Fall 2009 Edition

Natural Gas TODAY

For Municipal Gas Systems

Read about APGA's answer to the DIMP rule, SHRIMP on page 2A!

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Risk Management

This is a continuation of the Risk Management series from the Winter edition of the Natural Gas Today. This edition will focus on the basics of futures. All information in this series is courtesy of the NYMEX.

FUTURES BASICS

Prior to the launch of the Exchange's first natural gas futures contract on April 3, 1990, participants in the natural gas industry had limited means available to manage the relatively new risk of price uncertainty created by deregulation. Ultimate buyers and sellers of natural gas could try to enter into fixed-price transactions. Marketers could attempt only back-to-back transactions. Risk management depended heavily on a company's ability to find a counterparty, or in the case of a marketer's, two counterparties, with equal and opposite needs.

The natural gas futures contract greatly expanded risk management opportunities. By bringing together diverse market participants in a central forum, natural gas futures readily allow natural gas buyers and sellers to hedge their price exposure by transferring the risk to investors or to other commercials with inverse risk profiles. Moreover, the natural gas futures market provides an efficient means to discover the market value of natural gas, not just for the next delivery month, but for many months into the future.

The success of the natural gas futures contract in meeting the industry's price discovery and risk management needs is clearly demonstrated by the growth of trading activity and open interest in the contract. Open interest defines contracts for which there is no offsetting sale or purchase, or for which actual delivery has not yet taken place.

What is a Futures Contract?

A commodity futures contract is legally binding. The buyer and seller agree to make or take a cash payment for a physical commodity at an agreed price with the actual delivery and payment to take place at a set date in the future. However, a futures contract has additional features that make it unique - and extremely useful to buyers and sellers of the underlying commodity.

Futures are standardized, fungible, and traded in a centralized marketplace at publicly disseminated prices. They enable the trader to buy or sell (go long or short), and can be traded anonymously.

The quantity of the commodity covered by a futures contract, the delivery period, the specifications and location for delivery, and the timing and method of payment are all standardized. For example, assume a marketer has agreed to sell gas in May to a manufacturing company for $1.81. He does not yet own the gas, so to protect against the risk of a price increase, he purchases one natural gas May futures contract at a price of $1.80 per million British thermal units (MMBtu).

In purchasing the futures contract, he has entered into a contractual agreement to buy 10,000 MMBtu of gas (the standardized quantity) at the Sabine Pipe Line Co.'s Henry Hub in Louisiana (the standardized place of delivery) during the month of May (the standardized delivery period) at a price of $1.80 per MMBtu. The price, of course, is not standardized. It reflects the value of that commodity at that time. Futures prices change continually. The price of a futures contract at any given moment reflects the price that a buyer and a seller have most recently agreed upon, and it may change again in minutes (or seconds) when another buyer and seller agree to a contract at a higher or lower price.

Market participants do not always find these standardized terms ideally suited to their specific needs. However, without standardization, futures markets as we know them could not exist.

Market participants can get out of their positions easily. Take the marketer who has purchased one May contract at $1.80/MMBtu. Two weeks later, he buys gas from a producer to cover his cash market obligation and therefore needs to terminate his futures obligation. He is able to do so simply by selling one May natural gas contract. In other words, he does not have to locate the party on the other side of the trade or search for another counterparty. Instead, he reenters the futures market and sells an offsetting contract with the same delivery month as the one he previously purchased. The sale liquidates the earlier purchase and leaves him 'flat.' In other words, his position is closed and his obligation is terminated.

Continued on page 4A.

RECORD HIGH STORAGE INVENTORY, BEWARE OF COLD WINTER STRAIN

Storage inventory hit a record high during the last full week of September. The EIA reported a total of 3,589 Tcf in storage across the country with five weeks left in the injection season. This report surpassed the previous record for the same week of 3,254 Bcf back in 2006. However, industry analysts are beginning to caution thoughts of complacency. Some weather forecasters have indicated cold weather on tap for parts of the country this winter, which could drain storage inventories quickly.

For most of the summer, market analysts have been attempting to predict how full storage can get by the end of the injection season. Estimates have ranged from 3.7 Bcf to 3.9 Bcf, heftily surpassing 3.5 Bcf which was once thought to be the maximum fill. Recent weekly injections have averaged between 60 Bcf and 70 Bcf. These numbers are expected to decrease during the final weeks of the injection season. There's just nowhere to put the gas and pipelines have already begun calling OFOs due to increased linepack.

Once winter begins, buyers beware of the strain a cold winter could put on storage. With the downturn this past year in prices, rig counts have fallen in half from their September 2008 peak of 1606 (see Rig Count graph on page 3A). Production may not be able to keep pace with cold winter weather, which could cause a sharp increase in withdrawals and in turn prices. Let's just hope for a normal to mild winter.

With summer gone and October rolling off the board, thoughts are now turning to winter. Storage sits full, winter forecasters are predicting some cold and supply is dwindling. What's your inventory estimate for end of winter storage?

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Resources Available To Help With Integrity Management Plans

This article ran in the Fall 2009 issue of the American Public Gas Association's magazine THE SOURCE. The author, John Erickson is the Vice President of Safety and Operations for the American Public Gas Association.

Between now and the end of the year, the Pipeline and Hazardous Materials Safety Administration (PHMSA) is expected to release the long-awaited Distribution Integrity Management Programs (DIMP) rule. As often stated, this rule is expected to have a major impact on gas distribution operators, perhaps the most significant impact since the federal government first started regulating pipeline safety in 1970. The rule will require utilities to prepare and follow written DIMP plans within 18 months of the final rule. The rule spells out seven elements all plans must include.

Thanks to the APGA Security and Integrity Foundation (SIF) with support from PHMSA, utilities will have tools available to help write their DIMP plans. A powerful, yet flexible, plan-development tool called "SHRIMP" is nearing completion and will be available when the final rule is issued.

What is "SHRIMP"?

SHRIMP stands for "Simple, Handy, Risk-based Integrity Management Plan." It is an online tool that operators of gas distribution systems may use to create a written Distribution Integrity Management Plan. SHRIMP produces a complete, written DIMP plan customized for the specific needs of the user. It is much more than a model plan. It is more like Turbo-Tax, which asks questions about a user's finances and creates an income tax return ready to sign and submit. SHRIMP asks questions about the user's distribution infrastructure and creates a written DIMP plan ready to implement.

SHRIMP includes:

- A template for a written DIMP plan, which is filled out with user-specific information over the course of using SHRIMP;
- PHMSA Distribution Annual Report data preloaded into the program, so it already knows about the user's materials of construction and leaks repaired by cause once the user selects his/her system from a pick list of utilities in the PHMSA database. Users can edit these data or enter from scratch, if not found (as will be the case with master meter systems, which do not file annual reports);
- A question-and-answer threat assessment process including:
  - → Questions that ask for specific construction, inspection and maintenance history (e.g., "knowledge of the infrastructure") to assess each of the eight threats required by the DIMP rule,
  - → Questions that ask for information to help the user decide if subdividing the system for any threat is advisable, and
  - → Questions to help SHRIMP recommend one or more Additional/Accelerated Actions to address one or more threats;
- A mathematical risk-ranking model to rank threats according to the relative risk;
- An opportunity for users to revise the risk rankings, while entering the justification for each change, with the explanation incorporated into the final written DIMP plan;
- A list of possible Additional/ Accelerated Actions ("A/A Actions") the user may choose to address each threat. SHRIMP may recommend one or more A/A Actions and/or eliminate some from the possible choices based on the answers provided by the user in the previous steps. The user can enter his/her own A/A Action if the utility wished to address a threat through an A/A Action not listed in SHRIMP;
- A list of possible performance measures the user may choose to evaluate the effectiveness of the DIMP program in controlling each identified threat. SHRIMP may recommend one or more performance measures and/or eliminate some from the possible choices based on the A/A Actions selected by the user. The user can enter his/her own performance measure if they have a better idea. The seven performance measures required by the rule are written into all DIMP plans generated by SHRIMP;
- Includes all mandatory items, such as leak management, excess flow valve installation, recordkeeping, periodic evaluation and improvement, and more.

SHRIMP then generates a written DIMP plan customized based on the information entered by the user and the selections made by the user during the SHRIMP process.

Guided by Industry and Government Experts

At every step of its development, SHRIMP was guided by an advisory group composed of industry and state and federal pipeline safety regulators. In fact, SHRIMP's development was funded by PHMSA. The advisory group included one state pipeline safety manager from each of the five regions of the National Association of Pipeline Safety Representatives (NAPSR). Such input by the regulators at every phase provides confidence in the SHRIMP process.

Not Just for Small Operators

The only thing small about SHRIMP is its cost. SHRIMP is a complete DIMP compliance program, meeting all the requirements of the DIMP rule. While intended for small utilities, it may be used by ANY utility regardless of size. The SIF and PHMSA have taken care to ensure that the DIMP plans developed by SHRIMP fully address all the requirements of the rule - the same high standard that applies to all utilities from the very largest to the smallest.

For utilities with 5,000 or fewer customers, SHRIMP is **free**. For larger utilities, the cost is minimal, with proceeds used to provide technical support and enhancements to SHRIMP.

When Will SHRIMP Be Available?

SHRIMP currently is under development but will be available when PHMSA issues its final DIMP rule, expected to occur this fall. For up-to-date information on SHRIMP, log on to www.apgasif.org. For further information, contact John Erickson, APGA Vice President, Operations at 202.464.0834 or jerickson@apga.org.

An Early End to the Hurricane Season?

Written by Ed Dunham

Edited and reprinted with permission from the Central Florida Hurricane Center - http://flhurricane.com

On October 1st the Gulf of Mexico and the Caribbean Sea were dry aloft. The southern subtropical jet stream was well established from the Gulf through the Caribbean Sea and extended eastward to western Africa. Windshear was moderate to strong in all of the Atlantic basin tropical cyclone genesis zones. Easterly waves over western Africa have diminished in magnitude. If it had not been for the unusual arrival of Tropical Storm Grace in the far northeast Atlantic, it would have been the earliest end to the season (September 12th) ever recorded in the past 158 years.

In 1918 the season ended on September 14th, in 1855 and 1930 it was September 17th and in 1914 the only storm of that season ended on September 19th. There is still a chance for another hybrid subtropical type of system - but not much of a chance. There is a better chance that the next named system might not show up until next July. The current moderate El Nino is expected to strengthen during the winter, but it will probably slacken off considerably by early summer.

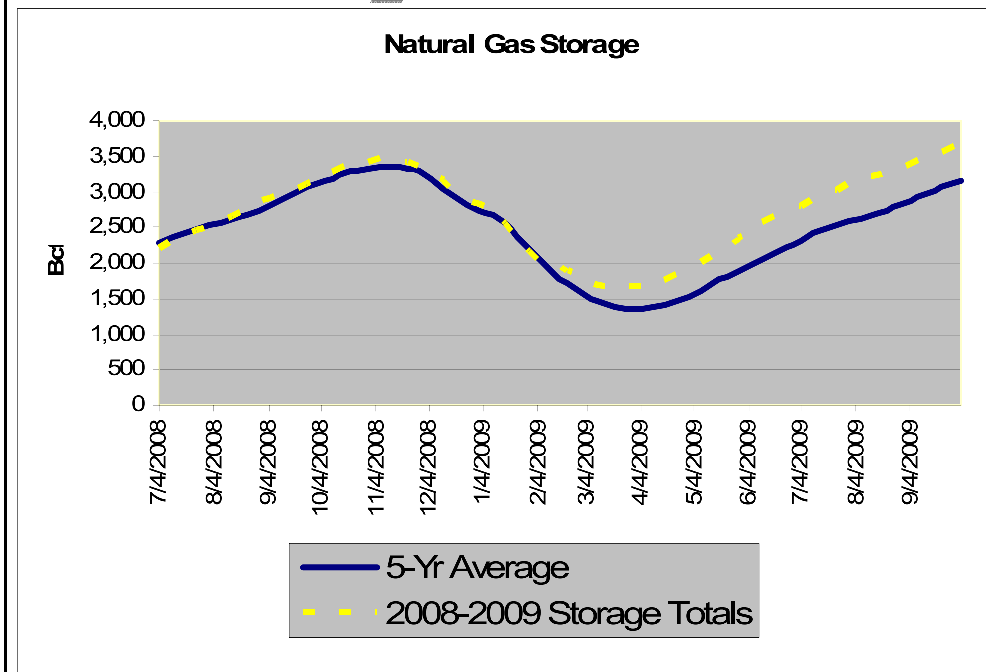
Nobody came close on the seasonal forecast totals for this year - even if another storm should increase the totals for the season. Everybody (myself included) was too high with their seasonal outlooks for named storms and hurricanes. With seven named storms so far, this season is the quietest since 1994 in the Atlantic basin.

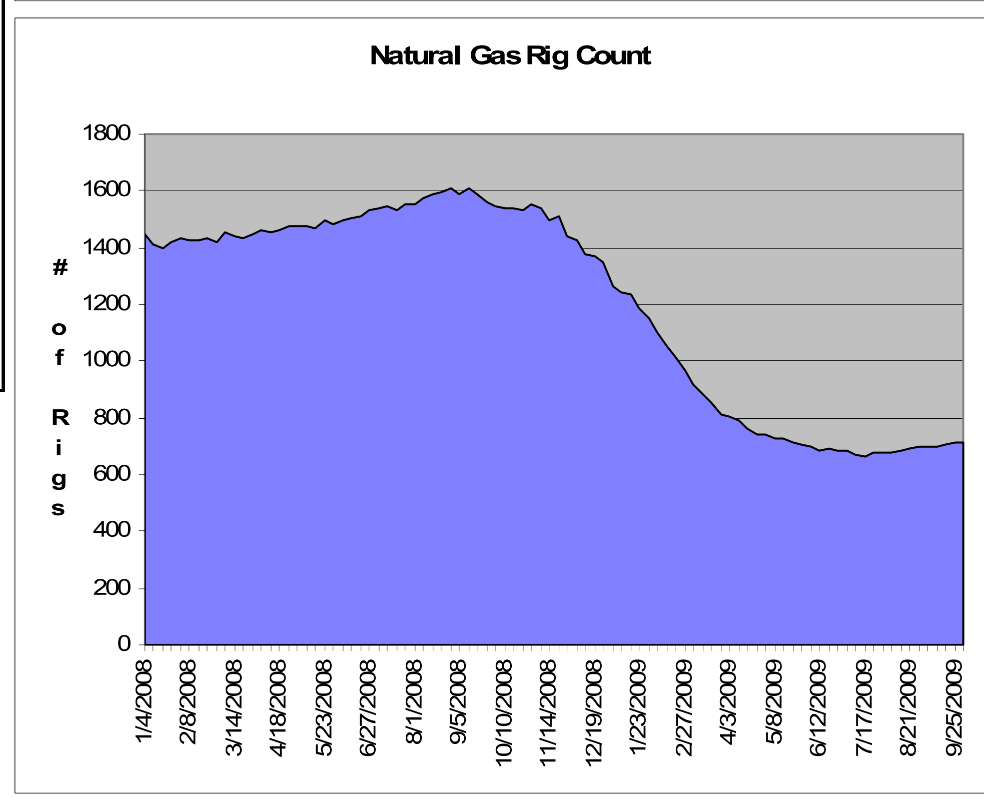
Its actually not too difficult to get an early hint into what the 2010 season might look like. If the El Nino drops off by early summer, the best analog years for SST anomaly would be 1966, 1958 and 1973 in that order - which would yield a more normal season for 2010 with storm totals of 10/6/3 or 11/7/4 (named storms/hurricanes/major hurricanes).

Did You Know?

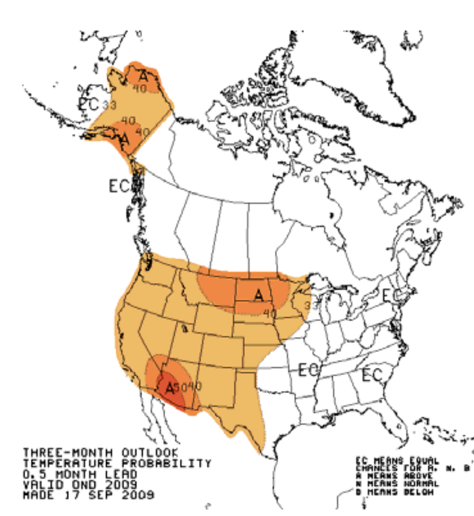
- **Tropical Storm Allison (2001)** was the most costly tropical storm in U.S. history with more than $5 billion in flood damage to southeast Texas and southern Louisiana. 23 deaths were reported in Texas and one in Louisiana.
- **Hurricane Floyd (1999)** brought extremely heavy rainfall to many locations in the eastern United States. Of the 56 people who perished in this country during Floyd, 50 died from inland flooding, including 35 in North Carolina.
- **Tropical Storm Alberto (1994)** produced tremendous rainfall along the Gulf coasts of Alabama and Georgia, killing 33 people and producing damages exceeding $750 million.
- **Hurricane Agnes (1972)** fused with another storm system, producing floods in the Northeast United States which contributed to 122 deaths and $6.4 billion in damage.
- **Hurricane Camille (1969)** produced maximum rainfall near 30 inches along the eastern slopes of the Alleghenies, resulting in flash floods that took more than 100 lives.

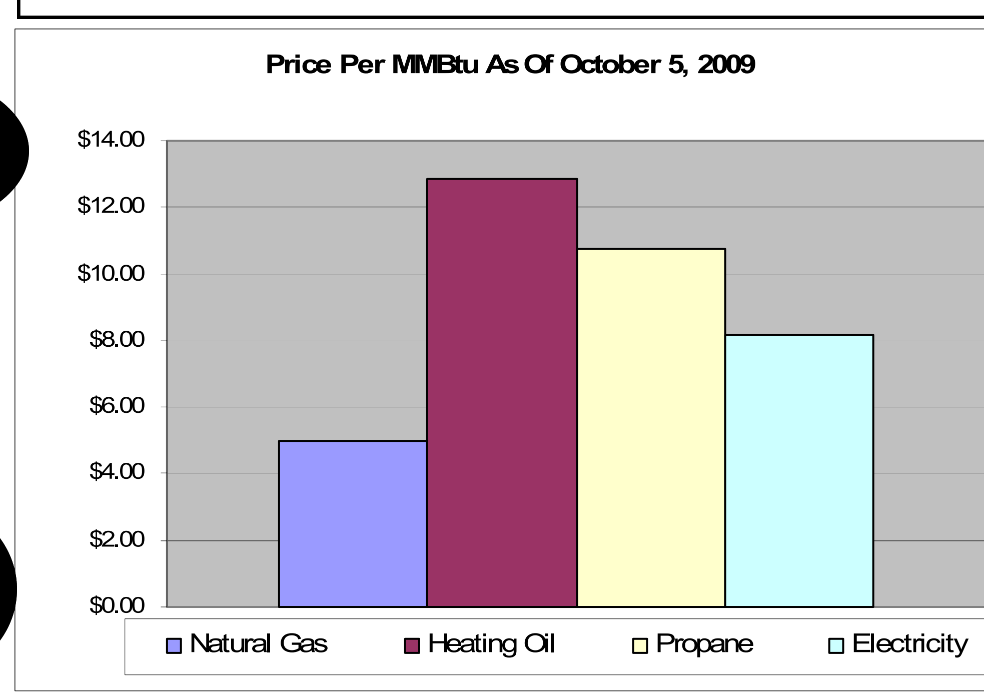
Snapshots





Seasonal Temperature Outlook
October - November - December





Risk Management Continued

The ability to establish a position easily and to close it out with equal ease without significantly changing the market price is referred to as liquidity, and it is one of the most important features of a futures market. This degree of liquidity is possible because a futures market is centralized and standardized. All potential buyers and sellers are represented in one location, and all agree to the same contract terms, with price the only variable.

The Exchange clearinghouse plays an important role in maintaining market integrity. The clearinghouse is interposed between the two sides of every trade. It assumes the counterparty credit risk, and guarantees fulfillment of the contract.

Futures contracts are primarily financial management tools; most futures market participants ultimately make offsetting transactions to close out their positions, rather than taking or making delivery of the commodity. In fact, less than 1% of the total Exchange contract volume results in actual physical delivery. Nevertheless, a viable delivery mechanism is needed because it ensures that futures market prices will converge with cash market prices at the termination of trading.

If the marketer wants to close out his May delivery position by making an offsetting transaction, he will have to do so no later than the designated last trading day for that contract. After that day has passed, traders with open positions must fulfill their obligations to make or take delivery. However, position holders who want to make an Exchange of Futures for Physicals, or EFP, have two hours following the close of trading to submit notice to the Exchange.

When the marketer liquidates his position, he will most likely do so at a price other than that at which he entered. The price of a futures contract is subject to a variety of forces, but the most important ones are changes in the supply/demand balance of the underlying commodity and changes in expectations for the future price performance of the underlying commodity.

Assume spot and futures prices have advanced in the two weeks since the marketer bought the May contract at $1.80/MMBtu, with both now trading at $1.90. If the marketer sells the contract at $1.90/MMBtu, he will have a profit of $.10/MMBtu ($1,000), excluding brokerage commissions, in his futures account. If prices declined rather than advanced, however, the marketer would show a loss in his futures account. Assume the price of the May contract has dropped to $1.70/MMBtu. If he sells at $1.70, the marketer will terminate his obligations but he will have a loss of $.10/MMBtu, plus brokerage commissions on the futures trade.

The futures gain or loss represents only half the picture, however. The marketer in this example was using the futures market to lock in a purchase price for gas that he had committed to sell at a fixed price of $1.81. If, in the case where prices rose, he later purchased spot gas at $1.89, he would have a loss of $.08 on the cash transaction. When this is offset against the $.10 gain on the futures transaction, the marketer is left with a $.02 margin. Similarly, if the marketer was able to purchase gas at $1.69 because spot and futures prices declined, he would show a $.12 gain on the cash transaction. When the $.10 loss on the futures transaction is offset against the cash market gain, the marketer again has a $.02 margin.

The marketer in this example initially bought the contract because he needed to protect his margin against the risk of prices going up. To close the position, he made an offsetting sale.

If the marketer had initially agreed to buy gas at a fixed price, he could have sold rather than have bought futures.

It is just as easy to sell, or "go short," a futures contract as it is to buy or "go long." Market participants who fear, or hope for, a price decline can take steps in advance to protect against, or profit from, the results.

In the original example, had the marketer agreed to purchase gas at $1.79, his initial futures trade could have been to sell one May natural gas futures contract at $1.80/MMBtu. In this case, he would incur the obligation to sell the gas at $1.80 in May, rather than to buy it. If the price subsequently went down to $1.70, he would have a gain of $.10/MMBtu ($1,000), less brokerage commissions; if the price went up to $1.90, he would have a loss of $.10/MMBtu($1,000), plus brokerage commissions. Again, the marketer would expect that this gain or loss would be offset by a loss or gain on the cash transaction, leaving him with an overall profit-margin of $.02 (if he was able to sell that gas for $.01 more than the prevailing futures price). Once the marketer completed his cash transaction, he would close out his futures position by making an offsetting purchase of one May contract.

Futures Spreads

Spread positions offer another way of using futures. There are many types of spreads, but they all have two things in common. First, a spread always involves at least two futures positions, which are maintained simultaneously. For example, a trader may be long (have an obligation to buy) 10 June natural gas contracts and short (have an obligation to sell) 10 September natural gas contracts. Second, the price changes in the two or more legs of the position are expected to have a reasonably predictable relationship, and the potential profitability of the spread lies in that relationship or expected changes to that relationship. For example, the trader who is long 10 June contracts and short 10 September contracts will benefit if market forces cause the near-term contract to make a larger advance than the more distant contract - or if market forces cause the distant contract to drop more sharply than the near-term contract.

A spread such as the one described above is called an intramarket spread because all the futures positions involved are based on the same commodity - in this case, natural gas. When two different commodities display a price relationship, like natural gas and propane, it is possible to establish intermarket spreads as well. The "frac spreads" - long natural gas futures/short propane - mentioned earlier are often used by natural gas processors to hedge their margin.

Basis

Successful hedging depends on a close relationship between the price of a futures contract and the price of the underlying physical commodity. This relationship is termed the basis. The closer the basis, the better the hedge.

In the hedge examples presented previously, cash and futures prices moved together perfectly. Hedging 10,000 MMBtus with one natural gas futures contract (representing 10,000 MMBtus) was assumed to result in futures market gains that exactly offset cash market losses, in other words, a perfect hedge with zero basis risk.

Since perfect basis relationships do not actually exist, potential basis fluctuations present the hedger with new opportunities and risks. Hedgers accept the risk of a changing basis because of the fundamental principle of hedging: the price risk laid off is greater than the basis risk taken on.

Basis risk results from the possibility of deviations in three types of relationships: product basis, cash/futures basis, and location basis.

Fortunately, a hedger in the natural gas industry can essentially exclude consideration of product basis. While there are a wide variety of crude oil streams traded, gasoline differs by octane, and even seemingly fungible heating oil can differ depending on its end-use market and sulfur content, pipeline quality natural gas is still pipeline quality natural gas - an almost perfectly fungible commodity. Btus per cubic foot may differ, but there is no real distinction in demand between lower and higher Btu gas. The cash/futures basis and the location basis must, however, be considered.

The cash/futures basis refers to the relationship between the futures price and the spot price of the underlying commodity. Arbitrage - the process of buying physical gas and selling futures, or vice versa - ensures that the two prices will converge by the termination of trading of the futures contract. (It is important to note that if the futures settlement price is compared to a published index, differences in timing between futures settlement and the period used to determine the index may result in differences between those prices. This does not mean that convergence has not occurred.)

For gas bought or sold at a location other than at the futures contract delivery site, the hedger must also consider his location basis. This is the relationship between the futures price and the spot gas price at a location away from the delivery site. On average, the difference between gas prices in two locations should be the cost of transportation between them. But if gas cannot move between two points, or until it does move, relative prices will also be affected by the supply/demand balance in each region.

The relationships between prices at the Henry Hub delivery site and those in most other regions of the country are quite good, and have strengthened over time as improved access to transportation increasingly allows gas to flow to its highest value market. Consequently, gas market participants throughout North America are able to use the futures market to manage their price risk.

Strip Trading in Natural Gas Futures

Energy risk managers who wish to hedge extended exposure to natural gas price risk do not have to buy or sell consecutive futures contracts in multiple transactions to do so. Instead, they can hedge through a single transaction called "strip trading."

Strip trading gives market participants considerable versatility. Price levels can be protected for several months at a time by simultaneously opening a futures position on the same side of the market in each of the months to be hedged. Exchange-traded natural gas strips are available for between two and 36 consecutive months, and the monthly positions are opened as a single transaction at a single price during open outcry trading hours. The strip is valued at an average differential to the previous day's settlement prices for the desired time span. A six-month strip, for example, consists of an equal number of futures contracts for each of six consecutive months, priced as a negotiated differential to the previous day's settlement prices. The differential is the same for each month in the strip and is calculated based on the current average value of those months versus the previous day's settlement.

For example, a trade involving 10 contracts for each of the October through March contract months might be executed at $.10 per million British thermal units (MMBtus) above the previous day's settlement price. In that case, the buyer would receive monthly consecutive long natural gas futures contracts at $.10 above the previous day's settlement price, while the seller would receive short positions in each of those months at the same average differential to the previous day's settlement. For example:

An October-through-March strip settled at an average price of $3.324 per MMBtu. The market is currently trading at an average of $3.424. The liquidation of any month or months of the strip can be accomplished by buying or selling the appropriate futures contract either individually or as all or part of the strip. Of course, buyers or sellers can also choose to go to delivery for any or all of the con-

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