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MISSOURI PUBLIC SERVICE COMMISSION

UTILITY SERVICES DIVISION

REBUTTAL TESTIMONY

OF

JOHN H. HERBERT

MISSOURI GAS ENERGY

CASE NOS. GR-2001-382, GR-2000-425, GR-99-304 AND GR-98-167 (Consolidated)

Exhibit No. 7
Case No(s). GR-2001-382
Date 5-12-03 Rptr KS

Jefferson City, Missouri
March 2003

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Missouri Gas Energy's Purchased Gas Adjustment Factors to be Reviewed In Its 2000-2001 Actual Cost Adjustment	)))	Case No. GR-2001-382

AFFIDAVIT OF JOHN H. HERBERT

STATE OF)
) ss.
COUNTY OF)

John H. Herbert, of lawful age, on his oath states: that he has participated in the preparation of the foregoing rebuttal testimony in question and answer form, consisting of 24 pages to be presented in the above case; that the answers in the foregoing rebuttal testimony were given by him; that he has knowledge of the matters set forth in such answers; and that such matters are true and correct to the best of his knowledge and belief.

John H. Herbert
John H. Herbert

Subscribed and sworn to before me this 13th day of March 2003.

Heather R. Kreutter
Notary Public

My Commission Expires: 1/31/06

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REBUTTAL TESTIMONY

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MISSOURI GAS ENERGY

CASE NOS. GR-2001-382, GR-2000-425, GR-99-304 AND GR-98-167

(CONSOLIDATED)

Q. Please sate your name, occupation and business address.

A. John H. Herbert, Independent Consultant, 2929 Rosemary Lane, Falls Church, VA 22042.

Q. Are you the same John H. Herbert who filed direct testimony in Case No. GR-2001-382?

A. Yes, I am.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to the direct testimony of expert witness John J. Reed and of Michael T. Langston related to Staff's proposed adjustments for Missouri Gas Energy, Case No. GR-2001-382. My rebuttal testimony is specifically related to price risk management and related issues.

Natural Gas Storage Withdrawals, Price Risk, Changes in Price Level, Market Analysis, Commission Responses to Purchasing Practices in Heating Season 2000/2001, Financial Derivatives, Index Contracts and Risk Premiums in John J. Reed Direct Testimony

Q. On pages 19-21 of his testimony, Mr. Reed indicates that storage withdrawal amounts reported by the AGA are relevant for drawing conclusions about the reasonableness of a Company such as MGE's withdrawal practices. Do you agree with this position?

A. No, I do not agree with this position for several reasons.

The reasonableness of a Company's withdrawal amounts for a month can only be gauged relative to a Company's supply capability for a specific month and for all months. Let's take a simple example.

One company has relatively large amounts of gas in storage relative to its expected requirements for the heating season and few or no fixed price forward contracts for all the heating season months. Another company also has relatively large amounts of gas in storage relative to its expected requirements for the heating season but it also has fixed price forward contracts for all the heating season months. Both Companies withdraw large amounts of gas from storage in November. This depletes storage volumes available for the later months and thus increases the price risk exposure of customers for later months.

The chance that storage activity is found to be unreasonable is greater for the first company than the second company because the second company has fixed price contracts for a certain volume of gas that limit customers' exposure to price risk. If the second company also has access to propane or LNG and other means of reducing its customers exposure to price risk then its chance of being considered unreasonable is even smaller.

Q. Are there any other factors that need to be taken into consideration when reaching conclusions about the reasonableness of a company's decision to withdraw large amounts of gas in the early heating season?

A. Yes, the Company's decisions need to be examined over the entire heating season on a month-by-month basis. For example, if the company purchases call options or fixed price contracts for the remaining months of the heating season, it has taken actions to reduce the price risk exposure of these volumes of natural gas for its customers. This reduces the chance that it is found to be unreasonable for withdrawing large amounts of natural gas from storage early in the heating season.

Q. Didn't the Company make a filing on September 27 2000, to renew the price stabilization fund as shown in Staff witness Sommerer's Direct Schedule 9?

A. It is my understanding that the Staff opposed this renewal, which will be addressed in Mr. Sommerer's rebuttal testimony.

Q. What is there about the AGA reports that is most useful for a Company to consider?

A. The level of storage relative to previous years and relative to expected demand for the remaining heating season is important so that a Company can obtain some idea of the chance of a price rise or an increase in price uncertainty.

In general, the lower the level of storage relative to expected demand, the greater the chance of a price rise and the greater the price uncertainty.

The lower the level of storage relative to expected demand, the greater the chance that when temperatures drop significantly, utility companies will need to purchase increasing amounts of gas on the cash market. This may very well elevate the price level.

Q. Then you agree with Mr. Reed's emphasis on the importance of price level as a guide for a price risk management program as discussed on pages 21-26 of his direct testimony?

A. No. For example, in the situation just described, an increase in gas price is likely to occur if temperature declines significantly, especially over a period of time when there are low storage levels relative to expected demand.

Yet, it is difficult to make such temperature predictions on a regular basis. This is particularly true because the time when a Company is making a decision (such as the decision in

September to enter into a forward contract for November at a certain price) is much different from the time when the outcome of the decision will be known.

If temperatures decline, prices are likely to increase but if temperatures increase price is likely to fall. Price will fall when temperatures rise because demand for gas from the cash market gets reduced and storage withdrawals are likely to decline as well. The reduction in gas withdrawals will increase the level of gas in storage relative to expected demand for the remainder of the heating season.

Some idea of how difficult it is to predict price is indicated clearly in a Figure 2 on page 35 of a Public Utilities Fortnightly article "The Gas Merchant Business: Still a Place for LDCs?" published on July 1, 1999. The forecasts illustrated in the Figure are made in the fall of a year for the next year. The figure shows that the forecasted price for 1996 made in 1995 was \$0.18/MMBtu greater than the actual price for 1995 yet the actual price for 1996 was \$0.96/MMBtu greater than the actual price for 1995. Thus, the forecast indicated a 10% increase but the actual increase was 53%. Similar results are shown for the other years in the figure. The figure also displays the fact that the peaks occur in different month in each year and the monthly pattern of price behavior varies greatly across years.

While a change in the price level is hard to predict, continued high price volatility or price risk is not.

Price risk or price uncertainty for natural gas is understood to be greater than price risk for most if not all-major commodities traded on regulated exchanges. This price volatility is the reason that active management of price risk must be undertaken to provide some level of protection for customers.

Q. Then you think that price risk should be the primary focus of a utility price risk management?

A. Yes, I do.

In fact one of the most popular financial derivatives for a Utility Company to use has been a call option, a type of price insurance that, in effect, can be used to put a cap on price. The price paid for this insurance, the cost of the call option, is ordinarily used to estimate price volatility. The costs of the insurance and price volatility are two sides of the same coin. The higher the price volatility, the higher the cost of the option. There is a very strong relationship between the cost of the option and price volatility.

Q. Is price risk information something that the Company could and should have known prior to the heating season?

A. Yes.

Such information is published daily in Gas Daily, which the company receives and reviews. This is information that could or should have been known to the Company. For example, the price volatility for Monday October 23 2000 for the November contract published in the Options table on page 4 of Gas Daily on October 24 2000, as reproduced in Schedule 1, Table 1, was 76%. This is a very high price volatility number.

The futures contract for November delivery upon which the option contract is based was scheduled to finish trading at the end of the week. The futures settlement price, the price near the close of trading, was $5.072/MMBtu on October 23.

Using $5.072/MMBtu as a likely value for price and the price volatility estimate of 76%, it can be calculated that there is roughly about a 5% chance that price would exceed $8.70/MMBtu over the next 3 months starting on October 23 and that a $10.00/MMBtu price is possible. The main purpose of such analysis is to get some idea of how much uncertainty there is in any price. Yet, this analysis assumes there is no change in the underlying conditions supporting the particular price level. When there is a change in conditions such as increasing evidence that supplies are becoming increasingly tight relative to expected demand, the likely value for price needs to be elevated and the chance of a price greater than $8.70 increases. In any case because of the high price volatility the chance of high prices needs to be considered and regularly reconsidered. Just keeping tab of the options table and price volatility will give a company a sense of this.

It is also useful to examine the option table in more detail for other purposes.

The table indicates that a $5.05/MMBtu cap for November, December and January could have been purchased.

The cap of $5.05/MMBtu for November, December and January could have been purchased for $0.151/MMBtu, $0.461/MMBtu and $0.63/MMBtu, respectively. The cap is only $0.022/MMBtu less than the settlement price for November delivery of $5.072/MMBtu on that day.

Thus, if the price of natural gas near the close of trading of the option contract for January was $10.00/MMBtu the Company could execute the contract at the $5.05/MMBtu price cap and receive a gross return of $4.95. When the Company subtracts out the cost of the option of $0.63/MMBtu it obtains a net return of $4.32 that it can apply against the cost of natural gas.

It is also useful to look at results for the previous year near the same time as reported in Schedule 1, Table 2.

The exact date chosen is October 22, 1999 which is similarly near the beginning of the last week of trading for the November contract but for 1999 not 2000. The settlement price on this date, \$3.072/MMBtu, was exactly \$2.00/MMBtu less than the 2000 price. When the Company examines the \$3.05/MMBtu cap, which is similarly less than the settlement price by \$0.022/MMBtu, it finds that the options were less expensive in 1999 near the same time of the year and month.

The option for January 2000 when compared to January 2001 was \$0.215 cheaper. The option for November 1999 at \$.075/MMBtu when compared to November 2000 was about half as expensive. The reason that the option in the previous year was cheaper than the option in the current year was, in part, because the price volatility was much less in 1999 when compared to 2000. The price volatility for the November contract was 49% in 1999 and 76% in 2000. The exact values are listed at the bottom of the tables.

Q. Mr. Herbert, are you aware that the call option plan that MGE had authorization to operate under until September 30, 2000, restricted MGE to a strike price no greater than \$4.40?

A. Yes. This plan is further discussed in Mr. Sommerer's testimony?

Q. Are you also aware that the average premium under these traditional call option programs was between 10 and 12 cents per MMBtu when the authorized funding was divided by the authorized hedge volumes of 70% of flowing?

A. Yes. It is my understanding that these plans were meant to be additional tools to address hedging. They did not preclude the use of other methods for hedging including the procurement of fixed forward contracts or a smaller percentage of flowing gas such as 30% of normal volumes.

Q. Was price level relevant to the Staff choice of 30% of normal requirements?

A. No. The level was chosen for the 2000/2001 heating season because it was considered to be a very conservative level that companies could have achieved, even those companies that were new to hedging.

Yet, in choosing such low levels on a regular basis some might think that a Company was speculating on price levels since a low level of hedging by non-utilities is sometimes associated with an expectation of a decline in price levels.

Thirty percent of normal requirements might also be considered as under-hedging for much of the heating season because a greater volume of price risk exposure could have been effectively hedged for much of the heating season. Hedging effectiveness is measured by the degree to which the purchased cost of gas is necessarily fixed or capped ahead of time by using hedging instruments. Given a high level of price risk or price uncertainty it makes sense for a utility to hedge the amount of its customers' price risk exposure that it can effectively hedge.

Q. But shouldn't these hedges get reduced if the company expects price to decline later in the heating season?

In general no, especially for a plan that considers a minimum level of hedges. A well-managed price risk management plan is put in place prior to the heating season and is sustained throughout the heating season for each heating season month. Once a hedge is put in place it should stay in place for the planned period. Generally, a company should not appear to make decisions in a current month for a forward time period that suggests it knows how prices are likely to turn out. Unless it has convincing and documented evidence (based on analysis that others are not likely to have and/or be able to act on) that price is more likely to move in one direction than another direction, it should resist making such decisions. This is especially true when a minimum level of hedging is being undertaken.

Given the high level of price risk faced by natural gas customers, it is incumbent upon the utility to reduce this exposure by putting in place and maintaining some minimal level of hedges for each heating season month. This can be accomplished with well-understood hedges such as storage or fixed price forward contracts or with financial derivatives such as futures contracts or call options. Utility companies generally should not use price speculations to rationalize price risk management decisions.

Q. Are there features other than the large magnitude of price risk that might be relevant for a utility price risk management program?

A. Yes. The relevant distribution of prices at any point in time is generally considered to be skewed toward high prices. What this means is that the chance of relatively high prices is greater than the chance of relatively low prices.

Of course, the chance of high or low prices depends on the circumstances at the time, but generally speaking, the distribution is considered to skew toward high values. This might give utility companies an added incentive to put a cap on price for their customers.

Q. Is there a natural upper limit on how high prices can rise?

A. In theory there is no natural upper limit. There is no natural upper limit for several reasons.

Consumers are generally unwilling to reduce their use per unit of temperature when temperatures plummet even when the price is high.

Most consumers have no alternative in the short-term but to turn down the thermostat significantly, which they are unlikely to do. Customers have heating systems because they want and need their homes and businesses to be warm and comfortable. The natural gas industry wouldn't tell potential customers that natural gas is cost-effective only when the weather is moderate or when prices are low. People generally expect to use their furnaces when the weather is cold.

Although some residential consumers may begin to use a wood furnace if they have one available, most residential consumers do not have this or other such alternatives. Other larger consumers may have an alternative fuel. But it is generally assumed that these customers have already switched to the alternative fuel when the natural gas price is particularly high.

Consumers are also generally not aware of the cost of gas at the time of use. There is not only a time lag in billing, but often current bills do not reflect the current actual cost of gas.

When demand is particularly great readily available supplies become increasingly scarce and price can continue to rise to ration the increasingly scarce resource.

Thus, when utilities increase greatly their demand for natural gas from cash markets, they can drive the price up significantly.

Q. Can some idea of the great price uncertainty in the gas market be obtained from the Reed testimony?

A. Yes, from the Inside FERC Gas Markets Report (IFGMR) for October 22, 2000 which he references, "over the last two weeks, the gas industry has watched the November gas futures contract fall more than $1.00/MMBtu from....$5.76/MMBtu .... On October 12 to $4.64/MMBtu, just nine days later. A month later in the November 24, 2000 issue of IFGMR it was reported that "the December contract on November 15 hit ... $6.32 only to fall ... the following day to ... $5.78/MMBtu". However, his discussion of price variability since the 1980s on page 24, which will be addressed shortly, is confusing.

Some idea of the great price uncertainty or variability during the year can be appreciated by examining Exhibit 1 in the "General Report on Analysis of Gas Supply and Hedging Practice by Regulated Natural Gas Utilities in Missouri." The Exhibits from this report were inadvertently left out of Schedule 2 of my direct testimony. They are attached to my rebuttal testimony as Schedule 2. The entire report, including these exhibits, were previously provided to MGE.

In general during the year, information on rigs, storage, new pipeline capacity additions and new natural gas power generation indicated a situation much different from the previous year and a situation with much price uncertainty. This information, which is reported either in Gas Daily or by the EIA and by other groups such as Baker Hughes, is information that was generally available to the Company and known by it.

Starting in April of 2000 the number of rigs was generally above year earlier levels. This suggested that production capacity and supplies would increase but they never seemed to increase enough because price continued at levels that were significantly above year earlier levels, generally 50% or more above year earlier levels.

The increased number of natural gas generators coming on line probably supported the high prices in the summer and early fall. Nonetheless, the amount of additional demand from new power generators was very uncertain.

However, an eroding supply situation was strongly suggested by a decline from year earlier levels in storage in the AGA producing region. When current demand exceeds current supply capability from the wellhead producers and their agents tend to withdraw large amounts of natural gas from storage in this area. Storage in this region represents a backup source of supply to provide additional natural gas to the market because demand or price or both are increasing.

Gas storage in the producing region can be used to smooth production to allow producers to produce at an optimal level much of the time. When supply capability exceeds current demand then producers can put the additional supplies of natural gas into storage for later use instead of reducing production at the wellhead and operating at a less then optimal level. At these times storage levels can build significantly in this area. It is not surprising that storage in the producing area is much more operationally flexible than storage in the consuming area.

The difference between storage levels in the producing regions between years is displayed in Schedule 3. This exhibit includes current information.

The price information displayed in Schedule 4 is for the same period of time as the storage information in Schedule 3. This should facilitate the comparison of the price behavior in Schedule 4 with the storage behavior in Schedule 3.

The numbers displayed in Schedule 3 are similar to inventories for any business. Since the natural gas business is a seasonal business we compare inventories between years. Most recently, the difference between storage levels in the year 2003 in the producing region compared to the previous year at the same time is lower than it has ever been, and as consequence Henry Hub prices are as high as they have ever been as shown in Schedule 4.

It is also not surprising that in the previous year, especially at end of December 2001, inventory supplies were high relative to their level in the previous year at the same time. This is because not only had demand decreased from more moderate weather but production capability had increased because of the high prices in the previous year. The high prices inspired a large increase in the number of rigs and development wells that have a lagged effect and not an immediate effect on production capability. Hence prices were low during heating season 2001/2002.

It is also clear from the figures that, between years, the relationship between changes in storage levels in the producing area and price is strong. Yet, these figures are not meant to suggest that it is easy to predict the price levels with estimated relationships between the variables depicted in the figures. However, the graph does show that a very good indicator of price levels was moving consistently in the direction of a higher price level, and not in the direction of a lower price level, between November 17, 2000 and January 5, 2001. Because of a reporting lag, this information was known starting on November 22, 2000.

It is worth noting that storage statistics are the most current indicator of current market conditions available to the industry and this is information that could and should have been known to the Company.. Probably no other series is examined more closely by the industry.

During the 2000 injection season it was reported in the trade press that Alliance Pipeline, a major pipeline with a capacity exceeding 1.3 Billion cubic feet a day was expected to come on line in October or early November. At first it was expected to bring additional Canadian natural gas into the United States. This was expected to put downward pressure on the price level.

Yet, as the year progressed it was discovered that a significant amount of the natural gas to be shipped on Alliance would be substituted for gas previously shipped on TransCanada Pipeline, the major Canadian natural gas pipeline. Moreover, the due date for Alliance kept on getting pushed back to later in the year.

In summary, the great uncertainty in the market created much price volatility (which price volatility numbers were reported every day in the Options Table published in Gas Daily previously cited in this testimony). This uncertainty was well stated by Mike Noack in response to Staff Data Request No. 2041, dated July 29, 2001, which asked "From what source did the company seek advice on the likelihood of a continuation of changes in the market price that occurred during May 2000?" Mr. Noack responded "The Company received various information from industry sources most of which was substantially conflicting. Many analysts expected increased prices while many expected the price ultimately to decline following the storage injection season."

Q. Please explain why Mr. Reed's discussion of price variability on page 24 is confusing.

A. Mr. Reed's discussion of price variability uses EIA wellhead prices instead of Henry Hub prices, which are the relevant prices for this proceeding.

Henry Hub prices represent wholesale prices for the period and are the key indices used throughout the industry for making both hedging and purchasing decisions. Published Henry Hub prices represent current prices in current contracts at the pipe after the gathering at the wellhead, shipping to the processing plant and then extracting the liquids from the raw natural gas stream at the processing plant. This processing standardizes the quality of the gas and makes it safer for shipping long distance.

Instead Mr. Reed examines wellhead prices.

Wellhead prices attempt to represent the cost of all natural gas produced at the point of production. Wellhead prices don't include the cost of shipping to the processing plant and the cost of processing at the processing plant. Moreover, the wellhead price is cost per Mcf instead of cost per MMBtu. By definition, the cost per Mcf is always different from the cost per MMBtu. For example if the cost of gas per Mcf is $10.00 and there are 1.028 MMBtu per Mcf, which is a reasonable conversion factor, the cost of the same gas per MMBtu is $9.73.

Naturally EIA wellhead prices are lower and less volatile than a series that only includes price information on current contracts especially when price is high.

Moreover, the EIA wellhead series includes imputed values for particular states. These imputed values are averages based on prices for other states. This is important because one of the states that the EIA has imputed values for in recent years is Louisiana, a major producing state. Naturally, series that contain imputed values, especially for major producing states, based on averages for other states will exhibit less variability than actual price information. Mr. Reed may have inadvertently chosen this series, but problems with using it need to be understood. It produces a lower and less variable series than a Henry Hub series.

When we take wellhead prices from the EIA website on March 7, 2003 for the relevant period under consideration here – November 2000 to March 2001 – and convert it to cost per MMBtu we find the following. The EIA wellhead price is $5.68/MMbtu with a standard deviation, a measure of variability, of $1.48/MMBtucf. The Inside FERC average for the same period is $6.34 with a standard deviation of $2.54/MMBtu.

Most striking are the results for January 2001. The Inside FERC price is $9.91/MMBtu and the EIA price is $7.84/MMBtu.

As expected, the measure of price uncertainty for the Henry Hub series of $2.54/MMBtu is strikingly larger than the measure of price uncertainty for the wellhead series of $1.48/MMBtu.

To repeat, the relevant price series to consider for this proceeding are Henry Hub first of the month indices as published in Inside FERC and other major publications; or Gas Daily Henry Hub daily spot indices; or NYMEX daily settlement prices for the futures contract next to terminate. The NYMEX settlement price for the contract next to terminate is often a good proxy for daily spot prices on most days and it is a good proxy for the first of the month indices near the last trading days of a futures contract.

Q. Do you find the comments on Commission Responses in other states to purchasing practices of utilities as described on pages 27-28 of Mr. Reed's testimony complete and relevant to this proceeding?

A. No. It is incomplete and fails to mention Commissions where in-depth reviews of utility purchasing and hedging practices were undertaken similar to the review in this proceeding. In fact, all cited documents in the Reed testimony were completed prior to the end of heating season 2000/2001 - hardly a sign of a comprehensive review.

In contrast, a proceeding in the nearby state of Oklahoma, completed in November 2001, supported a disallowance of $36,000,000 because a major utility in the state failed to have any hedges in place for heating season 2000/2001. Corporate Commission of the State of Oklahoma, Case No PUD 200100057, Order Regarding Prudency, November 2001.

A proceeding in Rhode Island, completed in October 2001, ordered two disallowances. One disallowance because a company did not hedge, another disallowance because a company did not hedge enough. Public Utility Commission State of Rhode Island, State of Rhode Island and Providence Plantations, Public Utilities Commission Docket Nos. 1673, 1736 & 3347, October 17, 2001.

A proceeding in California, completed in August 2002, also found that the company did not hedge enough. The disallowance in that proceeding was $2,7000,000. The disallowance amounted to almost 2 years of the Company's California profits. Public Utilities Commission of the State of California, Investigation into the Natural Gas Procurement Practices of the Southwest Gas Company, Investigation 01-06-047, Decision 02-08-064, August 22, 2002.

Oddly enough, Mr. Reed also makes reference to the Illinois Commission even though a major company in the State is still under review for its purchasing practices in the heating season of 2000/2001.

Much of the focus of the reviews in the other state proceedings cited above were on storage and fixed price forward contracts as in this proceeding.

Naturally, financial derivatives, which the utility could have used, were considered. But the focus was on the conventional and well-understood hedging tools of storage and fixed price forward contracts.

There have also been comprehensive reviews of purchasing and hedging practices on the power side of the utility business. For example, there was a $450,000,000 disallowance for Nevada Power by the Nevada Commission. Nevada Public Utilities Commission, Nevada Power Company, Docket No. 01-11029, March 29, 2002.

Commissions realize that they need to address the implications of the well-documented and understood price risk in the natural gas and power utility businesses that existed prior to heating season 2000/2001 and year 2000.

They then create a record as part of a proceeding and make disallowances because the utilities in their state failed to act to limit their customers' exposure to price risk. These price risk management decisions are necessary because all or much of this large price risk is passed onto their customers with consequent damages when utilities don't act or when they speculate on price levels.

Utilities may also not hedge much because their credit rating is not much dependent on the stabilizing costs. Many company improve their credit rating by stabilizing their cost or revenue streams by using hedges.

Q. Do you find the quotes from the National Regulatory Research Institute Paper referenced on page 40 of the Reed testimony convincing and relevant for this proceeding?

A. No. The focus of the paper was financial derivatives and possible utility strategies in the use of these financial strategies.

Many of the questions – the paper is really just a series of questions – listed in the paper are raised because for many utilities and Commissions financial derivatives and appropriate strategies are new material.

The main focus in this proceeding is on the conventional tools used by utilities to reduce the price risk exposure of their customers. These tools are storage and fixed price forward contracts.

When financial hedging tools such as call options are considered in this proceeding they are not considered as part of a required overall financial hedging strategy, they are considered as additional tools that the Company could have considered using.

Such considerations were expected to vary by Company because different companies have much different past experience with these tools. For example, call options were under consideration by MGE since at least 1997 and under continuing consideration in 2000. Moreover, these instruments are not that much different from price caps in standard index contracts where the utility might pay an explicit or an implicit premium for the cap.

Finally, MGE had never proposed a detailed hedging strategy for even the conventional hedging tools, much less a detailed hedging strategy for financial tools. Staff, in setting a reasonable minimum level of hedging for 2000/2001, focused on the fact that most Missouri LDCs had much experience with storage and fixed price forward contracts but not much experience with financial derivatives.

Q. Do you agree with the statement in Mr. Reed's testimony on pages 46-47 that purchasing natural gas at index is always prudent?

A. No, I do not agree with that position. In fact, if index prices were always prudent then proposed disallowance in proceedings at other States would not have been approved. Perhaps it would be useful to expand the discussion.

First, choosing one type of contract pricing for most if not all natural gas supplies required by customers may be considered to be imprudent when a Company has a variety of contract types such as fixed price contracts, contracts with caps and storage to choose from. Choosing a variety of means to satisfy customer requirements should diversify both price and supply risks. Moreover, a company, just like an individual investor, is advised to spread risk. It is reasonable to expect that a company might have a portfolio of fixed price forward contracts, storage service contracts or have its own storage, index contracts, swing contracts and daily spot contracts just as an investor will purchase into a mutual fund to obtain diversification.

Second, using index contracts if the contract market is thin can lead to huge damages for customers. The quality of a market and the competitiveness of the price index for that market is not a given.

Thin markets can be characterized in several ways. Thin markets are markets where the volume of gas traded on a day is small. Thin markets are also markets where the number of trades freely negotiated between distinct companies on a day are few. Thus, thin markets can be characterized by either the volume of trade, the number of trades or by one company being the dominant company in a market.

Third, thin markets are often very volatile. If the number of trades is small, then the average or index price can be greatly influenced by one or a few trades. They are also volatile because they often represent markets with a huge spread between the bid and ask price. Many companies will resist completing trades in these markets if they can, hence the large difference in the bid and asking price. Individual trade prices can vary greatly depending on whether the buyer or the seller is in the driver's seat for a particular trade.

There is a strong incentive for sellers in thin markets to attempt to set the price, especially if a seller has a lot of index contracts with buyers. For these index contracts the buyers automatically pay the index price. If a seller is able to set the price on a day then it reaps a windfall from all the other contracts it has that are automatically indexed to this 'market.'

A major issue in the natural gas industry at the current time is the degree to which particular companies have manipulated natural gas and power price indices in the past. It is not just State Commissions but also the Federal Energy Regulatory Commission, the Commodity Futures Trading Commission, senior management at companies and major publishers of indices such as McGraw-Hill that are addressing this issue. These groups are addressing the degree to which price indices may have been set and manipulated in the past, and taking steps to avoid such manipulation going forward.

If an index price can be shown to be a product of a truly competitive market then in the long run of perhaps ten years index pricing may well yield the lowest price for a company. But in the short term customers would, at times, be faced with avoidable and huge spikes in their monthly gas bills. Since the utility is making the purchasing decisions for its customers, it must consider volatility and the impact price volatility will have on its customers' bills, bills which are expected to be paid monthly, and provide, at least, minimal price risk protection for its customers.

Many major food processing and other companies hedge because they want to avoid instability in the cost they pay for the commodity. This instability in cost is for the most part much smaller than the cost of natural gas for utility customer because the price volatility for natural gas is much greater than it is for corn, soybeans and other commodities that these companies use. Yet, some utilities fail to act decisively to reduce price volatility even though they are the sole agent the utility customer has for price risk protection. When this happens, utility customers are left uninsured from price risk even though the utility has the capability to insure them. This often occurs because the utility is not focused much on the price risk exposure of its customers.

Q. Do you agree with the statement that obtaining price stability for utility customers necessarily carries a financial premium for utility businesses as stated on page 49 of Mr. Reed's testimony?

A. No, I do not. Providing price stability for customers does not necessarily carry a financial premium.

For example a company could enter into a forward contract with a producer. The producer and the utility hedging for its customers have different, and opposite, price risk concerns. Thus, they might enter into a fixed price forward contract with no premiums because both parties have the same desire to enter into the contract.

However, if there are more sellers than buyers who want to hedge, then sellers might have to supply buyers (utilities) with a premium in order to encourage them to enter into forward contracts. The converse may be true if there are more buyers than sellers that want to hedge.

Another way to view cost or premiums is to examine Schedule 1, Table 3, which duplicates the cost of the option contract for January 2001 delivery but also includes the put option contract information for the same day. The put information could be viewed as being particularly useful for a producer because it would let the producer know what it might cost to put a floor price on the natural gas it intended to sell.

If a producer bought a put with a strike price of $5.15/MMBtu, the table indicates that the producer might pay $0.534/MMBtu on that day near the close of business. This would give it the right to put a floor on price of $5.15/MMBtu. If the price fell to $4.00/MMBtu, it could execute the contract or put the contract back to the market at $5.15/MMBtu and avoid some of the cost of the decline in price. Naturally, the Company would have to take into account the cost of this right, which was $0.534/MMBtu.

However, a utility could also sell a put contract with a strike price of $5.15 and receive $0.534. It could then buy a call contract with a strike price of $5.30 and pay $0.52. The gross return to the utility (before broker and other transaction costs) from these transactions would be $0.014. This is like a cost-less collar where the utility would have a $5.30 cap on price and a $5.15 floor. If the price rises above $5.30 it will still pay $5.30. If the price falls below $5.15 it will still pay $5.15. Thus, the cost of gas for January would never be greater than $5.30 and never less than $5.15 for the volume of gas covered by the call options and this would cost it almost nothing.

<u>The Discussion of the Planning of Hedging Programs in Mr. Michael T. Langston's Testimony</u>

Q. Do you agree with Mr. Langston on pages 44-45 of his testimony that hedging programs need not be implemented on a month-by-month base?

A. No. Hedging programs should be implemented on a month-by-month basis for several reasons.

Price risk is not restricted to a single heating season month. Volumes of natural gas required vary throughout the heating season, with December and January typically being colder than November and March and hence having more price risk exposure. Hence the volumes that need to be hedged are generally greater.

Fixed price forward contracts, to include futures contracts, are usually for a delivery month. In fact, a company using the futures contract to hedge would be expected to match the volume under a futures contract with a like volume on the bid week monthly market. The futures market position is closed out at the same time the bid week contract is completed for the same delivery month.

Q. Do you think that the 30% of normal requirements as a volume to hedge is arbitrary?

A. No. It represents a volume of gas requirements that can be effectively hedged across companies. It is a conservative minimum volume. That a company or a Commission may not articulate such a percentage is beside the point. Companies make decisions all the time for which there is not an articulated standard. All other things being equal, it is readily understood that if a company has an offer for firm natural gas on the spot market at $5.00/MMBtu or $4.00/Mmbtu at the same delivery point, the company will choose the $4.00/MMBtu gas. If it doesn't choose the $4.00/MMBtu gas it is most probably an imprudent decision. It goes without saying that, all else being equal, companies should always choose the least expensive natural gas unless reliability of supply or such other crucial intervening factor drove this unexpected decision. And it goes without saying that Companies should almost always be expected to hedge at least 30% of their normal requirements.

Q. Does this complete your rebuttal testimony?

A. Yes, it does.

Schedule 1

Table 1: Call Options settlement prices for NYMEX contract at Henry Hub on October 23, 2000

Strike or Cap Price	November	December	January
$4.90	$0.239	$0.537	$0.703
$4.95	$0.208	$0.510	$0.678
$5.00	$0.18	$0.485	$0.653
$5.05	$0.151	$0.460	$0.630
$5.10	$0.124	$0.434	$0.607
$5.15	$0.099	$0.410	$0.584
$5.20	$0.078	$0.395	$0.560
$5.25	$0.062	$0.374	$0.54
$5.30	$0.048	$0.354	$0.52

Implied Volatility for call 76.29%. Source: Bloomberg/Gas Daily

Table 2: Call Options settlement prices for NYMEX contract at Henry Hub on October 22, 1999

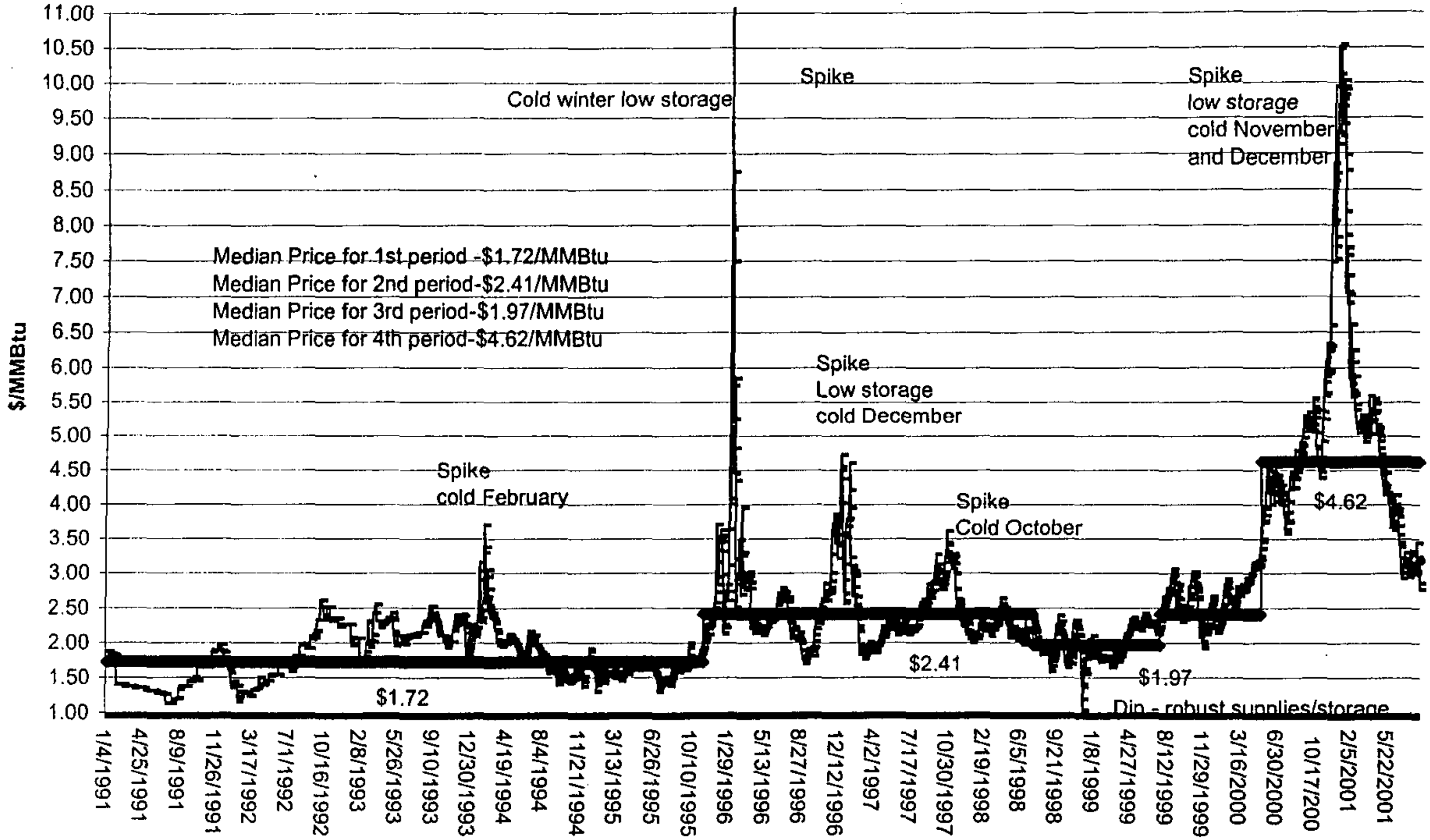
Strike or Cap Price	November	December	January
$2.90	$0.185	$0.396	$0.493
$2.95	$0.143	$0.364	$0.467
$3.00	$0.104	$0.334	$0.440
$3.05	$0.075	$0.306	$0.415
$3.10	$0.051	$0.278	$0.392
$3.15	$0.035	$0.251	$0.368
$3.20	$0.022	$0.224	$0.347
$3.25	$0.0152	$0.204	$0.329
$3.30	$0.009	$0.185	$0.312

Implied Volatility for call 49.63%. Source: Bloomberg/Gas Daily

Table 3: Call and Put Options settlement prices for NYMEX contract at Henry Hub on October 23, 2000, January 2001 delivery month

Strike or Cap Price	January Call	January Put
$4.90	$0.703	$0.405
$4.95	$0.678	$0.429
$5.00	$0.653	$0.454
$5.05	$0.630	$0.480
$5.10	$0.607	$0.507
$5.15	$0.584	$0.534
$5.20	$0.560	$0.560
$5.25	$0.54	$0.590
$5.30	$0.52	$0.620

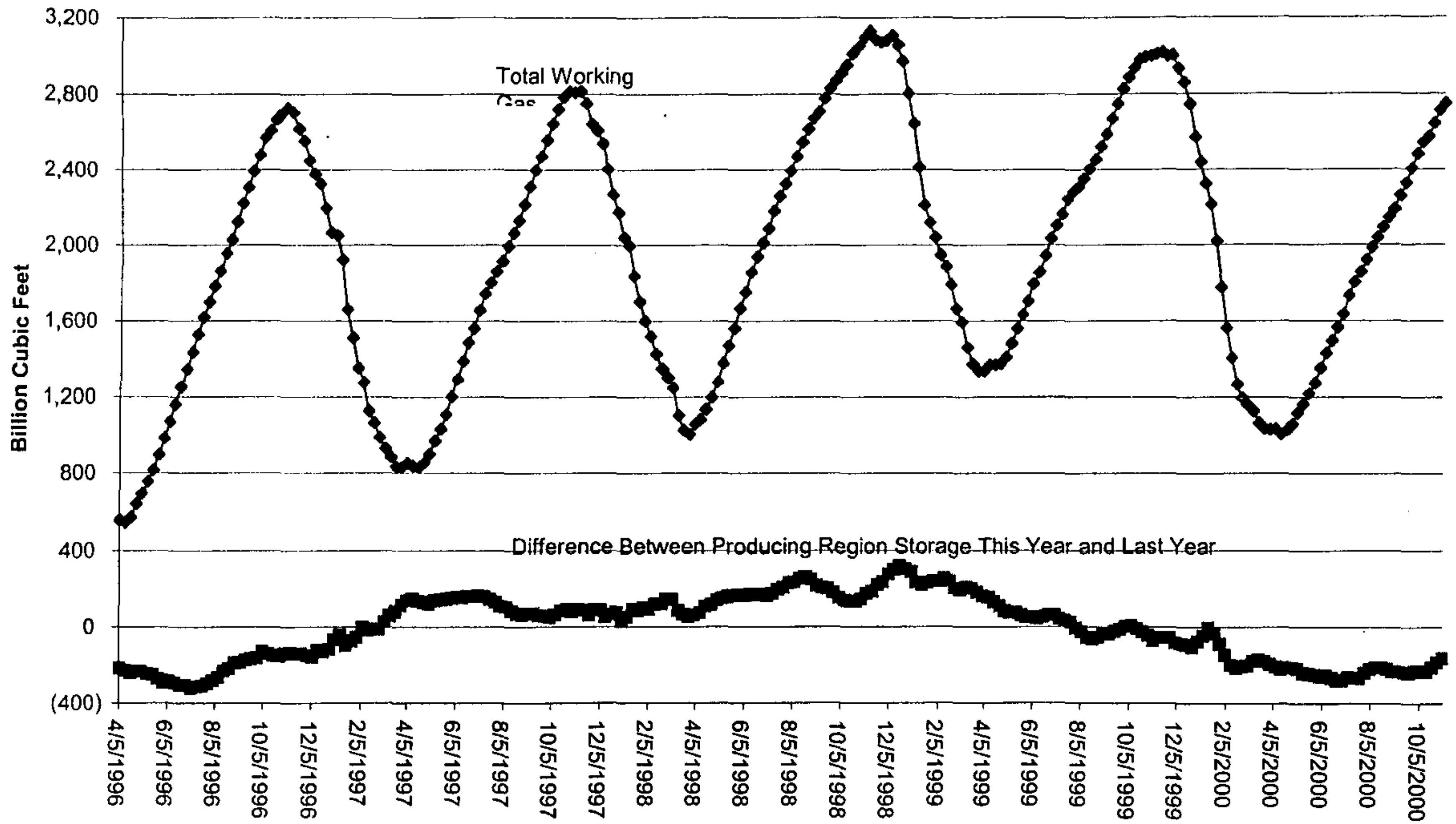
Figure 1. The Long History - Changes in Level of the Henry Hub Spot Price
(Reference Page 16)



Source: Gas Daily/John H. Herbert.

Note: A similar figure with discussion appeared in "Natural Gas Hedging: A Primer for Utilties and Regulators", Public Utilities Fortnightly, October 1, 2001, page 18-32.

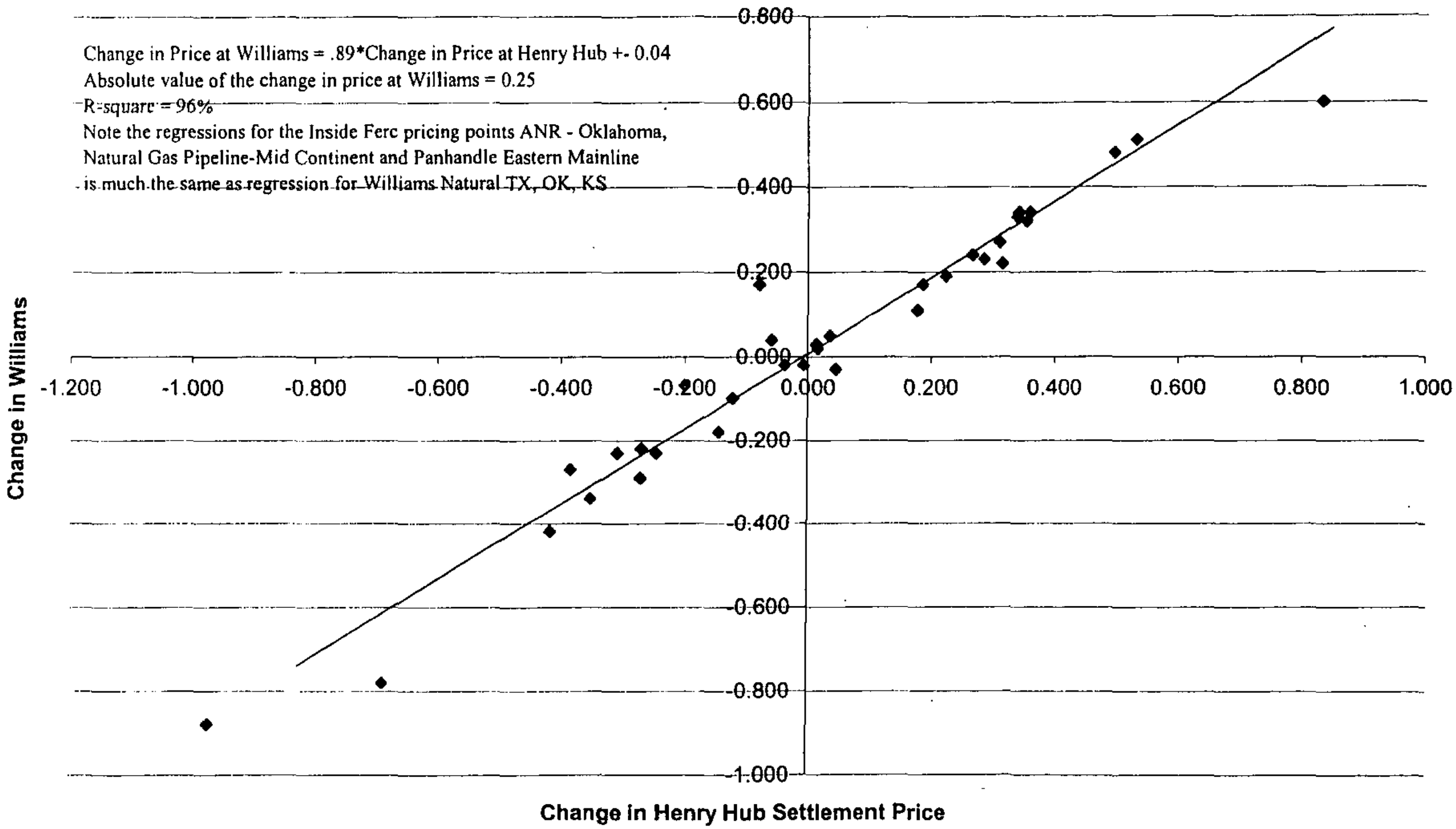
Figure 2. Storage Levels in AGA National Storage Levels and Difference in AGA Producing Region Storage Levels Between Years (Reference Pages 17, 49, 50)



Source: American Gas Association.

Schedule 2-2

Figure 3. Relationship between changes in price at Williams and *changes in price* at Henry Hub April 1997 to April 2000 (Reference Pages 40, 55, 83)



Source: Inside Ferc, Gas Markets Report

Figure 4. Fixed Contracts as a Proportion of Flowing Gas by Market Area in Missouri in December 2000 (Reference Page 43)

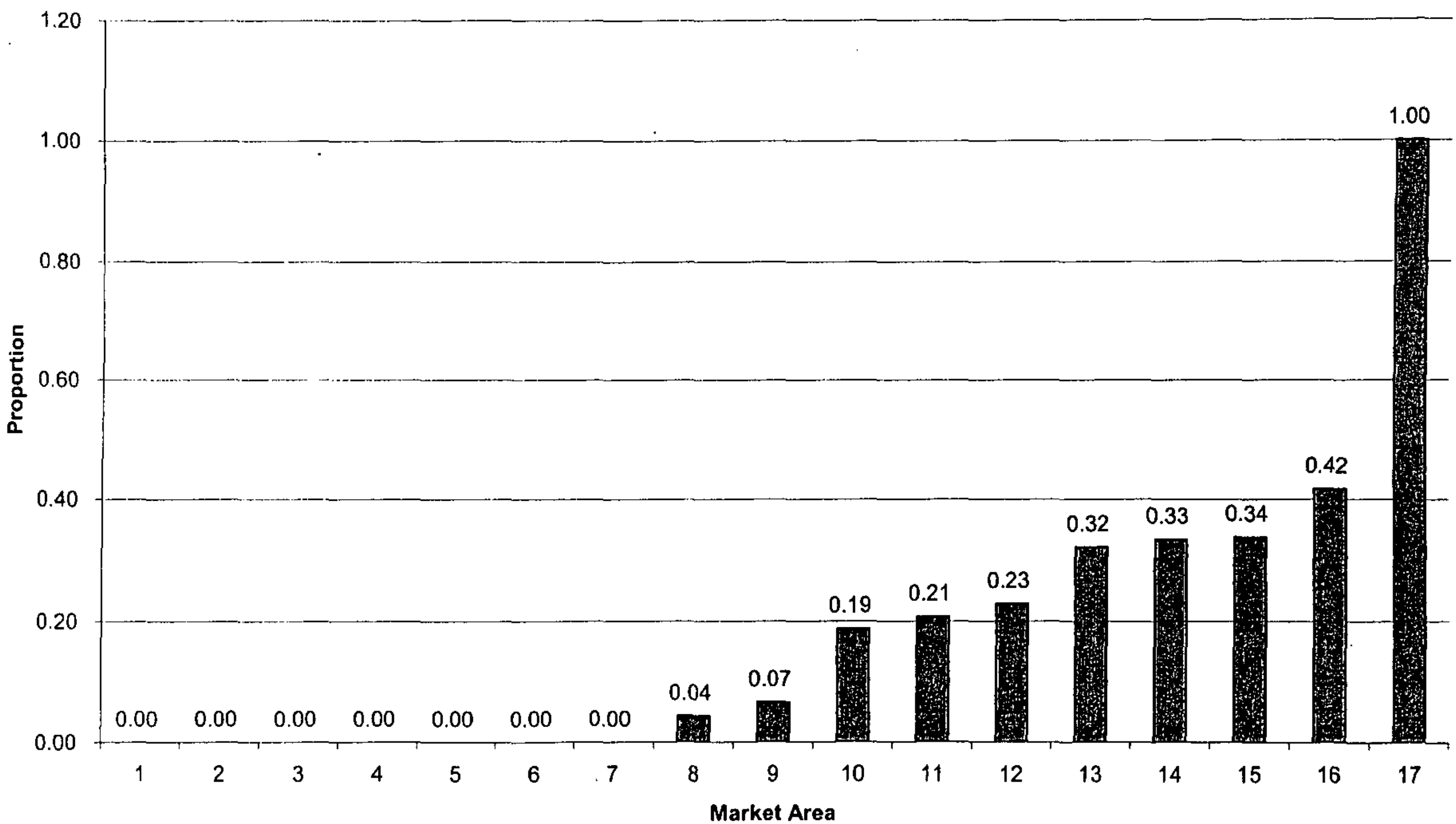


Figure 5. Storage Withdrawals as a Proportion of Actual Usage (Flowing Gas + Withdrawals) by Market Area in Missouri in December 2000
(Reference Page 44)

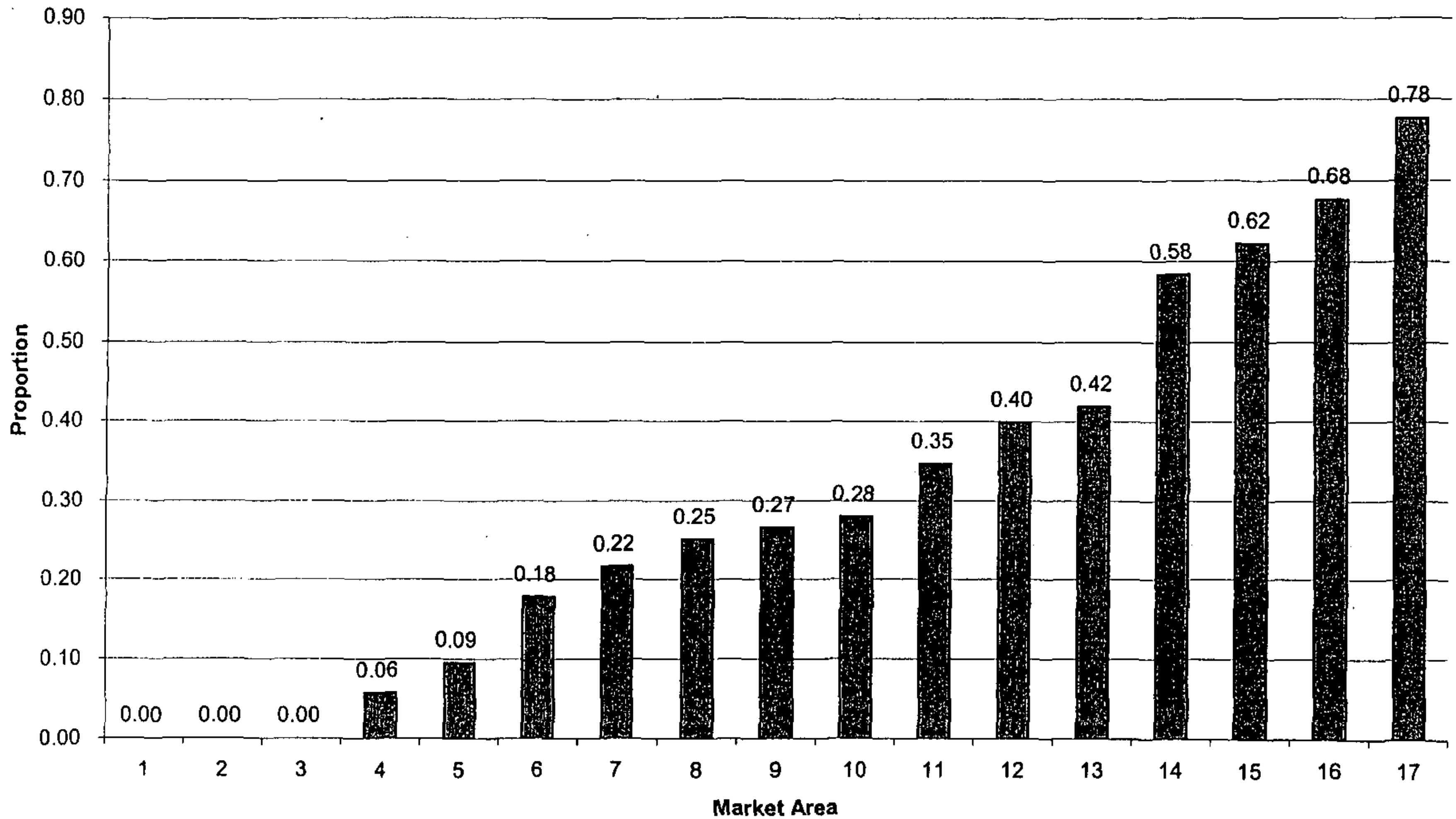


Figure 6. Storage Withdrawals as a Proportion of Actual Usage (Flowing Gas + Withdrawals) by Market Area in Missouri in December 2000 (Reference Page 44)

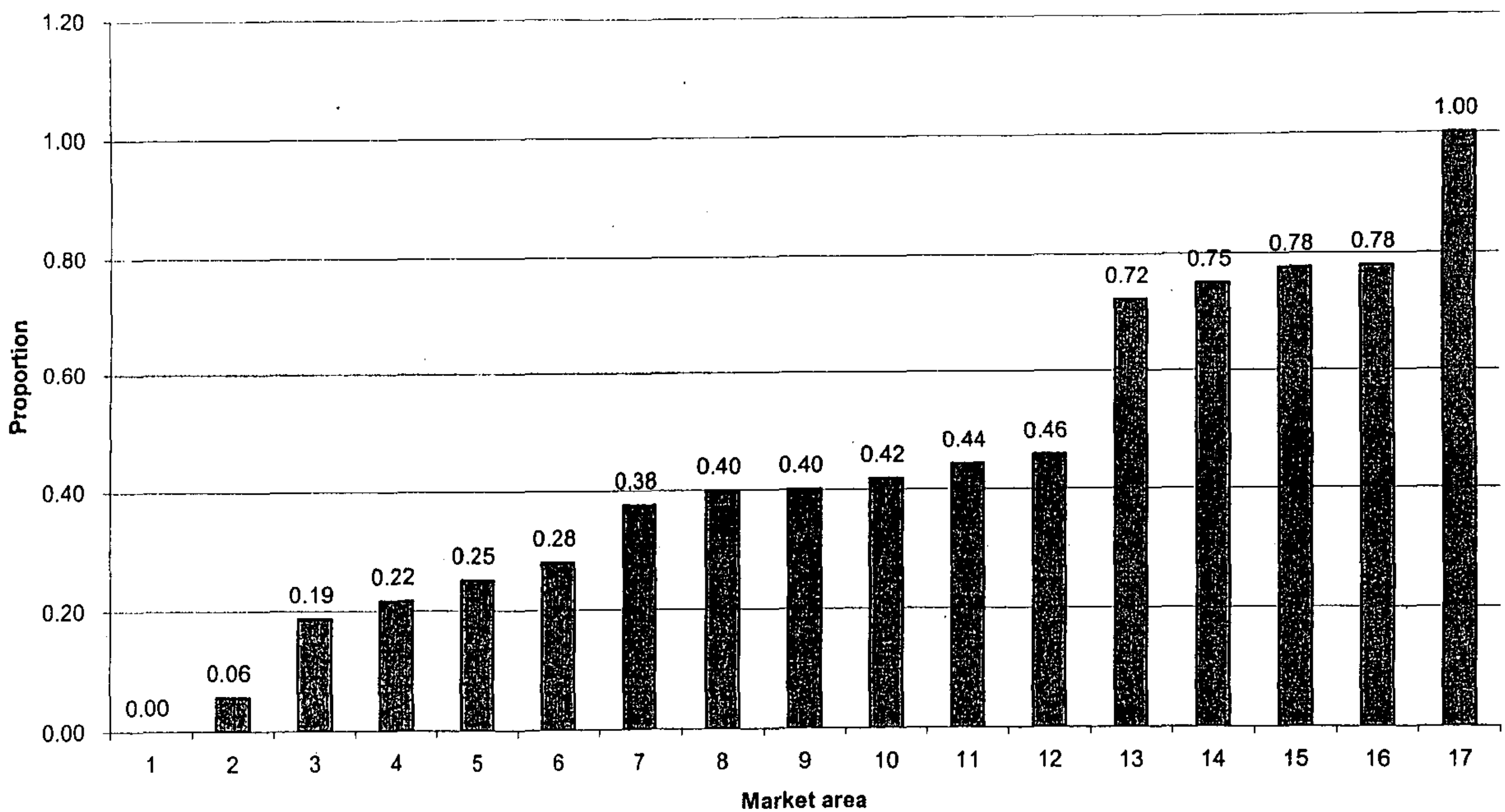
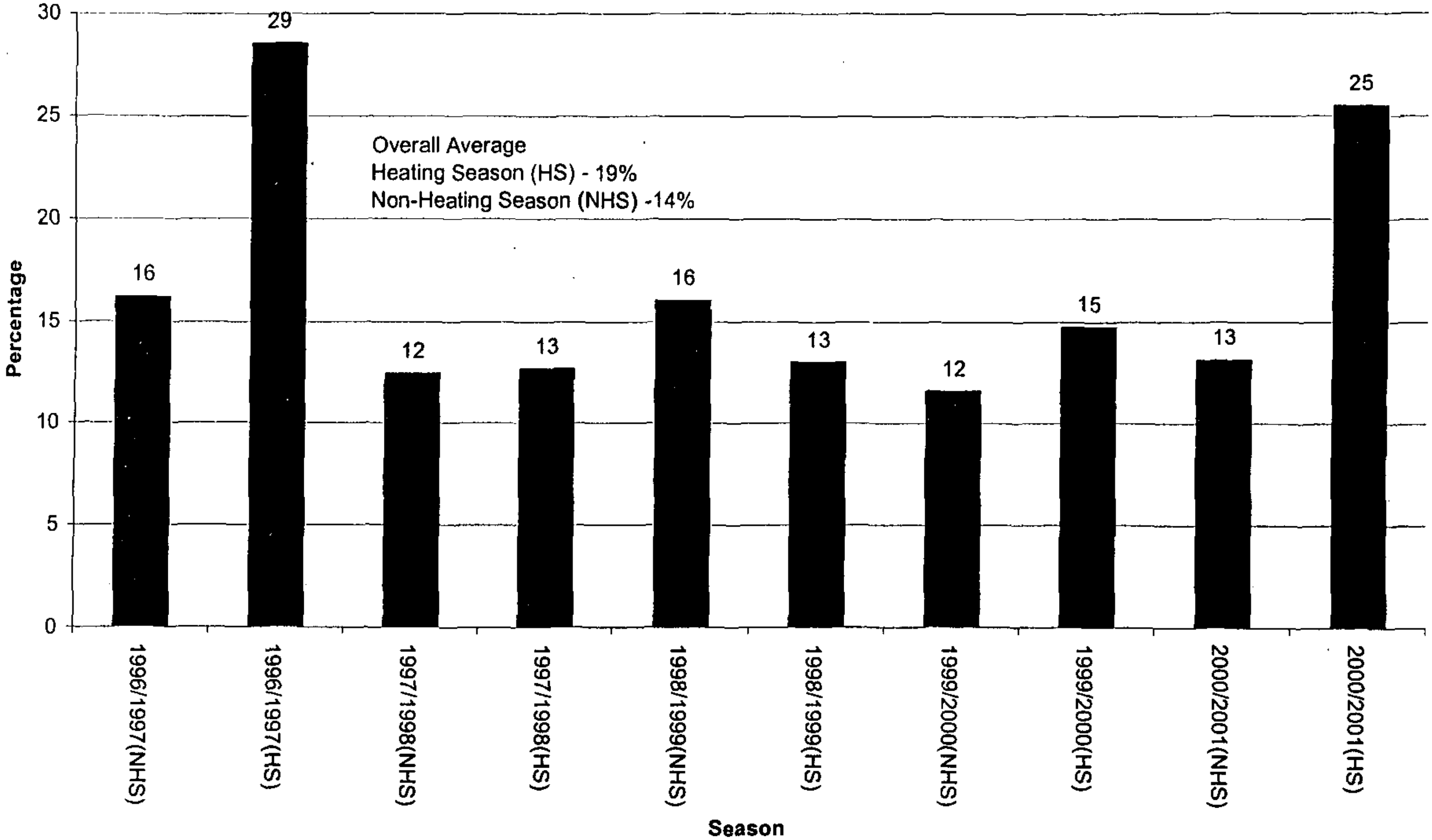
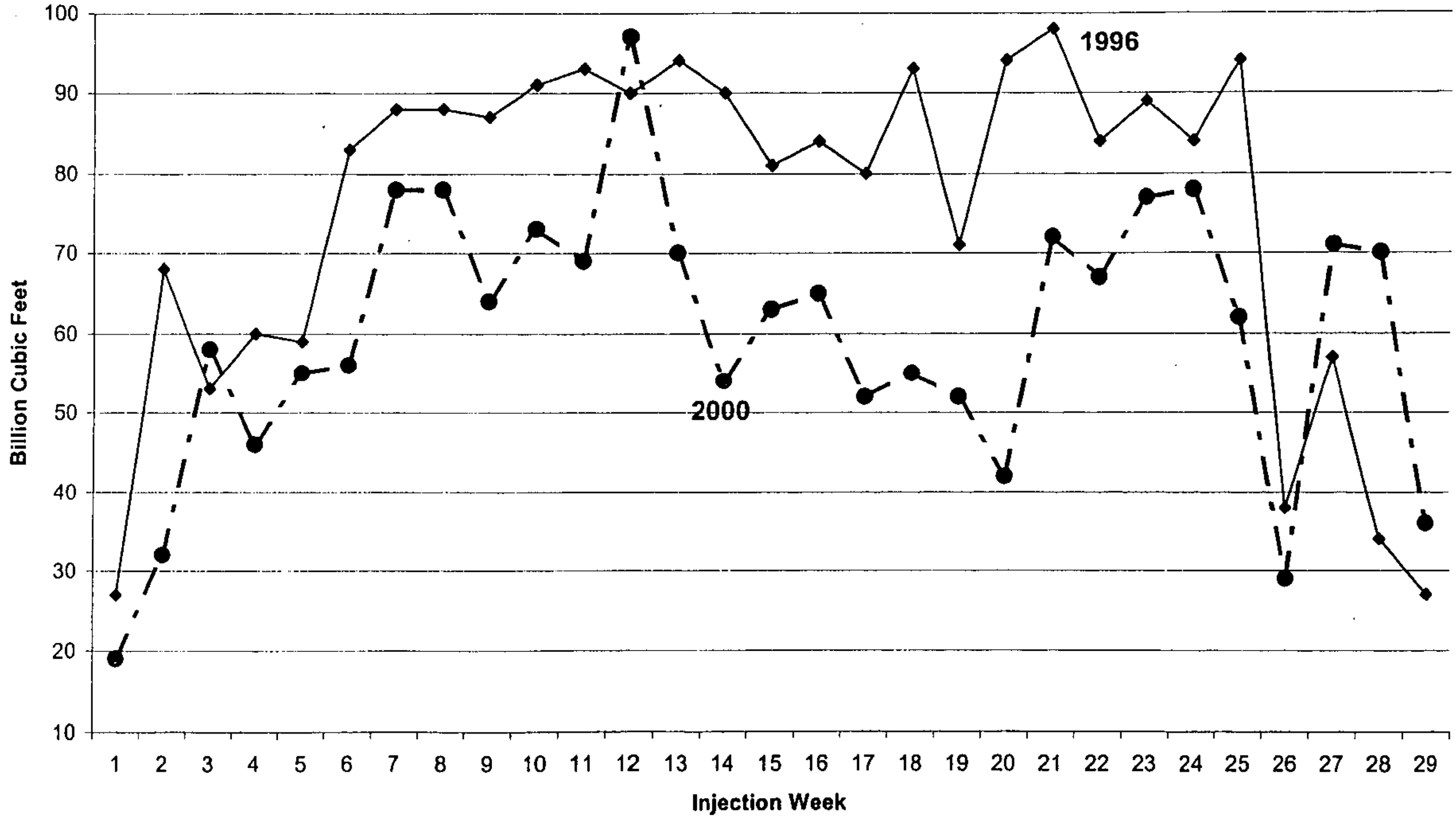


Figure 7. Henry Hub Price Volatility in the Heating (HS) and Non-Heating Season (NHS)
(Reference Pages 46, 76)



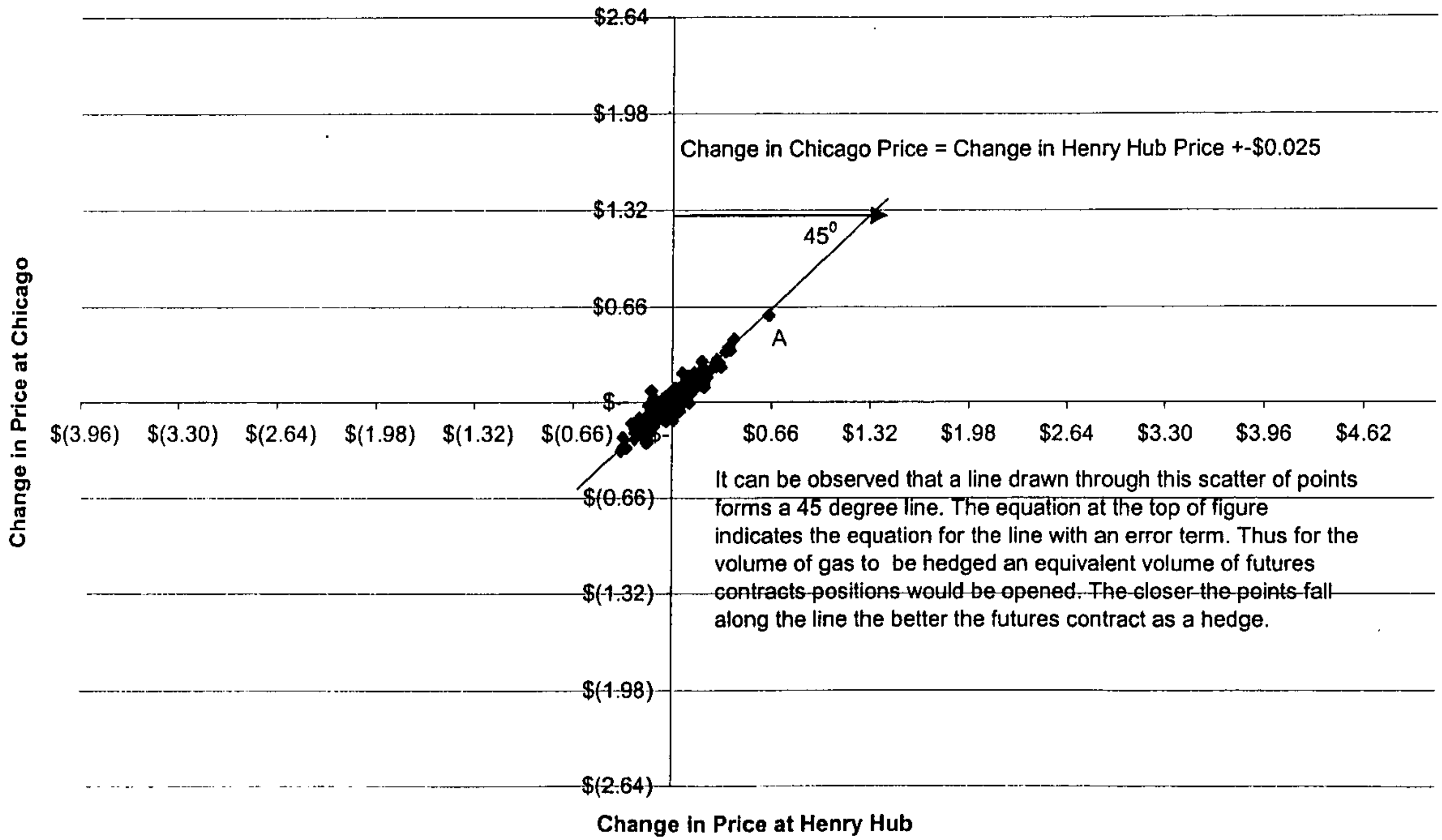
Source: Gas Daily, John H. Herbert

Figure 8. Aggregate Injections into Storage in the injection Season in 1996 and 2000 (Early April-beginning of November)
(Reference Page 50)



Source: American Gas Association

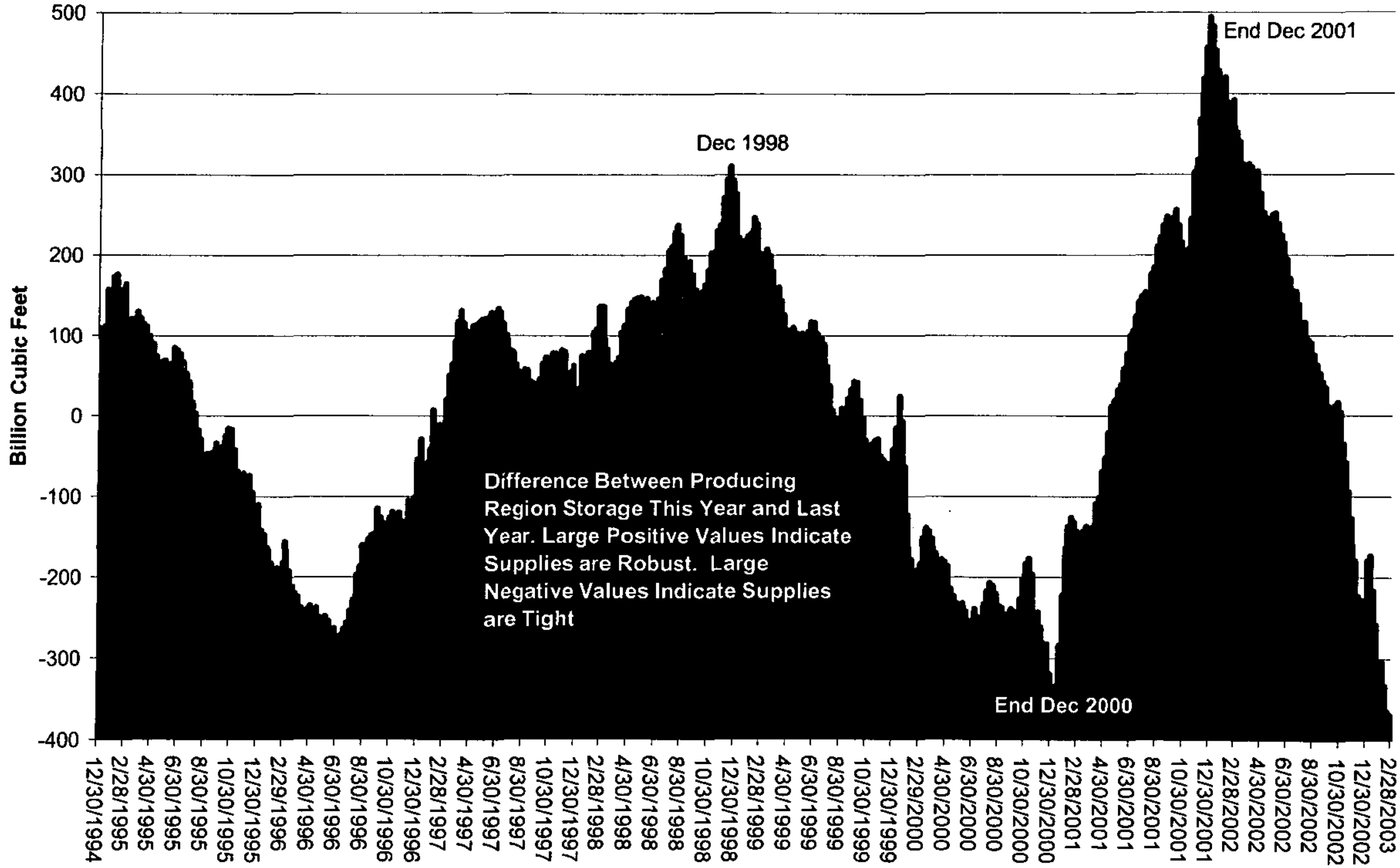
Figure 9. Plot of Changes in Price at Chicago Against Changes in Price at Henry Hub - A useful plot when considering using the Henry Hub Contract to hedge (Reference Page 55)



Source: Gas Daily/John H. Herbert

Schedule 2-9

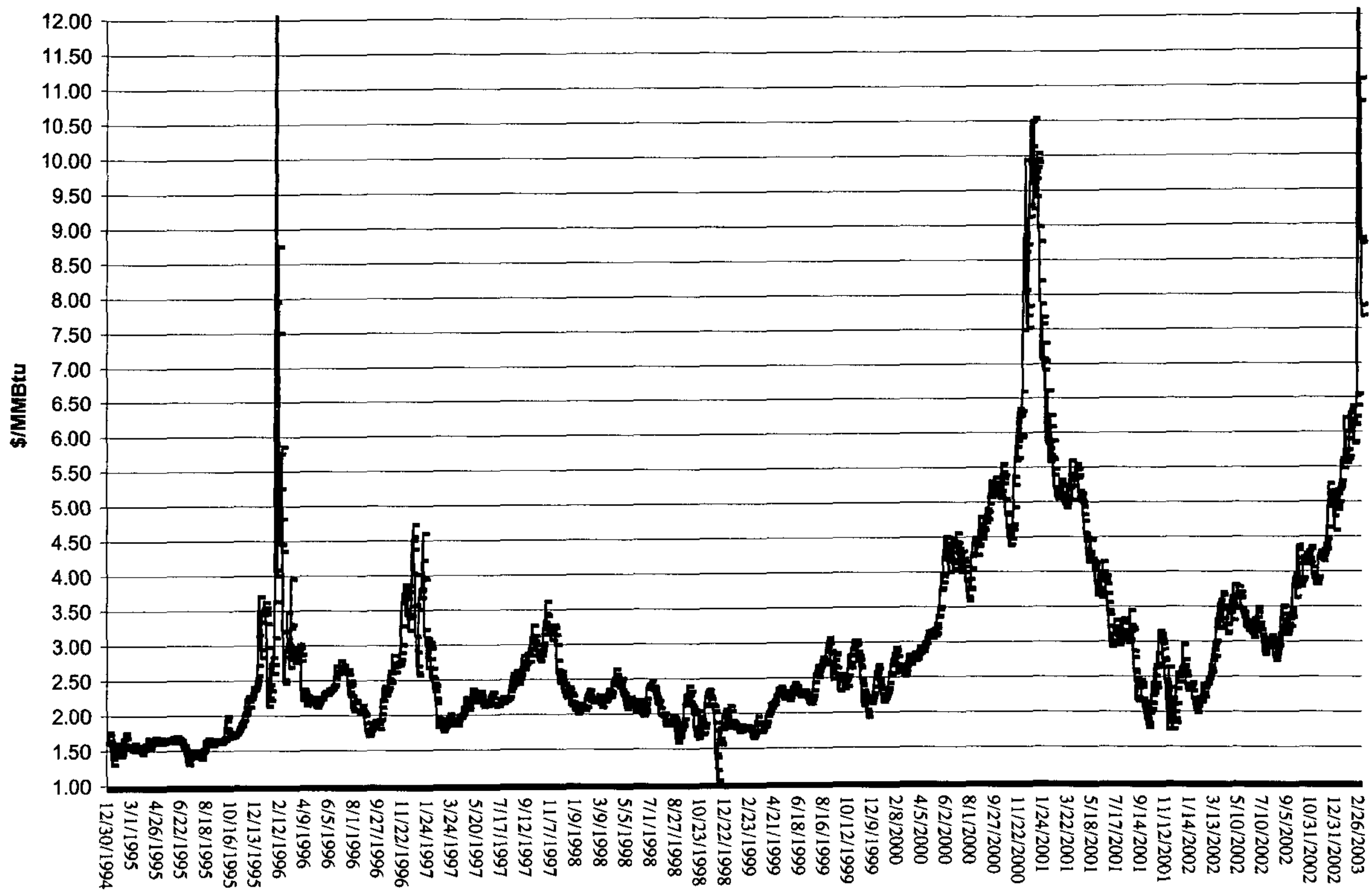
Schedule 3. Working Gas - Producing Area Storage - Difference in Storage Levels Between a Current Week and the same week in the Previous Year



Source: AGA/EIA/John H. Herbert

Schedule 3

Schedule 4. The Long History of the Henry Hub Spot Price - Dec 30, 1994 to Mar 7, 2003



Source: Gas Daily/Wall Street Journal/John H. Herbert

Schedule 4