

**NATURAL GAS PRICE VOLATILITY:
REGULATORY POLICIES TO ASSURE AFFORDABLE AND STABLE
GAS SUPPLY PRICES
FOR RESIDENTIAL CUSTOMERS**

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INTRODUCTION

Natural gas supply prices are headed up to potentially record setting levels again this winter, according to experts and observers. Natural gas distribution companies (NGDC) have filed for significant price increases for the natural gas supply portion of customer bills in most states. Politicians and regulators at both the state and federal level of government have warned consumers about high prices this winter, held public educational meetings to urge consumers to conserve natural gas and enter into budget or levelized payment plans, issued press advisories, and contemplated long term and significant natural gas supply options, such as increasing reliance on imported liquefied natural gas and creating federal subsidies for a natural gas pipeline from Alaska to the mainland U.S. The upswing in natural gas supply prices is typically blamed on the lack of sufficient exploration and drilling of U.S. natural gas fields, i.e., a shortage of supply, as well as the increased usage of natural gas to generate electricity and power industrial operations, i.e., an increase in demand.¹

As usual with natural gas pricing, the weather plays a major role. An unusual late cold spell in the Northeast in 2003 resulted in the draw down of stored gas to very low levels, resulting in very high prices to replenish this storage capacity during the summer, a period when traditionally gas prices drop. These factors led to record setting spot market prices at various times in 2003. In December, prices for natural gas futures on the New York Mercantile Exchange (NYMEX) were hovering at \$7 per thousand cubic feet, sparking calls from some Capitol Hill veterans for an investigation.² Natural gas prices have moved

¹ See, e.g. presentations by the Energy Information Administration (EIA), as well as a policy paper issued by the U.S. Department of Energy on September 25, 2003, available at: <http://www.fossil.energy.gov/programs/oilgas/publications/npc/03gasstudy/index.html> . This paper does not offer an opinion on the reasons for the recent price increases for natural gas.

² “U.S. Lawmakers Mull Probe Into Surging Natural Gas Prices”, *The Wall Street Journal Online*, December 15, 2003, http://online.wsj.com/article/0,,BT_CO_20031215_004929,00.html This was matched by a similar call by the Chairman of the New York Public Service Commission several days later.

to a new potentially sustainable level above \$4/MMBtu.³ Observers question whether this is a spike similar to that which occurred in late 2000-early 2001 or whether these higher prices are here to stay, creating a new higher level plateau within which the traditional seasonal volatility of natural gas prices will swing.

These events are occurring in an industry that is widely regarded as having achieved a workable competitive wholesale market as a result of policies adopted by Congress (prices at the wellhead, i.e., the locus of production, were deregulated by the Wellhead Decontrol Act of 1989) and the Federal Energy Regulatory Commission, which regulates the prices charged for the transmission of natural gas through interstate pipelines. FERC has consistently followed a policy to “deregulate” the interstate market for natural gas supply. The pipeline owners were pressured to renegotiate long term supply contracts and local natural gas distribution companies, whose rates are regulated by state regulatory commissions, were forced to obtain natural gas supplies on the open market where the price is set by the law of supply and demand.

Recent developments in both natural gas and electricity markets have called into question the transparency and competitive nature of wholesale energy markets. The following events and developments have contributed to an aura of suspicion that natural gas price spikes are not entirely “natural”: (1) allegations of price manipulation in natural gas pipeline prices in the West; (2) the California electric market implosion (caused in part by extremely high natural gas prices) in 2000-2001; (3) the financial meltdown of many energy companies, particularly the competitive electric generation companies; and (4) the significant decrease in wholesale “trading” for both natural gas and electricity. When suspicions concerning the operation of the wholesale market are coupled with the impact of higher

³ Testimony of Alan Greenspan, Chairman of the Board of Governors, Federal Reserve System, before the U.S. Senate Committee on Energy and Natural Resources, July 10, 2003. According to Mr. Greenspan, the long term equilibrium price for natural gas has risen persistently during the past six years from about \$2 per million Btu to more than \$4.50.

prices on residential and low-income customers in a time of record job losses and economic stagnation, a recipe for controversy is easily brewed.

Also key to the concern about higher prices for residential customers are several factors that reflect their usage profile and dependence on natural gas for home heating. First, residential customers typically rely on natural gas for home heating and so their need for this product at particularly vulnerable circumstances results in significant risk of health and safety when natural gas is priced too high to provide affordable home heating. Unlike industrial customers who use natural gas year-round and can make investments and long term plans based on this known need, residential customer usage for natural gas spikes every winter and is typically a direct function of weather. Second, residential customers are not particularly responsive to price spikes because they do not have what economists call “elasticity of demand.” Residential customers cannot typically change out the fuel necessary to generate winter heating without great expense and significant lead time. Nor can they access more efficient appliances or weatherize their homes without significant investment. Of course, low-income and working class consumers have even fewer options in this regard because they rarely have access to the additional cash or means to invest in these improvements. Third, the residential natural gas customer’s bill is greatly influenced by the price of natural gas supply. Over 50% of the average bill is driven by the price of natural gas supply and the pipeline transportation costs incurred to deliver that product to the “city gate”, where the local gas utility takes control. The balance is a reflection of local distribution costs incurred by the NGDC to deliver and operate the local distribution system, and bill and collect from its customers. This percentage is even higher in some states particularly in the winter where residential customer usage dramatically increases.

According to a recent General Accounting Office report⁴ on state natural gas price changes, many gas utilities and state commissions have endorsed at least a partial reliance on various forms of “hedging” or gas supply portfolio management by the incumbent natural gas utilities. In a survey of state decisions and policies adopted after the price spike of the 2000-2001 winter, the GAO reported that:

- Most states (82%) price natural gas supply by means of a Purchased Gas Adjustment mechanism with a reconciliation of actual and estimated costs. Only 3% rely on a fixed price for natural gas supply and 9% use of an incentive or Performance Based Rate approach.
- Frequent price changes are the norm, with 59% using monthly price changes, 36% quarterly price changes, 1% semi-annually, and 9% using annual price changes.
- After the 2000-2001 price spike, the GAO report documented the growing use of hedging and approval of financial hedging instruments. While only 20% of the larger gas utilities responding to the GAO survey reporting that before the price spike of 2000-2001, they had planned to hedge any of their gas supply, 90% of all utility companies reported that they had decided to hedge some portion of their gas supply before the winter of 2001-2002.⁵
- The report also documented the key role of storage facilities in the ability of the gas utility to manage its gas supply for price stability.
- Those utilities with access to local production were also favored, because they could avoid the costs associated with transportation of natural gas through interstate pipelines

This report will use the term “hedging” to refer to the management of a gas portfolio to mitigate price volatility, i.e., the use of both physical and financial instruments to avoid a total reliance on spot market acquisitions. Physical hedging occurs when a utility buys a contract for future delivery of gas at a set or

⁴ General Accounting Office (GAO), Natural Gas: Analysis of Changes in Market Price, GAO-03-46, December 2002. Available at <http://www.gao.gov/new.items/d0346.pdf>

⁵ Ibid. at 7. The GAO Report did not describe the type and amount of hedging that formed the basis for this conclusion, but it should be noted that the term “hedging” does not necessarily imply the formal procurement planning process that is discussed later in this report.

indexed price. This may or may not be coupled with the use of stored gas. This might result in a staggered series of contracts for natural gas supply that are bought early in the year for delivery at a fixed price later in the year during the winter heating season or the use of even longer term fixed price contracts from a supplier or pipeline owner. Financial hedging occurs when a utility purchases natural gas derivatives, which are contracts whose market value is derived from the price of the gas itself. Derivatives can be bought and sold through numerous sources, such as NYMEX and other over-the-counter marketers. Two basic types of derivatives include natural gas futures and options. A futures contract is a promise to deliver gas in the future on price set or a price formula set in the contract. This type of instrument can either result in the delivery of the product or the payment of cash. An option contract gives the buyer the right, but not the obligation, to buy or sell gas at a specific price on or before a specific date.

In addition to tariff adjustments that pass through the actual cost of gas (whether based on hedged products or spot market acquisitions) with frequent price changes, most states also conduct a reconciliation proceeding at least annually. This proceeding compares the amount charged to customers for natural gas supply with the actual costs incurred by the utility, which may reflect increased or decreased sales depending on the weather or rapid changes in natural gas costs that occur during the period of time the approved price is in effect. This approach typically means that commissions allow the utility to build up a balance that is owed to customers (refund) or a deferral that is owed by the ratepayers to the utility. This approach has been used as a means of spreading out significant price spikes so that the utility is allowed to charge somewhat less than the actual costs incurred and then bill customers for the deferred balance at the end of the winter period.

Another key variable in how states approach the pricing of natural gas supply is the presence of retail natural gas competition. While many states have initiated pilot programs or voluntary customer choice

programs on a utility-by-utility basis, only a few states have mandated retail natural gas competition for residential customers as the “law of the land”: Ohio, New Jersey, Pennsylvania, Georgia, and the District of Columbia,. Several other states have “virtually”⁶ restructured with programs in place that make all residential customers eligible: Massachusetts, New York, Michigan, Maryland, and Virginia.

According to statistics maintained by the Energy Information Administration (EIA)⁷ at the Department of Energy, there are far more residential customers who have entered the competitive natural gas market and selected an alternative to their incumbent utility than have entered the retail electric market. According to EIA, as of December 2002, 4.1 million residential customers have enrolled with a competitive natural gas supplier, approximately 13.5% of the total eligible to do so. This contrasts with the retail electric shopping statistics that show that in most states, 95% of the residential customers who are eligible have not left their incumbent electric utility. The only exceptions are in Texas (7-8%), the District of Columbia (12%), Consolidated Edison in New York, and in some utility service territories (Duquesne Light and PECO Energy) in Pennsylvania.

States have typically required the NGDC to obtain supply from the wholesale market and pass through that price to retail consumers. State commissions are often at great pains to explain to the public that the local gas utility does not make a profit on the sale of natural gas and that states do not directly regulate the price of natural gas supply.⁸ However, state regulators do have authority over the gas procurement practices of local gas utilities that are the focus of this paper and are responsible for answering the following key questions that affect the prices that are charged to consumers:

⁶ These states have typically not adopted legislative or statutory authority that mandates restructuring, but the regulatory commission has solicited customer choice programs and their expansion from local gas utilities.

⁷ http://www.eia.doe.gov/cneaf/electricity/chg_str/custpart.xls (electricity) and http://www.eia.doe.gov/oil_gas/natural_gas/restructure/state/us.html (natural gas) shopping statistics.

⁸ The statements by the Massachusetts DTE in its January 2001 Gas Cost Adjustment Order cited on in the Massachusetts case study in this report is the most explicit, but certainly typical, example of this approach.

- Should the NGDC base its procurement strategy on short-term wholesale market prices, i.e., on contracts and supply options that are typically less than one year and may rely in large part on monthly acquisitions or should state regulators require NGDCs to emphasize long-term price stability and enter into longer term contracts for at least a portion of the known customer load?
- How often should retail prices change to reflect changes in the wholesale price of natural gas supply—monthly, quarterly, annually?
- How should the impact of weather be reflected in natural gas pricing policies?
- Should gas supply prices for retail customers be fixed or estimated and then reconciled based on actual costs incurred by the NGDC?
- What should be the relationship between the procurement and pricing policies imposed on the NGDC and the existence of a competitive market at the retail level for customers? And should the answer to this question differ for larger customers versus smaller commercial and residential customers?
- Should state regulators pre-approve NGDC procurement plans or even specific contracts?
- Should utilities be rewarded or provided incentives for achieving price stability or meeting certain hedging targets?
- Should NGDC be allowed or encouraged to use financial instruments as part of their gas procurement tools, as well as the more traditional contracts for the physical storage and delivery of natural gas?
- Should regulators approve fixed price “options” or “price protection plans” for residential customers as a means of responding to natural gas market volatility?

- Should state regulators require NGDCs to invest in energy efficiency and demand reduction programs as a means of addressing gas price volatility? If so, how should rates be set to reflect the impact of such programs in reducing sales, thus reducing profits, for the NGDC?

The purpose of this paper is to examine how some representative states in each of the regional natural gas markets have answered these questions and to offer preliminary observations and recommendations on state regulatory policies for the procurement and pricing of natural gas supply for residential customers. This paper does **not** address how state commissions or gas utilities should create or implement programs for individual residential customers that respond to gas price volatility or high gas supply prices, such as budget billing mechanisms, low income bill payment assistance programs, and implementing voluntary bill or usage reduction measures. Rather, this paper focuses on state regulatory policies that impact the prices charged to residential customers and not how residential customers can respond to high natural gas prices once they appear on the bill.

**CASE STUDIES OF STATE POLICIES CONCERNING THE PROCUREMENT
AND PRICING OF NATURAL GAS SUPPLY:
OBSERVATIONS AND RECOMMENDATIONS**

The following summaries of state natural gas procurement and pricing policies demonstrate a wide range of approaches in states that have significant differences in natural gas supply costs, in their implementation of retail competition for residential and small commercial customers, and in the state's philosophy concerning price stability and the use of financial hedging instruments. The case studies are grouped by the following geographic regions:

New England: Massachusetts, Rhode Island, and Connecticut

Mid-Atlantic: New York, New Jersey

South: West Virginia, Arkansas

Midwest: Michigan, Indiana, and Ohio

West: Oregon

Southwest: Arizona

Key Observations

- The research and data gathered for this report from the various state regulatory commission orders, websites, and other documents suggests that it is very difficult to gather comparable data on retail natural gas supply prices or to compare this data with that gathered and reported at the federal level by the Energy Information Administration (EIA). The EIA retail natural gas supply pricing data is gathered from utilities who return an EIA survey and presents average retail price data by means of a simple division of sales and revenues for residential customer classes. As a result, the EIA data does not reflect individual utility residential customer class rates approved by state regulatory commissions and a comparison among the various natural gas utilities within a single state is not possible. Most states do not publicly maintain pricing data that breaks down the

components of the natural gas distribution company monthly bill and those states that do track and publicly report such data often do so in a manner that does not allow easy comparisons with other states. This report reflects retail pricing data gathered from state public utility commission websites and attempts to convert the state price data into a cents per CCF (hundred cubic feet) format, even though states and NGDCs often use a cents-per-therm pricing format in tariffs and customer bills. All per therm prices were converted to CCF prices by multiplying the cents per therm by 1.029.

- In general, the traditional method of pricing natural gas supply transfers most of the risk of price volatility and short-term price changes in the wholesale natural gas market to retail customers. This is true in most states whether or not retail natural gas competition has been adopted as the regulatory philosophy or state law. Unlike electricity supply, however, natural gas supply costs are typically over 50% (60-80% in the winter) of the residential customer bill so that this emphasis on price volatility and frequent price changes has a significant impact on residential customers whose usage pattern (dominated by winter heating) creates a dependency on natural gas at the exact time it is most costly. The impact of the weather, over which no customer has the ability to control, only exacerbates this impact.
- There is a remarkable lack of stated regulatory policies with respect to the procurement of natural gas supply. State regulatory commissions appear to treat the purchase of natural gas supply as not subject to their regulatory control even though the retail provision of natural gas service is fully “regulated” by state authorities in every state that was studied. State regulators have typically deferred to short term procurement policies in general and have only recently and only in a few jurisdictions explored the actual policies and programs that should be in place to govern the acquisition of this commodity for sale to end-use customers. While natural gas utilities do not

own the gas producing wells or the long distance pipelines that transport the gas to the NGDCs, they have the ability to buy long term contracts, build or contract for storage, manage a portfolio of both physical and financial gas supply products, and, in some cases, sell natural gas for a profit to other wholesale customers. The implications and responsibilities of state regulatory officials for the procurement policies that should govern this activity, particularly with respect to residential customers, is not widely discussed in either rulemakings, policy papers, or specific NGDC decisions.

- Unlike residential customers, utilities have the ability to manage gas supply costs. In part, this is due to the fact that natural gas can be stored for use at a later time, a factor that distinguishes natural gas supply from electricity. This means that utilities can physically purchase natural gas in advance of its use by retail customers and store this gas until it is pumped through its distribution system to retail customers. In addition, utilities can acquire a mixed or balanced portfolio of physical and financial contracts, storage options, fixed and variable priced contracts, short and long term contracts. This approach is more likely to be followed when the regulatory commission has adopted an explicit policy that favors price stability over time and engages in rigorous review and analysis of natural gas procurement decisions that document imprudent behavior and disallow excess costs when the utility has failed to follow established policy to hedge gas prices to mitigate price volatility. The states that have initiated a significant effort to regulate the NGDC's procurement of natural gas supply and emphasized the need to manage this procurement function to achieve specific policy objectives include Indiana, Michigan, Rhode Island, Arkansas, and Arizona. These states have demonstrated that they can provide natural gas supply at more stable or even lower prices either in comparison with neighboring states or by comparing individual NGDC prices with those in effect at an NGDC in the same state. For example, in Indiana

NIPSCO's failure to engage in gas procurement management and hedging resulted in higher prices than other Indiana NGDCs. In Rhode Island, the regulatory commission has documented that **it's** more proactive approach to gas supply procurement practices by its largest natural gas utility has resulted in lower and more stable prices than those passed through to residential customers in Massachusetts.

- In some states, the use of multi-year performance plans, rate freezes, or price caps for the total natural gas bill, including the natural gas supply portion of the bill, has resulted in at least temporary price stability for residential customers. Of course, any price cap or rate freeze that was in effect during the 2000-2001 winter generally operated as a "win" for ratepayers. The propensity of NGDCs to enter into such rate caps or rate freezes since that period has lessened. Also evident is that when the NGDC emerges from the price cap or rate freeze period, customers are typically in for a significant jump in natural gas supply prices. States in which the operation of rate caps or price freezes can be evaluated include Michigan, West Virginia, New York, Rhode Island, and Oregon.
- States that have adopted retail natural gas competition as an overriding policy objective typically have more volatile natural gas prices and higher prices generally compared to the other states reflected in this study. The implementation of retail natural gas competition for residential customers leads to the logical conclusion that (1) customers should see the "real" market price; (2) marketers should be responsible for offering fixed prices or more stable prices if that is what customers prefer; and (3) the price of natural gas supply should change frequently so that customers can make decisions in their usage and their selection of alternative services in the face of market conditions. Under this philosophy, it is not the responsibility of the incumbent gas utility to protect its customers from volatile prices or engage in substantial hedging activities that

might prevent the “real” market price from appearing on customer bills. This approach is readily apparent in Massachusetts and Ohio. However, some states that have adopted vigorous natural gas competition programs have also initiated such programs with multi-year rate plans or rate freezes for incumbent gas utilities that have resulted in low and stable prices for residential customers who remain with the incumbent during this transition period. This has occurred for some gas utilities in New York (particularly the upstate region) and in Michigan. Unfortunately, when the New York utilities transitioned out of these price freezes or rate stability plans, the state commission allowed a significant increase in natural gas supply prices to reflect the then-current wholesale market prices, thus contributing to a significant change in retail prices.

- States that have adopted portfolio management and hedging have uniformly acknowledged that such an approach will not necessarily result in the lowest possible price at any one point in time. In other words, there is a cost to portfolio management and price stability in the form of a slightly higher price than may be achievable over any particular short period of time using the spot market. The opposite may also occur. Furthermore, utilities incur administrative or management costs associated with hedging and portfolio management that are typically included in the gas cost recovery mechanism. These costs are obviously theoretically lower if the utility can take advantage of a multi-state management by a parent company or affiliate because those costs can be spread among a larger number of ratepayers, although most state commissions do not identify these costs or potential savings in their decisions. On the other hand, regulatory commissions may not be particularly skilled in the ability to audit and oversee the more sophisticated financial hedging programs without the investment in either consulting assistance or additional staff training. For examples of state policies that recognize the importance of price stability in the

NGDC procurement function, as well as the costs associated with the portfolio management programs, see Arizona, Indiana.

- States that have not emphasized portfolio management and price stability per se are more likely to allow the NGDC to offer voluntary options to residential customers, such as a fixed price option (typically over a 12 month period that begins in the fall) or a “weatherwise” product that offers bill stability. Under these programs, the gas utility offers residential customers an option to enter the program at a specific price, which is often higher than the price in effect during the fall and the beginning of the new gas price “season.” Such programs are often accompanied by limits on participation or viewed as “pilot” programs. However, marketers in states that have adopted retail natural gas competition (such as in Ohio and Massachusetts) vigorously oppose these options. Furthermore, it is not clear why such products cannot be purchased for all residential customers rather than a small subset of those who voluntarily elect this option.
- There is a remarkable lack of analysis and discussion of the effect of energy efficiency programs and efforts as a means of ameliorating price volatility or as a substitute for buying natural gas supply “on the margin” in times of high prices and tight supplies. While “interruptible” rates and services are routinely offered to larger customers, they are not offered to residential or small commercial customers. Nor have regulatory commissions analyzed purchasing decisions based on energy efficiency or interruptible load alternatives. The only program that even discusses these connections is the Oregon partial decoupling program adopted for Northwest Natural Gas Co. for a three-year period in 2002. The more typical state approach is to require a certain amount of spending on energy efficiency by gas utilities as a form of public benefit funding that is never discussed or analyzed in the context of the acquisition and pricing of natural gas supply. No regulatory commission has asked the question, “What would residential customers pay for a

voluntary reduction in usage at certain times in return for a lower price?” Or, “What would be the impact on the price of natural gas if the gas utility engaged in a dramatic effort to install energy efficient appliances at a subsidized cost at a time of rising prices and increased gas price volatility?” Rather, it is universally assumed that residential (and small commercial) load is “firm” and must be served at the demand level of those customer classes and the exhortations for energy efficiency and conservation are typically limited to energy reduction rather than energy efficiency. Most every regulatory commission has a press release, conference, or publication available on its website to prepare customers for higher gas prices. Most of the suggestions concerning energy efficiency are focused on reducing natural gas use, e.g., “use your appliances wisely”; “turn down the thermostat”; “reduce the use of hot water.” Few states have integrated their delivery or educational efforts on responding to higher winter natural gas prices with the comprehensive energy management or energy efficiency programs.

Recommendations

- (1) Regulatory commissions should proactively “regulate” the natural gas procurement policies and prices of NGDCs. Even though the price of wholesale natural gas market is “deregulated”, the retail acquisition of a natural gas portfolio should be monitored and evaluated based on consumer benefits, particularly for residential and small commercial customers. There are a wide variety of regulatory policies that, if adopted, enunciated, and enforced, will impact the rates charged for the natural gas supply portion of customers’ bill. In short, state regulatory commissions should not, as many do, seek to shift the responsibility for natural gas supply rates and charges to “the market” or contribute to the public aura that state commissions cannot regulate natural gas prices or gas procurement decisions. This overall policy directive concerning the establishment and enforcement of natural gas procurement practices may need to be established by statute in those states in which the regulatory commission fails to adopt this approach, but in most states the regulatory commission already possesses sufficient statutory authority to adopt a more proactive approach. State regulatory commissions can establish natural gas procurement practices and policies. These practices and policies should be adopted either as a rule or a policy statement and then implemented by conducting regular reviews of individual utility natural gas procurement and pricing proposals.
- (2) State commissions should require NGDCs to proactively manage their natural gas supply portfolio and acquire a balanced and diverse portfolio of physical and financial contracts that is designed to provide stable and reasonable prices for residential and small commercial customers over a long term planning horizon. As indicated by the Rhode Island PUC, simply making use of “dollar cost averaging” (the use of regular purchases of part of the overall load

over a period of time) may not be sufficient. Rather, it may be necessary to adopt performance benchmark goals and objectives, as discussed further below.

- (3) State regulatory commissions should require NGDCs to develop and submit for review and approval an annual procurement plan that describes the implementation of its overall approach to the management of its natural gas supply portfolio. In addition, the utility should prepare and annually update a five-year plan that reflects an analysis of its service territory, customer load profile, the state of the natural gas market, long and short term market trends, an analysis of long term contracts, and a review of the previous year's procurement plan and suggested amendments. This procurement plan should also include an analysis of the impact of energy efficiency and demand response programs that, in times of rapidly increasing wholesale gas prices, could be deployed to avoid the impacts of higher bills for residential and small commercial customers.
- (4) The Legislature and/or the regulatory commission should adopt an explicit policy that requires natural gas utilities to follow portfolio management principles that value price stability. That may include reliance on long-term contracts with either fixed prices or limitations on price upper and lower boundaries for some portion of the gas supply portfolio, financial hedging instruments, and an expansion of storage options. These pricing principles should be explicitly adopted to apply to "default" customers in states that have moved to retail natural gas competition, for the same reasons that advocates have urged more stable and long term pricing principles for electric service in restructuring states. Residential customers should not bear all of the risks associated with volatile or short-term movements of the wholesale commodity market. Rather, the incumbent utilities should be required to perform the public service function of managing this price volatility as a steward on behalf of their customers. Relying

on unregulated gas marketers to perform this function is dangerous for several reasons. First, the gas marketers have a habit of exiting the market (either voluntarily or by entering bankruptcy) whenever the going gets tough. This phenomenon was well documented in New York, Massachusetts, New Jersey, Illinois, and Ohio during the 2000-2001 price spike. Second, it is unlikely that the price paid to the gas marketer for providing a more stable price product is cheaper than if the incumbent utility incurred such costs on behalf of a much larger customer group and load factor. Third, there is absolutely no basis to conclude that gas marketers will offer an option for stable or fixed prices and in many jurisdictions they have not done so. Finally, and most importantly, it should be the obligation of the public utility that has received the privilege and obligation to provide service to all without discrimination to provide the “public interest” service of stable and reasonably priced natural gas service.

- (5) Utilities should bear more of the risk associated with the failure to achieve one or more pre-established performance benchmarks. Advocates and commissions should explore whether it is more likely that a utility will have the proper incentives to engage in portfolio management if it bears some of the rewards and risks associated with the implementation of a gas supply program that values price stability and achieving a price benchmark. These incentives and penalties might include benchmarking the resulting price of natural gas with a bandwidth, making the rewards explicit, requiring the utility to bear the risk of failure (imposing a fixed price), reducing the frequency of price changes, and exploring decoupling mechanisms that lessen the link between retail sales and profits. Even though utilities do not make a “profit” on the pass through of the sale of natural gas supply, utilities rely on the distribution revenues, which do reflect sales and are priced in the same manner as natural gas supply, i.e., on a per therm or per ccf basis. As a result, the theoretical indifference by NGDC management to the

price of natural gas supply is not apparent when price spikes cause large industrial load shedding or fuel shifting and increased incidence of default and disconnection from residential customers that result in higher customer service costs and public relations headaches, if not nightmares.⁹

- (6) The use of annual or semi-annual price changes is more likely to focus the utility's attention to price stability, particularly when compared to monthly price changes. Furthermore, a lengthier period between price changes can be more easily linked to decoupling initiatives as demonstrated by the program adopted in Oregon. The experience in Indiana shows how difficult it is to construct a policy that favors proactive gas procurement and hedging when monthly price changes are available to reflect short term changes in wholesale gas markets.
- (7) While commissions have traditionally and frequently relied on the use of the deferral mechanism to smooth out significant price increases for residential customers, this is a blunt instrument that should not be the primary basis for mitigating price volatility. First, such an approach has a significant cost in the form of interest paid on the deferred balance. Second, this approach masks the utility's failure to properly manage its natural gas supply portfolio and does not provide any incentive to rely on hedging techniques and a balanced portfolio approach to natural gas pricing.
- (8) Advocates should seek regular prudence reviews of natural gas procurement decisions, ideally in the context of an annual review of the implementation of the utility's procurement plan. While it may not be reasonable to question a particular contract or particular contract price with the hindsight of "perfect vision", it is reasonable to expect that a documentation of the failure to explore portfolio management or various portfolio management tools and the

⁹ Both Pennsylvania and New York have documented the death of a residential customer due to lack of natural gas heating following disconnection for nonpayment or the inability of the customer to obtain reconnection in the face of payment difficulties in recent years.

comparison of the resulting prices with similarly situated utilities in the state or region can result in a substantial disallowance and the adoption of improved policies.

- (9) While advocates typically want to rely on prudence reviews that look backwards and evaluate decisions already taken by utility executives, utilities themselves prefer pre-approval and have called for such an approach as a means of responding to calls for increased risk management by policymakers. This paper did not find many instances of pre-approval of actual gas procurement decisions, but the Arkansas approach in which a gas procurement plan is approved or individual utility programs, such as those in Indiana, in which a certain specified portion of a portfolio is required to be hedged, are examples of a more modest approach. Under the Arkansas model, the NGDC's procurement plan is reviewed and approved, but its actual implementation of that procurement plan is subject to prudence reviews at a later time. This is also the approach being explored in several states that are attempting to develop Default Service policies that impose a procurement obligation under certain specified policies on the incumbent electric distribution utility.¹⁰
- (10) There is little discussion by commissions in their gas pricing decisions about the expansion or use of natural gas storage by local distribution companies. Whether or not the availability or use of storage is a function of historical ownership of such facilities by the NGDC or the natural geography of the region that, similar to Michigan, supports large storage capacity is not clear. Nonetheless, advocates should press for a more proactive analysis of storage options as a means of reducing reliance on gas price volatility. However, the most controversial issues associated with gas storage, as revealed by the disallowance ordered by the Michigan PSC, is the pricing of gas when it is injected versus its price when it is removed and sold to end-use

¹⁰See, e.g., Alexander, Barbara, Managing Default Service to Provide Consumer Benefits in Restructured States: Avoiding Short-Term Price Volatility, National Center for Appropriate Technology, 2003 (available at <http://neaap.ncat.org/experts/defservintro.htm>).

customers. The pricing of the various “layers” within the stored gas deserves careful attention by advocates.

- (11) If the gas utility is allowed to offer “fixed bill” or “Weatherproof” billing options to residential customers, the same problems exist as those pointed out above when the competitive market is relied upon to offer these services. If the utility can offer a fixed bill or “weather proof” bill to some customers, why not to all? Customers who select these options often pay entry or administrative fees and the small pool of entrants are likely to increase the overall costs of such an option. Furthermore, utilities who offer such options often rely on third parties to deliver the program and these entities come and go similar to gas marketers themselves. For example, Kansas Gas Service recently announced that it was discontinuing its WeatherProof billing program because the outside company that administered it could no longer offer it.¹¹ Over 40,000 residential customers were enrolled in the program. Another example is NIPSCO’s “premium service” offered to Indiana residential customers that may have contributed to the internal incentives that resulted in the company’s lack of affirmative hedging as described later in this report. The objectives of these services should be provided to all residential customers and not just those willing to pay an additional fee for this service.

¹¹ Kansas City Star, Page C3, October 23, 2003.

Massachusetts

Massachusetts passes through gas supply costs through the Gas Adjustment Clause, which is changed at least twice per year¹² and reconciled annually in the fall. The annual reconciliation may result in supplemental recovery or credit to customers for over-recovery. Massachusetts has also ordered the statewide implementation of retail natural gas competition. As a result, customer bills are unbundled, competitive suppliers are licensed, and customer education programs encourage comparative shopping. However, the rate of residential customer participation in the natural gas supply market is miniscule. According to the EIA, as of December 2002, only 300 residential customers were participating. As a result, almost all residential customers receive natural gas supply service from their Local Distribution Company (NGDC).

Similar to most states, the Massachusetts Department of Energy and Telecommunications (DTE) confronted substantial increases in the price of natural gas supply in the winter of 2000-2001. Faced with proposed increases of in the Cost of Gas Adjustment Clause (natural gas supply portion of the bill) ranging from 8.33% to 65.9% for December-January (which followed double digit increases approved in November), the DTE discussed its overall approach to the recovery of the very high wholesale market prices that occurred that winter¹³:

The companies requested these increases to collect from ratepayers the costs that they incurred and will incur to purchase natural gas supplies for their customers. In their filings each NGDC noted that the increases in gas commodity costs are driven by natural and international forces beyond either the Department's or the Companies' control.

It is important to differentiate the components of the bill that are regulated by the Department. The Department does not regulate the interstate price of the gas commodity. Rather, the gas commodity price is determined by market forces, based on supply and demand.

In terms of pricing, natural gas is merely goods in trade, just like grain, oil, coffee, or any other fungible commodity. Natural gas commodity prices are determined by the marketplace. Factors affecting gas prices include the weather, overall gas demand, supply of gas, and the prices of competing fuels, such as oil and coal.

Costs incurred by the NGDCs for the purchase, storage, and interstate transportation of gas (referred to as gas supply costs) are recovered via the Cost of Gas Adjustment Clause on a dollar-for-dollar basis. See 220 C.M.R. §6.00. That is, NGDCs do not profit on the gas commodity component of a gas bill, and the cost of gas is a straight pass-through. NGDCs earn a rate of return solely and entirely on their investment in local distribution facilities, i.e., the second component of the gas bill.

Because this winter's dramatic and unprecedented increases in gas commodity costs are historic, the Department needs to review the CGAC mechanism and perhaps make it more responsive to extraordinary price fluctuations, analogous to the gas costs mechanisms used

¹² In the last several years the Department has accepted and implemented more frequent price changes in the Gas Adjustment Clause.

¹³ "Gas Cost Adjustment Order", January 31, 2001, available at <http://www.state.ma.us/dpu/gas/01-09/cgacorder.htm>

in New York, Connecticut, and New Hampshire, where comparable gas costs are being recovered in customer bills today.

The Department recognized the need to balance the urge to defer some of these unprecedented price increases until after the winter period with the “policy of mitigating severe billing swings.” As a result of this decision, the largest natural gas companies were allowed to charge a gas supply price of \$.95 per therm (Bay State Gas) to \$1.06 per therm (Boston Gas) in February 2001. In both cases, this was projected to eliminate any projected under-recovery as of April 30, 2001.

In 2002 the Department considered its overall approach to gas procurement and pricing for the NGDCs and rejected a proposal to emphasize the mitigation of price volatility in gas procurement practices and emphasized the importance of sending the proper “price signals” to all customers.¹⁴ With respect to the use of financial “hedging” instruments, the Department stated that it would consider such programs on a company-specific basis:

The Department will review the effect that a company’s use of financial hedging instruments will have on the reliability and transparency of commodity prices on a case-specific basis, taking into account the wide-ranging options, instruments, and strategies that are available to both the NGDCs and the Competitive Suppliers.

The Department noted that with respect to “reliability and transparency of commodity prices”, it meant “NGDC prices that reflect accurately what the prevailing market prices are likely to be in a CGAC period.” The NGDC’s prices must not “provide customers with distorted or misleading price signals.”

With respect to the impact of its pricing policies on the development of a retail competitive market, the Department quoted one participant in the proceeding:

Planalytics observes that, overall, NGDC risk-management programs will result in stable, consistent pricing; thus the customer will benefit from both reduced price volatility and low prices (Planalytics at 2). However, Planalytics argues that an environment of low price volatility and stable prices could hamper the development of competition and customer choice because gas unbundling and customer choice program become less attractive to consumers. (*id.*).

The Department rejected proposals to require NGDCs to engage in risk management activities that might require all customers to pay costs incurred for risk management. Rather, the DTE concluded that customer participation in NGDC financial risk management programs must be voluntary rather than mandatory and the costs associated with such a program must be recovered from only the customers who choose to participate in such programs. The Department also rejected the creation of any incentives to encourage or reward risk management activities or programs.

Finally, with respect to how it intended to evaluate an NGDC’s risk management activities, the DTE stated:

¹⁴ D.T.E. 01-100-A, Investigation by the DTE on its own motion pursuant to G.L. c. 164, §§76, 94 and 94A, to investigate the appropriateness of the use of the Risk-Management Techniques to Mitigate Natural Gas Price Volatility, October 9, 2002, available at <http://www.state.ma.us/dpu/gas/01-100/109order.pdf>

The Department agrees with the majority of commenters who state that the implementation of risk management programs would be designed to stabilize prices but would not necessarily result in “least cost” gas supply or minimize costs. As noted, due to the volatile and unpredictable nature of commodity derivatives markets, financial risk-management program unlikely to consistently produce prices below index levels.

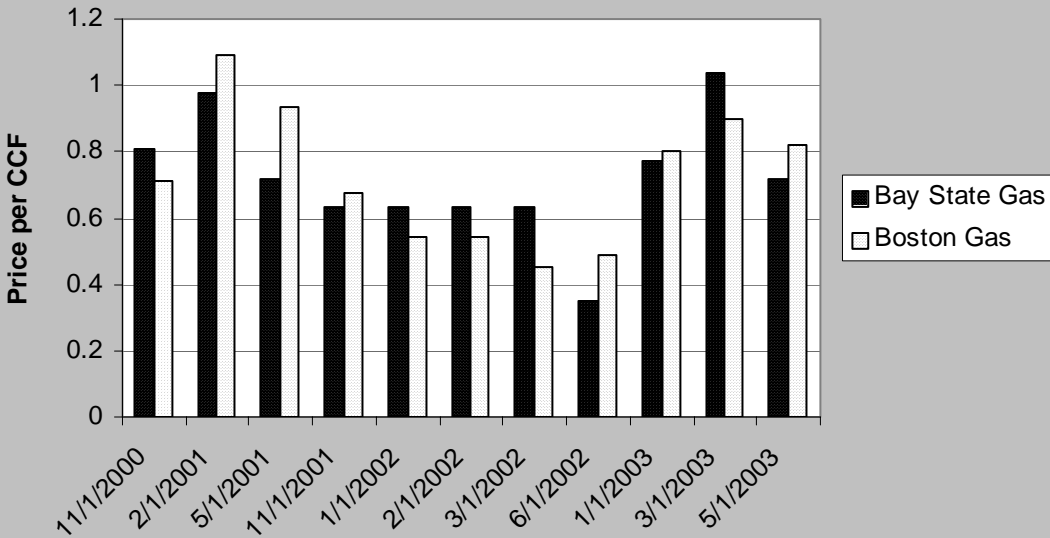
The following Table¹⁵ shows the price charged for natural gas supply for the two largest NGDCs for the period November 2000 through the summer of 2003.

Date	Bay State Gas	Boston Gas
11/1/2000	0.7853	0.6935
2/1/2001	0.95	1.0626
5/1/2001	0.6994	0.9097
11/1/2001	0.6138	0.6546
1/1/2002	0.6138	0.5282
2/1/2002	0.6138	0.5282
3/1/2002	0.6138	0.4412
6/1/2002	0.3395	0.4734
11/1/2002	0.6354	0.635
1/1/2003	0.7483	0.778
3/1/2003	1.0066	0.8749
5/1/2003	0.6992	0.797

The following chart presents the same data as the table, but in a CCF pricing format to allow for comparisons with other states in this report:

¹⁵ The MA DTE publishes changes in the CGAC on its website: <http://www.state.ma.us/dpu/gas>

MA Gas Prices per CCF



Rhode Island

Rhode Island, a small state, has devoted substantial regulatory resources to address gas price stability and affordability, primarily through reviews and decisions concerning the cost of gas supply of the largest natural gas utility, New England Gas Co., the successor to two smaller NGDCs and a “sibling” of Southern Union Co. While natural gas retail choice is available to commercial and industrial customers, there are no retail choice programs in place for residential customers.

New England Gas Co. (NEGas) serves 290,000 residential and commercial customers in Rhode Island and Massachusetts. NEGas operates pursuant to both an incentive rate plan for the distribution portion of its business and has litigated and resolved gas procurement policies and practices, stimulated in part by the extremely high prices that were flowed through to the ratepayers in 2000-2001. The RI Public Utilities Commission ordered an explicit gas procurement incentive program in early 2003, which has been widely acknowledged as responsible for lower gas prices for the 2003-2004 winter.¹⁶ The Commission ordered an incentive plan with both rewards and penalties for the purchase of natural gas supplies:

In this proceeding, the Commission has attempted to take gas procurement to the next stage. The Commission’s modifications to the parties’ Proposed Incentive Plan takes a middle path to this next stage. Rhode Island’s gas utilities have treated the recovery of purchased gas costs as a mere “pass-through” to ratepayers. Consequently, prior to the winter of 2000-2001, Rhode Island’s former gas utilities, ProvGas and Valley, tended to rely nearly exclusively on spot market purchases and claimed that this served the objective of affordability. A litigious and contentious prudence review by the Commission ensued, which resulted in savings to ratepayers. NEGas, the successor of ProvGas and Valley, learned the lessons of the winter of 2000-2001. NEGas hedged extensively and followed a dollar cost averaging approach to achieve price stability. Unfortunately, the winter of 2002-2003 demonstrates that dollar cost averaging is not enough to keep ratepayers’ bills reasonable and affordable. As a result, NEGas must utilize its discretionary purchases to depart from a simple dollar cost averaging strategy and take advantage of low priced gas in order to achieve affordability.

The Proposed Incentive Plan as modified by the Commission achieves a marriage of price stability and affordability. Price stability is achieved by requiring 50 percent of NEGas’ gas supply be purchased through a dollar cost averaging approach. Affordability is achieved if NEGas utilizes its discretionary purchases, covering up to 45 percent of the gas supply, to purchase gas below the price produced by its dollar cost averaging strategy for non-discretionary purchases. To incent Southern Union to utilize its discretionary purchases as envisioned, the Commission had to modify the reward and penalty structure proposed by NEGas. Under NEGas’ proposal, Southern Union would be nearly assured of never incurring a penalty and always receiving a reward, even if NEGas’ discretionary gas purchases did not lower gas costs by being lower than the price of its nondiscretionary purchases. A true incentive system provides a realistic opportunity for Southern Union to receive a reward for lowering gas costs and an equally real threat of incurring a penalty for failing to be proactive.

¹⁶ RI PUC, In Re: New England Gas Co. Gas Cost Recovery Filing, Docket No. 3436, Report and Order, May 1, 2003. Available at: http://www.ripuc.ri.gov/order/pdfs/NEGas3436_Ord17444.pdf

Therefore, utilizing its own expertise and choosing among the contradictory positions of the experts presented, the Commission under the broad authority conferred by Title 39 modified the reward/penalty structure of the Proposed Incentive Plan by eliminating the NYMEX benchmark and increasing the limits on rewards and penalties. If NEGas chooses to continue utilizing the dollar cost averaging approach for its discretionary gas purchases, Southern Union will face the possibility of absorbing a penalty. If NEGas utilizes its discretionary purchases to achieve lower gas costs for ratepayers than produced by its dollar cost averaging strategy, Southern Union's shareholders will have an opportunity to share in the cost savings. *** The Commission hopes this approach will be sufficient to incent NEGas' to be proactive in gas procurement so as to lower gas costs for its ratepayers. Wholesale gas costs account for more than 50 percent of the typical residential heating customer's annual bill. Also, NEGas' annual bill for a typical residential heating customer is clearly the most expensive utility bill for the average Rhode Islander. The Commission will not merely rubber stamp the pass-through to ratepayers of NEGas' gas cost increases. The Commission has taken the proactive step of ordering the implementation of an Incentive Plan that is designed to incent NEGas to be more proactive in procuring lower cost gas. If NEGas is not interested in pursuing rewards for Southern Union, then it will face penalties. The penalties could grow with time if NEGas refuses to be proactive. At this time, however, the Commission has chosen a middle path that gives ample opportunity for Southern Union to receive rewards. Southern Union can either embrace the Incentive Plan and pursue rewards or stubbornly refuse to change its ways and face penalties. The choice is for Southern Union to make.

[At 45-46]

In September 2003, New England Gas Co. issued a press release¹⁷ congratulating itself on keeping gas supplies at a reasonable price:

While many areas of the country are predicting substantial increases in the cost of natural gas for this year's heating season, Rhode Islanders will largely be spared. Thanks to an innovative program initiated by the Rhode Island Public Utilities Commission, the New England Gas Co. has already purchased much of the fuel supply that it expects to need to meet this year's heating demand.

As of July 1, 2003, Rhode Island residential heating customers of New England Gas Co. were paying \$.7120 per therm for gas charges. In November 2003, the Commission addressed New England Gas' proposed increase in the Gas Cost Recovery Charge for the 2003-2004 winter in which the utility proposed to increase the GCR factor on a per therm basis to \$.8195 for residential customers. In ruling on this request¹⁸, the Commission summarized its recent approach to the rates charged for natural gas supply and contrasted the Rhode Island PUC's approach from that adopted in Massachusetts:

Justice Brandeis once stated that "in no other field of public service regulation is the controlling body confronted with factors so baffling as in the natural gas industry." [*Pennsylvania v. West Virginia*, 262 U.S. 553,621 (Brandeis dissenting) (1923)] Thus, it is not surprising that certain members of the public

¹⁷ New England Gas. Co, "Rhode Island Customer to Avoid Price Spike in Natural Gas", September 3, 2003, available at <http://www.negasco.com>.

¹⁸ RI PUC, In Re New England Gas Company's Gas Cost Recovery Charge, Docket No. 3436, November 21, 2003. Available at: [http://www.ripuc.ri.gov/order/pdfs/3436_NEGasOrd17606\(11.21.03\).pdf](http://www.ripuc.ri.gov/order/pdfs/3436_NEGasOrd17606(11.21.03).pdf) The extensive quotation from this order noted above appears at pages 9-10 with extensive footnotes that are not included in this excerpt.

may be baffled as to how NEGas' rates continue to climb despite this Commission's best efforts to keep these rates low or stable. As an initial matter, it must be understood that this Commission cannot set the wholesale price of interstate natural gas. The GCR portion of ratepayers' bills was deregulated by the federal government in the Natural Gas Policy Act of 1978. This state Commission has been pre-empted in this arena and must treat these purchased gas costs as a utility operating expense. Therefore, in regards to the wholesale gas cost increases, this Commission has a few options such as: disallowing imprudent wholesale gas purchases, reduce interest charges on any undercollection for deferred gas costs, establishing a gas procurement policy to attempt to shelter residential heating ratepayers from price spikes during the winter, creating a gas procurement plan that imposes penalties on NEGas if it does not take advantage of price dips, or finding savings in NEGas' distribution rates to offset GCR increases. This Commission has done and will continue to do all of the above. It has not been a passive observer who simply blamed the wholesale gas market as prices rose.

In past proceedings relating to wholesale gas costs, the Commission has reduced gas costs by approximately \$1.26 million after it conducted a review of the prudence of ProvGas and Valley Gas' gas procurement for the winter of 2000-2001. Also, the Commission approved the development of a gas procurement plan that requires NEGas to purchase gas months in advance in order to ameliorate the price spikes of a colder than normal winter.²¹ In addition, this gas procurement plan contains a potential penalty of \$500,000 for NEGas if its gas purchases do not take advantage of drops in gas prices. This is quite a contrast from neighboring Massachusetts. In Massachusetts, gas utilities rely heavily on the spot market so if a winter is very cold and demand is high, the ratepayers are paying for a large amount of gas at a very high price. Furthermore, these gas utilities are not subject to a penalty plan for poor gas purchases. The difference in these two approaches has been made clear over the last four years. Since November 1999, in three of the last four years, NEGas/ProvGas' GCR rates have been below the GCR rates of at least two of three major Massachusetts gas utilities: Bay State, Boston Gas and NStar/Commonwealth. Specifically, NEGas/ProvGas rates were significantly lower in the winter of 2000-2001, and 2002-2003, when dramatic price spikes occurred due to colder than normal weather. This Commission's gas procurement policy has sheltered residential heating customers from extreme price spikes at the time their consumption is highest—extreme cold weather during the winter. Unfortunately, because of the legal limitations on this Commission regarding regulation of wholesale gas costs, ProvGas/NEGas' GCR rates for residential heating customers have increased from \$0.4531 per therm as of September 30, 2000 to \$0.7984 per therm as of November 1, 2003, or approximately a 76 percent increase in three years.

Connecticut

Connecticut prices its natural gas supply in the more traditional manner, at least with respect to residential customers. Gas costs are evaluated at the time of base rate cases and the Purchased Gas Adjustment factor is changed monthly to reconcile the commodity costs approved in the tariffs with actual revenues and costs. Connecticut has not approved retail natural gas competition for residential customers, but has approved such programs for multi-unit residential customers (more than 6 units), as well as commercial and industrial customers. The utility bills for residential customers were unbundled in 2002, showing the separate rates for natural gas supply and distribution service.

Energy East owns the two largest natural gas utilities. Both operate under multi-year performance based rate plans. Southern Connecticut Gas Company's rates and charges were last subject to a revenue requirements investigation in 1999, with new rates effective 2/1/2000. Since that time, the Company's rate design has been subjected to review and changes in various "phases" associated with the prior base rate decision. In mid-2002¹⁹, the Department of Public Utility Control (DPUC) revised the class revenue requirements by imposing a 20% increase on residential classes, most of which was imposed on residential non-heating customers. In addition, the DPUC altered the means by which the commodity charges are recovered in various customer classes. Instead of a system-wide average cost of gas, the DPUC adopted a class-specific gas cost approach. An attempt to increase the monthly customer charge for residential classes was rejected. As a result of these various changes, residential heating customers saw a previously unbundled rate of \$.9848 change to a delivery charge of \$.4636 and a commodity charge of \$.5243, plus itemized adjustments: Purchased Gas Adjustment, Weather Normalization Adjustment. The Weather Normalization Adjustment affects base delivery charges and affects bills during the months of September through June. It insulates the company's revenue requirement from the impact of abnormal weather.

Connecticut Natural Gas Corporation's revenue requirement was last approved in 2000, followed by a cost of service study and rate design proceeding in 2001.²⁰ The DPUC created two residential classes: heating and non-heating and significantly increased rates for non-heating residential customers. While the total bill for residential heating customers was estimated to remain the same as under prior rates, the unbundled rates for delivery service were decreased and the rate for commodity charges increased, as well as the monthly customer charge. As a result of this proceeding, residential heating customers saw their customer charge move from \$8.10 to \$10.25, delivery charge decrease from \$.4391 to \$.3762 and commodity charge increase from \$.4776 to \$.5225.

The DPUC rejected a proposal by the Office of Consumer Counsel to establish an average fixed commodity cost for residential customers for a twelve-month period on the grounds that such customers were not eligible for competitive alternatives and could not exploit the average prices for commodity service. The OCC's proposal was linked to its suggestion that the cost of gas supply could be fixed by the

¹⁹ CT DPUC, DPUC Review of the Southern Connecticut Gas Co. Rates and Charges Phase IV-Rate Design, Docket No. 99-04-18PH04, May 1, 2002, available at [http://www.dpuc.state.ct.us/FINALDEC.NSF/2b40c6ef76b67c438525644800692943/c6f7602a462352d985256bac006d1a27/\\$FILE/990418PH04-050102.doc](http://www.dpuc.state.ct.us/FINALDEC.NSF/2b40c6ef76b67c438525644800692943/c6f7602a462352d985256bac006d1a27/$FILE/990418PH04-050102.doc)

²⁰ CT DPUC, Application of Connecticut Natural Gas Corp. for a Rate Increase—Rate Design, Docket No. 99-09-03PH03, August 31, 2001, available at: [http://www.dpuc.state.ct.us/FINALDEC.NSF/2b40c6ef76b67c438525644800692943/3fd62f96b728941285256ab90067bced/\\$FILE/990903PH03-083101.doc](http://www.dpuc.state.ct.us/FINALDEC.NSF/2b40c6ef76b67c438525644800692943/3fd62f96b728941285256ab90067bced/$FILE/990903PH03-083101.doc)

purchase of futures contracts. The Department determined that the issue of hedging should be generically explored for all NGDCs. In a previous order, the Department had approved the use of the futures market (i.e., financial hedging) for up to 10% of the NGDC's gas supply portfolio, with any resulting profits split 80% to firm ratepayers and 20% to stockholders. The Department has not yet opened a specific docket to address hedging or gas purchasing policies, but continues to conduct semi-annual reviews and analysis of individual utility gas purchasing decisions. The most recent decisions do not address hedging policies.

Subsequent to the two revenue requirement decisions, the Department approved a comprehensive settlement for both Southern Connecticut and Connecticut Natural to resolve the pending impacts of the merger with Energy East on existing incentive rate plans, as well as pending affiliate transactions.²¹ In this decision the Incentive Rate Plans for both companies was extended until 9/30/2005, with substantial changes to the Earnings Sharing Mechanism to reduce rates by a total of \$5 million over four years. This decision address the gas purchase prudence standard and addressed deferred gas costs of \$26 million, due to the under-recovery of gas costs in the PGA during the winter of 2000-2001. Rate reductions in delivery base rates were also agreed upon (\$8 M over four years). As a result of these decisions, the DPUC authorized the recovery of previously unrecovered gas costs over a period of 4 years (instead of the normal 11 months) and the resulting delivery service rate reductions were ordered to be returned to customers in the form of credits on customer bills during the winter months of 2002 (March-April) and 2003 (November-March) so as to alleviate the higher gas bills. Both companies were warned that the DPUC would review any storage or supply agreements for prudence in light of its long standing policy to ensure that the companies' decisions "balance cost minimization with cost stability." [At 25] However, the Department did not elaborate on any further policy guidance in this regard and did not discuss financial hedging at all. A Dissenting Opinion issued with this Decision alleges that affiliate contracts for acquisition of gas supply resulted in higher costs for ratepayers.

The following Table of Purchased Gas Adjustment factors are derived from the DPUC website:²² These prices are added (or subtracted) from the tariffed commodity charge that is set at the time of a base rate case. With respect to these three NGDCs, the following table shows the tariffed commodity price for residential heating customers in effect for the last three years:

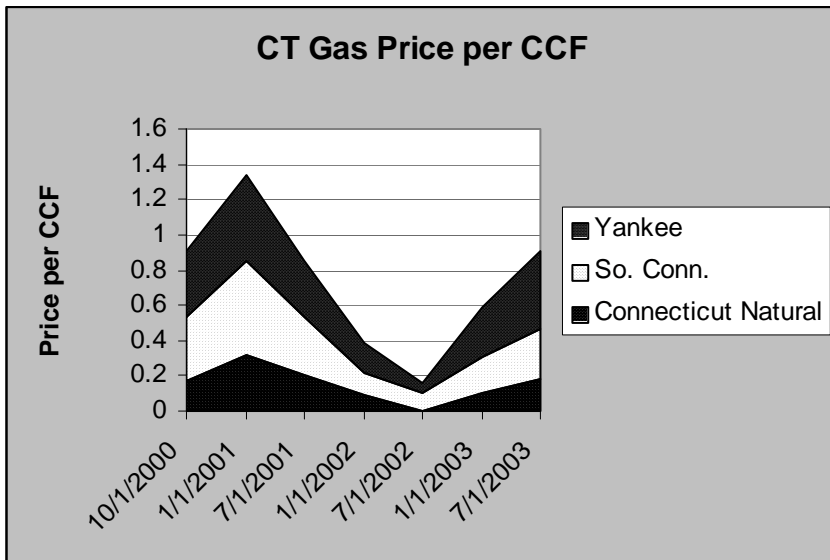
	Connecticut Natural Gas (\$ per ccf)	Southern Connecticut Gas (\$ per ccf)	Yankee Gas Service Co. (\$ per ccf)
October 2000	.1741	.3566	.3742
January 2001	.3152	.5332	.4926
July 2001	.2095	.3185	.3285

²¹ CT DPUC, Docket No. 01-10-17, et al., Decision, February 22, 2002, available at: [http://www.dpuc.state.ct.us/dockcurr.nsf/17ff825cfc1e297385256b040067883c/7b9c722f86d030e085256c0800548c34/\\$FILE/011017-022202.doc](http://www.dpuc.state.ct.us/dockcurr.nsf/17ff825cfc1e297385256b040067883c/7b9c722f86d030e085256c0800548c34/$FILE/011017-022202.doc)

²² The DPUC publishes regular updates of historical natural gas supply prices: <http://www.dpuc.state.ct.us/DPUCINFO.nsf/9d977919e146d12685256c4e0052595e/a40ef432558602c5852564dc00578d0d?OpenDocument>

January 2002	.0870	.1324	.1668
July 2002	.0003	.0980	.0630
January 2003	.0996	.2057	.2882
July 2003	.1800	.2910	.4945

As demonstrated by the Chart, below, Connecticut Natural’s natural gas supply prices are consistently lower than Southern Connecticut Natural Gas rates (and those of Yankee Gas) even though Energy East owns both companies. Furthermore, this Chart also reveals the significant variation in natural gas supply rates after the price spike in the winter of 2000-2001, falling significantly in the summer and fall of 2002, but then rising rapidly since then:



New York

New York's Gas Supply Charge (GSC) changes monthly, with an annual reconciliation. The New York Public Service Commission (PSC) has strongly supported the move to retail natural gas competition and instituted competition programs at each NGDC. Pursuant to the Commission's Gas Policy Statement issued in 1998 (and amended in 1999)²³, gas utilities are required to unbundle their rates and limit their acquisition of new capacity contracts, shifting to short-term and citygate arrangements for capacity necessary for system operation and reliability. While the PSC initially anticipated that the gas utilities would exit the merchant function within a relatively short time, this has in fact not occurred. While customer migration to competitive gas supplies has exceeded participation rates for electric generation service, the statewide migration rate for residential customers remains at 7% as of August 2003, a 10% reduction in the last 12 months²⁴. The degree of residential customer shopping varies significantly among the various NGDCs, with largest numbers in Keyspan Energy Delivery of New York and Niagara Mohawk Power Co. Most NGDCs are governed by multi-year performance plans that address the distribution and, in some case, the GSC portion of the customer bill. Each of these plans contains a Service Quality or Customer Service performance mechanism with established baseline performance standards and automatic penalties (in the form of reduced earnings) for the annual failure to achieve the minimum standards during the term of the plan and a company-specific low income bill payment assistance program funded through distribution rates.

New York State Electric & Gas Corp. (NYSEG), an upstate utility owned by Energy East, has operated under a multi-year performance rate plan since 1995 in which most customers enjoyed a rate freeze until October 2002. In late 2002, the PSC approved a rate plan that for the first time has resulted in unbundled customer bills and the use of market based rates for the gas supply portion of the bill beginning in October 2002.²⁵ Distribution rates will remain frozen through 2008. As a result of merger-related savings and a phase-in approach to market-based rates for gas supply service, bills for residential customers were expected to increase gradually until full market based rates will be in effect by the fall of 2003. The settlement also includes a Gas Cost Incentive Mechanism to share savings in gas supply costs as a result of NYSEG and Energy East efficiencies and procurement policies between customers and shareholders. The Gas Supply Guidelines attached to the settlement (Appendix C of the Agreement, attached to the PSC's order) do not discuss procurement policies, but merely describe how the GSC will be calculated. The commodity cost of gas will include a Merchant Function Charge of 16.4 cents per dekatherm, identified as a "proxy" for gas supply uncollectibles and administrative and general expenses typically incurred by marketers in interactions with their customers. The GSC will be calculated monthly and GSC recoveries will be reconciled with actual gas supply expenses on an annual basis. Any adjustment will be included in future GSC statements.

²³ New York PSC, Policy Statement Concerning the future of the Natural Gas Industry in New York State and Order Terminating Capacity Assignment, Case 97-G-1380, November 3, 1998. The Commission clarified some aspects of this order in April 1999. See <http://www.dps.state.ny.us/fileroom/doc4962.pdf> and <http://www.dps.state.ny.us/fileroom/doc5666.pdf>.

²⁴ The New York PSC publishes Gas Retail Access Migration statistics on its website: http://www.dps.state.ny.us/Gas_Migration.htm

²⁵ New York PSC, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of NYSEG for Gas Service, Case 01-G-1668, November 20, 2002, available at <http://www.dps.state.ny.us/fileroom/doc12529.pdf>.

National Fuel Gas Distribution Corp. (NFGC), an upstate utility, also operates under a multi-year rate plan that the Commission recently extended until December 2004.²⁶ This decision recites that Commission's actions in October 2000 to reduce the equity earnings sharing formula in the 1998 rate plan, resulting in a \$19.1 million credit to customers "to ameliorate gas costs that were expected to be much higher than in the prior winter." As a result, customer bills were lower than what might otherwise have occurred. Even so, however, NFGD residential customer bills were the highest in the state in January 2001, averaging about \$480 for 300 therms. These high customer bills were not matched by any other New York gas utility for that period.

Consolidated Edison's most recent three-year rate plan was adopted in April 2002.²⁷ Again, the Commission recites its actions in the winter of 2000-2001 to accelerate the return of some credits to customers to ameliorate high gas supply costs. Distribution rates will be decreased under the plan, but the monthly customer charge was increased. Several changes were made to the Gas Cost Adjustment Mechanism, all of which were designed to enable customers to more clearly compare the gas supply charge on their unbundled bill with marketer offers. The monthly GSC is allowed to differ among customer classes, based on customer load factor (heating versus non-heating, in particular). In this proceeding, the Public Utility Law Project (PULP) raised objections to the lack of any policy to prevent volatile commodity costs from being passed through to residential customers during the term of the plan and asked the Commission to require Consolidated Edison to "set a stable commodity prices as it says NYSEG has done, so that customers can be protected against an unwarranted risk of market price changes." [at 17] Both the PSC Staff and the utility objected to this proposal. The Commission rejected PULP's proposal, stating:

Action in this case with respect to either the company's gas procurement practices or the proposed institution of a stable market price option for Consolidated Edison's full service customers is also not warranted now. Not a single specific gas procurement problem or issue has been raised and no party has outlined a specific stable rate proposal or explained its impacts for our consideration.

At. 27.

The Commission adopted several proposals designed to foster competitive retail choice, including a retail choice credit and ratepayer funding or promotional or educational program funding.²⁸

The following Table presents the NY PSC Gas Supply Cost data²⁹ for four large gas utilities on a per therm basis. This data portrays significant differences in the price of natural gas supply service

²⁶ New York PSC, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of National Fuel Gas Distribution Corp., Case No. 00-G-1858, September 18, 2003, available at: <http://www.dps.state.ny.us/fileroom/doc11550.pdf>

²⁷ New York PSC, Order Concerning Gas Rates, Restructuring, Competition, and other Issues, Case 00-G-1456, April 22, 2002, available at: <http://www.dps.state.ny.us/fileroom/doc11565.pdf>

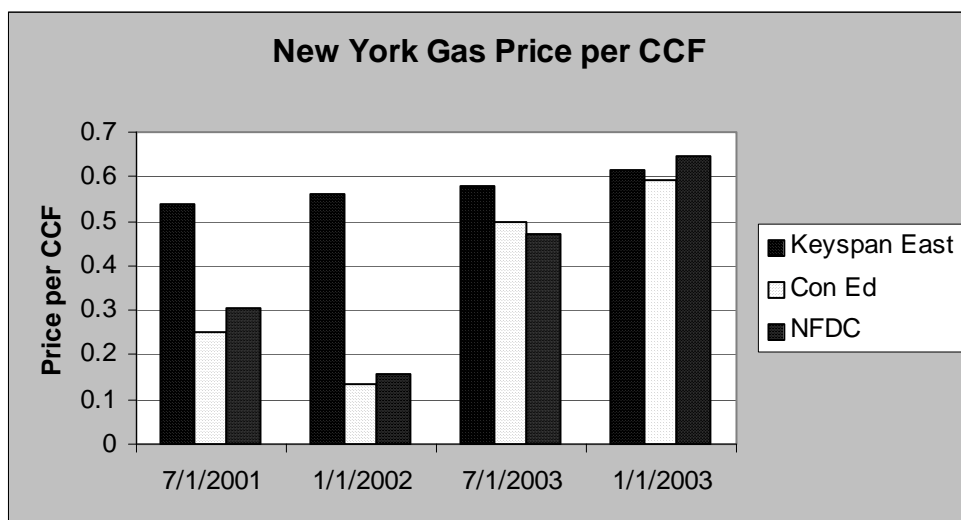
²⁸ While the Commission favorably quoted staff opposition to PULP's stable commodity procurement policy on the grounds that costs would be incurred to implement hedging, thus resulting in higher commodity costs, the Commission does not explain why higher rates to pay for promotional efforts and other costs incurred to implement retail competition choice programs are acceptable.

²⁹ See <http://www.dps.state.ny.us/bills.htm> In addition, PULP has prepared a Table presenting average residential customer bills for all New York gas utilities for the period July 1997-January 2003. This chart confirms the extreme volatility in winter bills for residential customers of Brooklyn Union Gas, Keyspan East (Long Island), NFDC, and Orange and Rockland. See <http://www.pulp.tc>

among the various New York utilities. It is likely that the significant increases in natural gas supply prices for Consolidated Edison in 2002 and NFDC in 2002 were the result of the end of their prior multi-year rate plans or rate freezes. However, the Commission has not discussed in its orders or in public documents any of these wide disparities in prices.

	Keyspan East d/b/a Brooklyn Union of Long Island	Consolidated Edison	NYSEG	NFDC
July 1, 2001	.522534	.244297	Not unbundled	.303920 per ccf
January 1, 2002	.545361	.132962	Not unbundled	.155770 per ccf
July 1, 2002	.563374	.484181	Not unbundled	.469380 per ccf
January 1, 2003	.597356	.575690	.566400	.629800 per therm (change in price presentation as reflected in PSC price charts)

The following chart presents the data in the above table in a uniform Per CCF pricing format. Immediately evident is that Keyspan (Brooklyn Union of Long Island) has consistently had a more stable, but much higher rate for natural gas supply than either Consolidated Edison or NFDC. This is most likely a result of the multi-year performance rate plans in effect for the latter two NGDCs.



New Jersey

New Jersey adopted statewide natural gas (and electric) retail competition for all customer classes in 1999. This resulted in changes in the way the gas supply service is priced and how it appears on customer bills. Basic Gas Supply Service (BGSS) is the label used for the “default” service for non-shopping customers. Since most residential customers have not shopped (as of May 2003, 5.3% residential customers had selected a competitive gas marketer³⁰), the vast majority of such customers receive BGSS. Gas utilities are required to file an annual BGSS filing on June 1st, proposing a BGSS rate to be effective the following October 1- September 30, subject to an annual review and reconciliation. A utility may file for two self-implementing BGSS rate increases, effective December and February. Each self-implementing rate increase is limited to no more than a 5% increase (based on 100 therms). Rates are also subject to a Temperature Adjustment Clause to insulate the utility from the impacts of abnormal weather (based on whether degree days are more or less than a 20-year average). This calculation is based on the October-May time period.

The Board’s Order Approving BGSS Price Structure³¹ rejected proposals to provided BGSS through a competitive process (but the Board has in fact adopted a competitive wholesale bidding approach for the equivalent electric service). Commercial/industrial customers receive monthly BGSS price changes based on the NYMEX spot market prices. Residential and small commercial customers receive periodic BGSS pricing, effective October 1, with the two discretionary rate increases described above. In approving this approach the Board noted favorably the customer benefits associated with “a price structure that is more consistent with market conditions” and the potential for such an approach to enhance retail competition. [at 3] However, the Board also noted that smaller users should be introduced to market-based rates at a more gradual pace, thus approving the approach that will result in a potential for up to three price changes during the year. While this approach contemplates an average price for BGSS based on both supplies bought on the spot market, as well as supplies whose price was previously set by hedges or other financial instruments, the Board’s order does not discuss procurement policies or the role that hedging should play in assuring stable gas supply prices for residential and small commercial customers.

However, the Board’s 2003 decision, Order Adopting Annual BGSS Minimum Filing Requirements Settlements, contains some additional discussion of procurement policies.³² The NGDC annual BGSS filing must include a “hedging” report and a “schedule covering both the reconciliation and projected period which shows monthly gas purchase volume requirements and price hedged volumes broken down into discretionary and non-discretionary hedging objectives.”³³ A plain English explanation in narrative form regarding these hedging activities should be provided.” [At 4]

³⁰ See New Jersey Gas Switching Statistics at <http://www.bpu.state.nj.us/energy/gasSwitchData.shtml>. Most of the residential switchers are South Jersey Gas Co. customers.

³¹ NJ BPU, The Provision of Basic Gas Supply Service Pursuant to the Electric Discount and Energy Competition Act, N.J.S.A. 48:3-49 et.seq., Order Approving BGSS Price Structure, Docket No. GX01050304, December 13, 2002.

³² NJ BPU, Docket No. GR02090702, et seq., June 20, 2003.

³³ Most of the gas utilities are operating under an agreed-upon percent of their portfolio that is hedged (non-discretionary) and a percentage of their portfolio that is subject to, but not required to be hedged (discretionary).

PSE&G has been under a Board requirement since late 2000 to adopt a mixed portfolio approach to its gas supply purchases. The Board's Order approving gas supply price increases in October 2000³⁴ required PSE&G to initiate a mitigation measure as follows:

On or before January 1 of each year, Petitioner shall provide the Board, Staff and the Advocate with its gas purchasing strategy based on a mixed portfolio approach consisting of fixed gas price contracts (both short-term and long-term), storage inventories, financial instruments and spot market purchases. With regard to financial hedging, Petitioner shall include parameters, triggers, and associated costs.

However, the Board's subsequent orders have not discussed or evaluated the gas procurement policies. Instead, for example, PSE&G's proposals to make changes in its BGSS charges have been routinely approved, often accompanied by stipulations that require further filings by the company concerning gas procurement and hedging practices. As a result, there is no publicly available analysis of PSE&G's gas supply procurement practices or the impact of its hedging program.

The Board required the same type of comprehensive hedging program and filing of New Jersey Natural Gas Co. in August 2001 at a time when it approved the recovery of a large under collection balance due from ratepayers in a surcharge that was authorized for three years beginning in December 2001.³⁵ New Jersey Natural Gas Co. claims to be the "lowest cost gas company in New Jersey" as a result of its long term purchasing practices and what pricing data is available for BGSS in New Jersey (see below) suggests that this allegation is correct.³⁶ Recently, the Board resolved several pending proceedings involving the BGSS rate for New Jersey Natural and approved an "omnibus" stipulation that covered the final BGSS rates and recovery methodology for 2000, 2001, and 2002, as well as numerous incentive designed to reward the company and share profits with ratepayers in certain procurement practices.³⁷ Specifically, the Stipulation³⁸ proposed and the Board approved the following factors and clauses concerning the price of natural gas:

- (1) The Gas Cost Recovery factors reflected in the BGSS rate (previously "provisional" 2000, 2001, and 2002 rates approved as final and the after-tax GCR factor within the BGSS rate of \$0.2745 per therm is deemed final for the February-August 2003 period);
- (2) The Gas Cost Under-recovery surcharge and its effect on the Gas Cost Recovery rate (reconciliation);

³⁴ NJ BPU, Order Authorizing Provisional Rates, Docket No. GR00070491, November 1, 2000, at 9.

³⁵ NJ BPU, Decision and Order, Docket Nos. GR99100778, et seq., March 30, 2001.

³⁶ See the 2000-2003 press releases at the New Jersey Natural Gas Co. website:

<http://www2.njresources.com/news/trans/NewsRpt.asp#njng>

³⁷ NJ BPU, Decision and Order Approving Stipulation, Docket Nos. GR99100778, et seq., November 13, 2003, available at the BPU website: http://www.bpu.state.nj.us/wwwroot/energy/GR99100778_20031113.pdf

³⁸ Typically and here, the Stipulation was negotiated and signed by the Board Staff (represented by the Attorney General's office), the Division of the Ratepayer Advocate, and the gas utility.

(3) A variety of incentive programs that “seek to align the objectives of customers and shareholders, while also supporting the State’s public policy goals”:

- a. Off System Sales and Capacity Release incentive program (profits are shared 85/15 between customers and shareholders);
- b. Financial Risk Management program (older “hedging” program);
- c. On-System Interruptible Sales, Transportation and Other Sharing (various incentive sharing programs relating to targeted sales);
- d. Market Development Fund (targeted to assist third party suppliers);
- e. Capacity Reduction and Portfolio Enhancement (older program with profit sharing designed to get rid of older capacity contracts);
- f. Capacity Reliability Incentive (newer program to recognize the need for long term capacity due to lack of development of the retail market);
- g. Storage Incentive (storage-related gains and losses will be shared on a 80/20 percentage basis, as measured by the difference between the actual cost of storage and an agreed upon storage inventory cost benchmark established through NYMEX forward prices for the injection season); and

(4) Weather Normalization Clause (levelizes the impact of colder or warmer weather on customers; operates as a reconciliation with a 3% rate impact cap).

The Board also approved a proposal to establish one or more Fixed Price Commodity Pools to respond to customer desire to locking in a fixed price for gas commodity. Specifically, the utility has committed to develop a “Low-Income Commodity Pool” on a pilot basis that will fix the BGSS price for a one-year period, but only when New Jersey Natural gas offers the available fixed price at a lower rate than the current BGSS rate, thus ensuring that participants will realize savings. This program will be offered on an “opt in” basis to the 17,000 NJNG customers currently receiving Lifeline or LIHEAP benefits. A comparable Non-Low-Income Commodity Pool will also be developed in the future, but without the price restrictions associated with the Low-Income Pool.

The existence of such a wide range of factors and incentive programs suggests that it would be difficult to determine the actual cost of natural gas supply charges at any one point in time.

The following table contains prices for BGSS service for residential customers as derived from the various Board orders. The NJ BPU does not maintain pricing data on its website.

	PSE&G Residential Heating \$ per therm	New Jersey Natural Gas Co. Residential Heating \$ per therm	South Jersey Gas Co. Residential Heating \$ per therm	
December 1999	\$.451973			
January 2000	\$.568173	11/2000: \$2343		
December 2001	\$.703373	\$.5748		
January 2002	\$.55247			
April 2002	\$.597827			
December 2002	\$.597827	\$.5238		
January 2003	\$.662757		\$.6715	
March 2003	+5% increase		5/2003: \$.7867	
August 2003	\$.71854	\$3617	\$.7867	
October 2003	\$.796357	\$.6981	\$.9017	

West Virginia

West Virginia has not adopted retail customer choice for residential customers. The two largest natural gas utilities—Mountaineer Gas Co. (Allegheny Power) and Hope Gas Co. (Dominion) have operated under a variety of performance based rate plans with rate freezes applicable to the entire bill, including the gas supply portion of the rates. During the November 1998-October 2001 incentive rate plan, the customers of Mountaineer Gas saw no rate increase during that period even though the wholesale prices for natural gas increased dramatically in the fall of 2000³⁹. At the time of the frozen rates, residential customers were charged \$6.11 per Mcf, which included a gas supply charge of \$4.361 per Mcf. As part of this agreement, the NGDC assumed the risk of any changes in interstate pipeline rates and charges, but also retained all supplier refunds received during this period. However, that rate freeze is no longer in effect and residential customers currently pay a total gas charge of \$9.680 per Mcf, of which \$7.850 per Mcf is purchased gas cost.

In December 2001, Hope Gas Co. entered into a two-year incentive rate plan (January 2002 through December 2003) with an initial rate increase of 8.3% for residential customer bills, but followed by a two-year rate freeze. This rate case was preceded by a three-year rate freeze that avoided the 2000-2001 price changes. The current rates in effect for residential customers is a total gas cost charge of \$7.687 per Mcf, that includes a commodity price of \$5.07 per Mcf.

The Consumer Advocate Division has entered into these agreements and the Commission has approved them because of the important advantage for residential customers in achieving rate stability. This approach was supported by the PSC Staff, which issued a report in July 2001⁴⁰ that supported the judicious use of hedging. While gas companies routinely relied on spot market purchases through most of the 1990s, flat or stable prices in the wholesale market did not result in any warning signals about the use of this pricing strategy until the winter of 2000/2001. The Staff Report compared various hedging approaches for the November 2000 through March 2001 period using actual data and compared two hedging approaches to spot market prices for each winter beginning in 1992/1993 through 2000/2001. The two hedging scenarios always produced a more stable price structure than reliance on spot markets. In one approach, the utility locked in its winter's gas supply in the five months preceding the winter (i.e., during the April 2000 through September 2000) period. In the other scenario, the utility acquired its winter gas portfolio over a 17-month period preceding the winter (i.e., between April 1999 through September 2000). Even though the author acknowledged that the most significant impact resulted from the comparison between the spot market of 2000/2001 and either hedging strategy, he concluded 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." [At 8]

It is also noteworthy that the author describes Mountaineer Gas' behavior after its entry into the "total rate moratorium." The utility immediately locked in gas costs for the rate moratorium period. In other words, the "Commission had hedged the customers' rates by locking-in a tariff rate." This transferred the risk of high gas prices to the utility who responded with the management decisions to

³⁹ PSC of West Virginia, Mountaineer Gas Co., In the Matter of Rates and Charges on and after November 1, 1998, Case No. 98-0008-G-42T, Commission Order, July 17, 1998.

⁴⁰ Ellis, David, Director of Utilities Division, PSC of West Virginia, "A Report on Natural Gas Pricing and an Evaluation of Opportunities for Price Risk Management Through Various Hedging Options", July 11, 2001. Available at http://www.psc.state.wv.us/Special_Reports/hedging.pdf

reduce that risk. Even though the gas utility was not required to hedge its purchases as a result of the rate agreement, it did so because it no longer had the ability to pass through gas price changes to its customers.

Arkansas

Arkansas has adopted the traditional Purchased Gas Adjustment Clause to govern its natural gas supply costs and has not adopted retail competition for residential and small business customers, although larger customers have access to a transportation service. Since rates have not been formally unbundled, there is a widely acknowledged blending of gas and non-gas related costs in delivery or base rates⁴¹. In any case, customer bills separately show delivery charges and commodity or Purchased Cost of Gas charges. Unlike other states, however, Arkansas natural gas utilities do not publish the actual Purchase Cost of Gas factor in their tariffs, relying on a tariff that describes the process of filing such charges with the Public Service Commission⁴². Unfortunately, the Commission does not publish these rates and charges in an accessible format either. However, the Commission does publish residential customer bill information for natural gas service (total bill) at various usage levels every month⁴³.

While many states reacted to the price spikes and volatility in natural gas supply prices in the winter of 2000-2001 with orders and directives concerning the need for hedging and gas procurement planning designed to achieve more stable natural gas prices for consumers, very few states issued comprehensive rules and specific requirements such as Arkansas. After a public proceeding, several hearings and rounds of testimony or comments, the Arkansas Public Service Commission issued Principles for Gas Procurements Plans of Utilities.⁴⁴ The rules state the policies that should guide the gas utility in developing its gas procurement strategy, require an annual submission of a Gas Supply Portfolio Plan, allows recovery of costs associated with financial risk management instruments, establishes recordkeeping requirements, requires outreach and customer education programs about upcoming winter gas prices, and requires all gas utilities to offer levelized billing or average payment plans for residential and small business customers, as well as assess the demand for and feasibility of a fixed price gas commodity supply option for customers at least once every two years.

With regard to the overall policy that must govern gas procurement activities, the Commission stated:

Each gas utility is expected to take all reasonable and prudent steps necessary to develop a diversified gas supply portfolio. The portfolio should consist of an appropriate combination of different types of gas purchase contracts and/or financial hedging instruments designed to yield an appropriate balance of reliability, reduce volatility and reasonable price. In so doing, each utility should take into consideration various factors including, but not limited to, its particular circumstances, the demographics of its customers, the then-current market projections of both volatility and price, supply/demand estimates, and other relevant information that is available in the industry.

⁴¹ For example, it appears from a review of PSC orders that some gas utilities account for underground storage costs in base or delivery rates and not in the PGA.

⁴² Nor do the utilities state the current PGA on their websites.

⁴³ Available at <http://www.accessarkansas.org/psc/compare-Gas.htm>

⁴⁴ AR PSC, In the Matter of a Notice of Inquiry into whether Arkansas Gas Utilities Should Integrate Gas Price Hedging, Fixed Price Options, and Other Alternative Mechanisms into Gas Procurement Plans, Docket No. 01-023-NOI, June 20, 2001, available at <http://170.94.29.3/rules/rulesnatgasprocureplanrules.pdf>. These principles were then formally adopted as rules on April 19, 2002.

One of the first regulatory proceedings to consider past gas procurement practices, as well as the annual gas procurement plan for the 2003-2004 season is pending in a review of Arkansas Oklahoma Gas Corp. practices.⁴⁵ This proceeding contains the results of a Staff investigation of the utility's procurement practices for the 1997-2001 period, as well as the company's proposed gas procurement plan for the coming gas year. The Arkansas Oklahoma gas procurement plan addresses the following topics in the context of the specific system, demographics, and procurement history of this utility:

1. Natural Gas Environment
2. Utility System Description
3. Markets and Forecasting
 - a. Types of Markets
 - b. Forecasting Models
 - c. Weather Data Collection and Use
 - d. Design Day Forecast
 - e. Design Year Forecast
 - f. Load Factor Calculation
 - g. Forecast Misses in Requirements
 - h. Daily and Hourly Variations in Load
 - i. Summary of Supply Requirements
4. Meeting Supply and Capacity Requirements
 - a. AOG's Preferred Contract Types
 - b. Current Supply Portfolio
 - c. Supply Mix Requirements
5. On System vs Off-System Supplies
6. Peaking Services
 - a. LNG/Propane Air
7. Purchasing of Suppliers
8. Price Stabilization
 - a. Need to Stabilize Prices
 - b. Summer Outlook
 - c. Price Stabilization Tools Available
 - d. Price Stabilization Actions
9. Cost of Gas Forecast
10. WACOG (Cost of Gas) Volatility
11. Customer Options and Education
12. Discussion of Actual vs. Plan for 2002-2003

In its plan (written in May 2003), the utility had this to say about the current natural gas environment:

AOG believes that prices will be driven primarily by weather and emotion for at least the next two years. Deliverability is so closely balanced by demand that changes in weather or weather forecasts now cause extreme swings in prices. AOG believes that we are living on the inelastic part of the demand curve. Open interest in the NYMEX and speculative

⁴⁵ AR PSC, Docket No. 02-179-U, where a Joint Stipulation and Settlement Agreement was filed on August 29, 2003 and is pending before the Commission. As part of this filing, the utility's 2003-2004 gas procurement plan is available.

interest in natural gas increased dramatically in 2002. Trend following speculators coupled with high market requirements will probably exacerbate price swings. As is typical in volatile markets, prices will probably over-react in both directions.

At 3.

The following table shows selected results of the monthly natural gas price comparisons prepared by the Arkansas PSC for the average residential usage for each of the billing months. Because the PSC reports “average bill” information, the actual usage for a particular month changes to reflect the impact of the time of year (winter versus non-winter) and the weather in effect during that particular year. The actual average usage bill for the period in question is reflected in parentheses for each month in question.

	Arkansas Ok. Gas	Arkansas Western Gas Co.	Arkla (Centerpoint Energy)
August 2000 (16-17 ccf)	\$15.53	\$14.06	\$16.35
January 2001 (192-224 ccf)	\$146.25	\$126.20	\$120.72
March 2001 (94-111 ccf)	\$109.93	\$141.61	\$60.99
July 2001 (16 ccf)	\$23.20	\$19.53	\$18.16
January 2002 (147-168 ccf)	\$160.72	\$83.42	\$
March 2002 (110-115 ccf)	\$97.44	\$75.62	\$106.53
July 2002 (16 ccf)	\$18.08	\$16.10	\$18.51

Indiana

Indiana's Utility Regulatory Commission (IURC) and the Indiana Office of the Utility Consumer Counselor have been very active in oversight and regulatory activities with respect to the management and pricing of natural gas supply. While this activity pre-dates the winter of 2000-2001, litigation about natural gas utility portfolio management decisions and hedging practices have escalated since that time. There are three large investor-owned natural gas utilities: NIPSCO (Northern Indiana Public Service Co., owned by NiSource); IGC (Indiana Gas Co., owned by Vectren) and SIGECO (Southern Indiana Gas and Electric Co., owned by Vectren). The state's largest municipally-owned gas utility (Citizens Gas serving Indianapolis) is also regulated by the URC, although other municipally-owned gas utilities have opted out of URC regulation. Together, these four gas utilities represent 90% of the natural gas sales in Indiana.

While Indiana has not adopted state-wide retail natural gas competition for residential customers, the URC has approved one pilot program for the NIPSCO service territory. The NIPSCO program was approved in 1997. While the entire customer base is theoretically eligible to participate, there are enrollment caps of 150,000 for residential customers and 20,000 commercial customers. Actual participation has never been high, but it significantly decreased in 2001 and 2002. In late 2002, NIPSCO made a concerted effort to revitalize the program, but by April 2003 only 51,000 customers were enrolled. Of the five marketers participating in this program, two were not accepting new residential customers.

The gas supply costs of a gas utility are reflected in the traditional Gas Cost Adjustment that is separately stated on customer bills and must be approved by the Commission. While the smaller NGDC's continue to file quarterly GCA adjustments, with an annual true-up, the larger NGDC's have been allowed to make monthly changes. NIPSCO has by far the broadest authority to change the GCA every month pursuant to prevailing market conditions. This authority to change the gas supply price monthly was approved in a 1999 alternative rate plan that supplemented a retail customer choice plan originally approved in 1997. Other large gas utilities are subject to quarterly GCA filings, but have been granted a much more limited authority to "flex" these charges on a monthly basis within a small bandwidth, typically \$1.00 within the original quarterly GCA price estimate.

According to the URC's 2003 Gas Report to the Indiana General Assembly, "In its orders, the Commission has encouraged utilities to explore innovative ways to control gas prices using strategies such as hedging, fixed and ratable purchases and efficient use of storage." Rather than relying on the spot market, the Indiana gas utilities have increased the amount of gas purchased under fixed price or other hedged contracts. The Commission has recognized that this approach does not guarantee that customers will be charged the lowest price for gas at any particular point in time: "More stable gas prices in a volatile market are desirable and generally considered worth the payment of a slight premium."⁴⁶ This policy is supported in part by the statutory obligation imposed on the gas utility to show that it has "made every reasonable effort to acquire long term gas supplies so as to provide gas to its retail customers at the lowest gas cost reasonably possible" [I.C. 8-1-2-42(g)(3)(A)]

In 2001 the IURC reviewed the gas costs incurred by Citizens Gas in its request for a Gas Cost Adjustment for March-May 2001. The Commission accepted a settlement⁴⁷ that resulted in a credit of \$3.38 million to customers, noting that the majority of the commodity purchased by the utility during the

⁴⁶ At 7 and 10. This report is available at the IRC's website: http://www.in.gov/iurc/issues/regflex/rf_natgas_03.pdf

⁴⁷ IN URC, Causes No. 37399-GCA67 through 37399-GCA70, August 8, 2001.

2000-2001 heating season was priced using index (i.e., non-hedged) prices, adjusted for delivery to the utility's city gate. In addition, the utility had some fixed or other structured price agreements, but these were not entered into until prices had already reached extremely high levels. The litigated position of the consumer advocate was that the utility should have purchased a greater portion of the portfolio at fixed or structured price arrangements as it had been previously authorized to do. The following year Citizens Gas filed for a substantially lower GCA (compared to 2001) and sought a Monthly Flex Mechanism whereby it could make monthly changes to its GCA within a certain bandwidth. The resulting Stipulation (approved by the Commission⁴⁸) contained a \$1.00 upwards and downwards limit on the use of the monthly price change (relative to the approved quarterly GCA benchmark estimate). This permission to "flex" the GCA is only applicable to the portion of the gas supply portfolio that is not otherwise hedged as emphasized by the Commission in its discussion of Gas Procurement Principles in its decision approving the Stipulation:

The Parties are committed to a diversified portfolio approach for gas procurement. The initiation of the monthly flex mechanism depends in large part on the Parties' agreement that development of a diversified gas supply portfolio is a reasonable effort—consistent with the goal of obtaining long-term gas supplies at the lowest cost reasonably possible. The Parties agree that reasonable price volatility mitigation efforts may not result in the absolute lowest priced gas being purchased for the period. The Parties further agree that review of Citizens' gas procurement efforts, include price volatility mitigation efforts, shall not be based on "20/20 hindsight" but shall be based on the information, facts and circumstances existing at the time its procurement decisions were made.

Stipulation, Part II(E).

The most controversial case in recent years was the IURC's review of NIPSCO's gas cost adjustment prices passed through to customers in the late winter 2003. This case was litigated and resolved by the Commission⁴⁹ with a \$3.8 million disallowance imposed on the utility after the Commission found that NIPSCO had failed to implement reasonable price mitigation strategies during this time period. Specifically, the Commission found that NIPSCO had purchased almost its entire gas portfolio at spot market prices and did not use fixed priced or other hedged gas contracts for volatility mitigation. Rather, the utility had relied almost entirely on stored gas to limit price volatility and used a storage pricing methodology that passed through the most expensive gas to customers during the high use winter period. These gas portfolio practices were documented as a change from the prior practices of NIPSCO and occurred during a period in which the utility was attempting to stimulate retail gas customer choice by incenting marketers to participate in its service territory, as well as during the time NIPSCO was marketing a fixed price bill option to residential customers at a premium price. NIPSCO's policies and its ability to pass through gas supply price changes on a monthly basis to its customers resulted in March 2003 GCA rates of \$232.06 for a residential customers using 200 therms⁵⁰. The Commission's decision to disallow a portion of the March 2003 gas cost adjustment documented the difference between NIPSCO's gas procurement practices and those followed by other Indiana utilities and the regulatory history of approved fixed price gas supply contracts for other utilities, particularly the decision in 2001

⁴⁸ IN URC, Cause No. 37399-GCA75, September 4, 2002.

⁴⁹ IN URC, Cause No. 41338-GCA4, September 10, 2003.

⁵⁰ The March 2003 GCA was \$.8194 per therm. See http://www.nipSCO.nisource.com/rates/tariffs/g_rates/ccgh.htm

that disallowed \$3.79 million in gas costs for Indiana Gas based on the failure of that utility to enter into any fixed price or other hedged gas in the 2000-2001 period.

It should be noted that in a presentation before the URC on natural gas prices and forecasts for the 2003-2004 winter in July 2003, the NIPSCO representative stated that the company intended to purchase at least 20% of its expected purchases at fixed prices.⁵¹

Indiana annually tracks residential customer bill comparisons for all its utilities as of January 1, but does not distinguish between the gas supply and base rate or distribution portion of the bill.⁵² Over a five-year average (1998-2002), NIPSCO had the highest average residential bill compared to these other large Indiana gas utilities and this trend continued in the January 2003 bill comparisons:

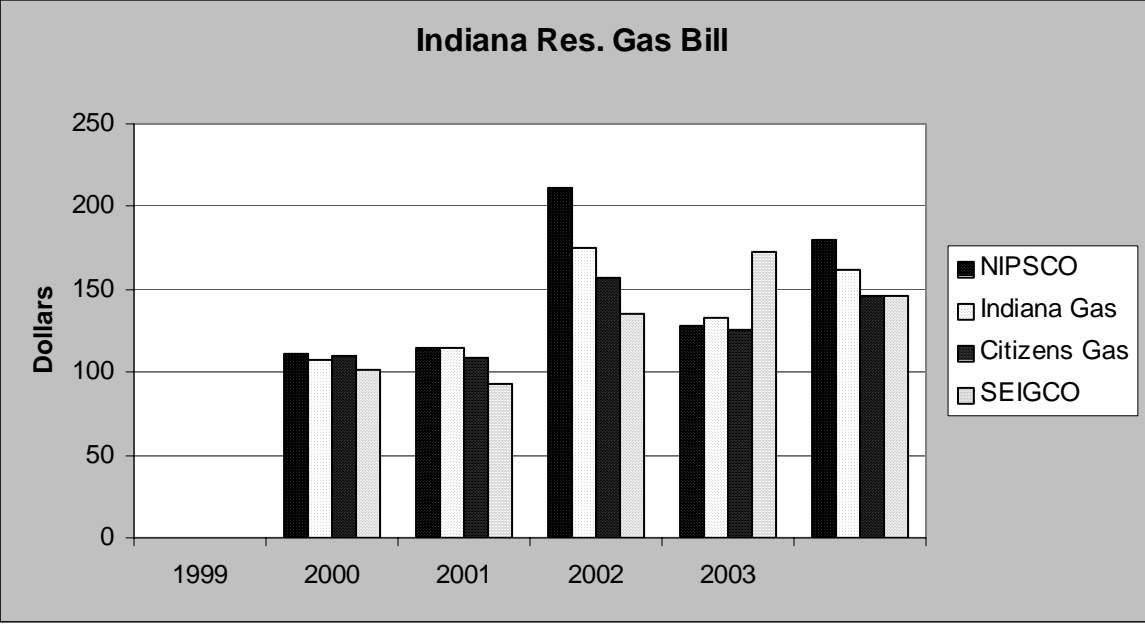
	NIPSCO (Res. 200 therms)	Indiana Gas (Res. 200 therms)	Citizens Gas (Res. 200 therms)	SEIGCO
1999	\$110.55	\$107.62	\$110.30	\$101.12
2000	\$114.53	\$114.46	\$108.58	\$92.94
2001	\$210.91	\$175.40	\$157.44	\$134.82
2002	\$127.81	\$133.22	\$125.92	\$172.41 ⁵³
2003	\$179.35	\$161.32	\$146.66	\$146.42

The following chart presents the data in the table in a format that allows for a better understanding of the differences in natural gas supply prices among the Indiana NGDCs:

⁵¹ All the presentations are available at http://www.in.gov/iurc/utilities/energy/03natgas/03_natgas_index.html

⁵² Available at <http://www.in.gov/iurc/issues/billcomps/index.html>

⁵³ This very high price reflects the utility's previous year's gas supply costs that were approved to be carried over into the next year in an attempt to smooth out "sticker shock."



Michigan

Michigan is the 12th largest natural gas producing state, but still consumes far more than is locally produced. However, Michigan has the largest working gas storage capacity in the nation, equal to more than two-thirds of the state's total usage.⁵⁴ These facts have had a significant impact on the state's natural gas prices overall and its gas portfolio management practices. In January 2003, the average cost of delivered gas to residential customers in Michigan was \$6.13/Mcf, well below the U.S. average of \$8.30/Mcf. While this was a 6% price increase compared to January 2002, it was a modest increase compared to most other jurisdictions.⁵⁵

Michigan has also adopted large-scale retail natural gas competition programs for residential and small commercial customers, but the degree of shopping activity and marketer interest in residential customers varies among gas utilities. As of December 2002, 162,644 residential customers had chosen an alternative gas marketer, but almost all of those customers were served by either Consumers Energy or Michigan Consolidated Gas Co. (MichCon). Approximately 11% of the eligible residential customers have entered the competitive market.

Under the Michigan approach to pricing natural gas supply, each NGDC must submit an annual plan that typically runs from April through the following March. The Commission annually reviews the Gas Cost Recovery Plan and sets a gas cost adjustment level designed to recovery the approved gas supply costs for the forthcoming year, as well as reflect any true up from the prior year's actual purchases and gas costs. As part of this annual filing, the utility also submits a 5-year forecast of the gas supply requirements, sources of supply and projections of gas costs. The utility is obligated to "minimize the cost of gas purchased by the utility."⁵⁶

The Commission's most recent decision concerning Consumers Energy Company's gas cost recovery plan for April 2003-March 2004 approved a stipulation that included a Gas Purchasing Strategy and Guidelines for the Use of Hedging Instruments.⁵⁷ This decision also allowed the utility to make quarterly price adjustment to reflect market price increases, based on a formula that reflects NYMEX 5-day average strip prices (i.e., futures contract prices). The Gas Purchasing Strategy Guidelines establishes fixed price contract target levels of commitment that range from 15%-20% of the expected load during the early period of the recovery period up to 75%-80% of the load by the end of the gas cost recovery period. This is a tiered approach that links the obligation for fixed price contracts to the gradual increase in load relating to heating needs over the summer and fall period. The Guidelines also contain Quartile Fixed Price Triggers, a method of fixing the price of gas on a portion of the utility's annual supply requirements if the current market price is within or below certain historical price ranges or quartiles. The Guidelines for Use of Hedging Instruments addresses the use of "put" and "call" options. Under a "put" option, a supplier will pay a premium to Consumers Energy to sell or put gas to the utility at a specified price at some future date. Under a "call" option, the utility will pay a premium to a supplier to buy or call gas from the supplier at a specific price at a future date in order to protect against rising gas

⁵⁴ MI PSC, Natural Gas Price and Supply Update, July 29, 2003. Available at http://www.michigan.gov/documents/Natgasupd2003Jul11_69868_7.pdf

⁵⁵ *Ibid.*, at 2.

⁵⁶ M.C.L. Chapter 460.6h(3).

⁵⁷ MI PSC, Case No. U-13570, July 8, 2003, available at <http://www.cis.state.mi.us/mpsc/orders/gas/>

prices. The Guidelines limit the use of put and call hedge instruments for a portion of the supply for a GCR period.

The 2003 Gas Cost Recovery Plan of MichCon will rely on acquiring 65% of its supply through fixed price contracts and 35% as purchases indexed to the NYMEX futures market.⁵⁸ This decision was preceded by the 2002 gas cost recovery plan decision⁵⁹ that found imprudent gas procurement practices by the utility and disallowed \$26.5 million. MichCon entered into a multi-year alternative rate plan for the 1999-2001 period that froze its overall price at \$2.95/Mcf. This alternative rate plan also reflected the initiation of the utility’s customer choice plan for residential and small commercial customers. The Commission found that MichCon used storage gas to meet the needs of its sales customers in 2001 rather than purchasing gas to replenish storage volume. As a result, in 2002 the utility had to rely on an increased firm flowing winter supply to meet its service obligation. This need was exacerbated when participation in the customer choice program declined in 2000 and 2001 and MichCon had to obtain additional supplies to meet the returning customer needs. Rather than buy higher priced gas (which would have cost more than the utility was recovering from customers under its fixed rate plan), MichCon relied on relatively low cost gas in storage. In 2002, the rate freeze ended and MichCon went into the market to obtain gas. The Company entered into a fixed price contract in April 2001 for the first quarter 2002 supply requirement. Of course, this action occurred at a time of rapid increases in natural gas supply prices. The Commission’s finding of imprudence was directed to the decision to withdraw so much gas from storage in 2001 and not the fixed price contract itself. As stated by the Commission, “Act 304 was enacted to ensure that the utility, not its customers, is responsible for such ill-advised gas supply decisions.” [Order at 24]

The following table represents the Gas Cost Recovery rates approved by the PSC for residential customers in a per CCF format that allows comparison with the other prices and charts in this report:

	MichCon	Consumers Energy
July 2000	\$.295	
July 2001	\$.295	
July 2002	\$.438	\$.366
July 2003	\$.497	\$.518

⁵⁸ MI PSC, Case No. U-13549, January 21, 2003.

⁵⁹ MI PSC, Case No.U-13060, March 12, 2003.

Ohio

Ohio has adopted a statewide and aggressive customer choice or retail competition program for natural gas service. Initiated in the late 1990's, these programs have expanded in two of the four investor-owned gas utilities. The Columbia Gas of Ohio program has enrolled 42% of residential customers and Dominion East Ohio Gas has enrolled 54% of its residential customers with alternative suppliers. This trend is likely to continue and increase since the Ohio Legislature has adopted a municipal aggregation program for natural gas that is similar to that in place for the Ohio retail electric competition program. It is likely that this enrollment activity is related to the relatively high cost of natural gas paid by customers of these two utilities. As reflected in the Table showing natural gas supply prices for the period January 2001-October 2003, both Columbia Gas and Dominion East have consistently charged higher prices compared to southern gas utilities in Ohio.

It appears that the Ohio PUC has in the past made gas cost recovery decisions based on a formulaic approach and has not imposed or promulgated procurement policies that mandate diversified portfolios, price stability, or hedging. The Commission has initiated a review of its Gas Cost Recovery rules to "make the GCR more reflective of recent events in the natural gas industry relating to price volatility and growth of customer choice."⁶⁰ The issues accompanying the rulemaking review issued by the Commission did not, however, raise concerns about price stability or hedging. Rather, these issues focused on whether the gas cost calculation should reflect weather normalized historical sales as opposed to projected sales and if the gas cost adjustment rules should allow flexibility to make adjustments other than quarterly. Perhaps not surprisingly, the marketers used their opportunity to comment to object to the Commission's approval of a modification of the GCR price or formula in the last two heating seasons that had the impact of smoothing out significant upward swings in prices over a longer period of time (i.e., using the deferral mechanism to allow recovery during the next quarter or over a longer period). The marketers stated, "The better response to addressing unacceptably high levels of GCR adjustments is to make the GCR track the authorized costs better so that the adjustments will be small."⁶¹ This in turn would of course allow marketers to respond to these gas prices with products that may offer price stability or fixed price options to the more volatile utility service. Pursuant to the marketers' view, the utility GCR tariff is a

safety net for those who cannot or do not want to shop. Thus, the GCR tariff service today should be viewed and priced as the provider of last resort service. Customers will come and go to tariff gas as a) they change suppliers; b) their supplier defaults; or c) their retail supply contract terminates without renewal. Since the time horizon for a provider of last resort is one in which changes are not only possible but often will occur on a month to month basis, fixing prices on such a time line is more logical than for in essence for four months at a time—with the inevitable adjustments that will follow.

Joint Marketer Comments at 7.

⁶⁰ Case No. 03-1384-GA-ORD, July 1, 2003, available at the PUCO website by selecting the Orders and Entries database and selecting the week that the order or entry was issued.

⁶¹ Joint Initial Comments on Behalf of The Ohio Gas Marketers' Group and National Energy Marketers Association, Case No. 03-1384-GA-ORD, August 1, 2003.

In fact, all commenters, including most utilities, favored the use of other than quarterly pricing, particularly in times of volatile natural gas prices. Only the Office of Consumer’s Counsel and Dominion Retail favored the continuation of the quarterly GCR price changes. The OCC has also proposed the implementation of a one year pilot with a fixed gas price “...because it seems inappropriate for residential customers to have to rely upon unregulated choice providers to obtain relatively stable rates.” [OCC Comments at 9] Naturally, the suppliers opposed this approach, arguing that “one year fixed gas prices should be available only from suppliers.” [Reply Comments of Energy America, L.L.C. and Shell energy Co., L.L.C. at 4]

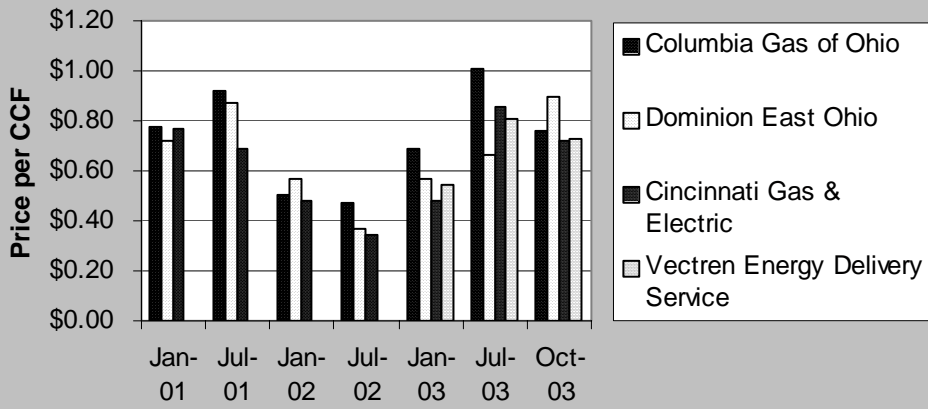
The following table reflects the GCR rates in effect at the stated months for residential customers. These prices (expressed as \$ per ccf) include the applicable Gross Receipts Tax.⁶² Even a casual view of this chart confirms that extreme price volatility of the GCR in Ohio and the price differential between Columbia Gas and Dominion East (where more customers are participating in choice) and the other two gas utilities. Furthermore, these prices are significantly higher than those in Michigan where the utilities have long been under an obligation to rely on fixed price contracts and other hedging instruments to mitigate price volatility.

	Columbia Gas of Ohio	Dominion East Ohio	Cincinnati Gas & Electric	Vectren Energy Delivery Service
January 2001	\$.77387	\$.71760	\$.7666	
July 2001	\$.92309	\$.86990	\$.6887	
January 2002	\$.50534	\$.56476	\$.4800	
July 2002	\$.47369	\$.36464	\$.3437	
January 2003	\$.68640	\$.56696	\$.47834	\$.54185
July 2003	\$1.00837	\$.66630	\$.85421	\$.80709
October 2003	\$.75895	\$.89980	\$.7213	\$.72632

The following chart shows the data in the table in a format that clearly demonstrates the higher rates for natural gas supply in effect for Columbia Gas compared to the other Ohio natural gas utilities. This is likely a key explanation, as well, for the higher rates of customer migration to alternative natural gas suppliers in that service territory:

⁶² These prices are taken from the Ohio PUC’s “Apples to Apples” Natural Gas Comparison Charts” available in the archive of the PUCO website: <http://www.puco.ohio.gov/emplibrary/files/NgA2A/Archive/>

Ohio Gas Cost per CCF



Oregon

Oregon (and other Pacific Northwest states) has historically enjoyed stable and relatively low natural gas prices due to their ability to access cheaper Canadian gas. However, this low cost advantage has been changing as the nation's pipelines have become more integrated and the Northeast and Midwest price and supply difficulties have reverberated in the Northwest. Oregon's approach to the pricing of natural gas supply is quite different from Northeast and Midwest policies. First, Oregon gas utilities file an annual rate change to reflect purchase gas costs. This rate change appears on customer bills as a single cents-per-therm price. The Purchased Gas Adjustment filing sets rates based on projected gas costs for the upcoming year and then also reconciles the prior year's actual gas costs with the PGA in effect during the prior year. With respect to any deferrals that are incurred, NGDCs can either accept at 20/80 percentage sharing (20% to the gas company) with an annual earnings review or accept a 33/67 percentage sharing with no required annual earnings review. While a gas utility can file for a more frequent change in rates to reflect gas costs, this is not typical.

Second, the Oregon PUC has experimented with decoupling policies that seek to break the link between a utility's sales and profits that has the supposed effect of discouraging energy efficiency investments and programs. This is important in a state that has a strong policy of favoring energy efficiency programs as a means of addressing high utility costs and prices. Finally, two of Oregon's NGDCs fund low-income bill payment assistance by means of surcharges on customers' bills and one NGDC has implemented a Public Purpose Funding surcharge to fund energy efficiency programs, market transformation programs, and low-income energy efficiency programs to benefit low-income residential and small commercial customers in its service territory.

Oregon's largest natural gas utility is Northwest Natural Gas Co., which serves over one-half million residential customers. In 2002, the PUC approved a Stipulation that contained a Partial Decoupling Mechanism and an Elasticity Adjustment. These adjustments do not reflect a full scale decoupling mechanism, such as the PUC had approved for PGE and PacifiCorp in the late 1990's. Under the elasticity adjustment, NW Natural will recover, on a prospective basis, an additional charge applied to rates for residential and commercial customers. The purpose of this adjustment is to help account for the affect that rate changes have on customer usage. Under the partial decoupling mechanism, NW Natural will defer and amortize 90% of the margins associated with the difference between each group's weather-normalized usage and usage baseline. Again, this results in an adjustment (positive or negative) included in rates for residential and commercial customers. As of October 2003, the residential rate of \$.92213 per therm includes a Price Elasticity Adjustment of \$.00304 per therm and a Partial Decoupling Mechanism Adjustment of \$.00305 per therm. These decoupling mechanisms were accompanied by stipulated provisions that implemented Public Purpose Funding for low-income bill payment assistance (\$.25 per residential customer per month), low-income weatherization assistance (.25% (one quarter of one percent) of the customer's monthly bill for residential and commercial customers) and enhanced energy efficiency programs (.65%, but recently increased to 1.25%, of the customer's monthly bill for residential and commercial customers). NW Natural also agreed to transfer the responsibility for its energy efficiency, demand-side management program, and energy audits to the Energy Trust of Oregon⁶³, an entity created

⁶³ See <http://www.energytrust.org/>. Subsequent to this Stipulation, the PUC approved a request to allow NW Natural to operate the low income energy efficiency program instead of an external agency, such as Energy Trust. Case UG 143, September 23 2003. The utility will form an advisory committee and implement these programs through local Community Action Program agencies.

to implement the public purpose and renewable programs associated with the electric restructuring legislation in Oregon.

The Commission has also recently approved a weather adjustment mechanism for NW Natural called WARM. The purpose of this adjustment is to true up the NGDC's fixed costs on a monthly basis for each customer during the winter. After a cold month the customer will get a credit reflecting that the per therm rate overcollects fixed costs due to increased usage alone. After a warm month the customer will get a surcharge that reflects the fact that the per therm rate undercollects fixed costs. Customers can individually opt out of this program. The fact that this adjustment operates on a monthly basis makes the connection between the cold or warm weather immediately visible on customer bills, a connection which would not occur if the weather normalization adjustment was included in an annual decoupling mechanism.

Avista Utilities operates under a difference incentive plan called the Natural Gas Benchmark Mechanism⁶⁴. Under this methodology, Avista Utilities prices natural gas based on a consolidated of gas procurement operations under the Company's affiliate, Avista Energy. The methodology reflects short term acquisitions, fixed and hedged contracts, off system sales, and actual transportation and storage costs. This methodology also reflect administrative and general cost savings that are passed through to Oregon customers. Avista is required to enter into a minimum amount of hedged transactions on a schedule that acquires 35% of the annual usage in a staggered schedule beginning in February of each year. This is referred to as the "fixed" portion of the hedged portfolio. In addition, there is a discretionary hedge volume that is triggered under certain market conditions. While gas costs are established on October 1 of each year, deferrals or refunds due to customers as a result of the actual cost of gas incurred monthly are calculated on a monthly basis and reflected in customer rates as a PGA Adjustment at a later time.

While not reflected on customer bills, the Weighted Average Cost of Gas adjustment is reviewed and approved separately by the Commission. The following Table shows the changes ordered for the two largest natural gas utilities as of October 1 of each year, expressed in a per ccf price format to allow for comparisons among the various charts and tables in this report:

⁶⁴ Avista Utilities Tariff, Schedule 464, PUC OR No. 4, available at <http://www.avistautilities.com/prices/rates/>.

	NW Natural ⁶⁵	Avista Utilities ⁶⁶
1999	\$.22961	\$.23667
2000	\$.35775	\$.32438 (October) \$.54666(December)
2001	\$.53910	\$.41880
2002	\$.38758	\$.38587 ((April) \$.32825 (October)
2003	\$.42772	\$.41324

⁶⁵ As provided in NW Natural 2003 PGA filing, Case UG 156, Order No. 03-587, October 2, 2003, page 5.

⁶⁶ As provided in Avista Utilities, 2003 PGA filing, Case No. UG 154, Order No. 03-588, October 1, 2003.

Arizona

Arizona has adopted the traditional Purchased Gas Adjustor clause, which adjusts monthly to reflect changes in the utility's average cost of natural gas over the previous 12 months. The PGA reflects the difference between the base cost of gas (reflected in the utility's base rates as set in the last rate case) and the actual cost of the natural gas commodity. As a result, the PGA itself does not reflect the total cost of natural gas supply.

In 1998, the Arizona Corporation Commission (ACC) adopted the recommendations on gas purchasing policies as reflected in a Staff Report on Purchased Gas Adjustor Mechanisms.⁶⁷ The Commission adopted the following recommendations:

- The NGDCs should pursue longer term, fixed price supply options as a viable option in procuring natural gas supplies. Such an approach will be deemed prudent and reasonable based on the situation at the time the utility entered into the contract. The Staff Report acknowledged that the purchase of longer term fixed price supply contracts for all or a portion of an NGDC's gas supplies would (all else being equal) result in somewhat higher prices compared to spot market prices due to the premium often charged for such longer term fixed price contracts. However, the Commission endorsed the notion of such an approach for at least a portion of the NGDC gas supply because of the consumer value of price stability.
- Price stability is one of the goals of the natural gas procurement process.
- The PGA should be set on the basis of a rolling 12-month average and price changes should be banded so that the new rate for a month is no more than \$.07 per therm [now \$.10 per therm] different than the rate in effect during any of the preceding 12 months.

As a result of this policy, Southwest Gas charges residential customers a total rate of \$.96051 for the first 20 therms and \$.87633 for over 20 therms. This rate is composed of a base rate for distribution services of \$.48762, a base gas cost of \$.37034, a rate adjustment to recover low-income program costs of \$.01194, and a monthly PGA adjustment of \$.09061, effective October 2003.

One advantage of the Arizona approach to pricing natural gas supply costs is that the Commission can alter the imposition or amount of the PGA to provide relief from particularly high gas prices during the winter months when usage spikes. In October 2002, the Commission ordered a "surcharge holiday" for the months of January and February for Citizens Arizona customer gas bills. The Commission then extended the period of time during which the utility could recoup its deferred balance from ratepayers.⁶⁸

⁶⁷ Arizona CC, In the Matter of the Commission Examination of Local Distribution Company Purchased Gas Adjustor Mechanisms, Docket No. G-00000C-98-0568, October 30, 1998.

⁶⁸ See the ACC press release at <http://www.cc.state.az.us/news/pr10-25-02.htm>