at the wellhead, the citygate,[15] and as delivered to residential customers. Price differentials between separate stages of the supply process show the unit revenue received by operators at that stage and they indicate whether firms were exploiting the response of customers under extreme conditions to gain an exceptional pricing advantage.

Prices at the wellhead rose dramatically during the early part of the winter, increasing to $3.53 per thousand cubic feet in December 1996, an increase of almost 83 percent from the October 1996 level of $1.93. The difference between delivered prices and those at the wellhead fell during the recent winter and it is less than that in the prior heating season. This pattern in the total markup from the wellhead is mirrored also in the intermediate stages, whether from the wellhead to the citygate, or from the citygate to the residential consumer (Figure FE8).

The only portion of residential prices that increased is that contributed by wellhead prices. Wellhead prices were substantially higher in 1996-97 compared with the prior year. This price increase, in conjunction with the declines in delivery markups, resulted in a much larger share of final revenue attributable to production. The largest share of residential price associated with the production phase in the 1995-96 winter was 37 percent in December. This same share was 55 percent in December of the following winter (Figure FE9).

The price differentials do not support a finding of market power beyond the wellhead and market power at the wellhead level is unlikely in light of studies in the literature. Recent studies have supported findings of growing upstream market integration across North America, although market integration is not effective between all regions.[16] Also, patterns in price data for five market hubs indicate improved competition between regional upstream markets (see box, p. lxvi). Beyond the citygate, local distribution is within the purview of State authorities, so the price markup thereafter is primarily a reflection of the impact of regulation in the States.

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[15]The *citygate* is the point or measuring station at which a gas distribution company receives gas from a pipeline company or transmission system. Source: Energy Information Administration, *Natural Gas Monthly*, DOE/EIA-0130(97/04) (April 1997).

[16]For example, Energy Information Administration, *Natural Gas 1996: Issues and Trends*, DOE/EIA-0560(96) (Washington, DC, December 1996), pp. 82-84; and National Energy Board of Canada, *Natural Gas Market Assessment: Price Convergence in North American Natural Gas Markets* (December 1995).

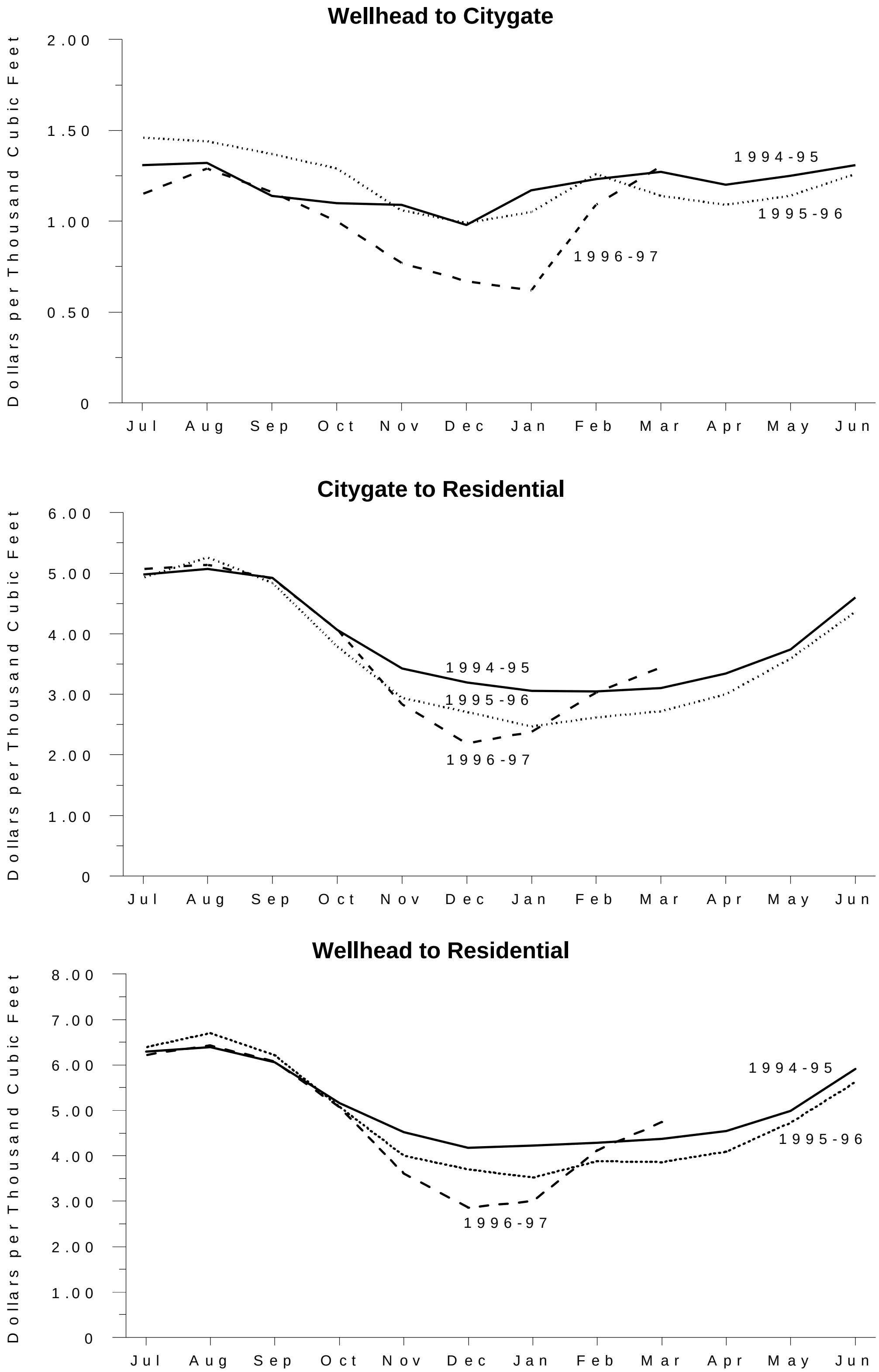
Implications for the Future

The experience of the 1996-97 heating season provides insights into possible, if not likely, outlooks for natural gas markets in future winters. The supply system—including producers, importers, storage operators, marketers, and LDCs—provided required volumes without incurring bottlenecks or the extreme spikes in spot prices seen in 1995-96. This improvement was offset at least partially by the generally higher prices throughout the winter— although the higher prices were in part because of the shift to a new price level that occurred in the rush to rebuild storage stocks by the start of the heating season. In some cases, such as that seen in New Mexico, the major contributing factors may be rather unique and so the extreme circumstances of this situation are not likely to recur (see box, p. lxvi).

A key element of the supply response system will continue to be gas from storage. The growing share of storage assets that consist of the newer storage preparation technologies or salt caverns ensures high deliverability potential for use on peak demand days. Further realization of storage advantages will depend on refinement of utilization strategies. One form of improvement would occur if operators diversify further in their storage utilization practices. Differing reactions to market conditions would tend to mitigate the immediate impact of conditions on markets and would lessen the lingering implications of storage decisions. The lack of singularity in individual behavior would benefit the markets, as actions that do not prove appropriate to subsequent conditions will be offset by that of other firms.

Two options that are being considered by PUCs in a number of States are improved consumer information in billings and better gas acquisition strategies by the LDCs. Improved price information is intended to promote efficient consumer behavior. As gas prices fluctuate within a season, the consumer reaction to the most recent gas bill may be inappropriate to the current market conditions. For example, the receipt of a higher gas bill in January or February 1997 reflects wellhead market conditions prevailing in earlier months. By February, gas supplies were relatively abundant judging from wellhead prices, which fell from $3.58 per thousand cubic feet in January to $2.73, a 24-percent decline. A reduction in residential gas use in February would have been inappropriate to the supply situation at that point, and it even might exacerbate the conditions behind the then declining upstream prices. Proposals to improve consumer information include the use of signal prices in billings, but price signals may not work as intended because of later adjustments or questions regarding their

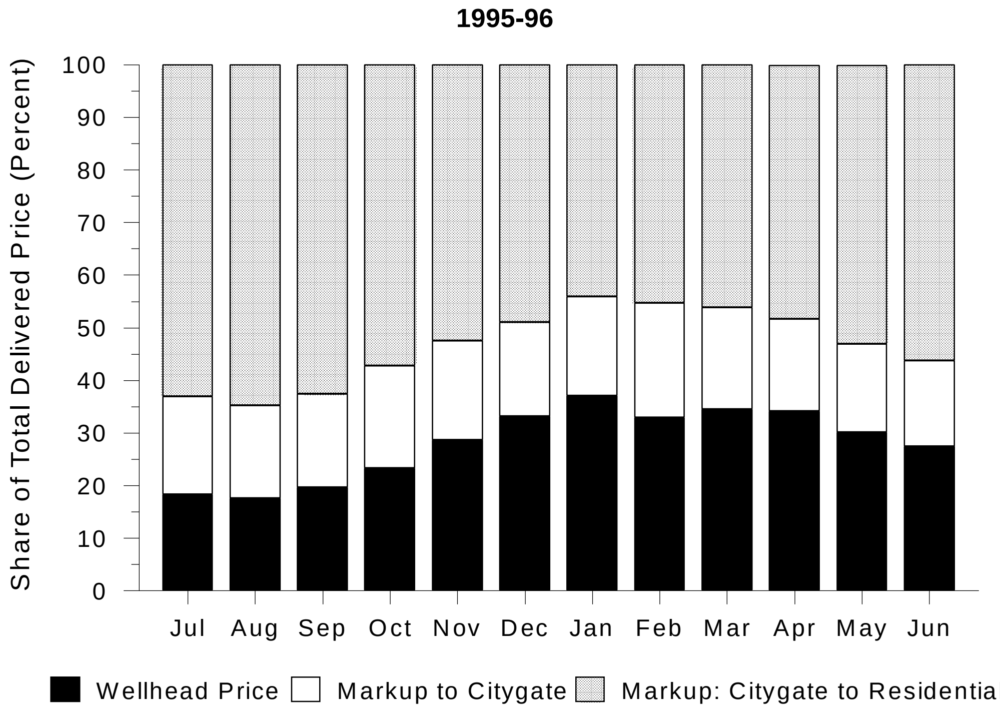
Figure FE8. Price Differentials, July 1994 - March 1997

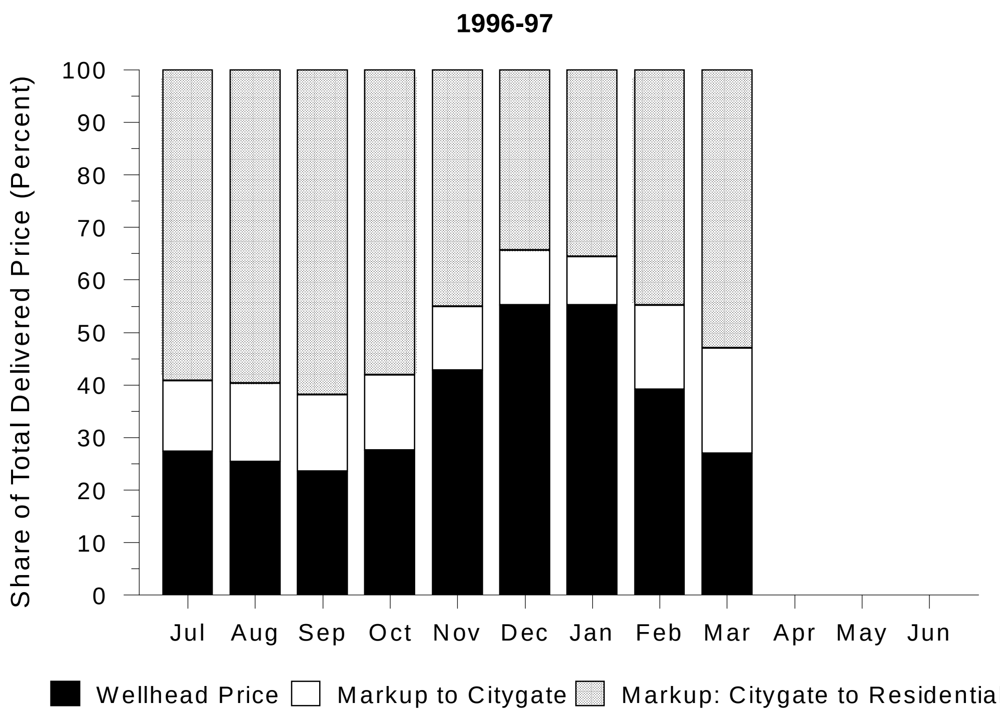


Note: Because vertical scales differ, graphs should not be directly compared.

Sources: Energy Information Administration, *Natural Gas Monthly*. **1994-95:** September 1995. **1995-96:** September 1996. **1996-97:** June 1997.

Figure FE9. Decomposition of Residential Price





Sources: Energy Information Administration, *Natural Gas Monthly* (September 1996 and June 1997), Table 4.

Gas Markets in New Mexico and Minnesota

Residential billings vary between locations reflecting variation in geographic markets, weather conditions, and relative availability of gas supplies. For example, the increase in delivered price for natural gas to residential customers between January 1996 and January 1997 varied between 25 and 70 percent for a sample group of States (Table FE1). The differences in price patterns are an outcome of the relative demand and supply in each State, which include the institutions and any special events or circumstances affecting that State.

Two of the States with the highest price increases this past winter were New Mexico and Minnesota where markets were strongly affected by conditions particular to those States. Temperatures in both States were significantly lower in November and December. Minnesota temperatures were warmer than 1995-96 beginning in January, but relief did not arrive in New Mexico until March. Minnesota has relatively little storage capacity, with withdrawals being roughly 1 percent of annual residential consumption. New Mexico has greater storage capacity, which provides withdrawals of gas sufficient to satisfy more than half the annual residential consumption. The impact of the more persistent cold weather in New Mexico was exacerbated by increased out-of-State demand for New Mexico gas production caused by expanded transmission facilities.

New Mexico historically has been a net supplier of natural gas because of its bountiful resource base, including coalbed methane deposits in the San Juan basin. Recovery of coalbed methane deposits for markets was stimulated greatly by the special production tax credits granted under Section 29 of the Windfall Profits Tax Act of 1980. These credits were established for 10 years of production for all coalbed recovery wells begun by the end of 1992.This sunset provision resulted in a surge of drilling for coalbed development during the early 1990s. Coalbed methane recovery projects require an extended period for dewatering of the formation during which gas production increases. This incremental supply in New Mexico served to depress prices as local demand growth did not keep pace. Spot market prices for New Mexico show a large difference for sales at the Blanco, New Mexico hub up to the end of the 1995-96 winter (Figure FE10).

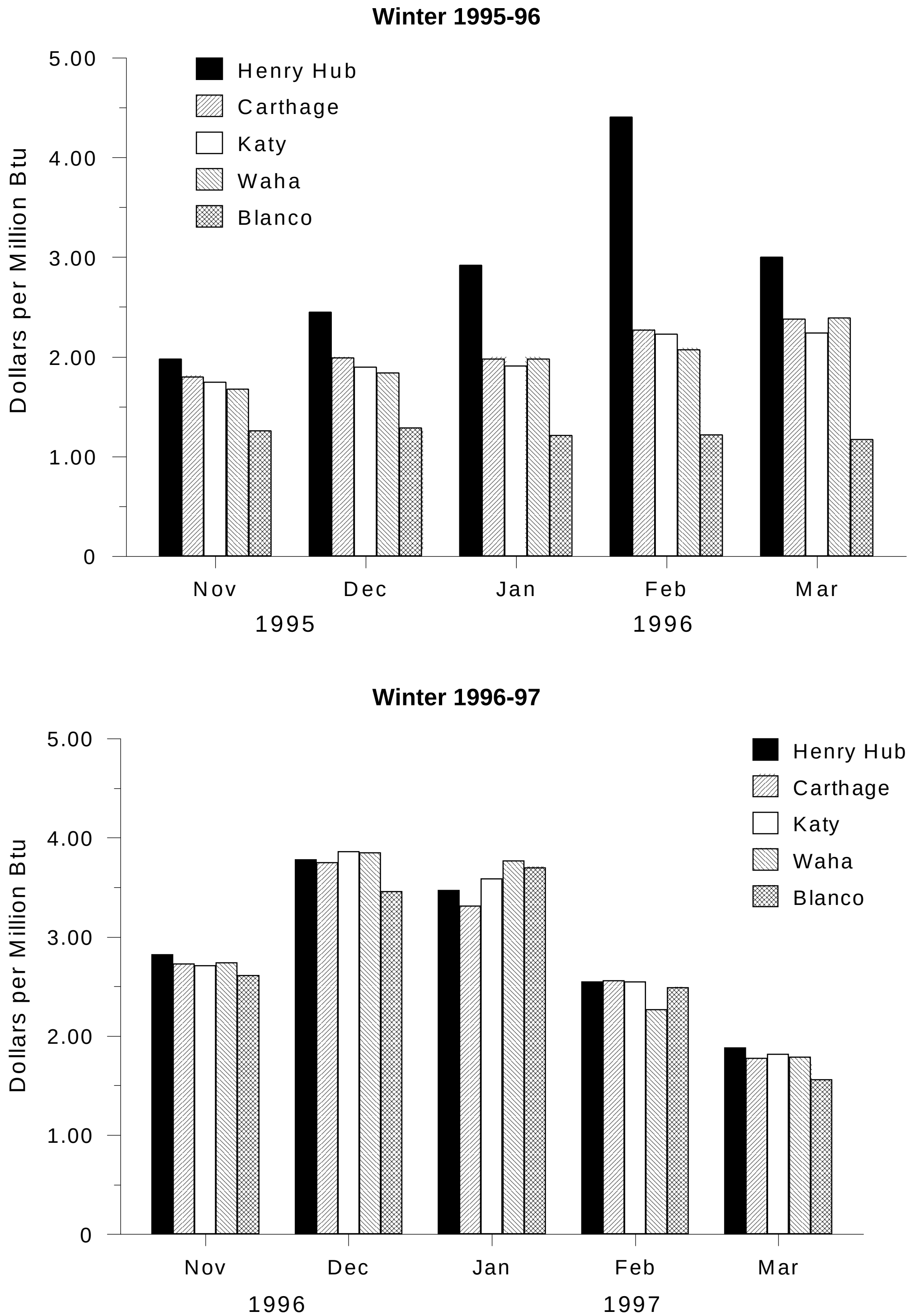
This price discrepancy indicates a lack of market integration between New Mexico and other markets. Pipeline expansion projects in the San Juan area, such as the lower section of the Transcolorado pipeline system (120 million cubic feet per day (MMcf/d)) and the San Juan expansion of Transwestern Pipeline company (255 MMcf/d), have relieved bottlenecks that have hindered the flow of production out of the area and improved producer access to potential customers in eastern and midwest markets. These two projects provide combined capacity expansion of 137 billion cubic feet annually, which is equal to 8.4 percent of New Mexico production in 1995. Improved access of San Juan gas to the Blanco hub in northern New Mexico also enhances the marketability of produced volumes. This expansion increased the effective demand for the gas by allowing access to New Mexico supplies for customers that otherwise were excluded.

The inevitable trading by gas purchasers between supplies of varying prices causes a convergence of prices between New Mexico and other hubs that is apparent by the beginning of the 1996-97 heating season. The prices in the 1996-97 heating season show a uniformity that contrasts greatly with the previous year. The November 1996 prices are between $2.61 and $2.82, which range is 7.7 percent of the mean. This is substantially below the 42 percent variation in prices during November 1995, when prices were between $1.26 and $1.98. Prices in the 1996-97 heating season are grouped more closely with variation of less than 13 percent relative to the mean in each month. This contrasts to the more than $3.00 discrepancy in prices during the 1995-96 heating season, which is 85 percent around the mean. The Blanco spot price in November 1996 is more than double that of November 1995. Another characteristic attributable to improved market integration is the similarity in monthly spot price movements. The Blanco spot price varies only slightly in 1995-96 despite the significant price shifts occurring elsewhere. The Blanco price in 1996-97 obviously has a stronger association with that of other markets.

A consequence of these developments to improve markets across the Lower 48 States is that the degree of market isolation previously affecting prices in New Mexico was greatly reduced entering the 1996-97 heating season. Exposure to external market factors was heightened for residential customers by a heavy reliance by State utilities on spot purchases for supplies. It is expected that this strategy provided ratepayers substantial savings in prior years due to the depressed prices of the area, however, it was not well positioned for 1996-97 as things turned out. Consumers in New Mexico, with higher priced gas and the need for more gas owing to the colder temperatures, were left with bills that were often double and triple those of the prior year.

The impact of such dramatic changes in energy costs from year to year is not lessened by arguments regarding increased market efficiency and improved long-term benefits. The State PUC held hearings with Public Service of New Mexico, the major LDC in the State. A key subject of inquiry in the hearings concerned the prudency of gas acquisition strategies that relied so heavily on spot market purchases. The PUC eventually found the utility was not imprudent in its acquisition practices, but it did encourage Public Service to utilize options such as price hedging tools. The interest in price hedging as a utility option to enhance gas acquisition practices is being expressed by PUCs in other States, such as Ohio, although it generally has not been widely pursued by LDCs to this point. They cite concerns about cost recovery when losses are incurred due to involvement in trading for price hedging.

Figure FE10. Monthly Heating Season Cash Market Trading Prices at Five Major Hubs



Source: The Oil Daily Co., *Natural Gas Week* (March 31, 1997), p. 17.

reliability. Additionally, this issue may be moot, however, if residential customer demand is so highly inelastic that reduced consumption in response to higher prices is effectively precluded.

A major feature of gas acquisition strategies is the associated costs. The PUCs have encouraged utilities to improve their gas acquisition by stabilizing prices through hedging in the futures market.[17] Futures trading allows market participants to establish the terms of expected transactions now as an alternative to simply allowing events to unfold and accept the rewards or penalties as they occur. Possible foregone profits or slightly higher costs are considered a preferred alternative to the uncertainty that can be detrimental in many ways, such as planning or attracting investment capital.

An LDC that correctly anticipated the rise in natural gas prices in the 1996-97 winter could have purchased gas for future delivery and avoided the high costs that prevailed later; however, *correct* expectations are a key requirement. Futures trading in practice is uncertain and it involves market sophistication at a much different level from that of the traditional cash market. The largest benefits tend to be gained when trades are made early, but many industry participants had a quite unclear picture of the pending heating season even on November 1, 1996.[18] The price for December deliveries at the Henry Hub remained unclear through the middle of the month and even very close to the settlement date. December deliveries were priced at $2.728 per million Btu on October 31, $2.662 on November 1, $2.908 on November 15, and $3.901 on November 21. The spot price for the Henry Hub in December averaged $3.78.

LDCs sometimes claim reluctance to participate in futures trading due to uncertainty regarding the treatment of any gains or losses, both of which are inevitable. Allowable cost recovery items recognized by PUCs varies by State and sometimes over time. One concern of LDCs is that all gains from futures trading will be distributed to the ratepayers, while any losses remain with the LDC shareholders. In one clear case, the PUC in Connecticut announced an 80/20 policy. The LDCs will be allowed to retain 20 percent of all gains, but they are liable for 80 percent of any losses. This asymmetric approach was not well received by the LDCs, who stated that this is an incentive not to participate in such trading.[19]

Futures trading is well suited to stabilize prices within a certain range, but its attainment may conflict with attempts to minimize costs. An LDC that capped its acquisition prices by futures trading may be criticized if an event such as an unexpectedly warm winter depresses prices below expectations. The prudency of such decisions is a difficult performance measure to capture. State authorities are reluctant to grant waivers from all review. One approach might be to diversify the supply portfolio to avoid a strong impact from unfortunate events affecting gas supply from any one area. The virtually complete reliance on spot purchases by major New Mexico utilities left them unguarded from the spot price spikes in 1996-97.

Futures trading during the early portion of the past heating season eventually contributed to higher prices. Many traders and marketers sold short, expecting prices to decline or not rise significantly.[20] The later price runup forced these traders to rely on the cash market to cover their positions, which would have exacerbated the price rise in two ways. Contract fulfillment under these circumstances comprises inelastic demand because as a fixed obligation, it is not price sensitive. Also, it would stimulate demand by effectively discounting prices to end users from what they otherwise would be. As the winter proceeded, the high price volatility led producers and other market participants to step aside, leaving futures trading for mostly speculative purposes. The eventual rise in prices did entice producers back into the market to capture high prices for new production. The introduction of this incremental supply later in the year was expected to work against maintaining price levels. Spot prices did decline to below $2.00 per million Btu in the latter part of February. The incremental supplies, however, seem to have been offset by the need to replenish storage levels, which has served to restore prices to levels above $2.00.

There is a final aspect of futures trading by LDCs that concerns the movement to competitive markets at the State level. A cornerstone provision of this shift is retail unbundling, in which the LDC offers major functions or services, such as sales, storage, and transmission, to the market as separate items with prices reflecting costs of that service alone. This functional division of the firm

[17]Futures contracts are obligations to buy or sell natural gas at an agreed price on a specified future date. Futures trading is just one of a number of financial tools that can be used to hedge price risk. For illustrative purposes, the present discussion will not explicitly include the use of other instruments, such as options, because the basic conclusions remain unchanged.

[18]Pasha Publications, Inc., "Market Uncertain Heading into November," *Gas Daily* (November 4, 1996).

[19]Pasha Publications, Inc., "Utilities call Connecticut Limits 'inappropriate,'" *Gas Daily* (April 28, 1997).

[20]"Cold Weather and High Prices Prompt Stellar Explanation," *World Gas Intelligence* (January 24, 1997).

promotes competition by disallowing the monopoly franchise established in one area, such as transmission service, to bestow market power on other services that would otherwise be offered on a competitive basis. Some LDCs have taken the initiative under the unbundling movement to focus operations in delivery services only. Without involvement in the merchant function, LDCs will not be acquiring gas for resale and futures trading is unnecessary.

The natural gas market has changed fundamentally during the past decade. The shift from intensive regulation to a highly competitive system has required tremendous changes in operations. The great success of the industry in performing well while adapting to these changes has sometimes imposed high costs on consumers. The long history of the industry belies its relative unfamiliarity with the present situation. Today's industry has been characterized as a relatively "immature" one because of its recent transition,[21] and so some "growing pains" may be inevitable.

Conclusions

Competition is increasing in U.S. gas markets. The overall nature of the market outcome—prices and volumes—depends on the interaction of the entire set of participating entities: producers, consumers, and infrastructure operators (e.g., storage, transportation, and hubs).

The system seemed to perform better in 1996-97 than in the prior heating season. Although prices were higher, the system avoided the extreme price spikes that occurred in some localities (e.g., Chicago) during the 1995-96 season. The 1996-97 price pattern reflects the improved interconnectedness of the system, which supports effective competition between regions of the Lower 48. Storage utilization during the past heating season may be questioned in light of subsequent events, but the strategy does not appear to be unreasonable. The early reliance on storage gas in 1995-96 left lower-than-preferred levels of gas as inventory, which became a critical factor when the severe temperatures persisted in major consuming locations. On the other hand, the lesser reliance on storage gas in early 1996-97 greatly contributed to increased prices for marketed production. The large volumes of gas remaining in storage were not necessary when temperatures abated and consumption declined.

The industry most likely will experience some growing pains as it settles into the new competitive environment. Strategies such as the conservative storage policy this past winter may reflect an approach in which the most recent problems are accorded highest priority. Industry approaches will continue to change as the industry evolves, but price shifts will still occur. These price changes are the communication mechanism for market participants.

Effective pricing signals, however, are not necessarily consistent with smooth (or low) prices. The actions required to negate price shifts generally cannot be expected in anticipation of the conditions. For example, the high prices this past winter led producers to operate crews at overtime rates in order to get the benefit of the higher prices. Such actions mitigate a price rise but cannot prevent it. It is not economically sensible to react before the price rise because the market signal has not been received. The shrewd operator will try to anticipate market changes and position the firm to take advantage of them, but the action will await the price as an incentive.

The performance of the natural gas industry during the recent winter is encouraging, although it should not be construed as indicative of expected success under all future conditions. The ability to satisfy any set of demands may be highly conditional on the particular intensity, timing, and spatial distribution of consumption requirements. Further validation of the system requires success under differing conditions in subsequent heating seasons.

A difficulty with attempting to achieve stable gas prices is that the uncertain events are not independent. Thus, losses may be coincident and overwhelm the system. For example, a severe weather event could lead to heavy gas demand that would drive up prices. Success in shielding customers from these signals will not provide appropriate behavioral responses by consumers. Acceptance of this situation depends on the ability of the system to accommodate residential customers under these conditions and the equitable allocation of these costs in revenue recovery by the LDCs.

[21] Pasha Publications, Inc., "AGA Finds LDC Winter Purchasing Habits in Flux," *Gas Daily* (June 11, 1997).