A Report on Natural Gas Pricing and an Evaluation of Opportunities for Price Risk Management Through Various Hedging Options

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Natural Gas Supply and Costs - Regulatory Concerns

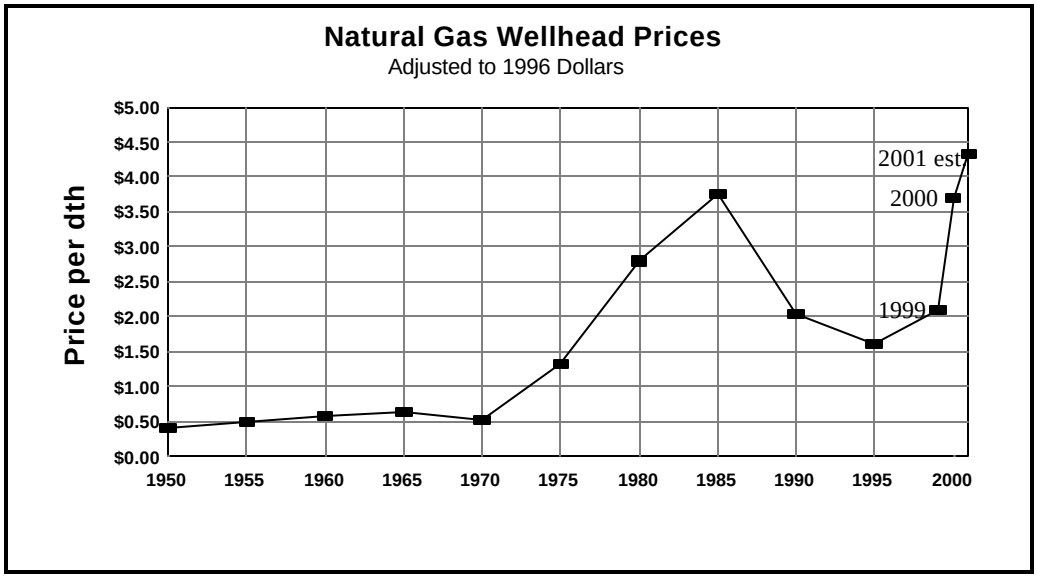
As the use of natural gas in the U.S. increased throughout the decades of the 50's and 60's, neither supply availability nor costs posed significant regulatory concerns for most State Regulatory Agencies. Natural gas sales gradually increased throughout the 50's and 60's, spurred by growth in all sectors: residential, commercial, industrial and electricity generation. From a level of approximately 5 trillion cubic feet in 1949, natural gas usage climbed steadily to 20 trillion cubic feet in 1969.

Things began to happen with regard to natural gas in the 1970's that would result in significant changes to the industry. From a usage standpoint, natural gas consumption continued to grow in 1970, 1971 and 1972, reaching a high of 22 trillion cubic feet in 1972. This represented the high water mark of natural gas usage in this country for at least the next thirty years. Usage declined modestly almost every year from 1973 to 1986, dropping from 22 trillion cubic feet to 16 trillion cubic feet. Thereafter, this decline has reversed, but by 2000, natural gas usage had just barely regained the level of 22 trillion cubic feet achieved in 1972.

The 1972 sales peak was the precursor of two significant disruptions in the status quo relating to natural gas supplies. First, from the mid to late 1970's, we faced severe natural gas shortages. Second, wellhead prices that had been controlled by the Federal Government were partially, at first, and then completely deregulated. This gave rise to a significant change from the history of almost flat natural gas prices (in real terms) that led up to the supply shortages.

Suddenly, beginning in 1972, State regulatory commissions had their hands full, first with supply problems and then with price escalation problems.

The following chart shows how wellhead prices had been very stable throughout the 1950's and 1960's. However, with supply problems and deregulation of wellhead prices in the 1970's and early 1980's, natural gas prices quickly escalated to previously unheard of levels, and for a while were even significantly in excess of price levels experienced throughout the late 1980's and 1990's.



As one might expect from the above table, after struggling with supply problems from 1975 to 1979, State regulatory commissions were next faced with strong consumer reaction to the nearly constant price escalations occurring from 1975 to 1985. During much of this period there was little that State regulators could do directly since almost all supply came through the merchant function of interstate pipeline companies. Since the tariff prices of these interstate pipelines were established by the FERC and most Local Distribution Companies (LDCs) had only limited options for alternate supplies, hedging or price risk management was not viewed as a realistic or viable option available to either LDCs or the State regulatory agencies.

From 1985 to 1990 State commissions took whatever measures that they could to encourage or require diversification of LDC supplies. As interstate pipelines departed the merchant function pursuant to FERC Orders, and market forces began to work in the natural gas industry, prices moderated significantly. By 1990 consumer dissatisfaction over natural gas prices likewise moderated. Thus, just as hedging, price discovery and price risk management tools became widely available in 1990 when the New York Mercantile Exchange (NYMEX) opened its trading in Natural Gas Futures Contracts, consumer attention and regulatory commission attention to these tools moved to the back burner.

Natural Gas Hedging Through Financial Instruments
The Devils Playground or a Legitimate Management Tool?

Some of the questions that are asked when commodities market trading is discussed among regulators are:

> Futures contracts? These are contracts for natural gas, but there is hardly ever an ounce of physical supply that changes hands pursuant to a natural gas futures contract. What manner of gas supply contract is this?
>
> Derivatives? Calls, puts, bull spreads, bear spreads, straddles? Surely these are the tools of speculators?
>
> All of these terms relate to financial instruments and/or use of financial instruments that are available to speculators as well as hedgers in the natural gas markets. Should any self respecting Regulatory Agency even entertain such "speculation" by a regulated utility company?

The fact is that both the regulated utilities and the regulators should understand and welcome the financial tools that are available to hedge future supply costs.

As natural gas supply was taken out from under the nearly total control of interstate gas pipeline companies and LDCs were acquiring gas supply on the open market, many regulators began to ask questions about the need to hedge Local Distribution Company supply against extreme spikes or swings in the natural gas spot market. It did not seem unreasonable to ask such questions ten years ago as we emerged from a period of unprecedented natural gas price increases. However, after ten years of limited hedging activities by LDCs, many LDCs and State regulators had lost sight of the potential for disruptive price spikes and still view futures contracts and related derivatives as something that

represents danger and speculatory risks.

Over ten years ago, I had the opportunity to participate in a series of presentations during which NYMEX officials were explaining their new natural gas futures contract. I was invited as a staffer of a state regulatory agency that was willing to suggest that LDCs should be knowledgeable in the area of futures contracts and should be willing to consider hedging their future supply costs through the use of futures contracts. My presentation included a suggestion that State commissions and tariff customers should expect their LDCs to consider various hedging strategies. Indeed, I suggested that "failure to hedge" or at least the "failure to fully consider hedging options" might be a more dangerous strategy than hedging and losing money due to a declining price in the physical market.

A friendly, bearish, gas market over the last ten years made those warnings ring somewhat hollow. Yet, I believed throughout the term of those price friendly gas markets that some form of hedging should be regularly **considered**. While the failure to hedge might not be wrong at all, failure to even consider hedging should be considered as a complete abdication of utility management responsibility.

"Did you consider hedging?"
"Did you consider futures contracts as a hedging mechanism?"
"Did you consider other financial tools including options as a hedging mechanism?"
"Did you consider locking-in fixed price supply contracts as a hedging mechanism?"

Each of these should be a standard question in a rate proceeding in which gas supply costs are being considered. Utility management should be expected to answer each of these questions in the affirmative, even if they ultimately rejected the hedging mechanism. Reasons should be given for either accepting or rejecting any hedging mechanism.

Unfortunately, many LDCs were not asked these questions on a regular basis due to the attractiveness of spot gas prices through most of the 1990's. Although 100% reliance on the spot market may not have been the best strategy at all times, it was the "strategy of the day" for many years. With no significant price spikes causing sharp rate increases, neither customers nor regulators saw an immediate need to challenge, or test, the spot market strategy.

Is the Expectation of a Hedging Strategy Unreasonable? Is Hedging Risky?

Only the experience of the erratic gas markets from mid 2000 through mid 2001 and the extreme price spikes in the spot market during the winter of 2000/2001 have caused most Regulatory Agencies and customers to begin to focus on the hedging issue for natural gas distribution companies. Yet, even with the price disaster of 2000/2001, many State Regulators still consider hedging with scepticism.

A weekly natural gas publication recently ran an article entitled: Burned by Last Winter's Prices, LDCs Eye New Hedging Programs. As reported, LDCs are ". . . hoping to overcome last year's high natural gas spikes and the resulting ill will from customers." The article went on to report that ". . . state utility commissions suddenly are more than willing to try and avoid a repeat of last winter's near debacle". Yet, even with this kind of strong reaction to last winter's "near debacle",

there are some who still categorize hedging as a "risk".

Before describing hedging as a risk, one needs to determine what the hedge is attempting to accomplish. If the goal is to establish a known price for future gas purchases and achieve price stability, then hedging is nearly risk free. It will accomplish such goals and do it quite well. The tools available, whether futures contracts or other mechanisms, can establish such a known price so that utility customers are insulated from deviations from that price. On the other hand, if the goal is to obtain the absolute lowest price for gas, then clearly there is a risk that hedging will not accomplish that goal. However, it is equally clear that waiting for spot prices to determine the level of future gas supply costs is just as likely to result in prices that are higher than the lowest possible price. I believe that the goal lies somewhere between the two. While the lowest possible price is a nice goal, stability at a reasonable price should probably take precedence. Looking than at those two joint goals and weighting each appropriately, hedging should be the preferred strategy.

It seems strange that forms of hedging that do not rely on commodities markets or derivatives are not only accepted, but expected of public utilities. For example, the most trusted way of hedging supply is to enter into **fixed price** medium term or long term **contracts** for the supply. Electric utilities have been doing that for years. It is doubtful that any State regulator would consider an electric utility coal supply portfolio that is made up 40% long term contract coal, 40% short term contract coal and 20% spot market coal (or some similar though not exact mix) as a dangerous and speculative strategy. It is equally doubtful that any State regulator would call a fixed price natural gas supply contract that was going to provide actual physical delivery of gas as a dangerous and speculative strategy. Yet, faced with the prospect of an LDC accomplishing the same level of certainty in future supply costs through a derivative or futures contract strategy, the "dangerous and speculative" warnings appear almost immediately.

It is not the intent of this paper to explain futures contracts and/or options trading. Suffice it to say that even though these are not intended to be devices through which physical supply is delivered, they are financial instruments that can effectively lock in prices, or establish price ceilings and floors, even when the physical commodity is going to be purchased at unknown future spot market prices. Under these circumstances, an LDC that employs the use of these financial instruments for the purpose of locking-in a price, or establishing a price ceiling and/or floor, is **not speculating**. Since the LDC (and more importantly, its customers) will have a real position in the natural gas physical delivery, the transactions herein described are true "hedges", not "speculation".

Examples of Alternate Hedging Scenarios and Results

In order to depict some possible outcomes of hedging strategies over the last 9 years, I have prepared some hedging examples **based on actual data**. These examples compare the actual spot market price for winter heating seasons (November through March) to a price that could have been achieved under alternate hedging strategies and outcomes.

For the purpose of these examples, I have set up two possible hedging schedules or

scenarios.

One, called the "5 month hedge", assumes that the upcoming winter's gas supply price is locked-in through hedging decisions made in the immediately preceding 5 month period running from April through September. In other words, for the "5 month hedge" example, gas supply for the period November, 2000 through March, 2001 is hedged at some point **between April, 2000 and the end of September, 2000.** Therefore, **all** hedging decisions for **all months** of the heating season are made prior to October 1, preceding he season.

The second scenario is called the "17 month hedge". For this scenario, it is assumed that hedging decision are made over a longer period of time preceding a winter heating season. Gas supply for the period November, 2000 through March, 2001 is hedged at some point **between April 1999 and the end of September, 2000**. Once again, **all** hedging decisions for **all months** of the heating season are made prior to October 1, preceding he season.

To test the potential for acquiring higher or lower net prices through hedging, I present the results of each scenario based on three possible outcomes. One outcome is called the "low hedge" outcome. This assumes that the prices hedged for the winter supply turned out to be the lowest prices achievable during the hedging period. A second outcome is called the "average hedge" outcome. This assumes that the prices hedged turn out to be the average price **achieved** during the hedging period. Finally, a third outcome is called the "high hedge" outcome. This assumes the worst possible timing of locking-in prices and that the prices hedged turn out to be the highest prices *achievable* during the hedge period (a dubious record that is highly unlikely).

The following tables compare the average spot price of gas to the outcomes of each of the hedging scenarios. Negative or (bracketed) differences in the "Cost or (benefit)"sections of the tables indicate that the hedge price was lower than the actual spot price, thereby producing a lower cost "benefit" for customers.

(See Data Tables on Next Page)

Five Month Hedges

Winter of ------->	92/93	93/94	94/95	95/96	96/97	97/98	98/99	99/00	00/01
Avg spot price	2.07	2.26	1.56	2.21	2.98	2.57	1.93	2.54	6.56
Avg hedge	1.95	2.40	2.16	1.85	2.34	2.52	2.49	2.74	4.36
Low hedge	1.75	2.28	1.91	1.74	2.13	2.27	2.19	2.53	3.20
High hedge	2.27	2.49	2.29	1.99	2.71	3.05	2.57	3.04	5.36
Cost or (benefit)									
Avg hedge	(0.12)	0.14	0.60	(0.36)	(0.64)	(0.05)	0.56	0.20	(2.20)
Low hedge	(0.32)	0.02	0.35	(0.47)	(0.85)	(0.30)	0.26	(0.01)	(3.36)
High hedge	0.20	0.23	0.73	(0.22)	(0.27)	0.48	0.64	0.50	(1.20)
Cumulative cost or (benefit) of each hedging outcome. Numbers represent cumulative $ per dth									
Avg hedge	(0.12)	0.01	0.21	0.07	(0.08)	(0.07)	0.02	0.04	(0.20)
Low hedge	(0.32)	(0.15)	0.02	(0.10)	(0.25)	(0.26)	(0.19)	(0.16)	(0.52)
High hedge	0.20	0.21	0.39	0.24	0.14	0.19	0.26	0.29	0.12

Seventeen Month Hedges

Winter of ------->	92/93	93/94	94/95	95/96	96/97	97/98	98/99	99/00	00/01
Avg spot price	2.07	2.26	1.56	2.21	2.98	2.57	1.93	2.54	6.56
Avg hedge	1.83	2.14	2.28	1.97	2.09	2.29	2.43	2.50	3.25
Low hedge	1.63	1.87	1.91	1.74	1.83	2.04	2.12	2.22	2.56
High hedge	2.27	2.53	2.53	2.32	2.71	3.05	2.71	3.04	5.36
Cost or (benefit)									
Avg hedge	(0.24)	(0.12)	0.72	(0.24)	(0.89)	(0.28)	0.50	(0.04)	(3.31)
Low hedge	(0.44)	(0.39)	0.35	(0.47)	(1.15)	(0.53)	0.19	(0.32)	(4.00)
High hedge	0.20	0.27	0.97	0.11	(0.27)	0.48	0.78	0.50	(1.20)
Cumulative cost or (benefit) of each hedging outcome. Numbers represent cumulative $ per dth									
Avg hedge	(0.24)	(0.18)	0.12	0.03	(0.15)	(0.17)	0.08	(0.07)	(0.43)
Low hedge	(0.44)	(0.42)	(0.16)	(0.24)	(0.42)	(0.44)	(0.35)	(0.35)	(0.75)
High hedge	0.20	0.23	0.48	0.39	0.26	0.29	0.36	0.38	0.20

As can be seen in the above tables, hedging outcomes always produce a more stable price structure than reliance on spot market prices. This stability is a plus for hedging strategies; however, it is important

to determine the probability of higher prices under either a hedging strategy or a spot market strategy. If there is a high probability that hedging will result in significantly higher prices than those achievable from a spot market strategy, we should be concerned with what is causing that high probability and reevaluate the hedging strategy. If the prices are modestly higher at times and modestly lower at times, the benefits of a known price and the resulting price stability should cause us to lean toward the hedging strategy, regardless of the net cost outcome.

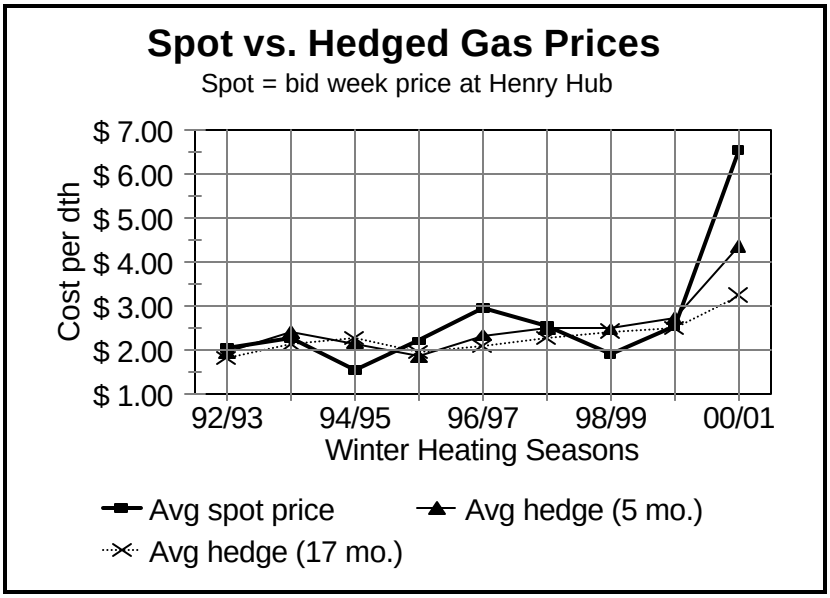
As might be expected, the price related benefits of a near term (5 month) hedging strategy are smaller than the benefits of a longer term (17 month) strategy. Using the 5 month strategy, and achieving only average results, the hedged prices would have been lower than the spot prices in 92/93 (12 cents), 95/96 (36 cents), 96/97 (64 cents), 97/98 (5 cents) and 2000/2001 ($2.20).

Because of higher hedged prices in 93/94, 94/95, 98/99 and 99/2000, the cumulative effect of an average hedge would have been a benefit of 20 cents per dth. Therefore, over the entire period hedging would have saved a utility with annual volumes of 20,000,000 dth an average of $4,000,000 per year or a total of $36,000,000.

It should be noted that the price benefits of the hypothetical hedging "strategies" are greatly influenced by the winter of 2000/2001. Because of the fly-up in spot prices from the mid $2.00 range to $6.56, any strategy produces a dramatic benefit for the 2000/2001 winter heating season. However, it is also interesting to note that the cumulative costs of most **unsuccessful** strategies would have been relatively small when compared to the benefits of price stability and the protection against a catastrophic price escalation.

Obviously, this is a somewhat perfunctory "study" of possible hedging outcomes. Nevertheless it is helpful for the purpose of obtaining a broad overview of the subject as measured against actual data of the last nine years.

A graphical representation of the hedging outcomes as compared to the spot market prices is shown on the following three graphs.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Spot = bid week price at Henry Hub
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$ 2.00
$ 1.00
Cost per dth
92/93
94/95
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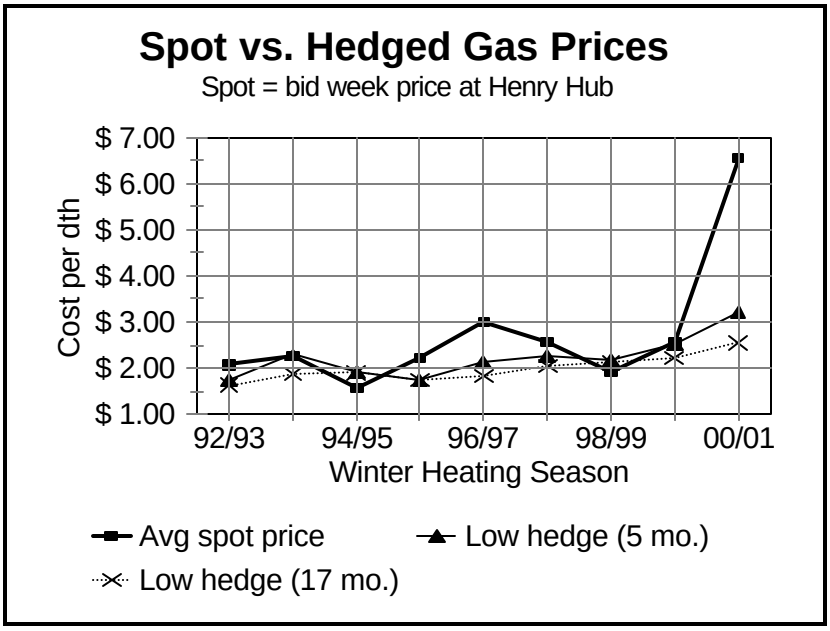
Winter Heating Seasons
Avg spot price
Avg hedge (5 mo.)
Avg hedge (17 mo.)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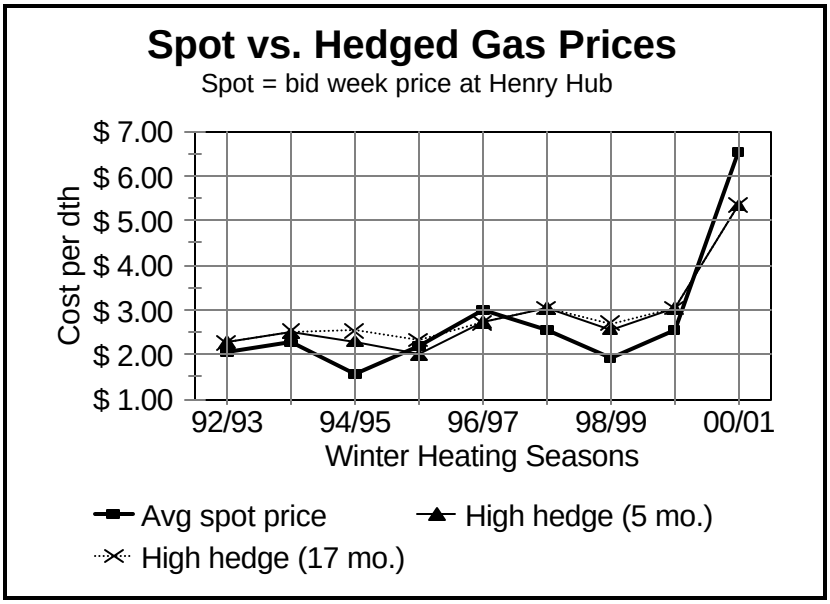
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Winter Heating Seasons
Avg spot price
High hedge (5 mo.)
High hedge (17 mo.)

If Hedging is Reasonable, Why Have Utilities Failed to Hedge?

The answer to this question lies in the availability of nearly automatic recovery of gas supply costs through annual Purchased Gas Adjustment (PGA) Clause mechanisms. Utilities have no reason to hedge since they neither profit nor lose when gas supply costs increase or decrease. Under the traditional PGA, rates are set based on either fully or partially projected purchased gas costs. If actual costs turn out to be lower than the projections, customers receive a credit. If actual costs turn out to be higher than the projections, customers are charged for the resulting "under recovery" by the utility. Under this regulatory approach, there is no incentive for utility management to hedge.

The West Virginia Alternative to Continuing PGAs

In early 1995, Mountaineer Gas Company, the largest LDC in West Virginia, filed a base rate case. This case did not include purchased gas costs since those costs were handled in a separate PGA proceeding. However, after reviewing the rate case and looking at projected natural gas commodity rates based on NYMEX futures prices, the Staff and Consumer Advocate proposed a settlement that would lock-in Mountaineers total rates for a three year period.

Mountaineer agreed to this "total rate moratorium" and the Commission ultimately approved a stipulation that locked-in a total rate for Mountaineer for 1996, 1997 and 1998*. At the time that this agreement was reached and a rate order issued by the Commission, the NYMEX based Henry Hub commodity costs were approximately $2.00 per dth. The locked-in rate for Mountaineer would allow for recovery of that $2.00.

Although locking in $2.00 gas costs today may seem like a no-brainer, at the time there was considerable discussion over this gas cost rate. Calendar year 1994 Henry Hub gas costs had been $1.91 per dth. For the winter season of 1994/1995 Henry Hub commodity costs had been only $1.56 per dth. Furthermore, gas costs for the first six months of 1995, which were known at the time the agreement was negotiated, had averaged only $1.58. Looking at that data, there was concern that locking in a $2.00 was a "risky" decision. Nevertheless, the Commission approved the rate moratorium and locked-in $2.00 per dth (Henry Hub) gas costs into Mountaineer's rates.

In effect, the Commission had hedged the customers' rates by locking-in a tariff rate. Mountaineer was not obligated by the terms of its stipulation or the Commission's rate order to likewise hedge its commodity costs. Mountaineer was free to make its own decision whether to continue to rely on spot markets. If Mountaineer did not hedge and actual costs came in below the projections that had been the basis for the locked-in rates, Mountaineer would have over-recovered its gas costs and that over-recovery would have flowed through to its bottom line, to the benefit of its stockholders. Likewise, if Mountaineer did not hedge and actual costs came in above the projections, Mountaineer would have under-recovered its gas costs and that under-recovery would have flowed through to its bottom line, to the cost of its stockholders.

It is interesting to note that the company did not hesitate in making a management decision to lock-in its gas costs for the full 36 month rate moratorium period. In other words, historically, when the risk of gas cost increases was on the customer because of a PGA mechanism, the

management decision was to rely on spot market prices and to forego any hedging or risk management. However, when the risk of gas cost increases was transferred to the stockholders, hedging became the strategy of choice.

The Commission approved a similar 3 year rate moratorium and locked-in tariff rate for Hope Gas Company, the State's second largest natural gas company. Therefore, beginning in 1996, approximately 90% of the state's natural gas customers were covered by the rate moratoria and were effectively hedged based on long term NYMEX natural gas futures prices.

As it turned out, the rate moratorium worked to customers' advantage; not only by achieving the rate stability that had been an original goal, but by also locking in a gas cost that was below the spot market prices over the next 36 months. Actual Henry Hub spot prices during the 36 months of the moratorium averaged $2.40 per dth.

In 1998**,** the Staff, CAD and Mountaineer entered into another agreement for another 3 year locked-in rate to cover 1999, 2000 and 2001*. By mid-1998 when this agreement was finalized, the three year NYMEX futures prices were averaging approximately $2.50 per dth.. Once again, there was discussion regarding the "prudence" of locking-in based on such a long term "hedge" and the prospect of prices returning to the $2.00 level, or below. Nevertheless, the rate stability of a new rate freeze and the satisfactory results of our previous rate freeze led the Commission to agree with the Staff's and CAD's recommendation and approve a locked-in tariff rate for 1999, 2000 and 2001.

The prospect of achieving the lowest possible rate by locking-in at $2.50 per dth. was dimmed in the first year of that moratorium. The winter of 1998/1999 saw another significant drop in spot market prices which averaged only $1.93 per dth. For the first full year of the second moratorium spot prices were somewhat higher, but they still averaged only $2.20 per dth., or 30 cents less than the cost that had been locked-in.

The winter of 1999/2000 saw another increase in average spot prices to about $2.54 per dth. Then, during the balance of 2000, spot prices began to trend upward at an alarming rate. The average spot price for 2000 turned out to be an incredible $3.80 per dth., driven by high winter prices, including an unheard of December price of $6.02 per dth. But, as we know only too well, December was a "Christmas present" compared to the next two months. Things only got worse (for non-hedged gas supplies) when January and February, 2001 came in at $9.98 and $7.26 respectfully. Who would have ever thought that we would be relieved when the March, 2001 contract closed at a **mere $5.00** per dth.

When the smoke clears for 2001, it looks like this year's average spot prices will be around $4.75 per dth. Therefore, it appears that the average spot prices for the 1999, 2000, 2001 period will be around $3.55. This, compared to the long-term hedged gas costs of $2.50 per dth built into rates in the 1998 case.

This customer benefit, once again, applied to about 90% of the gas utility customers in West Virginia, because at the same time that the Commission renewed the three year locked-in pricing approach for Mountaineer, it did the same for Hope Gas Company.

Note *: The actual Mountaineer locked-in periods were 11/95 through 10/98 and 11/98 through 10/2001. Calendar years have been used in this report for ease of presentation and averaging. Results for the two actual locked-in periods were slightly different, but not significantly, from the results summarized in this report.

Summary

The following Table summarizes the annual and total affects of the two rate moratoria applied to Mountaineer Gas Company for 1996-98 and 1999-2001. Comparable results were achieved for Hope Gas Company.

Tabulation of Results of Mountaineer Gas Company Rate Freezes and Locking-in of Gas Costs

First Moratorium	1996	1997	1998
Average gas cost rate locked-in	2.00	2.00	2.00
Actual spot gas costs	2.40	2.65	2.15
Net avg/dth cost or (benefit) of locking-in	(0.40)	(0.65)	(0.15)
Cumulative avg/dth net cost or (benefit) *	(0.40)	(0.53)	(0.40)
Second Moratorium	**1999**	**2000**	**2001**
Average gas cost rate locked-in	2.50	2.50	2.50
Actual spot gas costs	2.20	3.80	4.75
Net avg/dth cost or (benefit) of locking-in	0.30	(1.30)	(2.25)
Cumulative avg/dth net cost or (benefit) *	0.30	(0.50)	(1.08)

* Note: The cumulative costs or benefits are stated on an average per dth. basis for the entire period covered. Total net benefits for each three year period can be calculated by multiplying the cumulative average benefit at the end of the third year by the TOTAL sales for the three years. For Mountaineer Gas Company customers, aggregate net benefits for 1996, 1997 and 1998 equal 25 million dth sales per year, times $0.40 cumulative average net benefit, times 3 years, or $30,000,000. Net benefits for 1999, 2000 and 2001 equal 25 million dth sales per year, times $1.08 cumulative average net benefit, times 3 years, or $81,000,000.

To summarize, it must be acknowledged that the natural gas market price increases in 2000 and 2001 represent extreme fluctuations from historic norms. However, our adoption of a hedging approach for Mountaineer Gas Company and Hope Gas Company were intended to achieve rate stability at what appeared to be a reasonable gas price at the time that prices were locked-in. As stated in this paper, this rate stability at a known and reasonable price should be considered the primary goal of a hedging strategy. If actual spot prices turn out to be modestly below the hedged price, the strategy cannot be said to have failed. Gaining a significant price benefit from the hedging strategy should not be the primary goal. However, it will be achieved when most needed. That is when spot prices spike at extreme levels.

I believe that it is the responsibility of utility management to recognize the potential benefits of hedging and to regularly examine its hedging options and expected outcomes. It is poor management to wait for a price disaster to develop hedging knowledge and/or strategies. Furthermore, a regulatory agency should not be the super-management of a utility, making these hedging decisions on a day to day basis. A well run utility should not wait for a Commission to force it into a serious and studious evaluation of hedging opportunities. As stated earlier in this paper: "While the failure to hedge might not be wrong at all, failure to even consider hedging should be considered as a complete abdication of utility management responsibility".