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Arizona Corporation Commission
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Docket Control
Arizona Corporation Commission
1200 West Washington Street
Phoenix, AZ 85007

Subject: Docket No. G-01551A-04-0876; Decision No. 68487

Pursuant to Commission Decision No. 68487, dated February 23, 2006, Southwest Gas Corporation (Southwest) hereby submits an original and thirteen (13) copies of its Arizona Gas Procurement Review (Review). This Review includes the gas procurement benchmarking study and a review of available portfolio evaluation software as required to be undertaken by Southwest as a result of the Commission's decision in Southwest's most recent general rate case (Decision No. 68487).

If there are any questions regarding these matters, please contact me at (702) 876-7163.

Respectfully,

Debra S. Jacobson

Debra S. Jacobson
Director, Government & State Regulatory Affairs

Enclosures

c: Ernest Johnson, ACC
Bob Gray, ACC
William Gehlen, ACC
Brian Bozzo, ACC

SOUTHWEST GAS CORPORATION

Docket No. G-01551A-04-0876

Decision No. 68487

ARIZONA GAS PROCUREMENT REVIEW

July 7, 2006

Southwest Gas Corporation

Arizona
Gas Procurement Review

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OVERVIEW

In Decision No. 68487 dated February 23, 2006, the Arizona Corporation Commission (Commission) ordered the Staff to file a report regarding, among other items, the gas procurement practices of Southwest Gas Corporation (Southwest). This report was to be filed no later than 180 days from the date of the decision. The attached information is hereby submitted for Staff's consideration in preparing its report. The focus of this filing is a Natural Gas Procurement Practices and Benchmarking Study prepared by an independent consultant at the request of Southwest. Southwest has also included a Gas Supply Portfolio Financial Hedging Policy and Process Overview which provides Staff additional information regarding Southwest's intent to integrate the use of financial derivative instruments into its existing Arizona Price Stability Program (APSP). The final item included with this filing is a brief report by Southwest outlining its review of various software programs available for use in the annual gas supply portfolio process.

Natural Gas Procurement Practices and Benchmarking Study

The Natural Gas Procurement and Benchmarking Study, included in Tab 1, was prepared by Mr. Ralph E. Miller, an independent consultant with an extensive background in natural gas and electricity procurement practices.

Mr. Miller's qualifications are included as Appendix A to his report. In retaining an established industry expert to prepare this report, Southwest's primary objective was to secure a third-party review of Southwest's gas procurement practices and how they compare to the industry. To meet this objective, Southwest considered several consulting practices. Among the possible candidates were two large public accounting firms with whom Southwest already has well-established relationships. Southwest recently used one of these firms to assist it in creating its financial hedging policy and implementing hedging related software. Although this firm has the expertise to prepare such a study, due to the previous consulting work, the results of any such study may not have been deemed to be completely independent. The other firm was eliminated for similar reasons.

Southwest ultimately selected Ralph Miller to undertake the procurement practice review. Mr. Miller is an industry expert with over 20 years of experience and has previously testified before the Arizona Corporation Commission on behalf of Staff.

Mr. Miller's report covers the essential elements of load forecasting, pipeline capacity acquisition and describes the various gas procurement practices used by Southwest. His report compares Southwest's approach to contemporary industry practices based on his extensive experience. Mr. Miller's review refers to a recent study prepared by the American Gas Association (AGA) covering gas portfolio management during the 2004/2005 winter; the AGA study is attached as

Appendix B to Mr. Miller's report. As part of his discussion on procurement practices, Mr. Miller also describes price risk management strategies and the use of financial derivatives.

Mr. Miller draws a number of conclusions in the report but in summary states "Southwest's purchasing practices are generally consistent with the practices of well-managed gas utilities". The report does not find any deficiencies in Southwest's current portfolio construction practices. The report does discuss and support the addition of limited types of financial instruments to the current APSP for price volatility mitigation. This discussion reinforces efforts that Southwest has undertaken in this area over the last two years to prepare to enhance the APSP tools available for the portfolio. Mr. Miller also discusses how the absence of storage in the market area impacts the design of the Southwest portfolio.

Gas Supply Portfolio – Financial Hedging Policy and Process Overview

Tab 2 of this filing contains an overview of Southwest's financial hedging policy and process. For the past two years, Southwest has been establishing the necessary infrastructure to include financial derivatives in its APSP. To augment the information provided in Mr. Miller's report, Southwest has provided an overview of Southwest's price risk management strategies attendant to its financial hedging policy. Southwest anticipates using derivatives, specifically financial swaps, in the 2007/2008 APSP.

Portfolio Modeling Software Review

Tab 3 includes the report on the review conducted by Southwest on the UPlan-G portfolio optimization model currently in use at Southwest, and its effectiveness relative to other models available in the industry.

For many years Southwest has used the UPlan-G software as a tool to optimize its term gas supply portfolio. At its core, UPlan-G is a linear optimization engine that seeks the lowest cost combination of resources to serve forecasted demand needs. This is highly specialized software designed specifically for the gas industry. The report discusses the general history of Southwest's use of the current model and the types of models available in the industry and their specific purpose(s).

Southwest's review of available industry specific software has reaffirmed that UPlan-G best meets Southwest's needs and that a competing product (trade name "Sendout") does not have substantial additional functionality that would be beneficial in constructing the Southwest annual gas supply portfolio. Southwest has committed to continue to monitor developments in this area and keep Commission Staff informed of this activity.

Southwest Gas Corporation

Natural Gas Procurement Practices and Benchmarking Study

July 2006

Natural Gas Procurement Practices and Benchmarking Study
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Natural Gas Procurement Practices and Benchmarking Study
Prepared for Southwest Gas Corporation
By Ralph E. Miller
July 5, 2006

Introduction and Overview

This report is a review of the gas acquisition practices of Southwest Gas Corporation (Southwest). The Arizona Corporation Commission expressed an interest in this topic in the hearings on Southwest's recent Arizona general rate case, Docket No. G-01551A-04-0876, and in Decision No. 68487 (issued February 23, 2006) it directed Southwest to continue to cooperate with the Commission Staff in Staff's investigation of this topic. Southwest requested the preparation of this report in response to the Commission's interest in this subject, and in furtherance of its cooperation with Staff's continuing investigation of this matter.

The author of this report is Ralph E. Miller. Mr. Miller is a recognized independent expert on natural gas supply, acquisition, and commodity purchasing, and he has been active in this field for more than 25 years. During this period he has reviewed the gas supply arrangements of more than 15 different gas utilities in numerous regulatory proceedings in seven states, and he continues to testify regularly on this subject in three state regulatory jurisdictions. Appendix A to this report contains a more detailed description of his expert qualifications in this area.

Southwest distributes natural gas to 1.6 million customers in Arizona, Nevada, and California. Southwest's total annual throughput in 2005 was approximately 249 million Dekatherms or Dth. This total includes 104 million Dth sold by Southwest to end-users connected to its distribution systems, and a further 145 million Dth that Southwest delivered to customers who purchased their gas supplies from vendors other than Southwest itself. These total system throughput quantities include sales and transportation deliveries to all customer classes including large commercial and special procurement customers.

Southwest's Arizona service territory encompasses central and southern Arizona, which includes the Phoenix and Tucson metropolitan areas. In 2005, Southwest sold 66 million Dth of natural gas to 877,000 end-use customers in Arizona. Southwest's Arizona sales were 63% of Southwest's total gas sales to end-use customers in all three states where Southwest provides gas distribution service.

This principal focus of this report is a review of Southwest's commodity gas procurement practices for its Arizona service territory. Commodity gas procurement is one of three major aspects of the gas supply activities typically conducted by a gas distribution utility, sometimes known as a "local distribution company" or LDC, and more recently in some states as a natural gas distribution company or NGDC.

The two other major aspects of a typical LDC's gas supply activities are load forecasting and capacity acquisition. To provide a proper context for the review of Southwest's commodity gas acquisition practices, this report begins with an overview of Southwest's load forecasting and capacity acquisition for its Arizona service territory. This overview is a description of the load forecasts that Southwest has prepared and the gas supply capacity that Southwest has acquired. It is not intended as an evaluation of the quality of the load forecasts or an assessment of the adequacy or cost of Southwest's portfolio of capacity resources.

Annual planning -- Southwest plans and manages its commodity gas procurement on an annual basis, with each annual period running from November of the current year through October of the following year. The use of an annual gas supply planning period is a standard practice.

In the gas industry, annual planning periods typically begin either in November or in April. November is the start of the winter heating season. April is the start of the "summer" season when utilities having access to seasonal storage resources typically begin their storage injections.

<u>Load Forecasts</u>

Load forecasting is important for commodity gas procurement because an LDC cannot make appropriate gas purchasing decisions unless it knows how much gas it is likely to need, and when it is likely to need that gas delivered.

A complete load forecast generally includes the following components:

- Annual, seasonal, and monthly loads under normal weather conditions

  Commodity gas procurement often involves advance purchase commitments for part of the gas supply that a utility expects to purchase under normal weather conditions. A forecast of the normal weather purchase quantities is needed to establish appropriate levels of advance purchase and hedging commitments.

- Design day, design week, and design winter season loads

  A utility needs to project the loads it is likely to experience under design weather conditions so that it can acquire sufficient gas supply capacity to serve those loads. The utility should also plan its commodity gas procurement to assure a sufficient and reliable supply of gas available for delivery under these design weather conditions. As an adjunct to its development of projected design condition loads, a utility should from time to time review its determination of the design weather conditions on which the design loads are based. Although changes in the range of likely weather conditions occur only slowly and are difficult to measure, a utility should not ignore the possibilities for change.

- Maximum and minimum daily loads that may occur in each calendar month

  The maximum daily load that may occur in any calendar month is the design daily load for that calendar month, and a utility needs to establish it for the same reason that it establishes an annual design day load. The minimum daily load in each calendar month determines the maximum quantity of gas that a utility can appropriately schedule for baseload delivery every day of that month. This maximum baseload quantity also limits a utility's advance commodity purchase commitments.

- No-notice and swing requirements

  For Southwest, as for other gas utilities, daily loads depend upon the weather, especially during the winter heating season. Weather forecasts are never perfectly accurate, and daily loads are also subject to other random influences. A utility must therefore arrange its gas supply activities to accommodate the variance between its actual load on a given day and the load that the utility forecasted when it made it gas purchases and supply nominations on the preceding day. That variance is typically accommodated through the use of a no-notice supply. The utility also needs swing supplies to accommodate differences from one day to the next in the forecasted load level, so that it can schedule or "nominate" its daily supplies to match its forecasted daily loads.

Southwest prepares a comprehensive load forecast analysis annually. The load forecast document includes the first three of the four components identified above: *normal weather projected* loads; design condition loads; and minimum and maximum daily loads in each calendar month. Table 1 shows data from Southwest's most recently completed forecast for its 2006/2007 gas year.

Southwest's swing requirements in each calendar month are simply the difference between the maximum and minimum daily loads for that month, and they are implicitly included in the load forecast. These swing requirements are the range within which Southwest must be prepared to schedule or nominate its daily gas supplies in each calendar month.

As this discussion indicates, Southwest's load forecasting process is complete and comprehensive, and it provides all of the requisite information for Southwest to have an informed commodity gas procurement policy. As noted in the introduction, this report makes no attempt to evaluate the methods that Southwest uses to prepare its load forecast analyses, or to comment on the quality (as opposed to the scope) of the results.

Capacity Acquisition

Southwest maintains a separate portfolio of capacity resources for its Arizona service territory. The shape of this portfolio is determined largely by one overriding factual consideration - at present, all of Southwest's Arizona city gates are connected only to the interstate pipeline facilities of El Paso Natural Gas Company (El Paso, or EPNG), and for most (if not all) of those city gates it would be extremely difficult and expensive to establish connections to other pipelines or sources of gas supply. Southwest's portfolio of capacity resources for its Arizona service territory therefore consists entirely of services provided by El Paso. Southwest has sufficient firm transportation (FT) capacity on El Paso to serve the Arizona design day load indicated in Table 1.

The shape of Southwest's capacity portfolio is further restricted by the relatively narrow range of services provided by El Paso, which does not offer any market-area storage services. Southwest's capacity portfolio for Arizona therefore consists entirely of FT on El Paso from the San Juan and Permian basin gas production areas. Some storage services are available in the production area, but they would not add to or substitute for FT capacity on El Paso, because Southwest would still need FT capacity from the production area to deliver any storage withdrawals, and that capacity could be used equally well to deliver gas supplies that Southwest purchased in the production area. Southwest could perhaps use production-area storage as an adjunct to its commodity supply arrangements, as discussed below; but it is not at this time a relevant capacity resource for Arizona.

Southwest continually reviews the availability of alternative methods for delivering firm gas supplies to Southwest's Arizona city gates. As is appropriate, Southwest analyzes these possibilities to determine whether it could use these new resources to supplement or perhaps replace some of its El Paso FT capacity. The consideration of alternative capacity resources is an important aspect of Southwest's gas supply planning, but it has no direct impact on Southwest's procurement of commodity gas supplies unless and until Southwest is able to acquire some alternative capacity on an economical basis.

Southwest is participating in a proposed Transwestern project that would include the construction of a new lateral from Transwestern's mainline to the Phoenix metropolitan area. If this project is built, service would not begin until the fall of 2008 at the earliest. The Transwestern capacity would provide Southwest with an alternative to El Paso for part of its Arizona load.

Southwest's Commodity Gas Procurement

Southwest maintains a separate portfolio of commodity gas purchases for its Arizona service territory. The shape of this portfolio is illustrated in Table 2, which is a chart showing Southwest's planned Arizona Supply-Demand Balance for the 2005/2006 gas year. Southwest's portfolio for its Arizona commodity purchases has five major components.

- **Fixed price purchases** for the Arizona Price Stability Program (APSP)

  The APSP is designed to help stabilize the gas costs for Southwest's "core customer" residential and small commercial gas sales load. In the past, Southwest has implemented the APSP with fixed price gas purchase contracts having terms ranging up to 12 months. These fixed price contracts have been baseload contracts with must-take provisions. Southwest's fixed price purchases for the APSP were 50% of Southwest's forecasted core customer load of 59 Bcf for the 2005/2006 gas year. Fixed price purchases for the APSP were approximately 61% of Southwest's actual total purchases for the 2004/2005 gas year.

- Term contracts for **firm baseload supplies** — winter season

Southwest also purchases some baseload supplies at prices reflecting current gas market conditions for first-of-the-month purchases. During the winter season, Southwest uses firm contracts with terms up to five months in length to ensure that these supplies will be available. Pricing is index-based. Some of the term contracts for baseload supplies also have limited monthly swing capabilities. Southwest's monthly baseload purchases under its winter season term contracts were approximately 4% of Southwest's total purchases in the 2004/2005 gas year.

- Term contracts for **peaking supplies** — winter season

As indicated in Table 1, there is a very wide range between the highest daily load that may occur in a winter month and the lowest daily load in that same month. Southwest cannot make baseload purchases for more gas than the lowest daily load that may occur during the month, because baseload purchases flow at a constant daily rate for the entire month, but Southwest must still be prepared to serve the highest daily load. To obtain the needed flexibility in its daily purchase quantities, Southwest obtains contracts that allow it to adjust its purchase quantities on a daily basis. The supplies purchased under these contracts are called "peaking supplies." As indicated graphically in Table 2, Southwest relies on its peaking supplies for more than half of the maximum daily load that it prepares to serve in each winter month.

Southwest's contracts for peaking supplies are firm contracts for the winter months. Under each contract, Southwest has the right to nominate a purchase quantity from zero up to the maximum contract quantity on each day. Some of the peaking supplies are shown in Table 2 as "Late Cycle Peaking" because they are purchased under contracts that allow Southwest to adjust its daily nomination after the gas day has begun. These "intra-day" nominations enable Southwest to respond to weather and other load changes as they occur, even within a single gas day.

Southwest's contracts for peaking supplies have index-based commodity charges, often accompanied by demand or inventory charges to support the swing features.

For the 2004/2005 gas year, Southwest used its peaking contracts for approximately 16% of its total commodity purchases. The commodity volume of Southwest's peaking supplies is much smaller than the commodity volume of Southwest's APSP and other baseload supplies (64%, as noted above), despite Southwest's reliance on peaking supplies for more than half of its daily supply availability, because the actual load on most days is much closer to the minimum load served with baseload contracts than it is to the maximum daily load that Southwest is prepared to serve. Southwest therefore uses its peaking contracts at a low load factor, whereas the baseload contracts are — by definition — used at a 100% load factor in each month.

- Monthly **baseload supplies** purchased at current (**spot**) prices — summer

During the summer, Southwest purchases some baseload supplies at current market prices (in addition to the fixed price purchases in the APSP) under one-month contracts. These monthly baseload purchases are included in the "Spot" supply category in the chart in Table 2. Southwest's baseload supplies in the summer months were approximately 11% of Southwest's total purchases in the 2004/2005 gas year.

- Daily **spot purchases** for swing supplies — summer

During the summer, when daily load variations are not so large as in the winter months, Southwest matches its daily supply to its daily loads by making daily purchases in the spot market. Southwest makes some of these purchases at negotiated (fixed) prices, and some at index-based prices. Daily spot purchases were about 8% of Southwest's total purchases in the 2004/2005 gas year.

Term Structure of Southwest's Portfolio

Southwest obtains term contracts for all of the commodity gas supplies that it purchases during the winter season, but it relies on monthly and daily purchases in the spot market for about half of the gas it purchases during the summer season. These arrangements are consistent with the practice of other LDCs. A useful report of the purchasing practices of other LDCs is the American Gas Association (AGA) annual survey of the winter season gas commodity purchasing arrangements used by its members. The AGA published its report of the 2005 survey on July 19, 2005 as Energy Analysis report EA 2005-01, "LDC Supply Portfolio Management during the 2004-2005 Winter Heating Season" (*2005 AGA Survey*). This report is attached as Appendix B.

In the *2005 AGA Survey,* slightly more than half the respondents indicated that they did not obtain any of their gas supplies for the peak month using monthly or daily contracts, which indicates that reliance on term contracts (more than one month) is the standard industry practice for the winter season. The *2005 AGA Survey* did not collect data on the term structure of commodity purchase arrangements for the summer season, but a reduced reliance on term contracts for summer purchases is typical of LDCs with which the author is familiar.

Baseload and Daily Purchases

Southwest's reliance on extensive use of peaking supplies (in winter) and daily spot purchases (in summer) is atypical, but it is a direct and necessary consequence of Southwest's portfolio of capacity resources. Most LDCs use storage withdrawals as the primary "swing" supply in the winter, and they do not require large day-to-day variations in their purchase quantities. In summer, they achieve the same stability of daily purchase quantities by swinging their storage injections up on days when loads are relatively low, and swinging injections down on days when loads are higher. Southwest cannot use this portfolio strategy because currently there are no operating natural gas storage facilities serving Southwest's Arizona market area.[1]

Southwest could purchase production-area storage. If Southwest did so, it could reduce its use of peaking supplies in winter and daily purchases in summer, and instead increase its baseload purchases during the summer. Southwest's total winter purchase quantity would decrease, because storage withdrawals would replace some of the purchases, and Southwest's total summer purchases would increase despite the reduction in daily spot purchases. Southwest has analyzed production-area storage proposals in the past, and it has found them to be uneconomic because the price of the storage service exceeds the commodity cost savings that it would have permitted. Most other LDCs have market-area storage, and it provides the added benefit of reduced pipeline transportation capacity costs that Southwest cannot achieve with production-area storage, as explained in the discussion of Southwest's capacity.

Pricing Arrangements for Baseload Purchases

Baseload purchases are purchases that flow at a constant daily rate for an entire month. Southwest, like other gas utilities, makes some baseload purchases on a monthly basis. Southwest also makes some baseload purchases under contracts that extend for more than one month. Contracts that extend for two or more months, up to 12 months, can be called intermediate-term baseload purchases, and they are a staple of Southwest's APSP. Baseload purchases extending for terms longer than one year are long-term purchases. Southwest does not generally make long-term baseload purchases, but Southwest does make intermediate-term baseload purchases at fixed prices for the APSP, with the gas to be delivered as far as 24 months into the future.[2]

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[1] While several Arizona market-area storage projects have been proposed, including two projects from El Paso, none have successfully been developed. Southwest continues to review storage and other infrastructure projects in Arizona for inclusion in its mix of resources.

[2] For example, Southwest might purchase gas in the summer of 2006 for delivery during the winter months December 2007 through February 2008. The term length of such a contract would be only three months, so it would be an intermediate-term contract, but the delivery dates would be approximately 18 months after the contract was negotiated.

Several different pricing arrangements are available for baseload purchases. One method is for Southwest to establish a fixed purchase price with the seller.

A second method is for Southwest to establish a "basis" component of the total price with the seller, and then add the NYMEX component of the total price reflecting the current NYMEX price for the applicable futures contract. The "basis" component of the total price is the difference between the price at Henry Hub in Louisiana, which is the location where physical volumes purchased under NYMEX futures contracts are actually delivered, and the location at which Southwest wishes to make its actual purchase. Basis differentials thus represent the local market conditions that affect the price of gas at specific locations where gas is purchased. Most gas purchase transactions are priced by combining a basis differential with a NYMEX component, either explicitly or implicitly.

If Southwest and the seller fix the NYMEX component of the total price at the same time they agree on the basis, the purchase becomes, in effect, a fixed price purchase. Alternatively, the parties can agree that the NYMEX component will be the settlement price on the last day the applicable month's NYMEX futures contract is traded, or they can establish some other formula for setting the NYMEX component of the total price. A variation on this arrangement is to complete the purchase with a fixed basis and a floating NYMEX component, but allow Southwest to "trigger" the NYMEX component at any time on the basis of the NYMEX price of the applicable month's futures contract at the time of the triggering.

A third major pricing method is index-based pricing. With index-based pricing, Southwest and the seller would agree that the purchase price will be based on a specific published index for first-of-the-month purchases at a specific location, such as the Bondad receipt point on El Paso in the San Juan basin production area. The actual purchase price could be agreed to be the published index, or it could be the index plus or minus a relatively small amount (typically up to a few cents per Dth) agreed upon in the purchase negotiations or obtained as a result of a competitive solicitation by Southwest for index-based bids.

Southwest uses all three of these major pricing methods, making some of its baseload purchases under each method. Some use of fixed prices or NYMEX-based pricing methods is important because these methods provide greater flexibility and an opportunity for Southwest to diversify the times at which its prices -- and especially their NYMEX component -- are established. When Southwest makes an index-based purchase, it must accept a price that is not yet known at the time Southwest commits to the purchase, and the index price that is eventually published will represent gas market conditions on the last trading day or during the last few days of the month prior to the one when the gas flows. The *2005 AGA Survey* indicates that index-based pricing is the principal pricing arrangement used by LDCs for monthly purchases. Southwest's reliance on fixed price contracts for most of its baseload purchases is a direct consequence of the relatively large size of the APSP, which is discussed below as an aspect of Southwest's price risk management arrangements.

In procuring baseload commodity gas supplies, it is important for the utility to engage in a competitive process, and Southwest does so. Southwest uses bid solicitations to obtain the best (*i.e.,* lowest) basis for its fixed price purchases, including those under the APSP. Southwest uses informal solicitations or the Intercontinental Exchange (ICE) trading platform to obtain NYMEX-based or index-based contracts for its monthly purchases. These procurement methods are consistent with the practices of other gas utilities.

Pricing Arrangements for Swing and Daily Spot Purchases

A swing purchase is a purchase contract covering one or more months, but with a contractual right for Southwest to nominate or change the purchase quantity on a daily basis. Southwest calls its swing purchases "peaking supplies," and that is the rubric under which they have been identified as part of Southwest's portfolio for its winter season purchases.

A daily purchase is a purchase of gas supplies to be delivered on a single day, or sometimes for more than one day but less than an entire calendar month. The difference between a swing purchase and a daily purchase is that the swing purchase contract is arranged in advance, whereas a daily purchase is arranged on an *ad hoc* basis when Southwest is ready to purchase the gas, typically the day ahead of the day the gas is to be delivered.

Two pricing arrangements are available for daily purchases -- fixed prices, and index-based prices. They are similar to the fixed price and index-based pricing arrangements for baseload purchases. The only important difference is that index-based prices for daily purchases are related to a published index of daily gas transaction prices, whereas the index-based prices for baseload purchases are related to published indexes of first-of-the-month prices. NYMEX-based pricing is not available for daily purchases because the NYMEX trades gas futures contracts only for baseload monthly purchases.

Southwest uses both of the available pricing methods for its daily purchases, sometimes negotiating a set or fixed price, and sometimes purchasing at an index-based price. This practice is consistent with the practices of other gas utilities.

The commodity pricing arrangement for swing purchases is generally index-based. Fixed price arrangements are not generally available because a swing purchase contract is, in effect, an option -- but not an obligation -- for Southwest to purchase gas on any day of the month or months covered by the swing purchase contract. If the price were fixed in advance, Southwest would exercise its option to nominate the full purchase quantity on days when the market price exceeded the contract price, causing a loss for the seller. On days when the market price was less than the swing contract fixed price, Southwest would not nominate any swing contract purchases, and would instead make a daily purchase in the market. The use of index-based pricing assures that Southwest will each day pay a price bearing some relationship to the market value of the gas that it nominates for purchase under the swing contract.

Southwest obtains swing purchase contracts sufficient to provide the daily supplies that it will need during the winter season, to ensure that these swing supplies are available when and as needed, especially on cold days. As explained above, this arrangement is consistent with the practice of other gas utilities. Swing purchase contracts often involve modest demand charges to compensate the seller for standing ready to provide the full contract quantity every day of the contract term, even though the seller has no assurance that it will actually sell any gas because Southwest can choose to nominate zero purchases every day. Swing contracts may also have small commodity price premiums above the published index for any quantities actually nominated. Southwest uses solicitations to obtain the best available terms -- lowest demand charges, and smallest commodity price premiums -- for its swing purchase contracts. The use of solicitations is consistent with the practice of other gas utilities.

<u>**Price Risk Management and the Arizona Price Stability Program**</u>

Price risk management is an attempt to avoid the unexpectedly high purchased gas costs that occur when gas prices reach unexpected heights. Price risk management necessarily involves some costs, because there is no "free lunch" in the market for natural gas. The most common way of "paying" for price risk management is by sacrificing some of the opportunity to benefit from unexpected gas price decreases. Price risk management is not -- and cannot be -- a strategy to achieve uniformly lower gas costs under all market conditions, because there is no such magic strategy.

Southwest manages its gas price risks by purchasing approximately half of its projected normal weather requirements under fixed price contracts with prices established (*i.e.,* fixed or set) up to 24 months in advance of the time Southwest receives the gas. Southwest thus avoids the risk of <u>unexpected</u> gas price increases on half of its purchases, because the prices for those purchases are fixed -- and therefore known -- in advance. But this arrangement also sacrifices the opportunity to gain from any unexpected gas price decreases on those same fixed price purchases. The effect of this fixed price purchase program is therefore to provide some stability for Southwest's purchased gas costs, and the fixed price purchase program is aptly called the Arizona Price Stability Program, or APSP.

As noted above, price stabilization does not achieve uniformly lower gas costs. But it does tend to reduce gas costs in a rising gas market. The price that Southwest pays for its fixed price purchases reflects the gas market conditions at the time the fixed price contract was established, which is (on average) about 12 months before the gas is received. In a rising gas market, prices from last year are lower than current prices, and a price stability program thus achieves lower purchased gas costs. But in a falling market, a price stability program tends to yield higher prices, because the benefit of the falling prices cannot immediately affect the supplies already purchased in advance of delivery under fixed price contracts.

The evaluation of Southwest's APSP involves three principal issues. The first is the size of the program, which for Southwest is approximately half of its projected total normal weather requirements. The second is Southwest's decision to fix the prices of some gas purchases in advance of delivery, rather than use other possible price risk management strategies. The third is Southwest's use of fixed price purchase contracts as the instruments for fixing the price of the purchases included in the APSP.

Size of the APSP -- Southwest's use of price protection for 50% of its projected annual purchases is towards the high end of the spectrum of typical commodity purchasing practices. A more typical strategy is to obtain price protection (using fixed price purchases, financial instruments, or a combination) for approximately 50% of the planned normal weather flowing gas purchases in the winter season, with less price protection (often none) for gas purchased in the summer season. Fixed price purchase programs that apply only or primarily to the winter season are common in Maryland, Michigan, and Pennsylvania, and only in Michigan is the fixed price purchase target typically set as high as 50% of projected normal weather purchases in the winter season. The *2005 AGA Survey* reports that fewer than half of the respondents used fixed prices for any of their purchases under long-term or mid-term contracts, and only one-fourth used fixed prices for at least 25% of their mid-term contract purchases. On the other hand, the same survey also indicated that 70% of the respondents used financial instruments to hedge some of their purchases for the 2004-2005 winter season, and almost half of all the respondents hedged up to 50% of their winter purchases.

The relatively large size of Southwest's APSP reflects Southwest's atypical commodity supply situation, which is in turn a direct consequence of Southwest's lack of seasonal gas storage resources in its gas supply portfolio. Other gas utilities automatically obtain greater pricing diversity than Southwest because their commodity purchases are spread more evenly throughout the year than Southwest's purchases. They obtain this diversity by purchasing part of their winter delivery requirements in the summer months and injecting those summer purchases into seasonal storage. Seasonal storage also improves price stability for supplies used during the winter season, because the cost of gas in storage is established at the time it is injected and therefore known before the winter season begins. Southwest's purchases, in contrast, are concentrated in the winter season because they must match Southwest's seasonal load pattern. Southwest's extensive use of fixed price purchases, in both the summer and winter, helps to offset the absence of storage resources.

Alternative price risk management strategies -- Southwest's use of fixed price purchase arrangements is not the only possible way to manage price risk. The principal alternative is the purchase of call options. The holder of a call option has the right -- but not the obligation -- to purchase gas at the "strike price" of the option. The advantage of a call option is that the holder can benefit from any unexpected gas price decreases, whereas the holder of a fixed price purchase arrangement is obligated to purchase gas at the price fixed in advance, even if market prices decline between the time the price is fixed and the time the gas is to be delivered. The disadvantage of a call option is that it involves an up-front (and non-refundable) cost to purchase the option itself.

When an LDC uses call options for risk management, it typically uses them to protect against large, and therefore unlikely, gas price increases. It is therefore common for most of an LDC's call options to expire without being exercised, but that does not mean that the LDC's initial purchase of its call options was unwarranted.

An alternative way to offset the cost of purchasing a call option is to write (*i.e.*, sell) a "put" option. A put option obligates the writer to purchase gas at the specified strike price if the holder of the option chooses to exercise it, but the writer of the option has no right to demand that gas. The combination of a put option and a call option is called a gas price "collar." For example, if the NYMEX futures price for gas to be delivered in February 2008 is $10.00 per Dth, an LDC could purchase a call option with a strike price of $11.50 and write a put option with a strike price of $9.00 per Dth. The LDC would end up paying the market price if it remained in the range between $9.00 and $11.50 per Dth; but it would exercise its call option and pay only $11.50 if the market price rose above that level; and it would be obligated to purchase at $9.00 if the market price fell below that level. The LDC's purchase price would be collared in the range from $9.00 to $11.50 per Dth.

When the cost of a call is completely offset by the proceeds from the sale of a put, it is called a "costless collar." Costless collars are typically asymmetric relative to prevailing market prices and, as a result, they require the consumer to bear more upside price risk than the potential benefit from falling prices. For example, if the NYMEX futures price for gas to be delivered in January was $12.00 per Dth, a costless collar may result in a range of $11.50 to $15.00. The LDC could participate in falling prices up to $0.50 per Dth but would be exposed to price increases up to $3.00 per Dth. Under present gas market conditions, collars that are reasonably symmetric around the current NYMEX futures price still require a cash outlay by the LDC, because the price (cost) of the call option exceeds the sales price received by the LDC for the put option. Even with an asymmetric collar, like the asymmetric example in the preceding paragraph (with the put option strike price closer to the current NYMEX futures price than the call option strike price), reasonably structured collars tend to involve an up-front purchase cost.

The opinion of the author is that an LDC should use fixed price purchase arrangements as the foundation for its price risk management program. The use of call options or collars is not necessary. If an LDC uses them, it should only be as a relatively small supplement to a fixed price purchase program. The only advantage of a call option is that it preserves the opportunity to benefit from gas price decreases. But if an LDC does not have any fixed price contracts, then it will obtain the benefit of any gas price decreases on 100% of its purchases. Sacrificing part of this benefit by entering into some fixed price purchase arrangements is the least painful way to pay for protection against the risk of gas price increases, and in the author's view it is far better than incurring an out-of-pocket cost for protection. On the other hand, if an LDC already has fixed the prices for a substantial portion of its projected purchases, then it has obtained its upside price protection by trading away the opportunity to benefit from any price decreases on those purchases. If further protection against upward price movements on an even larger fraction of the projected purchases is desired, such protection may justify the use of call options.

The author is not aware of any compilations or reports of the extent to which gas utilities use call options or collars (as opposed to fixed price purchase arrangements) for price risk management. In the author's experience, LDCs that use call options or collars do so for only a relatively small fraction of their projected purchases, typically around 10% or less. All of the LDCs that obtain price protection for as much as one-fourth of their winter purchases use fixed price purchase arrangements as their primary price risk management strategy.

Price risk management tools, and the use of financial instruments instead of fixed price purchase contracts -- Fixed price purchase contracts are not the only way for an LDC to establish fixed price gas purchase arrangements. Alternatives include various financial instruments that hedge future purchase prices in ways that enable Southwest to achieve the same result as it would with a fixed price gas purchase contract. For example, some financial intermediaries and other gas market participants will "sell" the to-be-published index price for some future month (such as February 2008) at a specified purchase location (such as the Bondad receipt point on El Paso in the San Juan basin production area) for a fixed price. If Southwest purchases this "swap" as a hedge against a future gas purchase, it has the same effect as entering into a fixed price contract now for delivery of the gas in the specified future month. Southwest pays the published index price for its actual purchase, but it receives the same published index price from its swap arrangement and pays the fixed price that it obtained when it first entered into the swap transaction.

Another alternative is the use of NYMEX futures contracts as hedges. Instead of purchasing the gas that it actually plans to receive in a future month, Southwest can purchase a NYMEX futures contract for the delivery of a corresponding quantity of gas at Henry Hub in Louisiana, which is the physical delivery point associated with all NYMEX gas futures contracts. Then, when Southwest purchases the gas that it actually plans to receive, typically in the week or two before the month when the gas is to be delivered, Southwest sells the NYMEX contract at the same time. Southwest's net cost from the two transactions is the cost of its actual purchase, less the sales price of the NYMEX on the same day as Southwest's actual purchase, plus the price at which Southwest originally purchased the NYMEX futures contract. The difference between the first two of these three components is the so-called "basis" for the location where Southwest actually purchases its gas (relative to Henry Hub), so Southwest's total cost for the purchase is the original cost of the NYMEX futures contract plus the current basis at Southwest's actual purchase location, typically in the Permian or San Juan basin gas production areas. The NYMEX futures contract is a good hedge against this purchase price because the basis differentials for the Permian and San Juan basin production area receipt points are subject to much less market price fluctuation than the NYMEX itself, so the purchase of a NYMEX futures contract removes most of the price risk from the future purchase of gas even in the Permian or San Juan basins. To "perfect" the hedging arrangement, Southwest could use a "basis swap" to lock in the basis differential between the NYMEX contract and the market area, in this case the Permian or San Juan basin. The basis swap protects against a basis blowout where prices in the purchase area rise much more than the NYMEX contract. A good example occurred during the winter of 2000-2001, when gas prices at the California border were significantly more volatile than at the Henry Hub.

Southwest is considering the use of financial instruments such as NYMEX futures contracts and swaps instead of fixed price purchase contracts for at least part of the APSP. If Southwest makes this change, the price hedging arrangements for the APSP would be divorced from the commodity purchases being hedged, and the commodity purchases for the APSP volumes would be moved into one or more of the other categories of Southwest's commodity purchases. A change in this direction is consistent with the practices being adopted by some of the more forward-looking LDCs at this time. The *2005 AGA Survey* indicated that slightly more than one-fourth of the respondents used swaps and slightly less than one-fourth used NYMEX futures contracts as hedges for some of their 2004-2005 winter purchases. These figures probably overstate the use of hedges to achieve the equivalent of fixed price purchases because some LDCs may have responded affirmatively as using both swaps and NYMEX futures, and some of the respondents may have been using swaps for purposes other than achieving the equivalent of fixed price purchases.

In the author's experience, several LDCs have within the past two years adopted or proposed plans to use financial instruments rather than fixed price gas purchase contracts to hedge their future purchases and achieve the equivalent of fixed price purchases. The author has generally supported these proposals in the proceedings in which they have been presented.

Financial instruments have two advantages over fixed price gas purchase contracts as price hedges. The first is that a fixed price gas purchase contract can only be used to purchase baseload supplies that flow at a uniform daily rate throughout the delivery month. Financial instruments, in contrast, can also be used to hedge swing or peaking supplies, because the hedging arrangements are divorced from the actual gas purchase contract. Of course, the financial instrument hedges only the first-of-the-month price, and the LDC is still subject to the risk of daily price fluctuations during the month.

The second advantage of using financial instruments is that it can help to reduce the risk of counter-party default. With a fixed price gas purchase contract, Southwest is dependent upon the survival and eventual performance of the seller. If Southwest uses NYMEX futures contracts for its hedges, then the counter-party bearing the performance risk is the NYMEX itself, which is most likely a safer arrangement than a fixed price gas purchase contract. Even with a swap, Southwest probably has the opportunity to be more selective about the identity of the counter-party than with a fixed price gas purchase contract.

Summary and Conclusion

Southwest's purchasing practices are generally consistent with the practices of well-managed gas utilities. Southwest employs a variety of different gas purchase contract term lengths, contract "shapes," pricing arrangements, and risk management tools for its commodity gas purchases. Some of Southwest's purchases are for terms as short as one day, others for terms as long as 12 months. Some of the purchases with terms of one or more months are baseload purchase contracts; others have swing provisions for Southwest's peaking supplies.

Southwest uses a competitive bidding process to secure fixed price and term contracts. Term supplies are obtained through an annual solicitation process which encourages the participation of a broad base of suppliers. Fixed price purchases for the APSP are acquired on a periodic basis, generally every four to six weeks, through a competitive bidding process. Southwest secures spot supplies through informal solicitations via the telephone or electronic medium (like email or instant messaging) or the ICE trading platform. All of these procurement methods are consistent with the practices of other gas utilities.

Southwest manages gas price risks through its APSP. In the APSP, Southwest purchases half of its commodity supplies under fixed price arrangements established at least a month in advance of the delivery date for the gas, and it arranges some of its fixed price purchases as much as 24 months in advance of delivery. Southwest's use of a price risk management strategy is consistent with the practice of most other gas utilities, but not all utilities make such extensive use of fixed price contracts. The large size of Southwest's APSP relative to other gas utilities is due to the lack of storage resources in Southwest's portfolio. Production-area storage would not benefit Southwest operationally, and at present there are no market-area storage facilities available to serve Arizona.

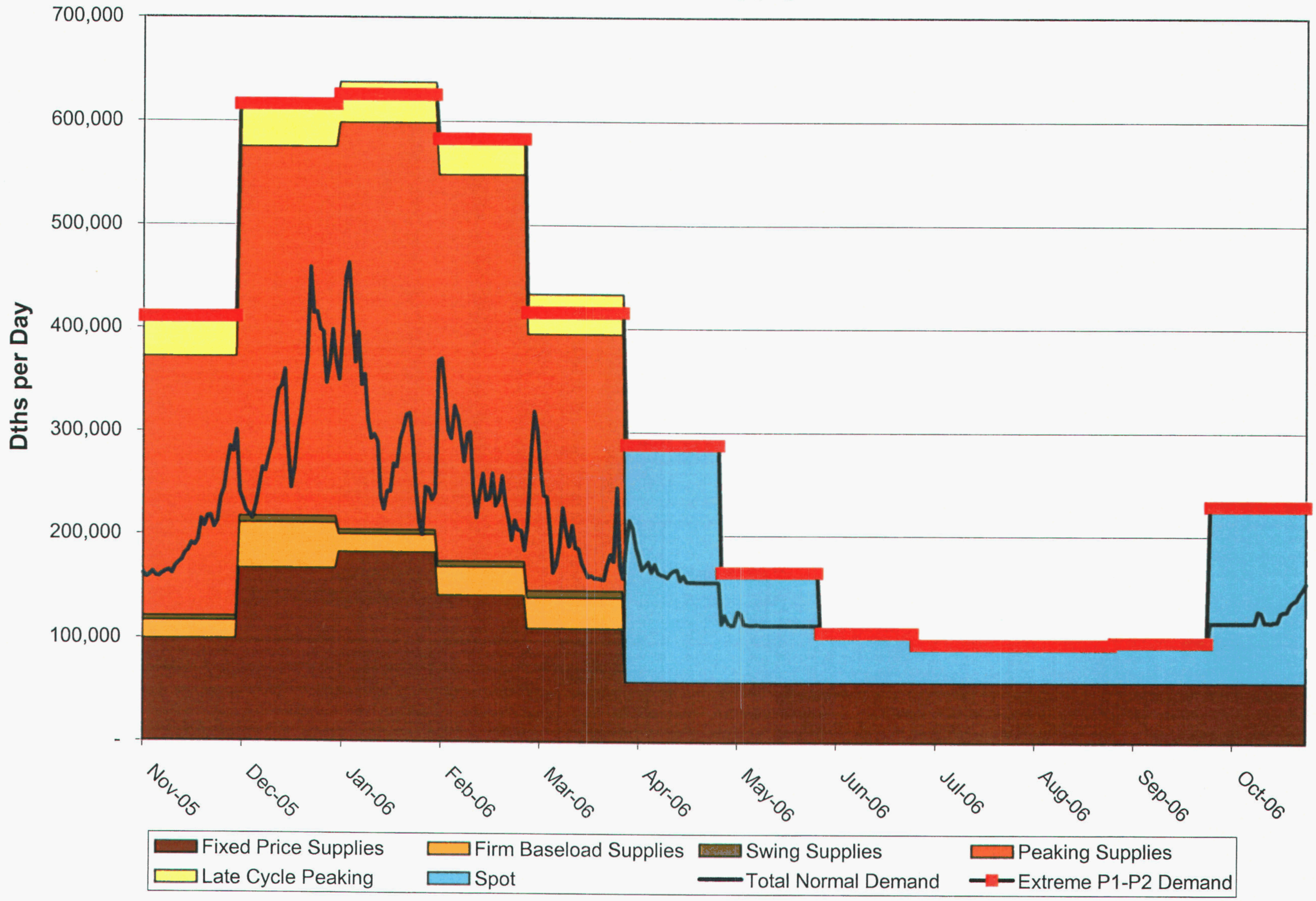
In the future, Southwest may wish to expand its APSP to include the use of financial instruments along with fixed price contracts. Some common instruments include price swaps, put and call options, NYMEX future contracts, and basis swaps. The use of these instruments, in a properly structured risk management program, may help Southwest to further reduce the short-term price volatility in its supply portfolio.

The other half of Southwest's purchases use pricing arrangements that reflect current gas market conditions at the time the gas is delivered. Southwest negotiates the prices for some of those current purchases, and it uses index-based pricing for other purchases. Southwest determines the relative importance of each of these different constituents of its commodity gas portfolio to match the loads that it serves at the best cost available within the constraints of the portfolio of pipeline transportation resources that Southwest uses to bring its commodity gas purchases to its Arizona city gates.

Table 1 - Projected Normal Weather Loads, November 2006 – October 2007
Southwest Gas Corporation, Arizona Service Area
(Volumes in Dekatherms (Dth))

	Projected Monthly and Seasonal Loads	Projected Average Daily Load	Projected Maximum Daily Load (Design Day)	Projected Minimum Daily Load	Projected Minimum as Percent of Average	Swing Requirement (Maximum Load Less Minimum)
November 2006	6,053,105	201,770	382,778	162,082	80%	220,696
December	9,847,886	317,674	604,204	165,948	52%	438,256
January 2007	9,571,375	308,754	627,248	166,964	54%	460,284
February	7,558,226	269,937	579,790	166,721	62%	413,069
March	6,601,901	212,965	441,730	166,094	78%	275,636
April	4,724,456	157,482	246,814	146,531	93%	100,283
May	3,749,076	120,938	162,059	119,678	99%	42,381
June	3,243,596	108,120	109,386	108,068	100%	1,318
July	2,991,128	96,488	96,488	96,488	100%	0
August	2,981,239	96,169	96,191	96,169	100%	22
September	3,021,000	100,700	101,002	100,700	100%	302
October	3,866,051	124,711	226,950	117,155	94%	109,795
Annual total	64,209,039	175,915	627,248			
Winter season total (November – March)	39,632,493	262,467	627,248		63%	

Table 2 - 2005/06 Arizona Supply Demand Balance



Qualifications of Ralph E. Miller

Ralph E. Miller is an independent consulting economist who works in the fields of regulatory economics, industrial organization, and public policy towards business. He has more than 30 years of consulting experience in the public utility and energy sectors of the economy, and several additional years in government and on the faculty of a major university. He specializes in energy supply and demand analysis, especially natural gas supply and distribution; antitrust and market structure analysis, including the introduction of competition into previously regulated areas; public utility ratemaking, especially gas and electric utility cost allocation and rate design; and the economics of regulation. He is the author of several published reports and papers in these areas.

During the past 30 years, Mr. Miller has presented expert testimony in more than 300 public utility rate cases and other proceedings before the FERC and other federal agencies, U.S. District Court and state courts, and more than two dozen state regulatory commissions. Over the years, he has addressed almost all the aspects of gas and electric utility regulation, including rate of return, accounting and revenue requirements, rate design and cost of service, electric fuel and purchased gas cost recovery, industry structure and the role of competition, incentive ratemaking and other types of innovative rate designs, gas and electric supply planning and power plant licensing, productivity and efficiency, and the determination of marginal, incremental, and avoidable costs.

Mr. Miller has more than 25 years of experience in gas procurement analysis. He has reviewed the gas supply planning and/or gas cost recovery arrangements of more than 15 gas distribution companies (LDCs) in numerous regulatory proceedings in seven states, and he has extensive experience in gas pipeline cases at the FERC.

Mr. Miller has been an independent consultant for twenty years. He also has ten years of experience as president or vice president of two different consulting firms specializing in public utility and energy matters. Before that, he spent three years in the federal government, where he was employed in positions at the Federal Power Commission (now the Federal Energy Regulatory Commission, or FERC), the Antitrust Division of the U.S. Department of Justice, and the Federal Energy Administration (now part of the U.S. Department of Energy, or DOE). He was on the faculty of the University of California for three years, where he taught economics courses at both the graduate and undergraduate levels.

Mr. Miller did his undergraduate work at Harvard College, where he received the A. B. degree *summa cum laude* in mathematics in 1961, and he was elected to Phi Beta Kappa. He then went on to graduate work in economics at Harvard, where he received a Master's degree in 1963. He continued his graduate studies there until 1966, and he completed all of the course requirements for the Ph.D. degree, but not a doctoral dissertation.

Mr. Miller has been working on gas supply planning and purchased gas cost recovery cases since prior to 1980, and he has concentrated his attention on these areas since 1990. Beginning in 1981, he analyzed the way Southern Union Gas Company acquired gas supplies for its New Mexico distribution system, and he testified on aspects of this subject in U.S. District Court in 1982.

At the FERC, he reviewed requests by three interstate pipelines for recovery of take-or-pay buyout and contract reformation costs under Order No. 500. He has also testified in many pipeline rate proceedings and two pipeline gas inventory charge proceedings, and he reviewed the gas supply restructuring plans proposed by two pipelines as part of their Order 636 compliance. He also reviewed the implementation of Order 637 by two pipelines.

At the state level, he (along with one or more colleagues) has performed many management/performance audits of the gas purchasing practices and policies of gas distribution companies in Ohio, and the reports on these audits were submitted to the Public Utilities Commission of Ohio (PUCO). The companies that he has audited include three of the major LDCs in Ohio.

In Michigan, he has reviewed and testified on the gas supply plans and gas cost recovery (GCR) reconciliations of Consumers Energy Company and Michigan Consolidated Gas Company in each year since 1988, except for the three years when their GCR clauses were suspended. He has also reviewed and testified on many of the gas supply plans and GCR reconciliations of the other LDCs in Michigan during this period.

In New Jersey, he participated in the levelized gas adjustment clause (LGAC) proceedings as a consultant to the Ratepayer Advocate (or its predecessor, the Public Advocate) for ten years. He reviewed the LGAC filings and gas supply planning of each of the four New Jersey LDCs at least once during this period. He also participated extensively in the consideration of gas cost recovery issues in the unbundling proceedings and base rate cases of the New Jersey LDCs.

In Maryland, Mr. Miller has for more than 25 years been reviewing the gas supply planning and gas purchases of several Maryland utilities, including Baltimore Gas and Electric Company and Washington Gas Light Company, in a variety of proceedings. Other states in which he has done similar work include Pennsylvania, Nevada, and Utah.

American Gas Association

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Policy Analysis Group
400 N. Capitol St., NW
Washington, DC 20001
www.aga.org

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LDC SUPPLY PORTFOLIO MANAGEMENT DURING THE 2004 - 2005 WINTER HEATING SEASON

I. Introduction

As with the prior winter, the issue for consumers and local distribution companies (LDCs) purchasing natural gas during the 2004-2005 winter heating season (WHS) was not its availability but its cost. With supply and demand relationships in the market remaining tight, most pressure on commodity prices was upward pressure. In fact, to begin the winter heating season the NYMEX close (October 27, 2004) for November 2004 futures contracts was $3.17 per MMBtu higher than the November close one year earlier.

Even with that backdrop, natural gas supplies remained relatively strong throughout the 2004-2005 winter. A review of gas supply sources shows that underground storage exceeded the five-year average for inventories at winter's end, domestic production appeared to sustain itself and LNG was in the process of setting another annual record for imports (now accounting for about three percent of available supply). Still, market prices (at $6.00-7.00 per MMBtu and more) seem to point to high level issues for the longer-term regarding natural gas supply -- and questions emerge. For example, if increasing gas supply and infrastructure in the form of LNG (or even pipeline gas from Alaska) is viewed as a positive element for mitigating price volatility and possibly the absolute price level for gas consumers, how can the infrastructure be developed without long-term commitments to support such projects? Are purchasing practices beginning to demonstrate changes in contracting terms or lengths and are more companies using financial or other instruments to protect gas consumers from market price fluctuations?

This analysis describes critical elements of the 2004-2005 WHS and reports the results of the *Winter Heating Season Performance Survey*, which was conducted under the guidance of the AGA Gas Transportation and Supply Operations (GTSO) Task Force. Data for this report were acquired by surveying AGA member local distribution companies and concentrate on defining peak-day and peak-month supply practices, as well as certain regulatory and market hedging practices.

This year, responses (whole and part) were received from 54 LDCs with service territories in 30 states. Ten of the companies have service territories west of the Mississippi River, while the balance of the companies that responded are located in the east. The sample companies had an aggregate peak-day sendout of 43,391,052 Dekatherms (Dth), acknowledging that the peak-day did not occur on the same calendar day for each company. However, these same companies planned for an aggregate peak-day of 54,200,554 Dth, meaning only 80 percent of the planned peak volume for sendout was actually required during the 2004-2005 WHS. This is the second year in a row that the sample company actual peak-day sendout was only 80 percent of the design peak-day for the companies supplying responses to the winter heating season survey.

A list of companies returning surveys for this year's study is shown in Appendix A. The purpose of the survey is to document some gas delivery system operations during the past winter season and to provide insights into gas supply trends and procurement portfolio management. *The aggregated data presented in this report is in no way to be interpreted as establishing standards or best practices for gas supply management.* It is instead a snapshot of supply practices. In some cases, the report compares survey results for the 2004-2005 winter heating season with those reported in prior years. *It should be noted, however, that the compared samples are not identical and the data are not normalized in order to compensate for sample differences, weather or other factors.*

II. Executive Summary

The foundation for this report comes from survey responses submitted by 54 AGA member LDCs (compared to 43 one year ago). These companies had a non-coincident peak-day sendout of 43 million Dth and an average peak-day sendout of 803,538 Dth per company. The 54 companies reporting represent about 45 percent of the gas delivered by all AGA member companies during an annual period. Results of the winter heating season survey are generally presented as counts of companies that fit into percentage based categories (1-25 %, 26-50 %, and so forth) of supply volumes. The intent of this report is to document the data as a snapshot of current supply behavior by large purchasers of natural gas, in this case LDCs.

Weather

- Each month of the 2004-2005 winter heating season was warmer-than-normal, with the exception of March 2005, which was 5.1 percent colder-than-normal. For the period October 2, 2004 - April 2, 2005, heating degree day totals were 6.0 percent fewer-than-normal and thus the winter was warmer-than-normal on average for the nation as a whole.

- A view of heating degree days by region yields similar results. Only New England was colder-than-normal (1.2 percent), while every other region of the country was warmer for the 2004-2005 winter heating season. The central portion of the country was warmest when compared to normal for the cumulative winter heating season.

- For the country as a whole, temperature conditions were 6.0 percent warmer-than-normal and compares to the prior winter heating season (October 2003 – March 2004) when conditions were nearly the same – 5.0 percent warmer-than-normal.

Gas Supply Portfolios

LDCs build and manage a portfolio of supply, storage and transportation services, which include a diverse set of contractual arrangements to meet anticipated peak-day and peak-month gas requirements. For the 2004-2005 winter, sample companies planned for over 54 million Dth of required peak-day gas throughput but only 80 percent of that volume was actually required.

- It should be no surprise that purchases moved by firm transportation provided much of the gas to consumers for the peak-day and peak-month. Fifty-three of 54 companies indicated that firm supplies were a part of their gas supply portfolio, including 29 companies that showed between 26-50 percent of their required peak-day volumes coming from firm supplies.

- Forty-six companies indicated that up to 50 percent of peak-day supplies originated from pipeline or other storage, while 34 companies also noted that up to 25 percent of the deliveries arriving at their citygate on a peak-day were earmarked for transportation customers on their system.

- Long-term agreements, defined as one year or longer, were used by 37 of 52 of companies within their peak-day gas supply portfolio (compared to 29 of 41 companies the previous year) and accounted for more than 50 percent of purchased gas for 15 companies on a peak-day (compared to 10 companies the previous year). Mid-term (more than one month, less than one year) agreements were utilized more often than one-month and daily agreements for 2004-2005 peak-day purchases.

- As a general statement, comparing 2004-2005 data to that collected two years ago (2002-2003 winter heating season with 65 companies responding to the survey), daily and monthly contract terms are less prevalent today than two years ago among the survey participants. This may be because recent daily pricing has been high relative to history. It may also be, however, that companies and Public Utility Commissions are becoming more comfortable with longer-term supply agreements as a part of a supply portfolio, remembering that a long-term deal today may be two years not 10 or 15 as in the past.

- When asked to describe the distribution of gas supply purchases among suppliers -- independent marketers, producers and producer marketing affiliates more than any other classes of supply aggregators, were cited by those responding to the winter heating season survey.

Supply Pricing Mechanisms and Hedging Issues

Several factors play a role in the market pricing of natural gas and of transportation services, including weather, storage levels, end-use demand, financial markets and various operational issues. When asked to identify the tools most effective to manage supply and price risk, survey respondents pointed to daily swing contracts, storage and LNG, weather-based calls and options, asset managers, fixed pricing and advanced purchases at fixed prices.

- When examining the purchase practices of companies during the past winter heating season, it is clear that first-of-the-month index pricing dominates the market for long- and mid-term supply agreements. However, this year's survey sample included references to fixed price, daily and other NYMEX-based arrangements.

- For long-term supplies (one year or more), 30 of 49 companies responding used first-of-the-month (FOM) pricing for a portion of their supplies, including 27 companies that used FOM for 51-100 percent of long-term gas purchases. Thirteen companies utilized some form of fixed long-term pricing.

- Mid-term purchases (more than one month, less than one year) were reported by 39 companies to most often be tied to FOM indices for significant volumes of gas. In addition, fixed-price (20 companies) and daily mechanisms (13 companies) were part of the mid-term pricing basket.

- Seventy percent of the companies responding indicated use of financial instruments to hedge at least a portion of their supply purchases. Even though this percentage is identical to last year, three years earlier only 55 percent of the companies responding had indicated the same. For this past winter, twenty-one of 37 companies providing data hedged up to 50 percent of their gas supply purchases during the winter.

- In addition, options (23 companies), fixed-price contracts (18 companies), swaps (16 companies) and futures (11 companies) were most often sited as financial tools used to hedge a portion of gas volumes delivered on a peak-day. This balance is similar to that of last year. The use of financial tools may be understated in this report inasmuch as some volumes delivered to LDCs from marketers and other suppliers are hedged by the third-party rather than the LDC or customer and may have been excluded from the LDC hedging calculation.

- On the physical side, in preparation for the 2004-2005 WHS 47 companies reported using storage as a primary hedging tool. Twenty-nine of those companies hedged between 26-50 percent of winter heating season supplies using underground storage compared to 22 companies last year. Several companies noted that storage (as a physical hedge) is the only hedge they employ, choosing not to use financial instruments at all.

- Companies use a portfolio of timed hedges to balance their approach to strategic price planning. When asked about the timing of hedging strategies, 25 of 38 companies (66 percent) responding indicated that they employ a six-month and less strategy for a portion of their hedges. Thirty-five of 38 companies utilized a 7-12 month strategy for a portion of their hedges, while 19 companies hedged forward for more than 12 months.

- Only seven survey respondents indicated that they used weather derivatives during the 2004-2005 winter heating season. This compares to six companies in 2003-2004 and eight companies during 2002-2003.

- When asked about their own regulatory environment, 37 of the companies responding to the question indicated that financial losses and gains were treated equally within their hedging plans. Only three noted that losses and gains were treated unequally.

- When asked about the relative ease of acquiring hedging products for 6-month or less hedges, thirty-eight companies saw current markets as less difficult or the same as the year before. Thirty-two companies said the same of hedges more than six months in duration. Very few companies indicated market conditions to be more difficult to operate within. This compares to last year's survey when up to a third of the companies viewed markets as more difficult to operate within.

- The majority of companies reported that acquiring financial hedges or implementing a strategy was no more or less difficult than the prior year. Thirty-one of the 54 companies responding indicated that for the 2005-2006 winter heating season they planned to hedge the same as this past winter heating season, eleven companies plan to hedge even more.

Gas Storage

Production and market area storage are key tools for efficiently managing LDC gas supply and transportation portfolios. However, it should be noted that storage practices are no longer dictated only by local utility requirements to serve winter peaking loads. Storage services now support natural gas parking, loaning, balancing and other commercial arbitrage opportunities that take place at market hubs and citygates.

- Forty-nine of 54 companies answering the question indicated that weather-induced demand compelled the respondents to utilize storage services. However, respondents also singled out no-notice requirements (42 companies), pipeline operational flow orders (20 companies), "must turn" provisions (35 companies) and arbitrage opportunities (18 companies) as reasons to maintain storage services within their gas supply portfolio during the 2004-2005 winter heating season.

- Must turn provisions may be in place for some storage contracts as a way to maintain facility integrity through an optimal pattern of injection and withdrawal in a storage field. During the 2004-2005 winter heating season, storage inventories were consistently higher than the prior five-year average. As a result, thirty-five of 54 companies (65 percent) singled out must turn provisions as influencing their use of storage this past winter – eighteen percent more than the prior winter.

- Forty-five of 54 companies used first-of-the-month index pricing to purchase gas for injection into storage with 20 of those companies indicating that 76-100 percent of gas into storage was based on FOM prices. Twenty-one of 54 companies (39 percent) used fixed-price schedules for some portion of their storage purchases – up from fourteen companies (33 percent) the year before. Twenty-five companies indicated that they purchased stored gas in the daily market compared to 18 companies the prior year. A majority of those 25 companies (15) acquired less than 25 percent of storage purchases in the daily market.

- Twenty-five companies indicated that they were actually constructing or examining the potential for physically adding underground storage, while 13 were considering peak shaving facility expansion during the next five years.

- For the nation as a whole, working gas inventories at the end of March 2005 were significantly higher than inventories from one-year prior (by 215 Bcf) and pointed to less gas required for net storage injections during the 2005 refill season.

LDC Transportation and Capacity Issues

Transportation-only customers have assumed a higher profile among all customers served by LDCs. Managing pipeline capacity efficiently is a challenge for many LDC's and can involve the release of capacity to the secondary transportation market.

- From April 2004 to March 2005, 20-26 of the companies (varying with the month) released between one and 25 percent of their pipeline capacity on a monthly basis to the secondary market, when that capacity was not needed to serve LDC customers. As many as 14 companies released between 26 and 50 percent of their capacity during the summer of 2004 compared to only 5 companies in the sample one year prior.

- Although not as active as two years prior when gas storage was under more stress, some operational flow orders (OFO) were issued during the 2004-2005 winter heating season. Twenty-two companies indicated impacts from OFOs. The median number of OFOs issued was 3 with a median duration of 3.5 days.

III. Weather

The 2004-2005 WHS started remarkably similar to the prior winter heating season as shown below in Table 1. For the October-December WHS kick-off, monthly heating degree days were fewer than normal in both years, resulting in warmer-than-normal cumulative conditions entering January. However, while January and February 2004 quickly turned colder-than-normal, January and February 2005 remained decisively warmer and, in fact, February was 10 percent warmer-than-normal for the nation as a whole.

Cumulative heating degree day totals eventually settled at 6.0 percent warmer-than-normal for the 2004-2005 WHS, even after a much colder-than-normal March, while the prior year winter heating season totals for temperature were 5.0 percent warmer-than-normal. For the 27-week period October 2, 2004 to April 2, 2005, only 10 weeks registered colder-than-normal conditions, on a national basis, with four of those weeks coming in March 2005. By winter's end and like the year before, only New England had seen greater heating degree day totals than normal (1.2 percent colder).

TABLE 1

MONTHLY COMPARISON OF NATIONAL HEATING DEGREE DATA
OCTOBER 2003 – MARCH 2005

MONTH	PERCENT CHANGE FROM NORMAL			
	2003 – 2004		2004 – 2005	
October	11.0%	Warmer	13.2%	Warmer
November	10.5%	Warmer	10.2%	Warmer
December	6.8%	Warmer	4.1%	Warmer
January	4.3%	Colder	6.5%	Warmer
February	2.2%	Colder	10.0%	Warmer
March	18.2%	Warmer	5.1%	Colder
TOTAL	5.0%	Warmer	6.0%	Warmer

Source: U.S. Department of Commerce, National Oceanic and Atmospheric Administration.

IV. Gas Supply Portfolios

LDCs build and manage a portfolio of supply, storage and transportation services to meet expected peak-day, peak-month and seasonal gas delivery requirements. The 1992 FERC Pipeline Restructuring rule (Order No. 636) increased competition in the interstate transportation market but introduced new risks to the process of acquiring natural gas and required pipeline capacity. In today's business environment, gas portfolio managers continually attempt to strike a balance between their need to minimize gas-acquisition risks and their obligation to provide reliable service at the lowest possible cost.

Given the reality of significant deviations from normal weather patterns (warm and cold), volatility in commodity prices and regulatory scrutiny of costs to consumers, local gas utility exposure to hindsight for gas supply practices has increased. Also, in some cases, the unbundling of gas sales and transportation services at the retail level have further prompted many LDCs to reassess the quantity of gas supplies they must contract for and at what cost.

Table 2 and Figure 1 illustrate the diversity of gas supply sources available to LDCs. It should be no surprise that purchases moved by firm transportation provided much of the gas to consumers for the peak-day and peak-month. Fifty-three of 54 companies indicated that firm supplies were a part of their gas supply portfolio, including 29 companies that showed between 26-50 percent of their required peak-day volumes coming from firm supplies. An additional eight companies showed 51-75 percent of peak-day supplies to be firm. But other categories of gas supply for peak-day deliveries are also important to the sample of companies.

For example, 34 companies out of 54 indicated that up to 25 percent of their citygate peak-day supplies were earmarked for transportation customers and 43 companies indicated that up to 50 percent of peak-day supplies originated from pipeline or other storage. Eighteen companies indicated on-system storage as a supply source, also. Citygate purchases, local production and LNG or propane-air also provided up to 25 percent of peak-day supplies for 23, 8 and 19 companies out of 54, respectively. The visual impact of Figure 1 demonstrates that very few companies source a supply portfolio with all of their eggs in one basket. The table and figure show that the largest number of companies tend to employ a multiple supply source strategy in increments often amounting to 50 percent or less of their total supply package.

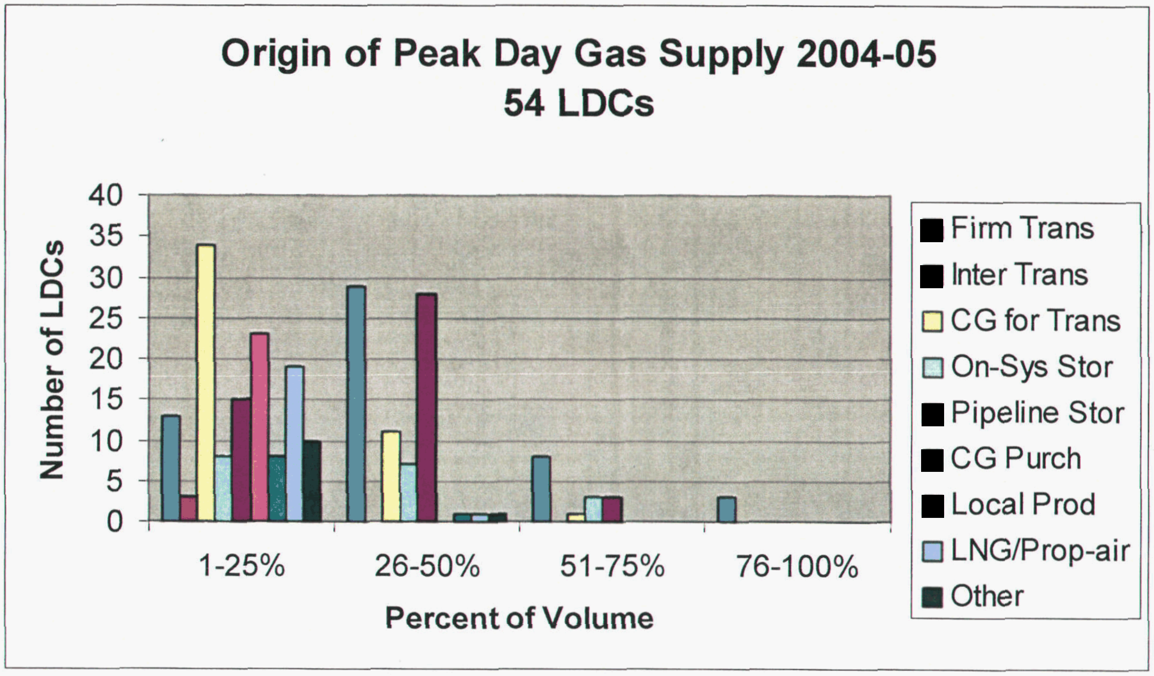
TABLE 2

ORIGIN OF LDC GAS SUPPLY
2004-2005 WINTER HEATING SEASON
(NUMBER OF COMPANIES)

PERCENT GAS SUPPLY	PURCHASES VIA FIRM TRANS	PURCHASES VIA INTERRUPTIBLE TRANS	CITYGATE SUPPLIES FOR TRANS CUSTOMERS	ON-SYSTEM STORAGE	PIPELINE OR OTHER STORAGE	CITYGATE PURCHASES	LOCAL PRODUCTION	LNG PROPANE-AIR	OTHER
PEAK-DAY									
1 – 25	13	3	34	8	15	23	8	19	10
26 – 50	29	0	11	7	28	0	1	1	1
51 – 75	8	0	1	3	3	0	0	0	0
76 – 100	3	0	0	0	0	0	0	0	0
0	1	51	8	36	8	31	45	34	43
PEAK-MONTH									
1 – 25	7	2	22	7	30	19	6	15	4
26 – 50	22	0	19	8	13	0	2	0	2
51 – 75	15	0	0	2	1	0	0	0	0
76 – 100	5	0	0	0	0	0	0	0	0
0	1	48	8	33	6	31	42	35	44

Source: 2004-05 AGA LDC Winter Heating Season Performance Survey.

FIGURE 1



According to Table 2, peak-month supplies were also heavily weighted toward purchases via firm transportation. Like peak-day supplies, peak-month supplies tended to be supplemented with pipeline and on-system storage, citygate purchases, citygate deliveries for transportation customers, LNG or propane-air and even some local production.

The diverse set of contractual arrangements that LDCs use to procure their gas supplies includes long-term, mid-term, monthly, and daily agreements. A mix of contracts allows the LDC to balance between competing needs, such as the obligation to serve its customers as the supplier of last resort and the need to maximize efficiency while minimizing costs. In many cases, longer-term contracts contribute to baseload obligations, while shorter-term contracts allow companies to respond to market changes. In the past, survey results reflected a transition toward shorter-term and spot contracts to meet peak requirements, which has been consistent with demands from consumers, regulators and the market, in order to pursue least cost options. However, recent developments in market volatility, particularly as they apply to natural gas acquisition prices is resulting in a reexamination by consumers and regulators of supply acquisition contracting with less emphasis on absolute least cost and more emphasis on price stability. Stability may mean a trend toward longer-term contracting and some argue that longer-term contracting will be necessary to underpin new supply sources in the future.

As a general observation, comparing 2004-2005 data to that collected two years ago (2002-2003 winter heating season with 65 companies responding to the survey), daily and monthly contract terms are less prevalent today than two years ago among the survey participants. This may be because recent daily pricing has been high relative to history. It may also be, however, that companies and Public Utility Commissions are becoming more comfortable with longer-term supply agreements as a part of a supply portfolio, remembering that a long-term deal today may be two years not 10 or 15.

Table 3 shows that long-term agreements, defined as one year or longer, were used by 37 of 52 companies (answering the question) and accounted for more than 50 percent of purchased gas for 15 companies on a peak-day. Last year's results produced only 10 companies that used long-term deals for more than 50 percent of their purchased gas on the peak-day. Mid-term (more than one month, less than one year) were utilized more often than one-month or daily agreements for peak-day purchases, also. This makes sense in an environment where daily gas prices tended to be high compared to recent history and many fluctuations in price were upward. In contrast, for peak-month gas purchases, 32 companies utilized mid-term agreements for between 26 and 100 percent of gas supplies, while 23 companies acquired the same range of supplies through long-term contracts. Monthly and daily agreements were used to some extent by 22 and 26 companies, respectively, for peak-month supplies – but like peak-day arrangements tended to be for 25 percent or less of volumes.

TABLE 3

CONTRACT TERMS FOR GAS PURCHASED
2004-2005 WINTER HEATING SEASON
(NUMBER OF COMPANIES)

Percent Contracted	Long-Term	Mid-Term	Monthly	Daily
		PEAK-DAY		
1 – 25	15	10	13	12
26 – 50	7	9	8	9
51 – 75	7	9	2	3
76 – 100	8	13	1	1
0	15	11	28	27
		PEAK-MONTH		
1 – 25	14	8	11	20
26 – 50	8	12	7	3
51 – 75	6	5	2	3
76 – 100	9	15	2	0
0	13	10	28	25

Source: 2004-05 AGA LDC Winter Heating Season Performance Survey.

When asked to describe the distribution of gas supply purchases among suppliers, 37 LDCs identified independent marketers as suppliers with producers (31 companies), producer marketing affiliates (29 companies) and pipeline marketing affiliates (9) providing the balance of gas supplies to LDCs. Table 4 also shows that LDC-owned production and purchases directly from pipelines played a very small role in supplying LDC customers with natural gas.

TABLE 4 PERCENT PEAK-DAY GAS DISTRIBUTED AMONG SUPPLY PROVIDERS 2004-2005 WINTER HEATING SEASON (NUMBER OF COMPANIES)							
Percent Peak-Day Gas Supply	Producer	LDC-Owned Production	Producer Marketing Affiliate	Pipeline	Pipeline Marketing Affiliate	Independent Marketer	Other
1 – 25	9	1	7	0	8	11	7
26 – 50	9	1	8	0	0	17	1
51 – 75	9	0	9	0	1	6	2
76 - 100	4	0	5	0	0	3	6
0	21	50	23	52	43	15	36

Source: 2004-05 AGA LDC Winter Heating Season Performance Survey.

V. Supply Pricing Mechanisms and Hedging

Pricing Mechanisms

Many factors play a role in the market pricing of the gas commodity and of transportation services, including weather, storage levels, end-use demand, pipeline capacity, operational issues, and functioning financial markets. Such market factors impact LDCs and other gas suppliers making it difficult for all players to plan. In order to deal with the inherent uncertainty of the market, supply planners use a portfolio approach to pricing gas supplies just as they use a portfolio approach for supply providers and transportation options. That said, when examining the purchase practices of companies during the past several winter heating seasons, it is clear that first-of-the-month (FOM) index pricing dominates the market for the largest portion of long- and mid-term supply agreements. Table 5 examines more closely the balance of pricing mechanisms among survey respondents during the 2004-2005 winter heating season. Figures 2-5 compare pricing mechanisms from this year's survey participants with last year's sample of companies.

Table 5 and Figure 2 show that for long-term supplies (one year or more agreement) 30 of 49 companies answering the question used first-of-the-month pricing for a portion of their supplies, including 27 companies that used FOM for 51-100 percent of long-term gas purchases. Thirteen companies utilized some form of fixed pricing for a portion of their long-term arrangements, which is interesting because two years ago when the survey included 65 respondents the number of companies citing fixed deals was only 10. A smaller number included daily, average-of-the-last-three-days and NYMEX based pricing mechanisms for small volumes within their gas supply portfolio. For those companies referencing fixed price mechanisms for gas supply, only five indicated that the arrangements lasted for more than two years. All others were of less duration. Using a scale of 1-10 %, 11-20 %, 21-30 % and so forth, the largest number of companies described their fixed-price deals as 11-20 percent of their supply portfolio.

Comparing Figures 2 and 3 (2004-2005 and 2003-2004, respectively) indicates that for the winter heating season just past there was slightly less diversity in pricing mechanisms for small volumes of gas but general agreement that the largest number of companies purchased the largest volumes of their supply using FOM pricing.

TABLE 5 GAS SUPPLY PRICING MECHANISMS 2004-2005 (NUMBER OF COMPANIES)							
PERCENT GAS SUPPLY PURCHASED	FIRST-OF-THE-MONTH INDEX	WEEKLY	FIXED	DAILY	AVERAGE LAST 3 DAYS	NYMEX	OTHER
LONG-TERM **ONE YEAR OR GREATER**							
1 – 25	0	0	5	4	2	3	0
26 – 50	3	0	1	4	0	1	3
51 – 75	10	0	4	0	2	2	1
76 – 100	17	0	3	0	0	2	5
0	19	49	36	41	45	41	40
MID-TERM **GREATER THAN ONE MONTH, LESS THAN ONE YEAR**							
1 – 25	6	0	8	4	0	4	1
26 – 50	9	0	5	5	0	3	1
51 – 75	10	0	3	2	0	2	0
76 – 100	14	0	4	2	0	8	0
0	13	52	32	39	52	35	50
SHORT-TERM **ONE MONTH OR LESS**							
1 – 25	8	0	9	11	0	3	2
26 – 50	8	0	5	6	0	3	0
51 – 75	14	0	3	8	1	5	0
76 – 100	10	0	2	10	0	1	2
0	13	53	34	18	52	41	49

Source: 2004-05 AGA LDC Winter Heating Season Performance Survey.

FIGURE 2

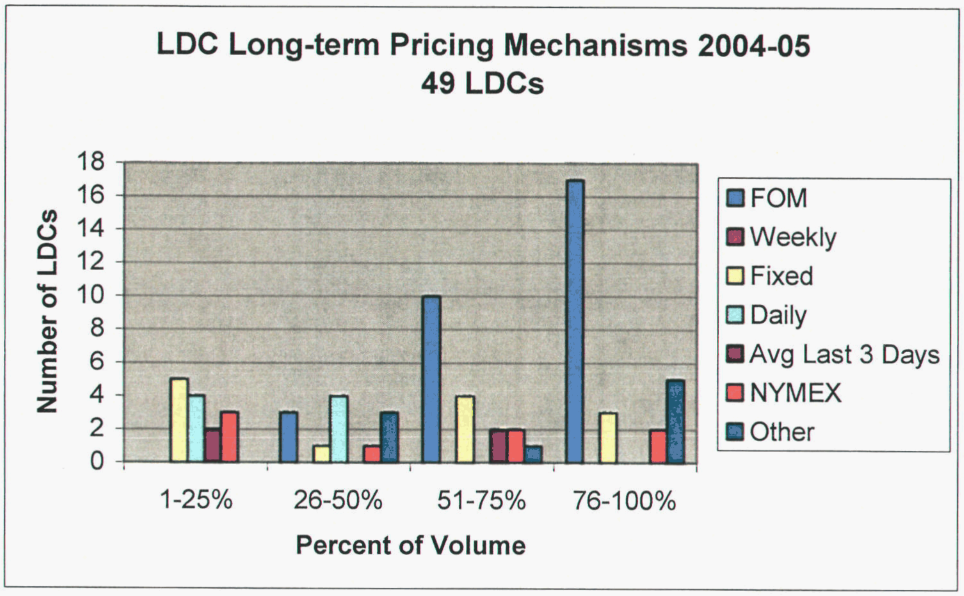
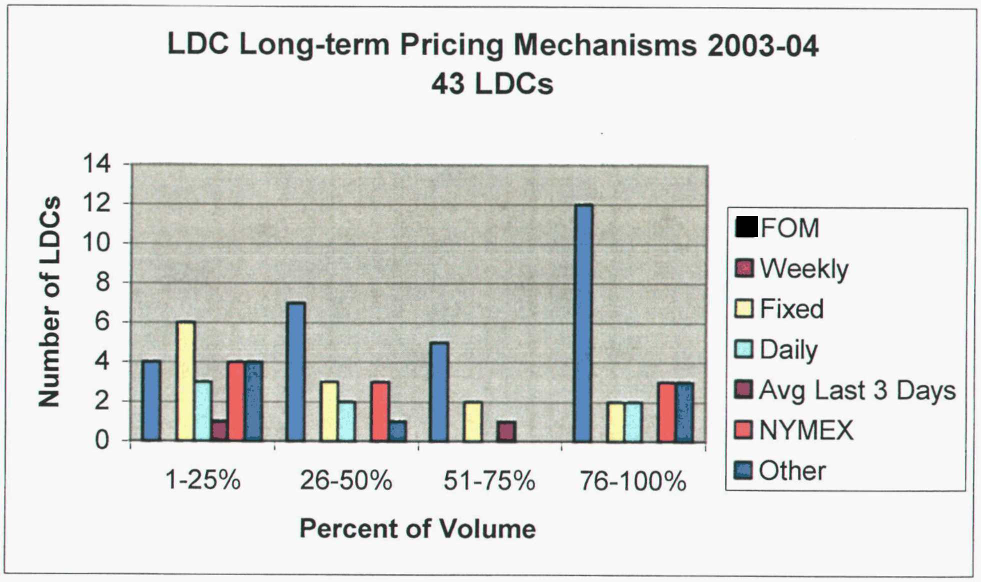


FIGURE 3



Mid-term purchases (more than one month, less than one year) were reported by companies to most often be tied to FOM indices for almost any volume of gas during the past two winter heating seasons, as shown in Figures 4 and 5. In addition, fixed-price, NYMEX and daily mechanisms were used to a greater extent for mid-term purchases than in the case of long-term purchases. Twenty companies reported using fixed pricing mechanisms for mid-term purchases compared to 13 companies for long-term and 13 used daily prices for mid-term purchases compared to eight for long-term purchases, which makes sense. In a volatile gas market, trading partners are more likely to limit the term of pricing arrangements because local utilities are encouraged by regulators to be in a position to capture lower gas prices when the market swings down, while suppliers are interested in capturing the high end of the market. However, there appears to be a growing undercurrent of concern among some gas market players that first-of-the-month indices are *over* relied upon and that index pricing of such large volumes of gas may need to change in the future. That could only happen if market players were willing to do so and regulatory support was forthcoming.

FIGURE 4

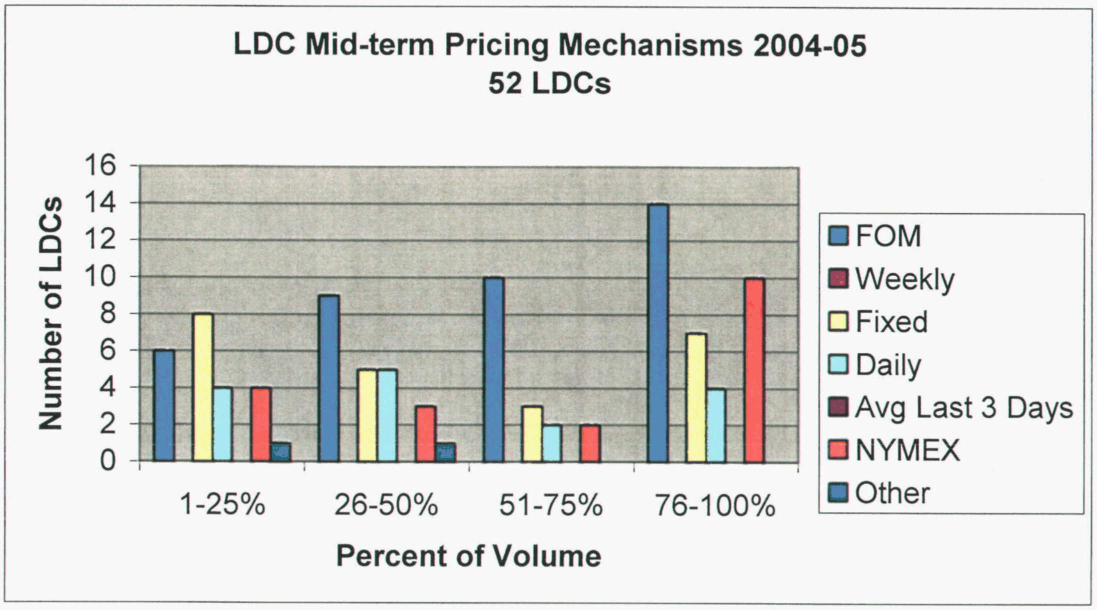
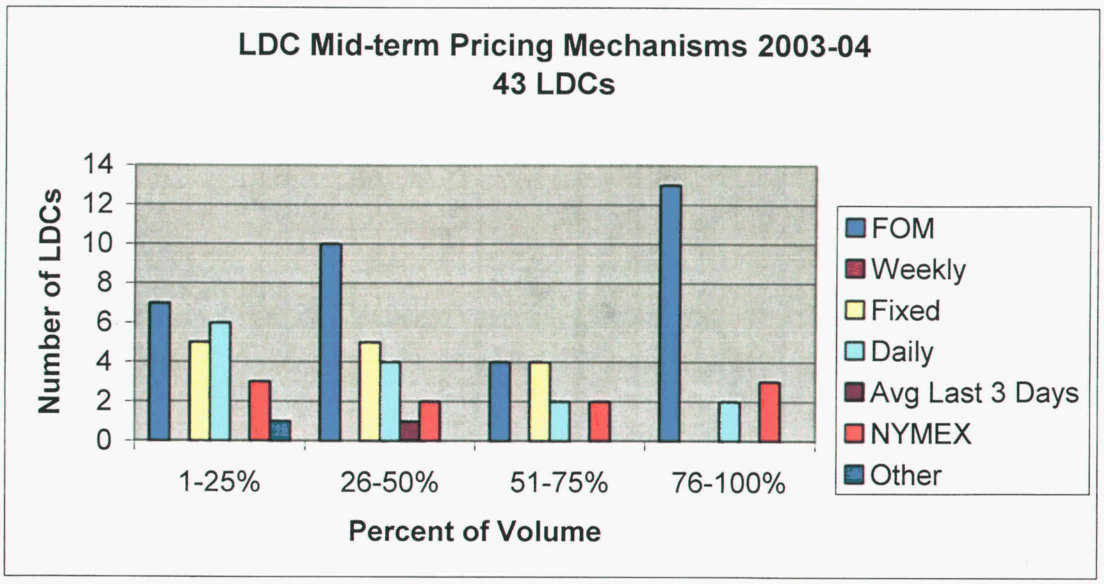


FIGURE 5



As expected, short-term purchases (one month or less) depended more heavily on daily pricing mechanisms but, also, were tied to first-of-the-month, fixed and NYMEX indices (see Table 5). It should be noted that LDCs build gas supply portfolios and pricing strategies based on prior and anticipated experiences. Even state regulatory approved pricing mechanisms can appear favorable one year and less attractive another. Flexibility and constructive review of policies, rather than second-guessing, can effect positive impacts on bringing natural gas and services to customers at the lowest possible cost.

Hedging Mechanisms

Market developments during the 1990s have expanded gas supply options, transportation capacity trading and the use of financial instruments. Today, industry players use futures contracts and other tools to offset the risk of commodity price movements. These financial instruments, which to some extent include fixed-price gas purchase contracts, futures, and options, allow gas supply portfolio managers to hedge or lock in a portion of the gas cost component of gas supplies. This is achieved particularly when the level of risk required and the rewards or benefits of managing the risk are properly balanced by the company, consumers and regulatory bodies.

Seventy percent of the companies responding to the AGA WHS survey said they used financial instruments to hedge a portion of their gas supply purchases during the 2004-2005 winter. That number is identical to the percentage last year and compares to 45 of 65 LDCs (69 percent) answering the question in the 2002-2003 survey and 55 percent in the 2001-2002 survey (remembering that the sample companies and sample size were different each year). For this past winter, twenty-one of 37 companies providing data hedged up to 50 percent of their gas supply purchases during the winter. Options (23 companies), fixed-price contracts (18 companies), swaps (16 companies) and futures (11 companies) were most often sited as financial tools used to hedge a portion of gas volumes delivered on a peak-day. This balance is similar to that of last year. The use of financial tools may be understated in this report inasmuch as some volumes delivered to LDCs from marketers and other suppliers are hedged by the third-party rather than the LDC or customer and may have been excluded from the LDC hedging calculation.

Only seven companies indicated that they used weather derivatives during the 2004-2005 winter heating season. This compares to six companies in 2003-2004 and eight companies in the 2002-2003 survey.

When asked about the timing of hedging strategies, 25 of 38 companies (66 percent) responding indicated that they employ a six-month and less strategy for a portion of their hedges. Thirty-five of 38 companies utilized a 7-12 month strategy for a portion of their hedges, while 19 companies hedged forward for more than 12 months. Of course, a single company may use one or all strategies simultaneously. The majority of companies also reported that acquiring financial hedges or implementing a strategy was no more or less difficult than the prior year. Thirty-one of the 54 companies responding indicated that for the 2005-2006 winter heating season they planned to hedge the same as this past winter heating season. Eleven companies plan to hedge even more of their purchased gas volumes. Thirteen of the companies reported that Public Utility Commissions were more receptive to hedging strategies than in the past, while 31 indicated PUC receptivity to be the same compared to last year.

On the physical side, companies view gas delivered to storage during the summer refill season as a price hedge against potential winter run-ups. In preparation for the 2004-2005 WHS, 47 companies reported using storage as a primary hedging tool. Twenty-nine of those companies hedged between 26-50 percent of winter heating season supplies using underground storage compared to 22 companies last year. Several companies noted that storage (as a physical hedge) is the only hedge they employ choosing not to use financial instruments at all.

When asked about their own regulatory environment, 37 of the companies responding to the question indicated that financial losses and gains were treated equally within their hedging plans. Only three noted that losses and gains were treated unequally. When asked about the relative ease of acquiring hedging products for 6-month or less hedges, thirty-eight companies saw current markets as less difficult or the same as the year before. Thirty-two companies said the same of hedges more than six months in duration. Very few companies indicated market conditions to be more difficult to operate within. This compares to last year's survey when up to a third of the companies viewed markets as more difficult to operate within.

Motivations behind hedging programs are varied among survey respondents. For some jurisdictions there are no formal standing plans. In some cases, however, companies are permitted to enter into fixed price deals well ahead of the delivery season (up to 2.5 years ahead) for a portion of their monthly requirements. Timing of a contract reflects historical price trends and demonstrates a desire to maintain diversity among market-based prices within a supply portfolio. In other cases, LDCs may be required to hedge portions of future gas supplies and those hedges must be in place by predetermined dates. Accelerating or slowing down the process occurs based on evaluation of market fundamentals. Variations on these themes are many and are shaped to fit the relationship between local distribution company, regulators and market conditions in a given area.

VI. Gas Storage

As noted earlier, LDCs are concerned with managing gas supply and transportation portfolios efficiently to reduce costs. Producing area and market area storage can help LDCs to meet such goals. The use of storage facilities helps LDCs to meet short-term swing opportunities, as well as, to satisfy peaking needs.

Table 6 shows storage levels as estimated by the Energy Information Administration for January-April 2005 compared to the same period in 2004. For the nation as a whole, working gas inventories during the January-April 2003 period were tested, eventually falling to 642 Bcf in total (a historic low). This occurred during a winter that was only 1.4 percent colder than normal nationally.

In contrast, the lowest volume of gas in storage for early 2004 was 372 Bcf higher than the previous year and the lowest point for storage inventories in 2005 was another 215 Bcf higher. This is consistent with the fact that the past two winter heating seasons were five and six percent warmer-than-normal, respectively. All of the additional gas in storage at the end of the 2003-2004 WHS was located in the Consuming Region East and Producing Region. By the first week in April 2005, higher inventories of natural gas in underground storage were distributed in all three regions of the U.S. and were more than 25 percent ahead of the prior five-year average and 20 percent ahead of the previous year.

Forty-nine companies answering the question indicated that weather-induced demand compelled the respondents to utilize storage services. However, respondents also singled out no-notice requirements (42 companies) and pipeline operational flow orders (20 companies) as reasons to maintain storage services within their gas supply portfolio. Thirty-five and 18 companies, respectively, also stated that both contractual "must turn" provisions and arbitrage opportunities influenced their storage decisions during the 2004-2005 WHS.

TABLE 6

AMERICAN GAS STORAGE SURVEY

WORKING GAS IN STORAGE

	2004 (Bcf)					2005 (Bcf)			
	Total	Prod	East	West		Total	Prod	East	West
Jan02	2567	753	1495	319		2698	802	1536	360
	2414	709	1412	293	Jan07	2610	783	1494	333
	2258	683	1297	278		2500	755	1438	307
	2063	633	1163	267		2270	692	1290	288
	1827	575	1009	243		2082	648	1155	279
Feb06	1603	512	880	211	Feb04	1906	599	1043	264
	1431	456	788	187		1808	576	984	248
	1267	406	689	172		1720	564	921	235
	1171	379	630	162		1613	571	838	224
Mar05	1143	376	619	148	Mar04	1474	523	737	214
	1097	371	575	151		1379	507	659	213
	1032	372	507	153		1290	487	592	211
	1014	380	474	160		1239	486	548	205
Apr02	1034	395	477	162	Apr01	1249	497	546	206
	1049	411	473	165		1293	521	562	210
	1077	423	483	171		1343	538	591	214
	1155	449	531	175		1416	558	636	222

Source: Energy Information Administration

For the previous year, only 20 of 43 companies (47 percent) noted must turn provisions as significant influences on their storage withdrawal strategy during the winter. Must turn provisions may be in place for some storage contracts as a way to maintain facility integrity through an optimal pattern of injection and withdrawal in a storage field. As such, once gas is stored portions must be removed within a scheduled cycle in order to manage the geologic nature of the reservoir properly. During the 2004-2005 winter heating season, storage inventories were consistently higher than the prior five-year average and, therefore, companies may have been faced with a need to cycle gas out of storage to meet the must turn provisions of their contract. As noted above, thirty-five of 54 companies (65 percent) singled out must turn provisions as influencing their use of storage this past winter – eighteen percent more than the prior winter.

Many influences were cited regarding decisions for storage injections during the Spring-Summer refill season in 2004. Price considerations were noted by 38 companies and were up from only 22 companies the year prior (2003). In addition, 46 companies sited operational issues as influencing storage injection patterns in 2004. Regulatory plans and mandates were reported by 21 companies, while 44 cited additional supply considerations as influencing storage injections.

TABLE 7

PRICING MECHANISMS FOR GAS INJECTED INTO UNDERGROUND STORAGE 2004
(NUMBER OF COMPANIES)

Percent Underground Storage Purchases	First-Of-The-Month Index	Weekly	Fixed	Daily	Average Last 3 Days	NYMEX	Other
1 – 25	5	0	11	15	1	3	0
26 – 50	8	0	6	6	0	3	2
51 – 75	12	0	3	2	1	3	0
76 – 100	20	0	1	2	0	2	1
0	7	52	31	27	50	41	49

Source: 2004-05 AGA LDC Winter Heating Season Performance Survey.

FIGURE 6

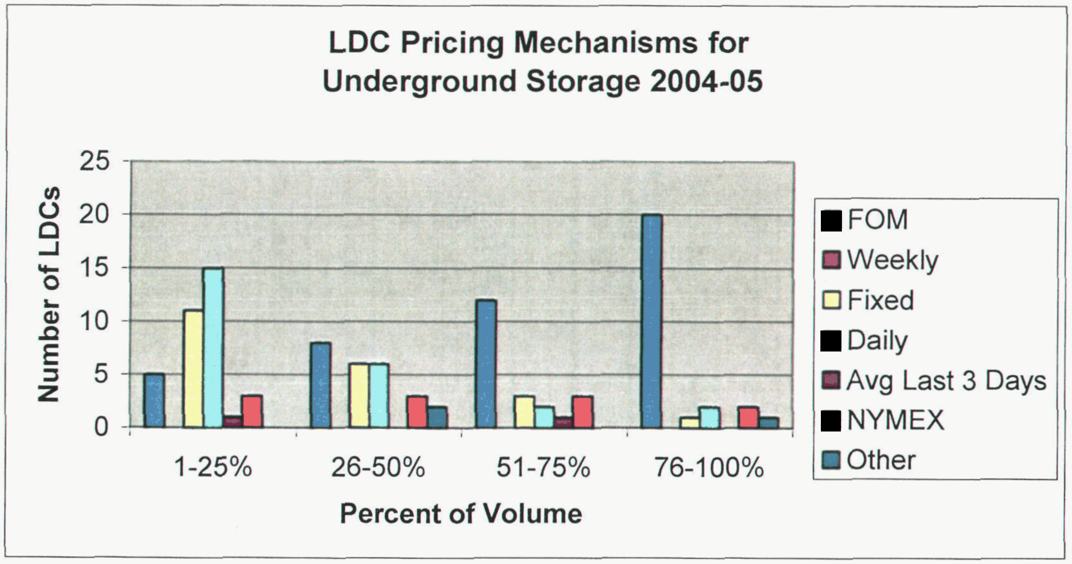


Figure 7

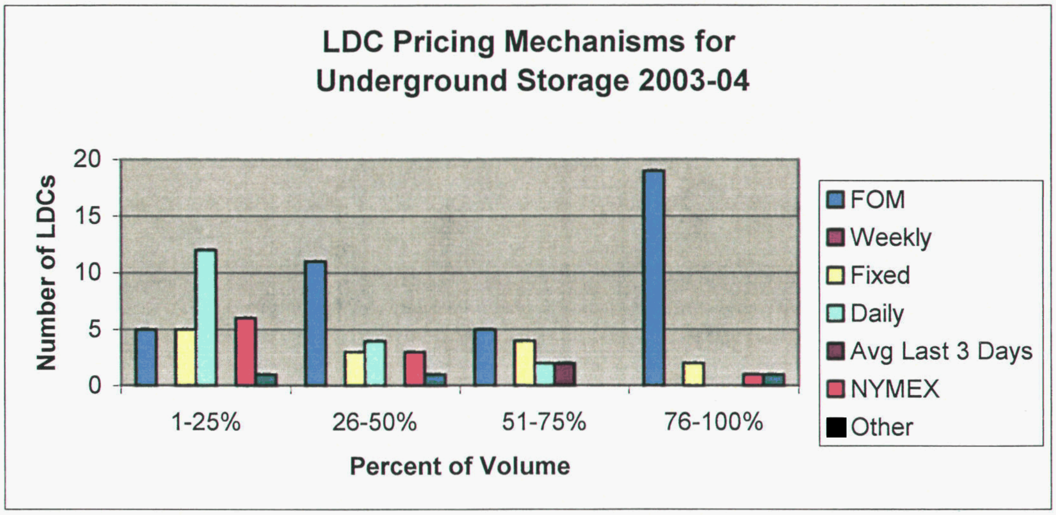


Table 7 and Figure 6 show that most gas purchases for storage injections during 2004 (preparing for the 2004-2005 winter heating season) were made based on *first-of-the-month* indices, although fixed price and daily priced gas was also prevalent for small volumes of gas destined for underground storage. The same is reflected in Figure 7 for the refill period in 2003. For 2004, twenty companies indicated that more than 75 percent of the supplies purchased for storage injections were FOM priced. Fixed schedules accounted for some storage volumes injected by 21 companies reporting, while daily pricing applied to 25 of the surveyed companies (compared to 18 companies in 2003). Generally, daily pricing was applied to 1-25 percent of gas purchased for underground storage, although four companies in 2004 indicated that between 51-100 percent of their stored gas was purchased on a daily basis.

Twenty-five companies indicated that they were examining options to build underground storage additions during the next five years or currently constructing expansions, while 13 companies were considering additions or expansions of peak-shaving facilities. Regarding contracted storage capacity, 10 companies plan to increase underground storage for the 2005-2006 winter heating season, while 33 companies reported plans to keep the same capacity as this past year.

VII. LDC Transportation and Capacity Issues

Transportation only customers have assumed a higher profile among all customers served by LDCs. As has been stated before, planning for transportation capacity and supply, in general, is ultimately held hostage to weather, economic activity and other factors that influence gas consumption. Managing pipeline capacity efficiently is a challenge for LDC's and can involve the release of capacity to the secondary transportation market, if events allow it to be so.

Table 8 takes a brief view of this issue. Companies were asked to identify the percentage of pipeline capacity held by the LDC and released to the secondary market by month from April 2004 to March 2005. In general, several elements can be noted by examining the table. First, most companies release no capacity or less than 25 percent of their capacity throughout the year. During the summer months, however, additional companies with capacity to release may have up to 50 percent of their capacity available to the secondary market. This makes sense, assuming that LDCs are less likely to have large blocks of excess capacity during the winter heating season months in order to meet seasonal heating loads.

The second item is that most capacity sales to the secondary market were for less than 25 percent of the LDC capacity portfolio. From April 2004 to March 2005, 20-26 of the 50 companies answering the question released between one and 25 percent of their pipeline capacity on a monthly basis to the secondary market, when that capacity was not needed to serve LDC customers. As many as 5 companies released up to 50 percent of their capacity during the winter of 2004-2005, which can be attributed to the warmer-than-normal conditions throughout the country for most of that period.

Regarding system operations, 22 of 53 companies (42 percent) in the 2004-2005 AGA Winter Heating Season Survey indicated that they had been impacted by the issuance of operational flow orders during the past WHS. That compares to 48 of 65 companies (74 percent) during the 2002-2003 WHS and 51 percent during the 2003-2004 winter. For those companies during 2004-2005, the median number of OFOs issued was 3. Duration for the orders ranged from one day to 45 days, however, the median duration was 3.5 days.

TABLE 8

PERCENT LDC PIPELINE CAPACITY RELEASED
2004-2005 WINTER HEATING SEASON
(NUMBER OF COMPANIES)

	2004							2004		2005		
Percent Pipeline Capacity Released	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
0	16	13	13	15	14	13	14	18	21	21	21	20
1 – 25	24	24	23	20	22	22	24	26	23	24	23	25
26 – 50	9	12	13	14	13	14	10	5	5	4	5	3
51 – 75	0	0	0	0	0	0	1	0	0	0	0	1
76 - 100	1	1	1	1	1	1	2	1	1	1	1	2

APPENDIX A

2004-2005 WINTER HEATING SEASON SURVEY PARTICIPANTS

AGL Resources
Ameren Corporation

Baltimore Gas & Electric Co.

Chattanooga Gas Company
Cinergy Corp.
Citizens Gas and Coke Utility
Clearwater Gas System, City of
Con Edison Co. of New York
Connecticut Natural Gas
Consumers Energy

Dominion – East Ohio Gas
Dominion Gas Delivery
DT Energy – Michcon

Equitable Resources

Hope Gas, Inc.

Indiana Gas Company
Intermountain Gas Company

KeySpan Energy Delivery-Long Island
KeySpan Energy Delivery-New England
KeySpan Energy Delivery-New York

LaClede Gas Company
Louisville Gas & Electric Company

MDU Resources Group, Inc.
Memphis Light Gas & Water
Mobile Gas Service Corp.
Mountaineer Gas Service Corp.

National Fuel Gas Distribution Co.
New Jersey Natural Gas
Niagara Mohawk Power Corp.
NICOR Gas
North Shore Gas Company
Northern States Power Company (Xcel Energy)
Northwest Natural Gas Company

PECO Energy
Peoples Gas Light & Coke Company
Peoples Gas System
Piedmont Natural Gas Co.
PNM Gas Services (Public Service of NM)
Public Service Co. of Colorado (Xcel Energy)
Puget Sound Energy

Questar Gas Company

Roanoke Gas Co.

San Antonio Public Service Board, City of
SEMCO Energy
Southern Connecticut Gas Company
Southern Indiana Gas & Electric Company
Southwest Gas Corporation

UGI Utilities

Vectren
Vermont Gas Systems, Inc.
Virginia Natural Gas, Inc.

Washington Gas Light Company
Wisconsin Public Service Company

Yankee Gas Services Co.

Southwest Gas Corporation

Gas Supply Portfolio – Financial Hedging Policy and Processes Overview

July 2006

Gas Supply Portfolio
Financial Hedging

Table of Contents

Section I:

Policy

Gas Supply Portfolio
Financial Hedging Policy

Background:

Southwest Gas Corporation ("Southwest" or "the Corporation") has established gas price Volatility Mitigation Programs (VMP) as a component of its natural gas procurement process. This component has been supported by the state commissions that regulate Southwest. The existing Arizona Price Stability Program (APSP) provides for the systematic purchase of baseload natural gas supplies at fixed-prices for a portion of the projected annual demand of Southwest's on-system, state-regulated bundled retail ratepayers ("customers").

As an enhancement of the existing APSP, Southwest is pursuing the ability to execute certain financial transactions. The primary business drivers for this course of action are: 1) to increase supplier liquidity; and 2) to expand the tools available for coping with varying market and operating conditions.

Supplier liquidity is the maintenance of robust supplier participation to provide bids and services to the VMP process. Most suppliers of fixed-priced and/or index priced gas supplies have an established limit on the amount of credit that they will extend to Southwest in the normal course of business. When that limit has been reached, the supplier will no longer participate in bid programs conducted by Southwest for natural gas supplies. Suppliers also have the option of not bidding in the Southwest solicitation programs when they deem market conditions are too volatile to extend fixed-price offers that must be available for the time period provided in Southwest's solicitation. By using financial instruments backed by index priced gas supplies, Southwest can augment the APSP by combining physical gas suppliers that currently only provide index-priced gas with financial institutions that engage in purely financial transactions that convert index-priced gas to fixed-prices (fixed for floating swaps).

In recent years, the gas market has become increasingly volatile and has experienced higher price spikes than have been observed in prior years. Southwest has also considered adding call options to the portfolio mix. The process to purchase call options for the portfolio requires the same effective internal control procedure as is required to purchase other financial instruments. Options provide another tool to guard against price spikes in the natural gas portfolio for its on-system, state-regulated bundled retail ratepayers. Due to increased volatility in the natural gas commodity markets the past several years, the cost of call options has increased dramatically. A careful evaluation of the costs and benefits of this financial tool must be performed prior to employing their use.

Purpose:

The purpose of this document is to:

- Set forth the policy for the gas supply portfolio financial instrument hedging activities;
- Establish the Governance Structure for the gas supply portfolio financial hedging objectives; and
- Establish the overall gas supply portfolio financial hedge processes and controls to meet the objectives.

This information serves as a guideline for financial hedging activities and the associated organizational requirements.

Policy Statement:

The VMP portion of the Southwest gas supply portfolio for on-system, state-regulated bundled retail ratepayers may from time-to-time contain a combination of hedges consisting of fixed-price physical contracts and financial instruments used as hedges to reduce gas price volatility for on-system sales customers.

Hedging activities for the gas supply portfolio shall be focused on reducing gas price volatility. The key to the policy is to maintain a disciplined, systematic, and transparent approach using simple hedging techniques.

Southwest is considering hedging activities that are solely associated with the business of prudently and reliably supplying gas to its customers. Therefore, no financial instrument shall be entered into that does not qualify as an effective option or hedge as defined by generally accepted accounting principles and the Federal Energy Regulatory Commission (FERC). The total of supply contracts, whether physical or financial, must not exceed the expected demand requirements for its on-system, state-regulated, bundled retail customers. Speculative trading for profit exceeds the risk tolerance of Southwest and therefore is not permitted.

A Risk Committee shall be appointed by the Chief Executive Officer which shall be responsible for approval and oversight of: 1) this policy statement; 2) the types of financial instruments to be utilized; 3) effective internal control procedures; 4) an information system that provides an adequate database for control and reporting; and 5) periodic reports to the Board of Directors.

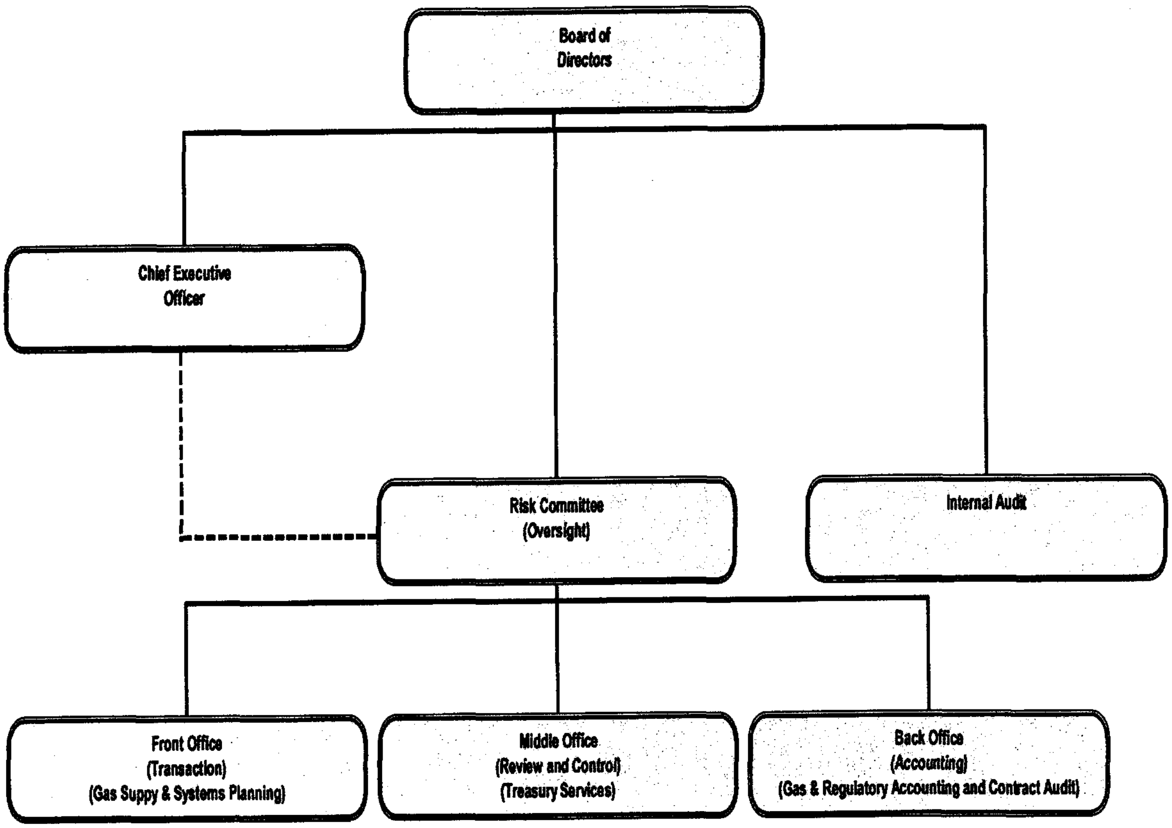
Internal Audit shall periodically review and report to the Board on the adequacies of the systems and internal control procedures established by the Risk Committee.

This policy statement has been reviewed and accepted by the Board of Directors of Southwest as of ____(Date)____.

Section II:

Governance Structure

Section II: Governance Structure



Board of Directors - General Responsibilities

The Board of Directors (Board) shall review and approve the Corporation's Financial Hedging Policy and overall risk management framework. The Board shall review and approve the governance structure, accountabilities, processes and controls that have been established by the Risk Committee to monitor and control financial exposure within the gas supply portfolio hedging processes. The Board will be responsible for the review of audit reports and for appropriate action thereon.

Risk Committee - Members

The Risk Committee shall consist of: 1) the Chief Financial Officer; 2) the most senior Officer responsible for the gas supply function; and 3) at least one other Officer of the Corporation as appointed from time-to-time by the Chief Executive Officer.

Risk Committee - General Responsibilities

The Risk Committee is responsible for the oversight of financial hedging as it applies to the acquisition of gas supply. The Risk Committee is also responsible for the approval of the Financial Hedging Policy (Policy) regarding financial hedges for gas supply and will oversee enforcement of the Policy to ensure that the hedging objectives and limits are adhered to by the Corporation. The Risk Committee responsibilities will include identification of any violation of any policies and procedures established herein. Further, the Risk Committee will oversee the development and implementation of a combination of systems and procedures that provides effective controls over all financial hedging activities. The Risk Committee will provide for reporting to the Board as needed or as required by regulation. The Risk Committee will be responsible for the approval of the types of financial instruments (options, swaps, etc.) to be utilized as hedges for the gas supply portfolio. The use of fixed price natural gas purchases under the existing VMP's is approved and will be monitored as part of the processes and controls set forth herein.

The Risk Committee will require and review risk reports prepared by the Middle Office. These reports shall at a minimum include: 1) mark-to-markets; 2) open positions; 3) limit utilization; 4) credit utilization; and 5) notice and status of any exemptions and exceptions. Meetings of the Risk Committee will be held at least monthly and will include a review and discussion of the above reports and a report of recommendations for any control requirements or enhancements.

Risk Officer

The Risk Officer shall be the Officer of the Corporation in charge of the Treasury Department or such other Officer as appointed by the CEO. The Risk Officer reports to the Risk Committee. The Risk Officer has the responsibility to develop and maintain all guidelines required for appropriate control infrastructure. This includes implementation and monitoring of compliance with the Financial Hedging Policy. The Risk Officer has direct oversight of the Middle Office functions of the Corporation. The Risk Officer is responsible for the development and administration of Middle Office processes and procedures. The Risk Officer will call and conduct routine Risk Committee meetings. The Risk Officer is responsible for reporting to the Risk Committee on the Corporation's compliance with its approved policies and controls.

Front Office - Members

The Front Office reports to the vice president in charge of gas supply portfolio purchases for on-system, state regulated bundled retail ratepayers. This Officer will assign Front Office responsibilities to employees from the Systems Planning Department and the Gas Supply Departments.

Front Office - General Responsibilities

The Front Office is responsible for the development and implementation of a hedging strategy for the gas supply portfolio within the parameters set forth in the Financial Hedging Policy. The hedging strategy will provide for the use of only those financial instruments which have been specifically approved by the Risk Committee and fixed-price gas purchases.

The Front Office in cooperation with the Middle and Back Office functions will develop and maintain documentation of procedures for conducting business related to the hedging of the gas supply portfolio. The Front Office responsibilities will include the set-up, maintenance and administrative functions for physical gas supply contracts within the operations system (currently the Gas Transaction System). The Front Office personnel that perform financial transactions will have proper knowledge and understanding of the instruments authorized to be utilized for hedging, trading limits, and restricted activities. The Front Office is responsible for the development of hedging strategies and procurement strategies in compliance with the Financial Hedging Policy.

Other responsibilities include administering solicitations for both fixed-price contracts and financial instruments for hedging the gas supply portfolio. The Front Office will plan the solicitations, review and evaluate bids and approve individual transactions. The Front Office will maintain documentation of all plans, bid solicitations, and bid negotiations for audit reviews and regulatory proceedings. Data for each transaction will be documented in the Hedge Capture and Control System (HCCS) by the Front Office at the time of the transaction. The Front Office will ensure accuracy of transaction terms in the HCCS and will work with the Middle and Back Office to resolve any errors or discrepancies on a timely basis. The Front Office is also responsible for negotiations of contracts with all gas suppliers.

Members of the Front Office will read, understand, and comply with the Financial Hedging Policy and the specific code of ethics set forth herein. Further, the members will comply with all other Corporate policies and the Code of Business Conduct and Ethics. Individual members will be responsible: 1) to maintain confidentiality of information used in hedging; 2) not perform any personal trading of natural gas as futures or derivatives; and 3) to report any violations of Corporate policies using methods consistent with the Southwest Gas Corporation Code of Business Conduct and Ethics.

Middle Office - Members

The Middle Office reports to the Officer in charge of the Treasury Department or such other Officer as appointed by the CEO. Other personnel with Middle Office responsibilities shall include the Senior Manager/Treasury and other employees within the Treasury Department as assigned by the Officer in charge.

Middle Office - General Responsibilities

The Middle Office serves as a central control or "policeman" for Financial Hedging Policy compliance. The Middle Office is responsible for maintaining the overall control environment for the financial hedging program for the gas supply portfolio and assessing compliance with the Financial Hedging Policy. Further, the Middle Office will conduct all activities regarding credit with counterparties. The credit activity will include establishing counterparty credit limits, and reviewing supplier positions. The Middle Office will perform financial reviews of the issuers of counterparty guarantees, monitor counterparty credit events for adverse effects on credit profiles and report to the Risk Officer credit exposures and credit risk metrics.

The Middle Office will: 1) confirm all financial transactions; 2) establish a rigorous process to ensure that all confirmations are reviewed and submitted pursuant to the transaction and contract terms; 3) maintain transaction detail and acknowledgement records; 4) validate all transaction details entered by the Front Office within the HCCS; 5) administer contracts and maintain custody of static master agreement data; 6) support risk systems, infrastructure development, and maintenance efforts; 7) identify opportunities for enhancement in the control environment to ensure compliance with policies, guidelines, and limits; and 8) report any violations of such to the Risk Officer. The Middle Office serves as the support staff for the Risk Officer by providing periodic reports of risk exposure, as well as performing periodic stress testing and calculating the Mark-to-Market and Values at Risk (VaR's) as directed by the Risk Officer.

Back Office - Members

The Back Office function reports to an Accounting Officer of the Corporation as appointed by the CEO. Other personnel with Back Office responsibilities will include other employees of the Accounting Department as assigned by said Officer.

Back Office - General Responsibilities

The Back Office includes the accounting for the Corporation for all financial hedging activities. The Back Office will ensure compliance with generally accepted accounting principles as may apply to financial hedging. This will include recording accounting entries for approved transactions, processing related bills and invoices and tracking payables and receivables related to financial hedging instruments and reconciling the transaction sub-ledger. The Back Office will reconcile margin accounts (as required). The Back Office will perform Settlements Actualization process.

Internal Audit - General Responsibilities

Internal Audit responsibilities will include: 1) reviewing and reporting to the Board on compliance with the Financial Hedging Policy; 2) conducting audits of the integrity of information systems and procedures to ensure effective control; and 3) conducting audits of trading operations to ensure compliance with controls, policies, and procedures.

Other Support Functions:

Support areas such as legal and information technology, play active roles in reducing the business risk profile of the gas supply portfolio hedging process.

Legal

Legal support is necessary when establishing new trade agreements or contracts, and resolving counterparty non-performance issues.

Legal will review trade agreements and contracts. Legal will also advise on applicable bankruptcy or insolvency laws and on the procedures necessary to ensure enforceable transactions and adequate documents.

Information Technology

Information Technology (IT) is critical to the hedging operation in ensuring that systems are in place and function so that transactions may be accurately captured and reported in a timely manner. The IT system supporting the hedging of the gas supply portfolio must provide for: redundancies; effective management of data; security of data; change control; disaster recovery; and business continuity plans.

Section III:

Processes and Controls

Section III: Processes and Controls

Governance Responsibilities

Risk Committee
- Oversight for processes and controls
- Approve types of financial instruments
- Ensure compliance with policy

Front Office (Gas Purchases)
- Develop strategy
- Implement transaction
- Record transaction
- Develop price curve

Middle Office (Treasury)
- Manage credit risk
- Develop and send deal confirmation
- Develop position risk data
- Ensure compliance with approved policies
    - ♦ Validate price curve

Back Office (Accounting)
- Settlements actualization
- Transaction accounting

Internal Audit
- Conducting audits of trading operations
- Conducting audits of information systems
- Reporting to the Board on compliance with policies and adequacy of procedures

Process and Controls - General Description

The following section provides directives for the business process and controls to be used for hedging activities related to the gas supply portfolio for Southwest's on-system, state-regulated bundled retail ratepayers.

In general, the process and controls address execution, validation, risk control, and accounting for individual transactions. The Risk Committee is responsible for approval of the types of financial instruments (options, swaps, etc.) to be utilized as hedges for the gas supply portfolio.

The Front Office is responsible for the development and implementation of a hedging strategy for the gas supply portfolio within the parameters set forth in the Financial Hedging Policy utilizing the types of financial instruments that have been approved by the Risk Committee. If a transaction requires the movement of physical gas, the Front Office is responsible for scheduling gas flow with a transportation provider. The Front Office is also responsible for entering details of the transactions into a system (Hedge Capture and Control System).

After a transaction has been executed and details of the transaction captured, the Middle Office is responsible for independently verifying the propriety and the accuracy of the transactions through third-party confirmations. This process serves as key control function over the deal execution process. The Middle Office is responsible for monitoring the deal over its life to ensure that contract provisions are maintained and credit risk managed. The Back Office is responsible for the appropriate accounting and reconciliations for these transactions.

Financial Instrument Approvals - Description

This process is designed to provide controls over the types of financial instruments to be utilized for hedging the gas supply portfolio. The Front Office is responsible for the development and implementation of a hedging strategy. A report detailing the instruments to be utilized, their uses, and an evaluation of any associated risks will be submitted to the Risk Committee for approval. Once the use of the instruments is approved, authorizations are issued and the approvals are communicated to the appropriate functional areas.

This process is designed: 1) to ensure that due diligence has been performed before the Corporation enters into transactions involving new financial instruments or transaction structures; 2) to develop a full understanding of the financial instruments and transaction structures; and 3) to establish proper management approval before entering into contracts with financial instruments or transaction structures.

Financial Instrument Approvals - Process

The Front Office will propose the financial instruments to be utilized for hedging the gas supply portfolio. The Front Office will develop a plan for use of the instruments including a description of the instruments and transaction structures, the hedge to be achieved, and the associated risks. The plan will be presented to the Risk Committee for review and approval of the types of instruments and transaction structures to be utilized.

The Front Office will explain the instruments and/or transaction structure to the Middle Office and Back Office to ensure that the HCCS is capable of capturing and tracking the transaction and that proper accounting treatment can be achieved. The Middle Office will compare the proposed new instruments or deal structure to the Financial Hedging Policy to ensure compliance with said policy.

The Middle Office will maintain the list of approved instruments, transaction structures, counterparties and credit limits, attached in Appendix B hereto. The Middle Office will review transactions to ensure they are in compliance with approved policies and report any non-compliance to the Risk Officer.

<u>Price Forwards Development and Validation</u> - Description

Forward curves, including correlation curves, price curves, yield curves, and volatility curves are the primary driver of portfolio valuation and, therefore, it is essential to ensure the accuracy and the consistency of the methodology used in preparing forwards. As such, the Front Office will obtain prices from quotes, online trading platforms, industry publications (both electronic and paper), transactions executed with counterparties, and other methods approved by the Officer in charge of the Front Office. For the purposes of validation, the Middle Office will independently evaluate the forwards provided by the Front Office. Inputs will include broker quotes, publications, and other sources for transaction prices.

<u>Price Forwards Development and Validation</u> - Processes

The Front Office will prepare price forwards for all financial instruments and fixed priced contracts utilized. When available, the market or published price will be utilized for forward prices; and when not available, the forward price will be modeled. (A model may be a simple spreadsheet reflecting basis differentials and futures prices.) A formal methodology will be established for each price forward and documentation maintained. Price discovery reports will be prepared by the Front Office that includes quotes, trades, bids, electronic trading platforms, and data feeds.

The Middle Office will independently verify the accuracy of the price forwards provided by the Front Office. For all modeled price forwards, the Middle Office will validate the inputs and verify model outputs. Custody of forward curves and pricing models will reside with the Middle Office.

Any disputes between the Front Office and Middle Office will be resolved by the Risk Officer with input from gas supply management. Final authority for approval will rest with the Risk Officer.

Contract and Deal Management - Description

Before executing a transaction with any counterparty, the Front Office will develop a legally binding master agreement. The negotiators will utilize existing standard enabling agreements which have been approved by the Legal Department. Any changes to the standard agreements require Legal Department approval and sign-off, and senior officer of gas supply approval. Once an agreement is reached and the master agreement has been executed by all parties, the provisions are captured in the HCCS by the Middle Office which retains custody of master agreement static data and they are monitored by the Middle Office throughout the life of the master agreement to ensure the provisions are met.

The Front Office will ensure that all transactions are executed consistently in accordance with the terms and conditions of the master agreement. If any transaction has any optionality, the Front Office is responsible for ensuring that these options are exercised appropriately. Any potential or actual violations of the master agreement terms should be immediately identified, communicated internally and to the counterparty, and resolved.

Contract and Deal Management - Process

The Front Office is responsible for all negotiations for all master agreements. All negotiations will be coordinated with the Middle Office for credit approval and with the Legal Department for approval of the master agreement. Industry standard master agreements, such as ISDAs, as modified to comply with Corporate standards will be utilized whenever possible. All other agreements should be reviewed and approved by the Legal Department and senior Officer of gas supply. All agreements should contain net-out, set-off, book-out, and margining provisions detailed in the agreement. Any changes to agreements should be circulated to those individuals in the Middle Office as designated by the Risk Officer and those individuals in the Back Office as designated by the Accounting Officer.

The Front Office will facilitate the agreement approval process and ensure that all approvals are obtained. The original agreements will be stored in a locked, fireproof environment. A copy of the agreement will be available for review by the Front Office and Middle Office. The Middle Office will function as contract and transaction administrators. They will maintain all files and records for each counterparty including, but not limited to name, address, contract names, phone numbers, bank account and wire information. The Middle Office will report any master agreements approaching credit limits or expiration to the Front Office and the Risk Officer.

The Front Office will ensure that all deals are executed in compliance with the terms of the agreements. If a deal has optionality, the Front Office is responsible for ensuring that the options are exercised appropriately. The Middle Office will ensure that the responsibilities of all parties to the agreement and/or transactions are performed. Any non-performance should be identified and quantified by the Middle Office, and resolved by the Front Office and the Risk Officer.

Each quarter, the Internal Audit group will audit procedures and controls to verify that transactions and master agreements are properly recorded within the system.

<u>Trading Control</u> - Description

The Front Office and the Middle Office establish a process that ensures control of trading activities. The process is designed to ensure that financial instruments and transaction structures have been approved and that those transactions executed by the Front Office are entered into the HCCS and independently confirmed and validated by the Middle Office.

This process is designed to: 1) provide for risk mitigation during transaction creation; 2) ensure complete, accurate, and timely transaction entry; 3) provide a sound internal control environment with separation of duties; and 4) furnish confirmation of transactions through third-party written verification.

<u>Trading Control</u> - Process

Prior to the start of any trading session, the Front Office will verify contracts are in effect and credit is sufficient. The Front Office will hold a strategy discussion to review current positions and review the plan for the hedges to be implemented. The Front Office will verify authorized counterparties lists and the credit approval and limits for all counterparties.

The Front Office will establish a time and date for "bid solicitation sessions" and notify approved counterparties. The notice will include a description of instruments or transaction structures to be considered. Bid evaluation and selection will be conducted by the Front Office during the bid solicitation sessions. The Front Office will ensure the terms of the transaction are entered into the system immediately. All telephone calls for negotiating and consummating transactions will be performed on a recorded line.

At execution, the Front Office will be responsible for entering and validating transaction terms into the HCCS. Transaction tickets will be prepared and forwarded to the Middle Office personnel for use in independently validating the deal entry and confirming the deal. The Front Office will review and sign all new transaction summary reports and the new transaction tickets which are immediately forwarded to the Middle Office. All change reports will go directly to the Middle Office.

Once verified by the Middle Office, a transaction confirmation will be prepared and forwarded to the counterparty. Transaction confirmations should be generated within four (4) hours of all transaction consummation. All confirmations sent and or received will be logged and tracked by the Middle Office. The confirmation format will be approved by the Legal Department. If a disputed confirmation from the counterparty is received by the Middle Office, the Front Office and the Risk Officer will be notified upon receipt of the notice to ensure that all parties are aware of the discrepancy. The Risk Officer shall be responsible for ensuring all discrepancies are reconciled.

All transaction tickets and confirmations will be retained for reporting requirements as set forth in regulation and/or the Corporate Retention Policy.

At confirmation, the deal will be locked into the HCCS and will only be modified upon approval by the Middle Office person with the proper level of authorization as established by the Risk Officer. Status of the confirmation will be updated, logged, and monitored by the Middle Office. The HCCS will create unique trade identification numbers and provide an audit trail of who has entered or changed the transaction entry and when the entries occurred.

Risk Control and Credit - Description

Each day the Middle Office will ensure that positions are recorded accurately and that credit and counterparty risks are measured. The process will include the review of daily reports to assess positions. The risk control and analysis process will include: 1) verifying the Mark-to-Market (MTM) valuation; 2) accounts receivables; 3) calculating risk measures, such as Value at Risk (VAR); 4) performing sensitivity analysis and stress testing; and 5) calculating any other risk metrics and analysis as directed by the Risk Officer.

The credit control process will be conducted by the Middle Office. The Middle Office will establish the limits on the amount of activity the Corporation is willing to transact with each counterparty. The Middle Office will monitor credit exposure and report any violation of the credit limits to Front Office and the Risk Officer so that corrective action can be taken.

Risk Control and Credit - Process

The Middle Office will ensure that all agreements and transactions do not exceed the predefined limits established by the Risk Officer.

For risk management purposes, both physical and financial positions will be marked-to-market (MTM) on a daily basis. The MTM will be calculated on both a nominal and a present value basis. Futures, swaps, forwards, and physical gas portfolio assets will be valued against the appropriate market prices. Single-variable options (calls/caps) will be valued against a Black-Scholes options model. A consistent measure should be used to calculate the market and credit risk of positions and compare it with credit risk limits.

At the close of each day's business, the Middle Office will lockdown the HCCS, validate the updated price curves and trades. The Middle Office will then initiate the risk report runs, including positions, MTM and VAR. The parameters for calculating MTM, VAR and other risk metrics, and issuing credit limits, must comply with guidelines established by the Risk Officer and approved by the Risk Committee.

A credit policy will be established by the Risk Officer with approval by the Risk Committee. It will include processes for establishing and approving limits, procedures for measuring and monitoring exposure, maintaining collateral and obtaining exceptions.

Each counterparty will be rated and have credit limits established prior to any deal execution with that counterparty. The Middle Office will monitor news articles, bankruptcy filings, legal actions, etc., for all established counterparties. As needed, full reviews will be conducted for each counterparty to assess potential changes in credit limits.

Settlements Actualization - Description

The Back Office will be responsible for settlement actualization. Settlements actualization is the process of reconciling any volumetric or pricing estimates to the actual amounts before invoicing and/or providing settlement statements to the counterparty. Statement items are confirmed with interstate pipelines for physical volumes delivered and the counterparty for other items as part of the statement preparation process. Any discrepancies are brought to the attention of the appropriate Front Office personnel for resolution with the counterparty.

This process tracks the variances by counterparty by location, by purchase contract, and by transport contract among other variables.

The Back Office will report variances and trends to appropriate Front Office personnel for active evaluation and to the Middle Office for fraud vigilance. The Front Office and the Middle Office will report any improper or out of the ordinary findings to the Risk Officer for resolution. The settlement process includes verification of data, and the preparation of statements and check requests. These functions are performed by the Back Office independently of the trading processes. Settlement payments are processed pursuant to GP&P. Settlements are to be netted where possible, aggregating purchases, swaps, and options with each counterparty.

Settlements Actualization - Process

The Back Office will reconcile scheduled volumes with actual flows using pipeline data feeds. The existing system(s) (Gas Transaction System) used for physical gas purchases maintains historical data as an audit trail. For any discrepancies between scheduled and delivered volumes and penalties, etc., the counterparty should be contacted by the Back Office for verification and reconciliation. Any discrepancies identified during the monthly settlement processes must be resolved. The Back Office will contact the Front Office and the two should conclude resolution of discrepancies with counterparties and the interstate pipeline transporters, as necessary.

Settlement statements will be prepared and forwarded to counterparties in accordance with the terms of applicable agreements. Intercompany transactions will be confirmed and net amounts captured in financial records using the processes utilized for counterparty transactions. The settlement function for financial instruments shall be performed within the Back Office.

The Back Office is responsible for ensuring that payment requests are processed and received timely. Where possible, netting should be included for each counterparty's settlements. The Back Office shall monitor receipts and payments of balances due. The

Back Office shall notify the Middle Office and the Front Office of any past-due payments or underpayments by counterparties. The Middle Office shall proceed to collect any past-due or under-paid amounts pursuant to the terms of the master agreement.

Compliance with Accounting and Disclosures Rules - Description

The Back Office will ensure that proper accounting treatment is applied to all financial instruments used as hedges. The Back Office will work in conjunction with the Front Office and the Middle Office to ensure that proposed transactions meet the standards set forth in the Policy and that appropriate information is obtained to properly record and disclose hedging transactions. All departments will cooperate to ensure that the Back Office has all information needed to meet financial disclosure requirements in a timely and accurate manner, as defined by regulatory agencies (SEC, FASB, FERC, and State Regulatory bodies).

Compliance with Accounting and Disclosure Rules - Process

Generally accepted, accounting procedures will be followed in all instances. The Back Office will adhere to all applicable regulatory disclosure requirements. This includes disclosure of any changes in accounting methods, measurement techniques for hedge positions, analysis calculations and estimates. Processes and procedures for accounting for hedges of the gas supply portfolio will be reviewed by the Risk Committee and approved by the Chief Accounting Officer and the Chief Financial Officer of the Corporation.

Risk Reporting - Description

Risk reports are tools that specifically address credit, liquidity, financial and operational risks of the hedging program. These reports are used by the Front Office, the Middle Office, the Back Office, the Risk Officer, and the Risk Committee to monitor and evaluate risks. The reports will cover critical risks and positions associated with hedges. Reports will be prepared by the Middle Office on a daily basis and the Back Office as directed by the Chief Accounting Officer.

Risk Reporting - Process

The Middle Office will be responsible for the daily preparation of position and credit reports. Other reports or analysis will be prepared as directed by the Risk Officer. Where possible, risk reports will be available through the HCCS. Risk reports will include all hedged gas supply positions, including fixed-price physical transactions and financial transactions. The reports will be reviewed and validated by the Middle Office. Daily risk reports will be initiated as soon as markets close and shall be distributed no later than the beginning of the next business day. Position reports, credit reports, and MTM reports shall be categorized by physical transactions and types of financial transactions within each regulatory jurisdiction and then aggregated to the Corporate level. MTM's and limits will be reported daily. Margin reports, stress test results, and limit violations will be reported monthly.

Section IV:

Hedge Capture and Control System

Hedge Capture and Control System (HCCS) - Description

A key component of the gas supply portfolio hedging infrastructure is the HCCS. The system is used to capture deal terms, document and manage those terms, value transactions, document approvals and to calculate positions (risk and credit). The system to be implemented will provide the basis for the processes set forth in the Gas Supply Portfolio Financial Hedging Policy and Processes. However, no system will provide a fully integrated solution without significant modifications. Therefore, the system will provide functional support and detailed procedures will be developed around system functionality.

The practices set forth below are general best practices and controls for a system. However, the final HCCS to be implemented may require manual processes to economically achieve these goals. The use of some manual intervention should not necessarily be construed as a degradation of controls over the use of financial hedges.

Hedge Capture and Control System - Leading Practices

The objective of the following list of leading practices is to ensure that the HCCS used to support financial hedging operations has the capability, security and data integrity to properly and accurately capture data and provide adequate controls for the trading process. Some of the items listed below may become manual interfaces depending on the design of the final system implemented.

The energy trading system should be able to capture all energy transactions or positions dealing with the hedging of the gas supply portfolio, both fixed-price physical deals and financial instruments used as hedges.

The system should calculate MTM and VAR.

The system should contain a detailed audit trail and a change log by user ID. The system should lock transactions' details upon input and validation.

Controls should ensure that changes to any data entry requires proper authorization and/or requires confirmation from the Middle Office.

The system should allow for logical user groups within the Front Office, Middle Office, and the Back Office. Permissioning should be granted consistent with these predefined user groups and predefined levels within those user groups.

Business continuity plans should be established and tested on a regular basis.

System ownership should reside in the Middle Office with system support maintained through the Information Systems, Applications Services Department.

Hard copies should be maintained for all transaction data (e.g., confirmations, deal slips, etc.) in accordance with the Corporate Retention Policy.

System back-up should occur daily to ensure system integrity.

Section V:

Code of Ethics

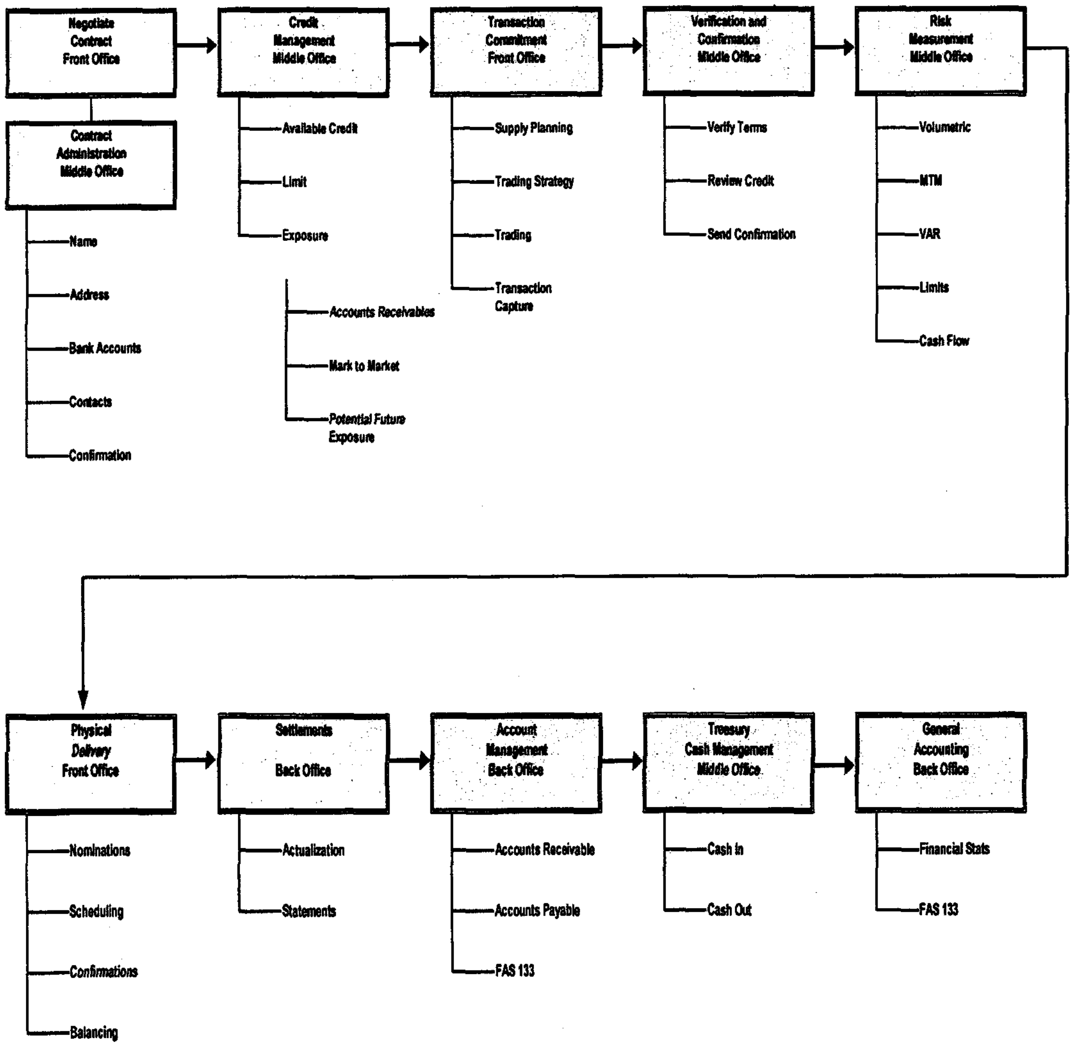
Code of Ethics

All employees dealing with the hedging of gas supply portfolio (Front, Middle, and Back Office) shall comply with the "Code of Business Conduct & Ethics" for Southwest. In addition, all said employees shall abide by the specific items set forth below:

1. Maintain and adhere to internal procedures designed to ensure that all trades/hedges are properly documented and that no trades/hedges are concealed or misrepresented.
2. Maintain documentation on all transactions as required under applicable laws regulations, policies, procedures, and the employee handbook.
3. Avoid participation in any form or fashion in "wash trades" (e.g., simultaneous offsetting buy and sell trades).
4. Not participate in any personnel financial transactions regarding natural gas futures or derivatives thereof.
5. Comply with all applicable laws, regulations, policies, procedures, and the employee handbook.
6. Disclose to an Officer of the Corporation or the Corporate Compliance Officer, any practices that violate or may violate this Gas Supply Portfolio Financial Hedging Policy and Processes.

Appendix

Transaction LifeCycle



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Southwest Gas Corporation

Portfolio Evaluation
Software Review

July 2006

Portfolio Evaluation Software Review

Introduction

As an outcome of the Arizona General Rate Case (G-0155A-04-876), the Commission adopted Staff's recommendation that Southwest Gas Corporation (Southwest or Company) examine certain gas procurement practices in order to enhance greater price stability for customers. As such, Southwest agreed to a number of recommendations including: conducting a fuel and procurement practice benchmarking study; separating the contract award group from the invoice approval authority within the Company; *reviewing Southwest's portfolio evaluation software* (emphasis added); eliminating the use of cell phones in term bidding and negotiating activities and having a neutral party observe these activities; and reviewing stock ownership rules for employees in gas procurement.

Background

Prior to this rate case and for over ten years, Southwest has selected indexed-based term supply contracts for its Arizona system utilizing the optimization and dispatch software package "UPlan-G" (developed and owned by LCG Consulting). UPlan-G is a software package that utilizes a linear optimization model to determine a least cost mix of resource contracts. The contract selections are a function of the forecasted daily demand, available contracted interstate resources, and contract pricing.

Software Models

Southwest conducted research to identify software that is currently available to Local Distribution Companies (LDC). There are currently three distinct groups of software available: Macroeconomic Models, Transactional Software, and Optimization and Dispatching Models.

The first group[1], Macroeconomic Models, model gas resources on a regional level. That is, the software is designed to evaluate gas flows between different regions of the country as a function of demand, supply price and available pipeline and storage facilities. The results of these models show how the gas and money flow between these regions as a result of changes to the market. This group of software is not designed to develop an individual LDC's supply portfolio, but rather models the supply/demand interactions within the United States.

The second group[2], Transactional Software, provides the LDC with the ability to maintain the data necessary to track each supply-related transaction that occurs in the day-to-day purchase, transportation and sale of natural gas. This group of software does not provide any ability to optimize the selection of the LDC's portfolio of supplies, transportation and storage resources.

The third group, Optimization and Dispatch Models, enables the LDC to optimize the selection of natural gas supply contracts, natural gas transportation contracts and natural gas storage contracts. Two Optimization and Dispatch software packages are currently available: New Energy Associates "Sendout" and LCG's UPlan-G. Each of these two software packages helps the LDC to develop an effective portfolio by determining a least cost group of indexed-based term supply, pipeline and storage resources. Currently, neither of these two packages couples the development of a least cost portfolio with the ability to develop an effective risk management strategy. New Energy Associates claims over one hundred LDCs use Sendout and LCG Consulting has informed Southwest they have fourteen licenses with clients.

Conclusion

As stated above, the only Optimization and Dispatch Modeling software packages currently available for use in selecting indexed-based term supplies are Sendout and UPlan-G. While both of these software packages utilize linear optimization algorithms to select an indexed-based supply portfolio, there have been significant differences in how data is input into these models, and how the results of the optimization are reported to the user. Southwest is currently using the UPlan-G optimization modeling software to aid in the development of Southwest's Arizona indexed-based term supply portfolio. UPlan-G continues to meet Southwest's needs and a review of the Sendout software did not reveal any functionality that would warrant changing software at this time. Southwest will periodically monitor developments in this segment of the software industry and inform the Commission Staff of this activity.

1. RBA Consultants "GPCM Natural Gas Market Forecasting System", Altos Management Partners "MarketPoint Model" and "North American Regional Gas Model".
2. Sol RC "Right Angle", e-Systems "Attaché", Allegro Development "Allegro", EnCompass Technologies "EnCompass Application Suite", Trinity Apex "TIES II".