An Analysis of the Increase of Natural Gas Production from 2007 - 2010: Specific Causes and Implications

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ABSTRACT

An impressive rise and fall of commodity prices shook the energy market during the years 2008 – 2009. Oil spot prices rose to $145 / barrel in 2008 and steeply descended to $35 / barrel in 2009, with natural gas spot prices following suit. The issue this thesis addresses is that in 2009, despite the fact that both natural gas and crude oil spot prices were falling, and demand for these commodities was at its lowest, natural gas production was at its highest. We attempt to understand the causes of this increasing natural gas production over the past few years. First, a background of natural gas and its history of production are given. The relatively new field of unconventional gas, including shale gas, is explored. Then, various quantitative models illustrate the relationship between natural gas and crude oil, and a relationship is defined. After analyzing the natural gas and crude oil spot and futures markets from the period 2007 – 2010, we attempt to understand why exactly natural gas production increased during this time.

INTRODUCTION: THE NATURAL GAS MARKET

Natural gas production has been instrumental over the past few years in reducing American dependence on foreign oil and providing a sustainable source of energy that meets strict carbon emission requirements. According to William P. Albrecht, natural gas already fulfills approximately 25% of U.S. energy needs. Thus, it is important that we understand the natural gas market, including the drivers of production, in order to fully take advantage of it and lessen our dependence on crude oil.

Natural gas wellhead prices became deregulated in 1989, a highly significant step taken for the natural gas market. Eventually, the natural gas market has turned into one of the most price transparent commodity markets globally (Albrecht, “Price Transparency in the US Natural Gas Market”, 1).

There are two aspects to the natural gas market: the physical market and the financial market. The financial market is derived from the commodity, but doesn’t actually involve the physical commodity itself. According to Albrecht, the financial market consists of transactions that involve various financial instruments, including exchange-traded futures, options, and swaps, based upon the price of natural gas. The prices involved in the financial market are real-time. The physical market involves the actual commodity: physical market participants either rely on a price index or negotiate the price for their transactions. Both the physical market and the financial market are closely interrelated (Albrecht, 1).

Natural gas storage is integral to the natural gas market in terms of pricing natural gas. However, due to costs of storage, natural gas is usually not stored for longer than a season. Demand for natural gas is highly seasonal: usually natural gas production occurs during the summer to build up storage, and then is used during the winter months when there is peak demand. The winter months range from November to February of the following year.

The Henry Hub is the primary physical natural gas market center in the United States, and also a focal point for pricing and delivery of natural gas futures contracts. Essentially, Henry Hub (HHUB) comprises 16 natural gas pipelines (both interstate and intrastate) that receive natural gas supplies from both onshore and offshore production in the Gulf of Mexico. In terms of the futures market, the majority of purchasing or selling of natural gas contracts occurs during bid week, or the last five business days of the month. Many of these contracts place a fixed price, a result of buyer and seller negotiation, upon the natural gas that will be delivered daily during the next month. Monthly price indices, such as the Henry Hub index, are based on these fixed prices, and are available on the first business day after the last day of bid week. Firms that do not engage in fixed price contracts can use these indices as a basis for pricing (Albrecht, 4-5).

Post the 1989 deregulation, the New York Mercantile Exchange (NYMEX) created the natural gas futures market, basing it on the physical market and how fixed price contracts were trading. The standard contract is normally for 10,000 Mbtu (or million British thermal units). Though the futures contract provides essential "price insurance," as buyers of futures contract can lock in a price for future delivery, it doesn't reflect what the actual price in the physical market will be.

Slowly but surely the natural gas market became highly liquid, as participants were able to trade both on NYMEX, as well as the Intercontinental Exchange (ICE). Technology enabled investors to enter into non-standardized, "non-cleared" transactions (Albrecht, 8). Many of the financial instruments, such as futures and derivatives, are used for hedging risk as well as price speculation.

I. Natural Gas Pricing: The 6:1 Ratio

Historically, the prices of natural gas and crude oil have ranged from a 6:1 ratio to a 10:1 ratio. This means that a barrel of crude oil would be priced approximately anywhere from six times to ten times as much as 1 Mbtu of natural gas. The 6:1 ratio derived from the fact that one barrel of WTI crude oil actually contains 5.825 Mbtu of natural gas –thus, many analysts assumed that under this rule of thumb, it naturally follows that 1 Mbtu of natural gas should be approximately one-sixth the cost of a barrel of WTI crude oil (Brown and Yucel, "What Drives Natural Gas Prices?", 48). Analyses of price movements of both natural gas and crude oil since the early 1990s had resulted in this pattern (Refer to Exhibit 8 in the Appendix for the price movements). As can be seen, the Henry Hub spot price follows a 6:1 ratio, albeit a bit loosely, until 2007, when the ratio increased to about 10:1. Post 2008, both natural gas and crude oil price movements became more extreme and unpredictable.

II. Seasonality and Storage in the Natural Gas Market

Primary factors that affect natural gas pricing include seasonality, weather, and storage. As stated previously, natural gas consumption is seasonal: demand is usually high during the winter months and low during the summer months. Natural gas consumption is split into residential, commercial, industrial, and electric power (Mu, “Weather, storage, and natural gas price dynamics: Fundamentals and volatility”, 48). Because production is not seasonal, however, usually natural gas inventories are built up during the summer to be used during the winter months. Normally, inventories that are greater than the seasonal norm depress prices, as there is more supply than demand, and vice versa. Thus, it can be established that inventories and commodity prices follow an inverse relationship. Disruptions to production, including geopolitical events and natural disasters (such as hurricanes), also increase natural gas prices.

In terms of storage, there are three costs: the physical storage cost, forgone interest, and the opportunity cost (when the spot price might depreciate while held in inventory). The first two costs mentioned comprise the “cost of carry”, or the cost of carrying one additional unit of inventory. Normally, this marginal value is expected to be very high if the initial inventory is low, and vice versa (Pindyck, “The Dynamics of Commodity Spot and Futures Markets: A Primer”, 6-7). Demand for storage depends on the spot price of natural gas, the volatility of the price, the current and future demand for natural gas, and the current and future production. Ultimately, if the spot price is higher, it makes sense for one person to pay more for a higher priced good than for a lower priced good. Also, the greater the volatility in the spot price market, the greater the demand for storage because of the uncertainty that exists in the market.

III. Unconventional Natural Gas

According to the American Petroleum Institute, unconventional gas deposits are generally distributed throughout the United States, are lower in resource concentration, and require more sophisticated technology. Shale gas is the most prominent form of unconventional natural gas production, and is derived from shale rock formations. There are numerous shale fields throughout the United States (in the Southern, Northern, Western and Eastern regions): Exhibit 18 in the Appendix depicts the domestic shale gas fields in every region.

Previous shale wells were vertical. Lately, however, producers have been investing in horizontal wells with hydraulic fracturing technology to stimulate and produce natural gas. Hydraulic fracturing and horizontal drilling are the two primary technologies that are associated with shale gas production. According to the Potential Gas Committee, a non-profit organization, the United States has over 2,000 trillion cubic feet of natural gas in its grounds (American Petroleum Institute).

Discoveries of global unconventional gas supply has shaken up the energy markets as unconventional gas production has revolutionized the natural gas industry in terms of technological investment, cost structure, and consequently pricing. According to the American Petroleum Institute, domestic shale gas alone is enough to satisfy the energy needs for the United States for the next 100 years. Up until the end of the financial crisis, around 2010, natural gas producers and market participants alike have believed in the traditional pricing structure of the 6:1 ratio. When addressing the apparent discrepancy between low natural gas demand and the extremely high natural gas production rate in 2009, we find that producers had been adhering to this ratio before the crisis set in, and have apparently based production decisions on this ratio. In 2008, when natural gas prices and crude oil prices were steadily increasing, many exploration and production companies believed that these prices increases would be sustained, and thus invested in new technologies for unconventional gas production. These technologies increased production in 2009 despite market conditions. Many market participants and natural gas producers alike have also hedged future production based on this 6:1 ratio, locking in production in 2009.

We eventually find, however, that the 6:1 ratio is not fundamentally sound and cannot apply to contemporary markets. It may have been held previously, but in light of the extreme amounts of unconventional gas that have been found in the United States, and the technological investments made, this ratio can no longer apply. This is just one prime example of the effects unconventional natural gas has had on the industry.

THE RELATIONSHIP BETWEEN CRUDE OIL AND NATURAL GAS

The relationship between oil and natural gas has been established for decades. As stated previously, natural gas and oil prices approximately follow a 6:1 ratio in terms of commodity market prices: natural gas would be priced at approximately one-sixth a barrel of crude oil. However, the 6:1 ratio has been volatile in recent years, at times following a 4:1 or 12:1 (Hartley, Medlock, and Rosthal, "The Relationship of Natural Gas to Oil Prices", 47), especially during the extremely volatile period from years 2007 - 2009. According to Exhibit 8, it can be seen that the ratio has been consistently increasing since 2007, and has reached approximately 18:1 in 2010. This volatility has called into question the true relationship between natural gas and oil prices.

I. Bivariate Error-Correction Model

Examining past research, specifically that done by Villar and Joutz, it can be seen that WTI crude oil prices and Henry Hub natural gas prices are both co-integrated variables: this implies a stationary, long-term relationship between natural gas and crude oil prices (Villar and Joutz, "The Relationship Between Crude Oil and Natural Gas Prices", 2006). A stationary price series implies that there is mean reversion. In this case, the long-term relationship between the West Texas Intermediate (WTI) and Henry Hub spot prices can be characterized by the 6:1 ratio.

Please refer to Exhibit 1 in the Appendix for the Johansen test, run by Stephen Brown and Mine K. Yucel in their 2009 article "Market Arbitrage: European and North American Natural Gas Prices", that determines the co-integration between Henry Hub spot price and the WTI spot price. As shown in the exhibit, the beta between Henry Hub and WTI is .44: this implies that a 1% change in the spot price of WTI is accompanied by a .4% change in the Henry Hub spot price. Co-integration must be taken into account when determining the relationship between natural gas and crude oil. According to Villar and Joutz, this co-integrated relationship between natural gas and crude oil exhibits a "positive time trend, continually evolving as opposed to staying constant."

Brown and Yucel, in 2007 also used an error-correction model—very similar to the model used by Villar and Joutz—that included exogenous variables such as seasonal dummy variables (to account for the seasonality of the prices), storage levels for natural gas and other fleeting shocks. Both Brown and Yucel validated the co-integrated relationship between crude oil and natural gas, and proved that short-term variations in this relationship are due to weather and storage level shocks, using this error-correction model.

The error-correction model implies that short-term deviations from the long-term relationship will eventually correct themselves. The model depicts changes in the dependent and independent variables, as well as an error-correction term (Engle and Granger, "Co-Integration and Error Correction: Representation, Estimation and Testing", 251-76). Brown and Yucel (2008) used the following three bivariate equations to find a statistical relationship between crude oil and natural gas prices:

$$P_{h,t} = Y_{hj\ t} + B_{hj}\ P_{j,t} + u_{\ hj,\ t,}$$

$$\Delta P_{h,t} = a_{\ hj} + \alpha_{\ hj}\,(CI_{\ hj\ ,\ t-1}) + \Sigma\ b_{\ hj,i}\,\Delta P_{\ j,\ t-1} + \Sigma\ c_{\ hj,\ i}\,\Delta P_{\ h,\ t-1} + \varepsilon_{\ hj,t}$$

$$\Delta P_{j,t} = a_{\ jh} + \alpha_{\ jh}\,(CI_{\ hj\ ,\ t-1}) + \Sigma\ b_{\ jh,i}\,\Delta P_{\ h,\ t-1} + \Sigma\ c_{\ jh,i}\,\Delta P_{\ j,\ t-1} + \varepsilon_{\ jh,t}$$

$CI_{hj\ ,\ t-1}$ signifies the co-integrated relationship between WTI and Henry Hub. $P_{h,t}$ expresses the logged natural gas price, while $P_{j,t}$ is the WTI oil price. The other variables present in the equation are estimated parameters, with the additional errors $\varepsilon_{\ hj,t}$ and $\varepsilon_{\ jh,t}$. Additionally, in this model, a shock affects the dependent variable and consequently disturbs the long-term relationship between the dependent variable and the explanatory variable. The dependent variable then proceeds to adjust at a weekly rate in order to stabilize the long-term relationship with the explanatory variable.

Exhibit 2 in the Appendix depicts the regression output of this bivariate error-correction model. WTI is shown as having a significance of greater than one percent in the Henry Hub equation (Brown and Yucel, "Market Arbitrage: European and North American Natural Gas Prices, 180). In this model, the Henry Hub price adjusts at a weekly rate α to deviations from the long-term relationship between Henry Hub prices and WTI prices, in an error-correction process. The short-term dynamics are determined by the lagged WTI prices and the dependent variable: this contributes to the proof that crude oil prices affect those of natural gas.

II. Multivariate Error-Correction Model

Another significant, possible determinant of Henry Hub natural gas prices is natural gas prices from another market, such as the U.K. market. While Henry Hub serves as the pricing point for the U.S. natural gas prices, National Balance Point (NPB) is the primary pricing point for the U.K. market. This could be a possible explanatory variable, along with WTI. In addition, the multivariate model includes other variables that may affect the Henry Hub price, including heating and cooling degree days, deviations from normal heating-degree and cooling-degree days, the Gulf of Mexico shut-in production, and the U.S. natural gas storage (Brown and Yucel, 180). These variables are stationary and are considered exogenous variables as they are driven by neither natural gas nor crude oil prices.

As can be seen in Exhibit 3 in the Appendix, Brown and Yucel confirmed once again that the relationship between WTI and Henry Hub is an error-correction process, with the Henry Hub price periodically correcting itself of any short-term deviations from its 6:1 pricing ratio with the WTI price. Exhibit 3 depicts two models used in the regression: Model 1 is bivariate, while Model 2 is multivariate. The co-integrating terms of both models are significant at the 10% level, confirming the results of the co-integration Johansen test that was put forth earlier by Brown and Yucel. Model 1 depicts a 6% coefficient for the co-integrating term: this implies that should WTI and Henry Hub spot prices deviate from the 6:1 price ratio relationship, the Henry Hub price will change approximately 6% per week to close the gap between the two prices series, and once again establish the 6:1 ratio. It’s interesting how academics place emphasis on the fact that Henry

Hub prices, as opposed to WTI prices, move to the close the gap. In terms of the regression output, the lagged dependent variable, in this case the lagged Henry Hub prices, are also significant: this suggests that the historical price movements of the Henry Hub contribute to this 6% correction. Historically, natural gas prices have been more volatile than WTI prices. Given contemporary technological changes in terms of unconventional gas production and greater domestic supply, natural gas prices today have also been highly volatile as compared to crude oil prices, and thus are more likely to change in response to short-term fluctuations from the 6:1 ratio.

Further examining Exhibit 3, Model 2 is the multivariate model and thus includes exogenous variables that were mentioned previously. In terms of the model output, the coefficient for the co-integrating term is about 12%, indicating that any deviation from the 6:1 pricing relationship between crude oil and natural gas would result in the Henry Hub spot price changing about 12% per week to close the gap. The lagged prices of the Henry Hub are insignificant in this case. Most of the exogenous variables, except for the NPB and cooling-degree days, are significant at the one-percent level.

III. Noureddine Krichene's Analysis Based on the 1970s

The oil shocks that occurred from approximately 1973 – 1985 also demonstrated that any short-term deviations from the interrelationship between natural gas and crude oil are transient. As explained previously, natural gas eventually corrects any short-term deviation and moves at a rate alpha to come back in line with the 6:1 ratio held with crude oil. During the period from 1973 – 1985, crude oil peaked at about $36.70 /barrel in nominal terms; the real crude oil prices were approximately 4.3 times higher during this period than during the previous fifty years

(Krichene, "World crude oil and natural gas " a demand and supply model, 561). Natural gas prices increased from an average of 9.7 cents/tcf in nominal terms from 1918-1973 to 167.5 cents/tcf in 1973-1999. During 1918-1973, natural gas prices slowly increased despite the significant increase in output, thereby signifying stability in production costs. During 1973 – 1984, the period of the oil shocks, however, prices increased rapidly and peaked at 266 cents/tcf in 1984. In terms of the properties of these price series, according to Krichene, it can be seen that crude oil prices were stationary even during the time of the oil shocks from the period 1973 – 1999: this signifies that the prices moved around a "predictable permanent component" due to a stable, longer-run cost structure, increased supply, and the demand reductions that must have taken place during the oil shocks.

In terms of natural gas prices, they embodied a non-stationary process from 1918- 1973; only post 1973 – 1983 did the prices become stationary, mostly absorbing the oil shocks. Prices eventually became stationary, and like that of crude oil, eventually stabilized around a "predictable permanent component" (Krichene, 563). The significant aspect of that, however, was that the permanent component was higher than it was before the oil shocks. This could be because there exists now higher demand and higher production costs as well.

IV. Robert Pindyck's Analysis of the Trend Line

Analyzing the 1970s oil shock, Pindyck understood that crude oil and natural gas mostly follow a multivariate stochastic process, in the sense that there is mean reversion back to the "trend line", but the trend line is itself constantly fluctuating over time. The "trend line" that Pindyck refers to is the long-run marginal cost, consistent with the resource depletion theory. Akin to "peak oil", the resource depletion theory states there is a limited amount of resources that can be produced in the world. For the majority of the depleted resources, demand extraction costs and reserves all fluctuate unpredictably and constantly over time. Pindyck would expect the prices of crude oil, and consequently natural gas, to revert to the long-run total marginal cost – this cost includes reserve accumulation costs and resource depletion. Unfortunately, as Pindyck also points out, the long-run marginal cost itself is actually unobservable: any estimated parameters that may exist change over time. Because the marginal long-run cost fluctuates over time, crude oil and natural gas prices also fluctuate over time (Pindyck, "The Long-Run Evolution of Energy Prices", 3). As Krichene shows, though crude oil and natural gas eventually stabilized to a "predictable permanent component", the component itself was higher than what it was previously.

Exhibit 4 in the Appendix depicts the log prices of natural gas and of crude oil. As Pindyck points out, the crude oil price mostly follows a mean reversion pattern: from 1900 to the mid 1970s, crude oil retained an average price of about $3.50, in terms of the 1967 dollar value. By the mid 1980s, post oil shocks, crude oil prices had reverted to levels not too much above the levels of approximately 30 – 80 years earlier. For each graph, the price series was fit to a quadratic time trend. As seen from the graphs, the price series follows a quadratic U-shaped trend because it is consistent with the exploration and production, accumulated proved reserves, and technological change. Looking at the price series versus the quadratic lines, it further confirms the crude oil mean-reversion process. Analyzing the crude oil graph further, we can see the mean reversion process takes approximately a decade, and that the trend line itself fluctuates as the sample is extended over a longer period of time. The natural gas graph, however, depicts that the natural gas price series not been as mean reverting as that of crude oil. As Pindyck notes, this may be due to lack of data for natural gas before 1917 (Pindyck, 6).

V. Relationship between the Respective Volatilities of Crude Oil and Natural Gas

Often times, extreme changes in volatility underlining commodities such as natural gas and crude oil increase risk. This in turn affects both producers' and consumers' hedging decisions, valuations, and the decision to invest in the "physical capital' of these commodities (Pindyck, "Volatility in Natural Gas and Oil Markets, 2). Two primary questions are addressed when analyzing the volatility of natural gas and crude oil. First, do the volatilities of both crude oil and natural gas share a causal relationship of some kind? Second, will these changes in volatility affect real or financial derivative (such as options) pricing?

Data collected includes daily futures prices during the period May 2, 1990 to February 26, 2003 for crude oil and natural gas. Spot prices were calculated from futures prices using the equation:

$$P_t = F1_t\,(F1_t / F2_t)^{n_{0t}/n_1}$$

P_t is the spot price on day t, determined by the prices on the nearest futures contracts, depicted by $F1_t$ and $F2_t$. Lastly, n_{0t} and n_1 express the number of days from t to first contract expiration, and the number of days between the expiration dates for the first and second contracts (Pindyck, 4-6). Daily net marginal convenience yields were also taken into account for the data. The marginal convenience yield, according to the Federal Reserve, is the convenience gained by holding one extra barrel of inventory – net marginal convenience yield is the marginal convenience yield net of physical holding costs. Daily and weekly returns from holding the commodities can be calculated from the daily prices and marginal convenience yield.

Volatility is then calculated for both daily and weekly returns using the generalized autoregressive conditional heteroscedasticity (GARCH) models, where the volatility can be compared to the sample standard deviations. Using the GARCH Models of Weekly Returns, the weekly return to holding the natural gas or crude oil commodity is equal to:

$RET_t = a_0 + a_1\,TBILL + a_2\,\sigma_t + a_2\,\sigma_t + a_3\,ENRON + a_4\,TIME_t + \Sigma\, b_j\, DUM_{jt\ [\text{from } j = 1 \text{ to } 11]} + \varepsilon_t$

Furthermore, the variance of the error ε_t is expressed as:

$\sigma^2_t = \alpha + \Sigma\, \alpha_j\, \varepsilon^2_{t-j\ (\text{from } j=1 \text{ to } p)} + \Sigma\, \beta_j\, \sigma^2_{t-j\ (\text{from } j=1 \text{ to } q)} + \gamma_1\, ENRON_t + \gamma_2\, TIME_t$

DUM_{jt} stands for the monthly dummy variables. The TBILL is included because interest comprises a huge part of the cost to hold the commodity in storage: the interest rate thus correlates with the cost of storage. σ_t and ε_t are also included because as risk increases, return increases. The ENRON dummy variable is also included in order to account for any volatility that may have occurred during the time of Enron's fall for natural gas and crude oil commodities.

Exhibit 5 in the Appendix displays the regressions run with this model. The half-life of volatility shocks shown at the bottom of the table is determined by the sum of the GARCH and ARCH coefficients:

Half-life = $\log(.5) / \log(\Sigma\, \alpha_j + \Sigma\, \beta_j)$

From this regression, it can be seen especially in columns 3 and 4 that the crude oil returns have a significant positive dependence on the interest rate and the volatility (standard deviation of ε_t). As Pindyck highlights, for natural gas, the interest rate and volatility are actually insignificant. Thus, crude oil follows the normal theory of storage, while natural gas does not. In addition, this regression output depicts an interrelationship between the volatilities of natural gas and crude oil: crude oil is shown to have "some predictive power" in terms of natural gas volatility. Natural gas volatility, however, does not have predictive power for crude oil volatility.

The GARCH models essentially create estimates for conditional volatility based on commodity returns. These conditional standard deviations are then compared to the estimated sample standard deviations. To further prove that crude oil volatility has predictive power for natural gas volatility, Granger causality tests were conducted (Pindyck, 4-5), between the conditional standard deviations garnered from GARCH models, and the sample standard deviations. F-tests are also run on "exclusion restrictions" b1 = b2 = bl = 0 depicted through regression equation:

$$y_t = a_0 + \Sigma\, a_i\, y_{t-i\ (\text{from } I = 1 \text{ to } L)} + \Sigma\, b_i\, x_{t-i\ (\text{from } i = 1 \text{ to } L)}$$

Two, four, and six lags were used for the weekly regressions, while "four, six, 10, 14, 18, and 22 lags" were used for the daily regressions (Pindyck 15-16).

Please refer to Exhibit 6 in the Appendix for the regression output of the Granger causality test. Though the weekly returns do not express any type of causation, the daily returns show causality from crude oil to natural gas. The bottom three rows depicted in the table relate to the weekly sample standard deviations and daily volatilities, determined by GARCH. These three rows also confirm the causality from oil to gas (and not vice versa). Overall, the Granger test also confirms the relationship between volatility of crude oil and natural gas: that crude oil volatility has some predictive power over that of natural gas.

THE SPOT MARKET DURING 2007 – 2010

WTI spot prices experienced heavy volatility from 2007 to 2010. According to the Energy Information Administration, WTI crude oil spot prices were roughly around $52 per barrel in mid-2007. Within a few months, from the latter half of 2007 to mid-2008, the spot price steeply climbed to approximately $145 per barrel around July 2008. Crude oil spot prices then descended to approximately $37 per barrel in February 2009. As can be seen from Exhibit 7 in the Appendix, in 2010 WTI maintained a consistent spot price of approximately $79 per barrel. There exists a mixture of factors that have contributed to the massive spot price increase that characterized the latter half of 2007 and mid-2008, including fundamental demand and supply, the deflation of the U.S. dollar, and commodity speculation.

Oil supply growth became stagnant, notably in countries outside of the Organization of the Petroleum Exporting Countries (OPEC).[1] The gap between world non-OPEC oil supply and demand has led to an increased dependence on OPEC production, as well as withdrawal of supply from stored inventories belonging to countries in the Organization for Economic Cooperation and Development (OECD). Increased OPEC reliance, as well as the inventory drawdown, contributed to the WTI spot price increases.

Exhibit 9 in the Appendix, there is a strong negative correlation between the USD/EUR exchange rate, and the WTI spot prices, post 2002. When the U.S. dollar depreciated from 2002 to 2008, oil prices surged. In addition to the devaluation of the dollar, various academics, including Michael Masters of a private financial fund, believe the oil price spike that occurred during 2007-2008 was a result of increased commodity speculation. Progressively convoluted trading techniques were used by hundreds of funds – according to Masters, by March of 2008, the commodity index trading funds possessed at least "a quarter trillion dollars" worth of futures contracts. When trading the crude oil futures contracts, essentially investors took a long position in the near-term futures contract, sold it before expiration, and then used the proceeds to take a long position in another near-term futures contract.[2] Thus, when the price of the commodity

[1] Cline, Matthew. "Short-Term Energy Outlook Supplement: Outlook for Non-OPEC Oil Supply Growth in 2008 – 2009." Energy Information Administration, February 2008. Web. 18 March 2011.

[2] Hamilton, James. "Causes and Consequences of the Oil Shock of 2007 – 2008." Brookings Papers on Economic Activity, Spring 2009. Web. 12 February 2011. <www.brookings.edu/Economics/bpea/bpea.aspx.>.

rises, the investor sells the contract for a higher price than bought, and pockets profit. Masters argues that the long positions exceeded the short positions in these contracts as more investors took up this strategy –the hoped for effect was to increase the futures price so more investors would profit, and consequently drive up the spot price itself. This, in effect, became a speculative bubble.

As can be seen from Exhibit 7 in the Appendix, Henry Hub spot prices mirrored that of WTI spot prices– prices surged from an average of $6.98 per million BTU in 2007 to $13.19 per million BTU in July 2008. Mirroring WTI crude oil spot prices, natural gas prices then declined rapidly to approximately $2.42 per Mbtu in August 2009. Throughout 2010, prices finally stabilized at about $4.39 per Mbtu. This price movement is quite unusual as normally natural gas prices are lowest during the summer, when consumption is lowest, and highest during the winter, when consumption is greatest.

One of the primary insights to be understood from the relationship between crude oil and natural gas prices is the 6:1 ratio: according to analysts, the price of the HHUB spot price should be roughly one-sixth the price of WTI crude oil. On a daily, even monthly, basis, there obviously existed short-term deviations from the 6:1 ratio between natural gas and crude oil. In accordance with the multivariate error-correction model Brown and Yucel had introduced, the relationship between natural gas and crude oil embodies an error-correction process: any short-term deviations from the 6:1 ratio are eventually corrected. During this period, the short-term deviations were caused by the WTI price shock, and eventual price remission. In compliance with Brown and Yucel, Exhibit 8 in the Appendix depicts that the long-term annual average of the WTI and HHUB spot price follows the 6:1 ratio from 1997 until approximately 2006, thus proving that any short-term (daily or monthly) deviations are eventually corrected. However, as can be seen from the exhibit, this price ratio significantly diverged during the 2007 – 2009 period, when both natural gas and crude oil had undergone significant price changes in both the spot and futures markets. It follows according to Brown and Yucel that a deviation correction is imminent. Brown and Yucel also argued the point of stationary vs. non-stationary processes that energy price series tend to follow. Non-stationary processes allude to the "random walk" nature of the price movements: in reality, their main conclusion holds that natural gas and oil prices, when co-integrated, follow a stationary process of the 6:1 ratio.

Furthermore, Pindyck and Krichene both highlight in their academic research the nature of the "trend line" that these prices follow. As stated previously, they believe that crude oil and natural gas follow a multivariate stochastic process, meaning that there exists a mean reversion back to the "trend line", but the trend line itself is constantly changing over time. This trend line reflects the long-run marginal cost – though this cost is technically unobservable, it may be estimated using complex quadratic models. Examining Exhibit 7 from the Appendix, post the 2008 shock, both natural gas and crude oil prices are still in the mean-reversion process. The mean reversion process takes approximately a decade, and the trend line itself fluctuates as the sample is extended over a longer period of time. In recent years from 2010 to 2011, the WTI and HHUB spot prices have been diverging. Natural gas prices have been depressed due to increasing domestic supply, while oil prices have been rising due to recent geopolitical strife in oil-producing regions. According to this research, then, and as was the perception of many natural gas producers during the 2007 – 2009 time period, both price series will eventually converge to their new respective long-term costs and maintain the 6:1 ratio.

Additionally, there have been many sunk costs incurred when natural gas prices peaked around $13 in July 2008. According to Dermot Gately and Hillard G. Huntington, higher energy prices induce investment in “energy-efficient” equipment and a reallocation of existing capital (Gately and Huntington, “The Asymmetric Effects of Changes in Price and Income on Energy and Oil Demand”, 31). Technological investments were made from 2007 - 2008, as the increasing spot prices were expected to offset the technological costs. When natural gas prices fell, heavy sunk costs were incurred in terms of the technological investments made in breakthroughs such as hydraulic fracturing and horizontal drilling. In light of increasing supply as a result of these technological breakthroughs, and the sunk costs incurred with other investments, natural gas prices remain depressed.

THE FUTURES MARKET DURING 2007 - 2010

As there existed a “shock” in the spot market for both crude oil and natural gas, so there was an effect on the futures market for these respective commodities. In the Appendix, Exhibit 10 displays the natural gas and crude oil futures price series throughout 2007 – 2010. Crude oil futures prices of the Cushing, OK, futures 3-month contract also increased rapidly to approximately $132 per barrel in July 2008, mirroring crude oil spot prices. Prices then dropped to around $45 per barrel early 2009. In 2007, the Henry Hub Future 12-month Strip Price averaged around $8.12 per Mbtu. The peak futures price occurred in June 2008 at $13.13, and steeply declined to approximately $4.61 in April 2009.

I. Relationship between Inventories, Spot Prices, and Future Prices

According to Pindyck, there exist two markets for crude oil and natural gas: the cash (spot) market, and the storage market for inventories held by consumers and producers. Inventories levels are highly significant in determining prices: inventories reduce the cost of changing production by responding to changes in demand, reducing marketing costs, and avoiding stockouts. Thus production and inventory levels are joined in the sense that the producers must set production levels that are based on their expectations of any inventory drawdowns or buildups. If the marginal production costs are increasing and demand is also fluctuating, then producers can sell out of inventory during the high-demand periods and reduce costs, eventually replenishing their inventories during low-demand periods. Normally, because inventory can never be negative and it is expensive for firms to reduce holdings beyond a certain threshold, price volatility will be greater during periods of low inventory (Pindyck, “The Dynamics of Commodity Spot and Futures Markets: A Primer”, 2-7).

The cost of storage or cost of carry, for natural gas is equal to the physical storage cost and the forgone interest. The marginal value of inventory derives from the value of the services accruing from holding one extra unit of inventory, and is referred to as the marginal convenience yield. As spot prices and volatility increase, the demand for storage increases: during periods of high volatility, there is a higher need to store commodities and have the inventories buffer against fluctuations in demand and supply in the spot market, regardless of the price of storage. In addition, producers are more likely to store a higher-priced good than a lower priced good. If there is greater volatility in the spot market, there is an increase in the volatility of production and consumption, increasing the demand for storage; the price of storage, or marginal convenience yield, then depends on what happens to inventories, which in turn depends on expectations regarding future conditions of the market (Pindyck, 12-15).

Increased price volatility also increases the demand for production because the value of producers' operating options, which entails that the producer will produce the commodity now, increases. The exercise price is the marginal production cost, and the payoff is the spot price. These options are usually exercised immediately in place of waiting for any increases or decreases in the spot price. An increase in volatility essentially increases the demand for production, and in the storage market it increases the demand for storage. If we assume that the supply of storage is fixed, the price of storage (the marginal convenience yield) will also increase, and the spot price will also increase because of increased demand for production as well as inventories being built up. Eventually, as inventories continue to build, the spot price will fall back, along with the marginal convenience yield.

On the assumption that the volatility persists, the spot price, convenience yield and level of inventories will rest at a new equilibrium, higher than they were previously: the spot price, futures price, and inventory levels by mid-2008 were all higher than in 2007 when the volatility started. This is also in line with Krichene's research during the 1970s, stating that though during the oil shock both WTI crude oil prices and HHUB prices eventually stabilized at a "predictable price component", that "price component" was higher than it was previously. In 2009, however, due to the recession that essentially wiped out demand in the latter half of 2009, HHUB spot prices mirrored those of WTI crude oil and steeply fell. Crude oil spot prices fell due to a combination of the recession and OPEC. Falling spot prices brought futures prices down along with it.

II. What Actually Happened During 2007 – 2010

Henry Hub spot prices increased during the latter half of 2007 into July 2008. Because of the steep price increase, many natural gas companies heavily invested in unconventional gas projects. Unconventional gas, as mentioned previously, has suddenly unveiled a huge domestic supply for the United States, decreased dependence on foreign energy, and proved to be more sustainable given environmental restrictions on carbon emissions. Thus, many natural gas companies such as Talisman, Chesapeake Energy, and Anadarko have heavy investments in the technology that is needed to cultivate the unconventional gas. Normally, unconventional gas projects require a significant amount of capital, commonly around $1 billion, relative to conventional gas projects. Unconventional projects are larger and more complex, require more advanced technology, and have higher density drilling than do the conventional projects.[3] The huge investments that these companies made represent sunk costs that will come into play the next year.

From early to mid 2008, inventory levels were very low as they were drawn down in order to meet winter demand; according to the EIA, consumption was very high during 2008, slightly higher than 2007 levels. Consumption was high especially during the beginning of the year because of the unusually cold winter months of January to March. In line with Pindyck's research, price volatility was also high during that time for both WTI crude oil spot prices and HHUB spot prices. As can be seen in Exhibit 12 from the Appendix**,** inventory levels then proceeded to seasonally build up during the latter half of the summer in order to meet anticipated winter demand. Thus, in 2008, there was nothing particularly abnormal regarding natural gas production, consumption, and inventory levels.

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[3] Corrigan, John, Andrew Steinbul, Mark Uffhausen, and Justin Petit. "Removing Risk: Hedging Capital Investments in Unconventional Gas Projects." Booz & Company, 2009. Web. 12 February 2011.

Exhibit 13 in the Appendix shows that demand was still seasonal from 2008 – 2009. Yet, post July 2008 and into early 2009, Henry Hub spot prices were still dropping. According to the EIA, the price drop was accompanied by a huge drop in consumption (during early 2009 and late 2009) because of unusually warmer winter days. The abnormal aspect of 2009, however, was that despite depressed (and continuously dropping) natural gas prices and a huge drop in consumption, production reached 21.9 trillion cubic feet (Tcf), the highest level since 1973, according to the EIA. Exhibit 14 in the Appendix shows that natural gas production remained strong despite the depressed natural gas prices. According to Pindyck, a drop in the spot price and seemingly balanced volatility (natural gas spot prices stabilized during the latter half of 2009) should not increase demand for storage and should not trigger production because the options to extract and produce now are not more valuable. Thus, according to Pindyck, at this time the marginal convenience yield, or price of storage, should also not increase and should be fairly stable.

The year 2009 was abnormal, however, because of the effects of the weakened economy from the recession that started in the latter half of 2008. However, inventory levels during 2009 were higher than the average of the past 5 years, mostly because of warmer winter months. Inventory levels were very high, natural gas prices were depressed, and still production increased. This is because of the sunk costs that natural gas companies had made a year earlier, betting on natural prices to stay high for a longer period in order to make profitable returns. The investments in technology such as hydraulic fracturing and horizontal drilling allowed the projects to start extracting gas, such as shale gas, from the ground in 2009, despite the detrimental market and demand conditions. In addition, there was increased foreign investment in these small exploration and production companies: many international companies, including sovereign wealth funds, engaged in joint ventures in 2009 with the North American natural gas companies when natural gas prices were depressed, in the expectation that they will increase and yield higher returns. Thus, 2009 was considered an abnormal year in terms of the relationship between spot prices, inventory, and production.

HOW 2007 – 2010 AFFECTED NATURAL GAS PRODUCTION

I. The Role of Hedging From 2008 - 2009

In addition to unconventional project investments, hedging may have also contributed to increased production during 2009, even in the presence of depressed natural gas prices and waning demand. In terms of the natural gas futures market, because it is difficult to determine the exact cost of storage, the Fed Funds rate has been used as a proxy. As seen in Exhibit 15 in the Appendix, in 2009 interest rates were at their lowest (reflecting the Federal Reserve's efforts to stimulate the U.S. economy), implying that the cost of storage should have been minimal. According to Lien and Root, the futures price should equal the spot price and any additional carry costs to store the commodity. Because the cost of storage was minimal, the price differential between the HHUB spot price and futures price should have been small. However, as can be seen in Exhibit 11 in the Appendix, especially in the expanded version, the futures prices and spot prices diverged through most of 2009. Hedging from various consumers and producers caused this divergence.

Normally, natural gas futures prices obtain a premium during the months leading up to winter from October to December, and decline during the months leading up to summer from February to April. The process is highly seasonal. Thus, during the months leading up to winter, natural gas futures normally undergo a contango, where the futures price is higher than the spot price. Because of increasing demand during the winter months, many speculators expect the HHUB spot price to increase, and thus they go long in futures contracts in which they can store natural gas and sell it at a later date when the price would be higher. In contrast, during the months leading up to summer, futures prices normally undergo a backwardation due to increased storage and less demand: backwardation implies that the futures price is lower than the spot price. The futures price becomes less than the spot price as speculators short futures contracts. Futures contracts in this sense refer to the one-month and two-month contracts, to control for external factors that may affect futures prices such as inflation and interest rate change (Pindyck, "The Dynamics of Commodity Spot and Futures Markets: A Primer", 18-20).

If we examine Exhibit 11 once more in the Appendix, we see that during 2008, the HHUB 2-month futures contract and HHUB spot price did not follow the normal relationship because of hedging: from February 2008 to June 2008 (months leading up to summer), in place of undergoing backwardation, HHUB 2-month futures were actually at a slight contango. The HHUB 2-month futures price was higher than the HHUB spot price. This is because spot prices were rising well into 2008 and there existed greater uncertainty, so speculators were increasingly taking a long position on futures contracts. In 2009, from July to November 2009, the futures prices were at a contango; however, this was a more extreme contango than previous years. As explained previously, this was also due to hedging.

During the latter half of 2009, in the period leading up to the summer of 2010, seasonality dictates that futures prices should begin to trade at a discount to spot prices and thus enter backwardation. However, the futures price was much higher than the spot price in the latter half of 2009, meaning that natural gas was undergoing a strong contango. Potential reasons for this include the depression in spot prices in 2009, and great uncertainty regarding the direction natural gas prices might be heading in during 2009, and how low they could dip. As a result, a number of speculators, including exploration and production companies, took a long position on futures contracts due to greater uncertainty and to hedge production. Thus, this also contributed to very high inventory levels throughout 2009, as natural gas was stored to be sold at a later date. Going long in an increasing amount of futures contracts also buoys the futures price at a level that is higher than that of the spot price.

In addition to affecting inventory levels and the futures prices, hedging also affected production. Many companies enter into hedging agreements that hedge the price at which they can sell production output for a certain time period, especially during a period of volatile prices. As mentioned above, many producers exercised their operating production options because they became highly valuable during the volatile period that 2008 brought. Many producers thought that in 2009 crude oil and thus natural gas prices would revert back to their normal levels, and volatility would be lower. Thus, many producers exercised these options during 2008, locking in production for 2009.

During 2008 when HHUB spot prices were increasing at a rapid rate, and companies speculated that within a year prices would fall, companies such as Chesapeake Energy also engaged in a series of knockout swaps. Knockout swaps obligate buyers to buy their production output at a certain price. Since Chesapeake Energy used these contracts to hedge in 2009, the set price was $9.30 / Mbtu. However, one important clause in the contract is that buyers are not obligated to buy if the spot price of natural gas falls below a certain level, in this case $6.28 / Mbtu.[4] Because during most of 2009 prices were below this level, Chesapeake Energy suffered losses. Simultaneously, however, these swaps ensured production into 2009, despite the declining prices and lessened demand. Thus, hedging contributed to increasing production.

II. The Role of Weather from 2008 – 2009

Unpredictable weather changes, such as an unusually warm winter, or an unusually cold winter, will have an effect on natural gas demand, storage, and hence pricing. According to Xiaoyi Mu, weather affects approximately 50% of the US natural gas demand. Weather changes affect both spot and futures markets as it creates uncertainty about future natural gas supply conditions.

Natural gas consumption in 2008, though above 2007 levels, was dramatically decreased due to price spikes, and mild temperatures during the winter of 2008. According to the EIA, cooling-degree days were 11% less than the previous year, affecting electric power generation, residential and industrial demand. Both the winter of 2008 and the winter of 2009 had experienced mild temperatures, comparatively. This mild 2009 winter contributed to the fact that natural gas storage was at its highest in November 2009 at 3,833 billion cubic feet.

Because natural gas consumption is highest during the winter months, it follows naturally that natural gas prices should be highest during the winter months, and lowest during the summer months. Interestingly, as can be seen in Exhibit 7 in the Appendix, this was not the case. The Henry Hub spot prices heavily spiked during mid-2008. Though normally a strong driver in natural gas prices, weather did not play a crucial role in terms of prices during 2008. Exhibit 16

[4] Lonkevich, Dan. "Chesapeake Falls Amid Concern Over Hedging Contracts (Update 1)." Bloomberg.com, 10 October 2008. Web. 18 March 2011. <http://www.bloomberg.com/apps/news?pid=newsarchive&sid=aqnK.q7icy7Y&refer=us>.

in the Appendix displays the regression output, pitting average heating days in the United States against the HHUB 12 month futures price. The regression shows a statistically insignificant (or indeterminable) relationship based on the extremely low R^2. This exemplifies the fact that in terms of warmer than average days, these weather “shocks” had little effect in terms of natural gas pricing during the crisis years.

Weather did, however, play an important role in terms of consumption and production of natural gas in terms of hurricanes, another classifiable “weather shock”. Both Hurricane Gustav and Hurricane Ike damaged the Gulf Coast in September 2008, causing a huge reduction in supply. Supply reductions were estimated at around 413.6 bcf (billion cubic feet) by the end of 2008, according to the Energy Information Administration. Additionally, electric power was delayed for approximately 4 million people. Due to the hurricanes as well, 84% of the drop in industrial consumption was due to the consumption decreases in Louisiana and Texas, where the hurricanes struck.

Both hurricanes struck in the latter half of 2008, already at a time when volatility and uncertainty were high. As mentioned previously, storage levels during the latter half of 2008 were already decreasing to an average of $7 / Mbtu, in contrast to its highs of $12 / Mbtu during the summer of 2008. Hurricane Gustav hit the Gulf Coast around August 30, 2008, while Hurricane Ike hit Louisiana and Texas around September 13, 2008. On September 26, 2008, the Minerals Management Service reported that approximately 53% of the federal natural gas production in the Gulf of Mexico was considered “shut-in” (Energy Information Administration, “Hurricane Updates for week of 9/26/10”). There were 26 natural gas processing plants in Hurricane Ike’s path. Additionally, 7 of the major pipelines that extended from the Gulf of Mexico to the Henry

Hub were declared as “non-operating”. This resulted in a loss of approximately 3.8 Mbtu of natural gas per day.

As can be seen from Exhibit 7 in the Appendix, though both hurricanes had disturbed natural gas and crude oil supply, both commodity prices have not stopped their downward slide. The primary reason for the soft market impact is the abundance of domestic natural gas supply, mostly through unconventional sources such as shale gas. Fields such as Haynesville, Barnett Shale, and Fayetteville have all contributed much needed natural gas supplies while the Gulf Coast was still recovering. Thus, even during this time period, natural gas production remained robust as continued time and investment into these fields became more pronounced.

III. Sunk Costs and Joint Venture Interest

Unconventional gas production, according to consulting firm ICF, is expected to increase from 42% of total gas production in 2007 to approximately 64% in 2020 (American Petroleum Institute, “Facts about Shale Gas”). Shale production will constitute the majority of this production due to the overwhelming number of shale gas fields in the United States. The question that needs to be posed, however, is the following: despite depressed natural gas prices, why was unconventional gas exploration production, notably shale gas, still continued in 2009? The answer is three-pronged: hedging, as covered in the previous section; sunk costs; and joint venture interest.

Natural gas prices increased at a steep rate during the early half of 2008, leaving natural gas producers with the perception that it is now, and will be in the future, economic to invest in the expensive technology and acreage that are required for unconventional gas production. Thus, many of these producers have locked in steep investments for technology and committed to a variety of leasing programs to capture acreage for shale gas production. By the end of 2008, proven gas reserves increased by 3% and 29.5 trillion cubic feet of natural gas were discovered, according to the Department of Energy. Shale reserves alone increased approximately 50% since 2007. Suddenly in 2008, there was a major rush by small, domestic exploration and production companies to lease land where natural gas was thought to be present underground, sometimes around $20,000 per acre (Mason, *Well Servicing Magazine*, 2010).

Many of these lease agreements, however, expired within 3 years. Thus, despite falling natural gas prices into the latter half of 2009, many of the natural gas producers strove to produce as much natural gas as possible before the leasing contracts expired. In order to do this, heavy investments in hydraulic fracturing and horizontal drilling were made –these investments could not be recouped in 2009 when prices started falling, and so production continued. Technology especially improved in terms of horizontal drilling: before the mid- 2000s, many of the natural gas exploration and production companies had incorporated vertical wells for vertical drilling, with finding and development costs around $1.71 per thousand cubic feet of natural gas. During 2008, however, improved technology in horizontal wells reduced this highly significant cost to around $1.06 to $1.34 thousand cubic feet of natural gas. This technology made a huge difference in terms of cost reduction (Braithwaite, “Shale-Deposited Natural Gas: A Review of Potential”, 20), though the initial capital outlay needed to develop the technology was high. The spike in the number of horizontal wells versus the Henry Hub spot price can be seen in Exhibit 17: this shows that investment in horizontal drilling increased in 2008 when the Henry Hub spot price was at its peak.

In addition, many foreign companies entered the domestic market in order to take advantage of the continued shale gas boom occurring within the United States. They did so for three reasons: the United States is more politically stable than other countries with sufficient shale gas, such as Africa; costs at this point were a bit cheap because of joint venture interest with domestic exploration and production companies and because of the recession; and, lastly, natural gas prices were expected to increase. These joint venture investments involved foreign companies and sovereign wealth funds, mostly from Asia, that would carry some of the costs incurred to produce the natural gas, and ultimately share the return. These joint venture contracts obviously pressured many of the natural gas producers to continue producing natural gas, even during 2009 when prices were depressed. Exhibit 18 in the appendix displays investment in shale gas fields by region.

IV. Rational Expectations Hypothesis

According to Krichene, producers can learn very quickly about all relevant information and behave accordingly. The rational expectations hypothesis states that rational producers assess all available information efficiently, and rationally predict future conditions of the market. Producers may base their decisions off existing economic beliefs; there is also a possibility that many producers do not fully understand the relationship between the future events and their own expectations. Because the producers made their decisions rationally, however, the market expects their predictions to be correct, with minimal error (Bausor, "The rational-expectations hypothesis and the epistemics of time", 2). Earlier sections displayed a variety of quantitative models that attempted to identify the relationship between crude oil and natural gas. The primary relationship that we identified was that the prices of crude oil and natural gas historically follow a 6:1 ratio (per barrel in relation to 1 Mbtu of natural gas), and any short-term deviations from this ratio will eventually correct itself at a rate alpha. This ratio, though historically entrenched because crude oil contains approximately 6 Mbtu, has not proven to be consistent since approximately 2007. Natural gas producers, however, firmly believe in this pricing ratio, and for this reason believe that the current short-term deviation will eventually correct itself as natural gas prices will rise and oil prices will comparably fall. The relevant “theory” in this case is the 6:1 pricing ratio, and is the basis for producer expectation.

Because of this expectation, natural gas producers, while in the short-term have reduced production due to a fall in demand, have ultimately increased production and invested in unconventional drilling technology in the apparent belief that natural gas prices will eventually rise and the 6:1 ratio will be restored again. On Cramer’s Mad Money, a popular investment show that many average investors follow, Cramer states that “…an historical six to one ratio between oil and natural gas; with oil sitting at $136, natural gas should be at $23 rather than $13.” Additionally, Cramer notes that Chesapeake Energy CEO, Aubrey McClendon, has bought back $34 million of the company’s shares since May 30th, and “if he believes in natural gas, so should investors” (Metzinger, “Gas but Not Least – Cramer’s Mad Money (6/18/08)”, 2008). Chesapeake Energy is a domestic exploration and production company that has enormous stakes in shale fields and is engaged in numerous joint ventures, including with foreign conglomerates such as Reliance Industries. CEO Aubrey McClendon bought back a significant amount of his company’s stock in May 2008, believing that natural gas price increases would be sustained, and that the 6:1 pricing ratio would be maintained. Unfortunately (for McClendon), the natural gas price increase was not sustained, and natural gas prices fell even more sharply than did crude oil prices, to the point where the ratio was at 12:1 vs. 6:1. McClendon almost became bankrupt from this move.

Natural gas prices began to fall only towards the latter half of 2008. Natural gas producers at the time believed that despite the recession, natural gas prices would eventually increase. As a result, they did not hesitate to continue drilling as much as they could before their leasing contracts ended, and investing in both technology and joint ventures with foreign firms. Without that confidence, these domestic exploration and production companies would not have been able to take such steps.

Unfortunately, the 6:1 ratio has not been maintained since approximately 2007. The basis for the ratio is not fundamentally sound: because crude oil contains approximately 6 Mbtu of natural gas does not indicate that the cost to extract that natural gas would be 1/6 that of crude oil. With the development of unconventional resources such as coalbed methane and more specifically shale gas production, the entire cost structure of the industry has essentially changed. Thus, a new "ratio" or pricing pattern should be developed for both the crude oil and natural gas industries.

CONCLUSION

We first pulled from models identifying relationships between natural gas and crude oil, and analyzed both the spot and futures markets for natural gas and crude oil during 2007 – 2010. Examining this information, we finally have a greater understanding of why, despite a period of extremely low demand, natural gas production was highest in 2009. Several factors prove to be integral in influencing natural gas producer perceptions, including hedging policies, unconventional production sunk costs, and the rational expectations hypothesis.

Going forward, it can be seen that unconventional gas production, specifically shale gas production, will contribute heavily to natural gas production, and is already transforming the industry in terms of foreign intervention, technology, and cost structure. Not realizing the impact that unconventional natural gas production had at the time, natural gas producers continued to produce natural gas in conjunction with the theory that natural gas prices will increase in order to once again establish the 6:1 ratio with crude oil. Taking the transformation that unconventional natural gas has brought into account, however, pricing models such as the 6:1 ratio have become irrelevant and obsolete, paving the path for more dynamic and bold models relating crude oil with natural gas pricing.

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APPENDIX

Exhibit 1: Johansen Co-integration Tests Between HHUB and WTI

Table 2. Bivariate Johansen Cointegration Tests

Henry Hub and NBP

Ho: rank=p	Eigenvalue	Trace Statistic	Max Eigenvalue Statistic
p=0	0.0297	17.3779**	17.0249**
p≤1	0.0006	0.3530	0.3530

Standardized Eigenvalues or βs with Standard Errors

Henry Hub	NBP
1	-1.1322
0	(0.0674)

Standardized α Coefficients with Standard Errors

Henry Hub	NBP
-0.0096	0.07249
(0.0093)	(0.0182)

Henry Hub and WTI

Ho: rank=p	Eigenvalue	Trace Statistic	Max Eigenvalue Statistic
p=0	0.0172	12.3209*	9.7984+
p≤1	0.0055	3.1330+	3.1330+

Standardized Eigenvalues or βs with Standard Errors

Henry Hub	WTI
1	-0.4376
0	(0.0297)

Standardized α Coefficients with Standard Errors

Henry Hub	WTI
-0.0327	0.0008
(0.0107)	(0.0054)

Henry Hub and Brent

Ho: rank=p	Eigenvalue	Trace Statistic	Max Eigenvalue Statistic
p=0	0.0270	14.7727*	14.7216*
p≤1	0.0001	0.0510	0.0510

Standardized Eigenvalues or βs with Standard Errors

Henry Hub	Brent
1	-0.8004
0	(0.1096)

Standardized α Coefficients with Standard Errors

Henry Hub	Brent
-0.0514	0.0092
(0.0144)	(0.0093)

continued on next page

Exhibit 1: Johansen Co-integration Tests Between HHUB and WTI [Continued]

Table 2. Bivariate Johansen Cointegration Tests (continued)

NBP and WTI

Ho: rank=p	Eigenvalue	Trace Statistic	Max Eigenvalue Statistic
p=0	0.0163	12.3847*	9.3746+
p≤1	0.0053	3.0101+	3.0101+

Standardized Eigenvalues or βs with Standard Errors

NBP	WTI
1	-0.3953
0	(0.0426)

Standardized α Coefficients with Standard Errors

NBP	WTI
-0.0452	0.0009
(0.0148)	(0.0038)

NBP and Brent

Ho: rank=p	Eigenvalue	Trace Statistic	Max Eigenvalue Statistic
p=0	0.0202	12.6498*	10.8538+
p≤1	0.0034	1.7960	1.7960+

Standardized Eigenvalues or βs with Standard Errors

NBP	Brent
1	-0.3790
0	(0.0382)

Standardized α Coefficients with Standard Errors

NBP	Brent
-0.05147	0.0019
(0.0382)	(0.0053)

+, * and ** denote significance at better than 10, 5 and 1 percent, respectively.

Source: Stephen P.A. Brown and Mine K. Yucel. 'Market Arbitrage: European and North American Natural Gas Prices'. *The Energy Journal*. Special Issue. 2009.

Exhibit 2: Bivariate Error-Correction Model of HHUB and WTI Prices

	HH causes WTI		WTI causes HH	
explanatory variables	coefficients	Significance of joint F-tests‡	coefficients	Significance of joint F-tests‡
constant	0.0033 (1.8662)		0.0032 (0.9206)	
ΔP_{WTI} (t-1)	-0.1454** (3.3814)	0.0001	0.0949 (1.1189)	0.0085
ΔP_{WTI} (t-2)	-0.1577** (-3.6419)		-0.0894 (-1.0438)	
ΔP_{WTI} (t-3)	-0.0906 (1.0908)		0.0251 (0.2904)	
ΔP_{WTI} (t-4)	-0.0715+ (-1.6485)		-0.0826 (-0.9640)	
cointegrating term (t-1)	0.0008 (0.1022)	0.1102	-0.0532** (-3.6025)	
ΔP_{HH} (t-1)	0.0239 (1.10440)		0.0815 (1.9039)	0.0531
ΔP_{HH} (t-2)	-0.0323 (-1.4912)		0.0154 (0.3607)	
ΔP_{HH} (t-3)	-0.0303 (-1.3967)		-0.0503 (-1.1755)	
ΔP_{HH} (t-4)	0.0431* (1.9859)		-0.0749+ (-1.7452)	
	$R^2 = 0.05$ adj $R^2 = 0.04$ Significance of Overall F-Statistic: 0.0003‡		$R^2 = 0.18$ adj $R^2 = 0.03$ Significance of Overall F-Statistic: 0.0009‡	

Lags determined by Akaike information criteria. Values shown in parentheses are t-statistics.
+, * and ** denote significance at better than 10, 5 and 1 percent, respectively.
‡Probability that coefficients are jointly equal to zero.

Source: Stephen P.A. Brown and Mine K. Yucel. 'Market Arbitrage: European and North American Natural Gas Prices'. *The Energy Journal*. Special Issue. 2009.

Exhibit 3: Bivariate and Multivariate Causality Models

	Model 1		Model 2	
explanatory variables	coefficients	joint significance	coefficients	joint significa
constant	0.0028 (0.7545)		-0.0050 (-0.3794)	
cointegrating term (t-1)	-0.0577 (-3.5274)**		-0.1158 (-5.7203)**	
ΔP_{WTI} (t-1)	0.1071 (1.2002)		0.0840 (0.9941)	
ΔP_{WTI} (t-2)	-0.1252 (-1.3890)	0.0083	-0.0651 (-0.7633)	0.0000
ΔP_{WTI} (t-3)	0.0255 (0.2808)		0.0540 (0.6300)	
ΔP_{WTI} (t-4)	-0.0919 (-1.0215)		-0.1296 (-1.5181)$^{+}$	
ΔP_{HH} (t-1)	0.0925 (2.0693)*		-0.0301 (-0.6857)	
ΔP_{HH} (t-2)	0.0123 (0.2759)		-0.0336 (-0.7845)	
ΔP_{HH} (t-3)	-0.0351 (-0.7843)	0.0464	-0.0433 (-1.0172)	0.3491
ΔP_{HH} (t-4)	-0.0844 (-1.8811)$^{+}$		-0.0602 (-1.4125)	

Source: Stephen P.A. Brown and Mine K. Yucel. 'What Drives Natural Gas Prices'. *The Energy Journal*. Vol 29, No. 2. 2008.

Exhibit 4A: Log Price of Crude Oil and Quadratic Trend Lines

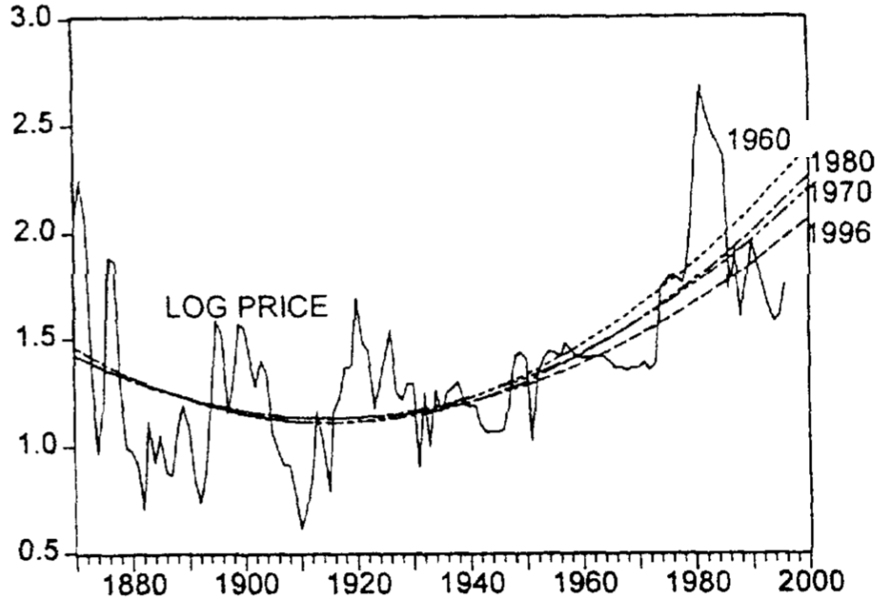
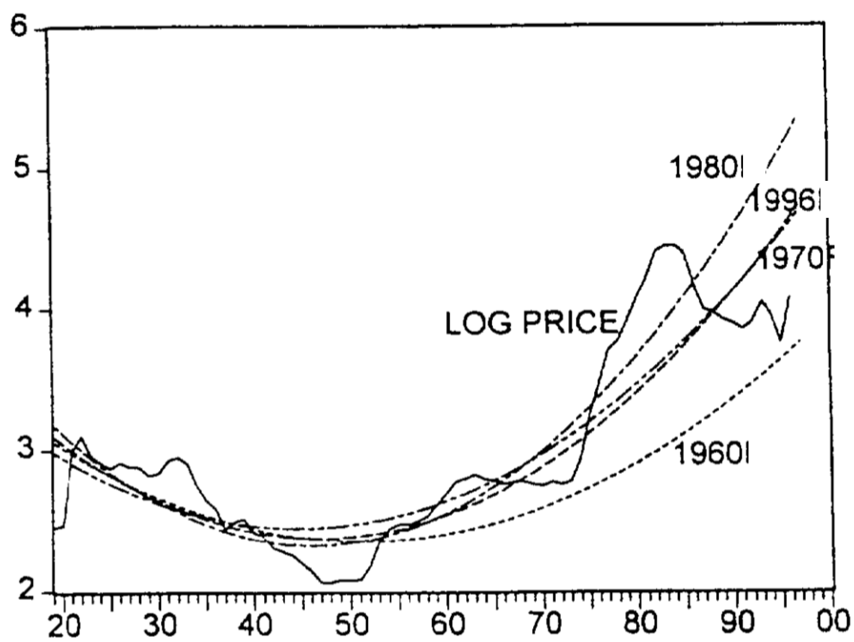


Exhibit 4B: Log Price of Natural Gas and Quadratic Trend Lines



Source: Robert Pindyck. 'The Long-Run Evolution of Energy Prices.' *The Energy Journal*, Vol. 20, No. 2. 1999.

Exhibit 5: Regression for Multivariate Causality Tests with Exogenous Variables

Dependent Variable	(1) NG	(2) NG	(3) CRUDE	(4) CRUDE
Const.	0.0160	0.0150	-0.0577	-0.0498
	(1.12)	(1.11)	(-9.55)	(-5.75)
σ	-0.1005	-0.1085	0.3673	0.2978
	(-0.71)	(-0.90)	(5.21)	(3.28)
TBILL	-0.1303	-0.1255	0.7694	0.7204
	(-1.43)	(-1.52)	(12.24)	(8.01)
ENRON	-0.0622	-0.0577	-0.0270	-0.0211
	(-1.56)	(-1.63)	(-0.87)	(-0.45)
TIME	1.42E-05	1.67E-05	-1.53E-05	-6.66E-07
	(1.05)	(1.28)	(-1.39)	(0.04)
MA (1)		-0.1196		0.3432
VARIANCE EQUATION				
CONST.	0.0005	0.0004	9.31E-05	7.03E-05
	(4.78)	(3.93)	(0.57)	(0.68)
ARCH (1)	0.1237	0.0999	0.2434	0.0400
	(2.34)	(2.08)	(4.79)	(1.32)
ARCH (2)	-0.0644	-0.0596	0.1488	0.2072
	(-1.14)	(-1.13)	(3.58)	(3.15)
ARCH (3)	0.0292	0.0500	0.1446	-0.0429
	(0.62)	(0.99)	(3.96)	(-1.02)

(continued)

Dependent Variable	(1) NG	(2) NG	(3) CRUDE	(4) CRUDE
ARCH (4)	0.2458	0.2638	0.2504	0.2838
	(1.72)	(1.48)	(5.60)	(5.06)
ARCH (5)	-0.2217	-0.2463		
	(-1.87)	(-1.63)		
GARCH (1)	0.8427	0.9359	0.1174	0.5585
	(9.08)	(8.79)	(1.40)	(3.13)
GARCH (2)	0.0510	-0.0127	-0.1699	-0.5046
	(0.32)	(0.07)	(-2.00)	(-2.52)
GARCH (3)	-0.1301	-0.1470	-0.3591	0.1020
	(-1.01)	(-0.98)	(-4.71)	(0.48)
GARCH (4)	0.2778	0.2629	0.5343	0.2690
	(3.65)	(2.16)	(7.44)	(2.09)
GARCH (5)	-0.2422	-0.2134		
	(-3.40)	(-2.39)		
ENRON	0.0028	0.0022	0.0027	0.0035
	(1.06)	(0.98)	(0.77)	(1.09)
TIME	7.56E-07	6.40E-07	2.15E-06	1.46E-06
	(4.98)	(4.20)	(2.58)	(4.37)
Half-life (weeks)	7.5	10.1	7.3	7.6

[a]Regression equations for weekly returns include monthly dummy variables, which are not reported. Numbers of ARCH and GARCH terms were chosen to minimize Akaike information criterion.

Source: Robert Pindyck. 'Volatility in Natural Gas and Oil Markets'. *The Journal of Energy and Development*, Vol. 20, No. 1. 2004.

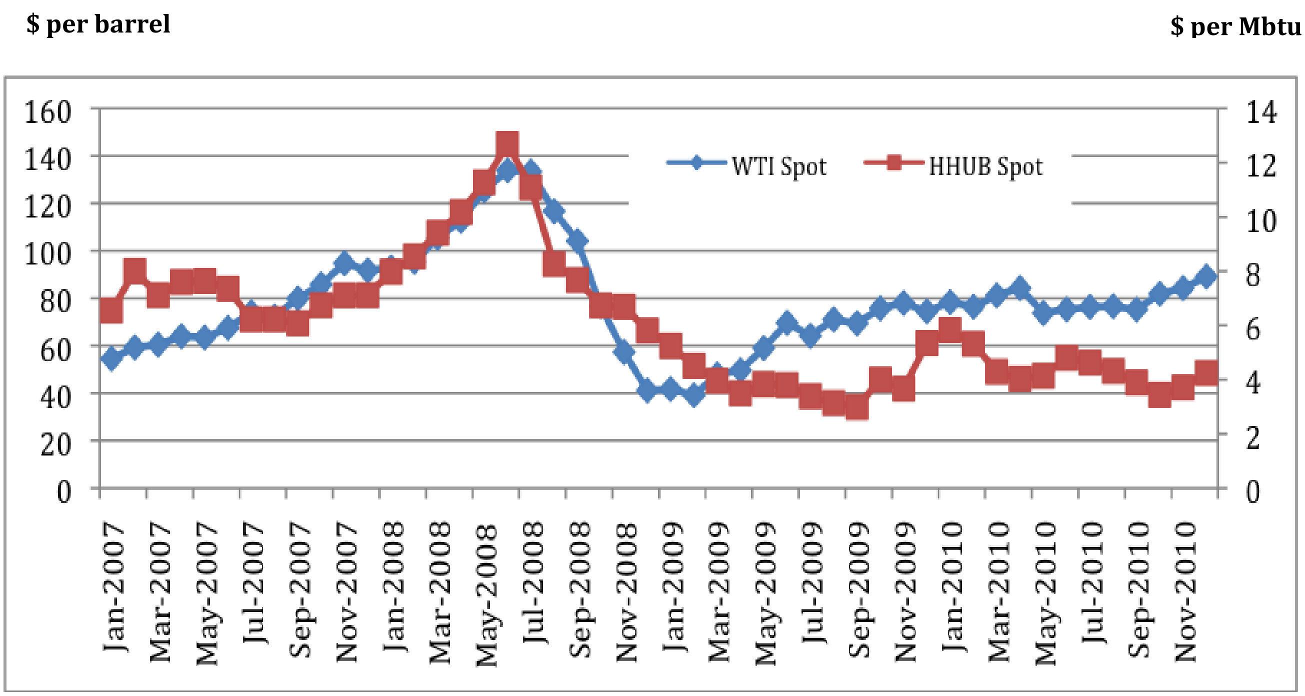
Exhibit 6: Generalized Autoregressive Conditional Heteroscedasticity (GARCH) models of Natural Gas and Crude Oil Daily Returns

Dependent Variable	(1) NG	(2) NG	(3) NG	(4) CRUDE	(5) CRUDE	(6) CRUDE
CONST	-0.0004	0.0031	-0.0004	-0.0012	-0.0013	-0.0014
	(-0.15)	(1.35)	(-0.13)	(-1.46)	(-1.52)	(-1.77)
σ	-0.0960	-0.0838	-0.0867	0.2196	0.2660	0.2266
	(-1.79)	(-1.70)	(-1.60)	(3.98)	(6.51)	(4.15)
TBILL	0.0254	0.0254	0.0237	0.0642	0.0570	0.0610
	(0.47)	(0.51)	(0.51)	(2.52)	(2.24)	(2.39)
ENRON		-0.0071	-0.0106		-0.0167	-0.166
		(-0.80)	(-1.19)		(-4.95)	(-5.05)
TIME	2.54E-06		2.26E-06	4.86E-07		7.04E-07
	(1.98)		(1.81)	(0.96)		(1.44)
VARIANCE EQUATION: GARCH (p, q)						
(p, q)	(8,7)	(4,8)	(5,8)	(5,9)	(4,9)	(4,9)
CONST	2.08E-05	4.91E-05	2.06E-05	1.78E-06	9.57E-06	2.57E-06
	(111.93)	(54.78)	(1136.09)	(0.53)	(3.63)	(0.80)
ENRON		0.0005	0.0007		0.0002	0.0002
		(1.78)	(1.57)		(0.97)	(0.91)
TIME	7.32E-08		3.37E-08	1.16E-08		1.08E-08
	(2.43)		(1.55)	(1.19)		(1.16)
Half-life (weeks)	8.5	7.8	5.8	3.2	10.7	2.9

[a]Numbers of ARCH and GARCH terms were chosen to minimize Akaike information criterion. ARCH and GARCH coefficients are not shown.

Source: Robert Pindyck. 'Volatility in Natural Gas and Oil Markets'. *The Journal of Energy and Development*, Vol. 20, No. 1. 2004.

Exhibit 7: WTI vs. HHUB Spot Prices During 2007 – 2010



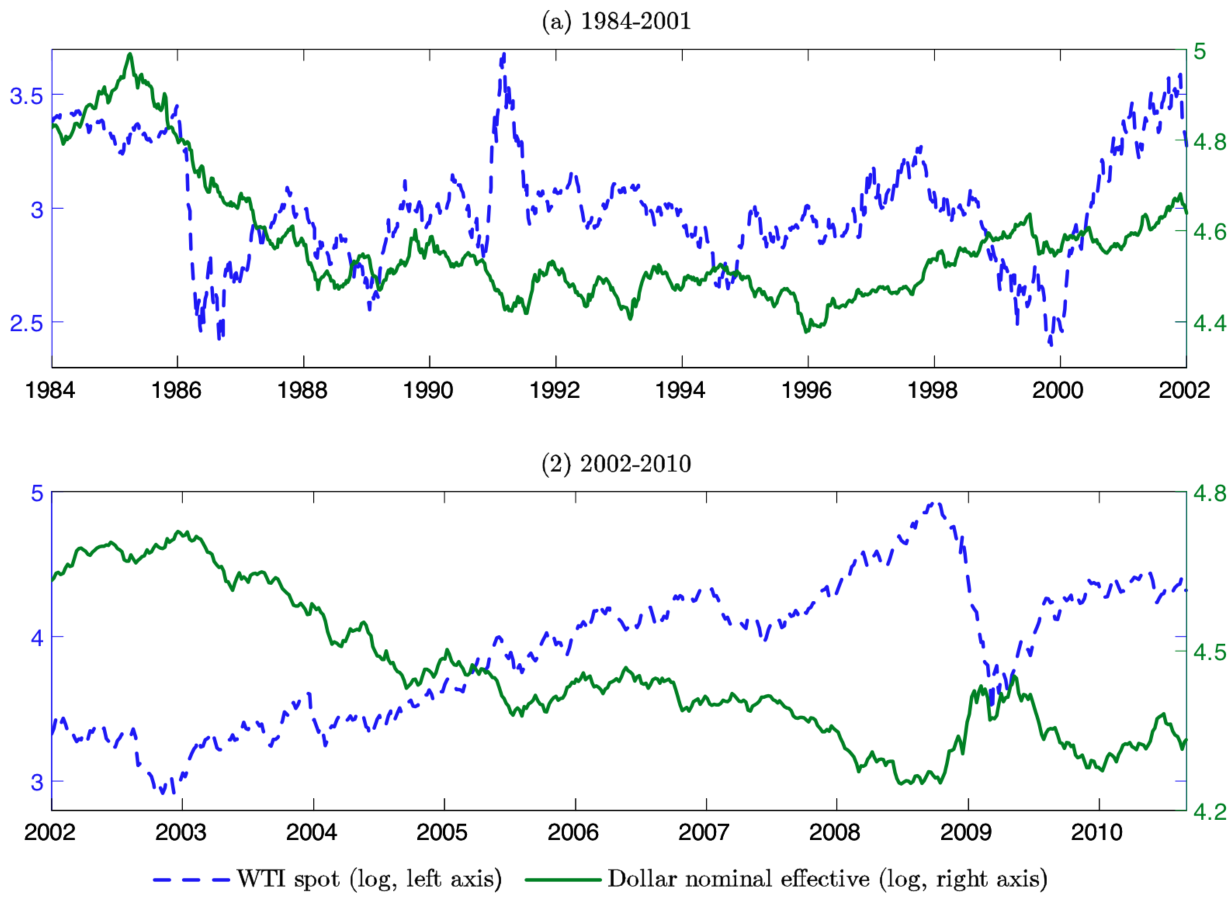
Source: Energy Information Administration

Exhibit 8: 6:1 Ratio Displayed Between WTI and HHUB Spot Prices 1997 - 2011

Year	Average Annual WTI Spot Price (Dollars per Barrel)	Implied HHUB price from 6 : 1 ratio	Actual Average Annual HHUB Spot Price (Dollars per mill. BTU)	Ratio between WTI and HHUB Spot Prices
1997	$20.61	$3.44	$2.49	8.28
1998	$14.45	$2.41	$2.09	6.92
1999	$19.26	$3.21	$2.27	8.47
2000	$30.30	$5.05	$4.31	7.03
2001	$25.95	$4.32	$3.96	6.55
2002	$26.11	$4.35	$3.38	7.74
2003	$31.12	$5.19	$5.47	5.69
2004	$41.44	$6.91	$5.89	7.03
2005	$56.49	$9.42	$8.69	6.50
2006	$66.02	$11.00	$6.73	9.81
2007	**$72.32**	**$12.05**	**$6.97**	**10.38**
2008	**$99.57**	**$16.60**	**$8.86**	**11.23**
2009	**$61.65**	**$10.28**	**$3.94**	**15.64**
2010	**$79.40**	**$13.23**	**$4.37**	**18.17**

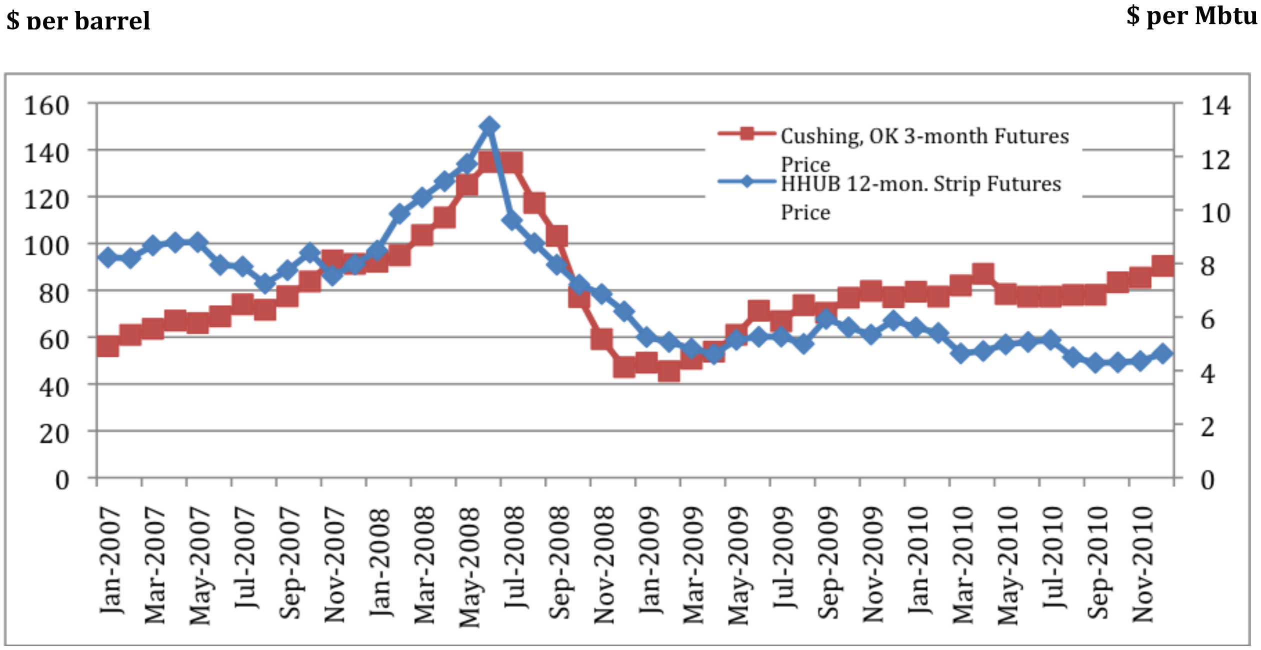
Source: Energy Information Administration

Exhibit 9: WTI Spot Price and USD/EUR Exchange Rate Correlation



Source: Grisse, Christian. "What Drives the Oil-Dollar Correlation?" Federal Reserve Bank of New York. December 2010.

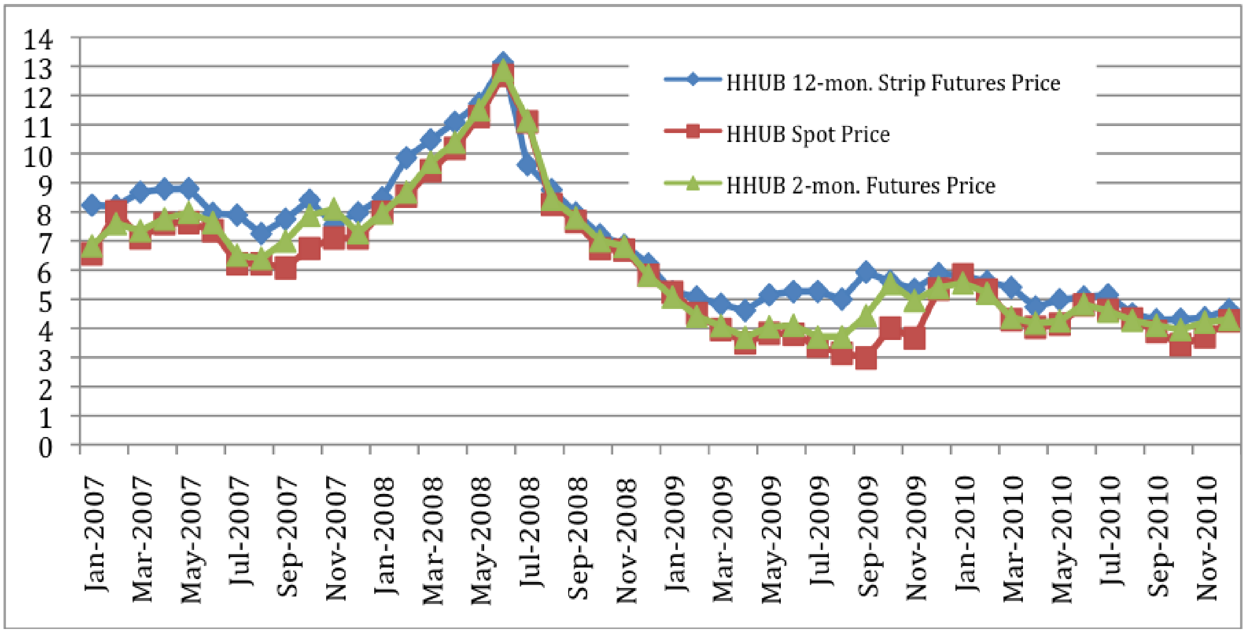
Exhibit 10: Cushing, OK 3-month Futures Contract vs. Henry Hub 12-month Strip Futures Prices



Source: Energy Information Administration

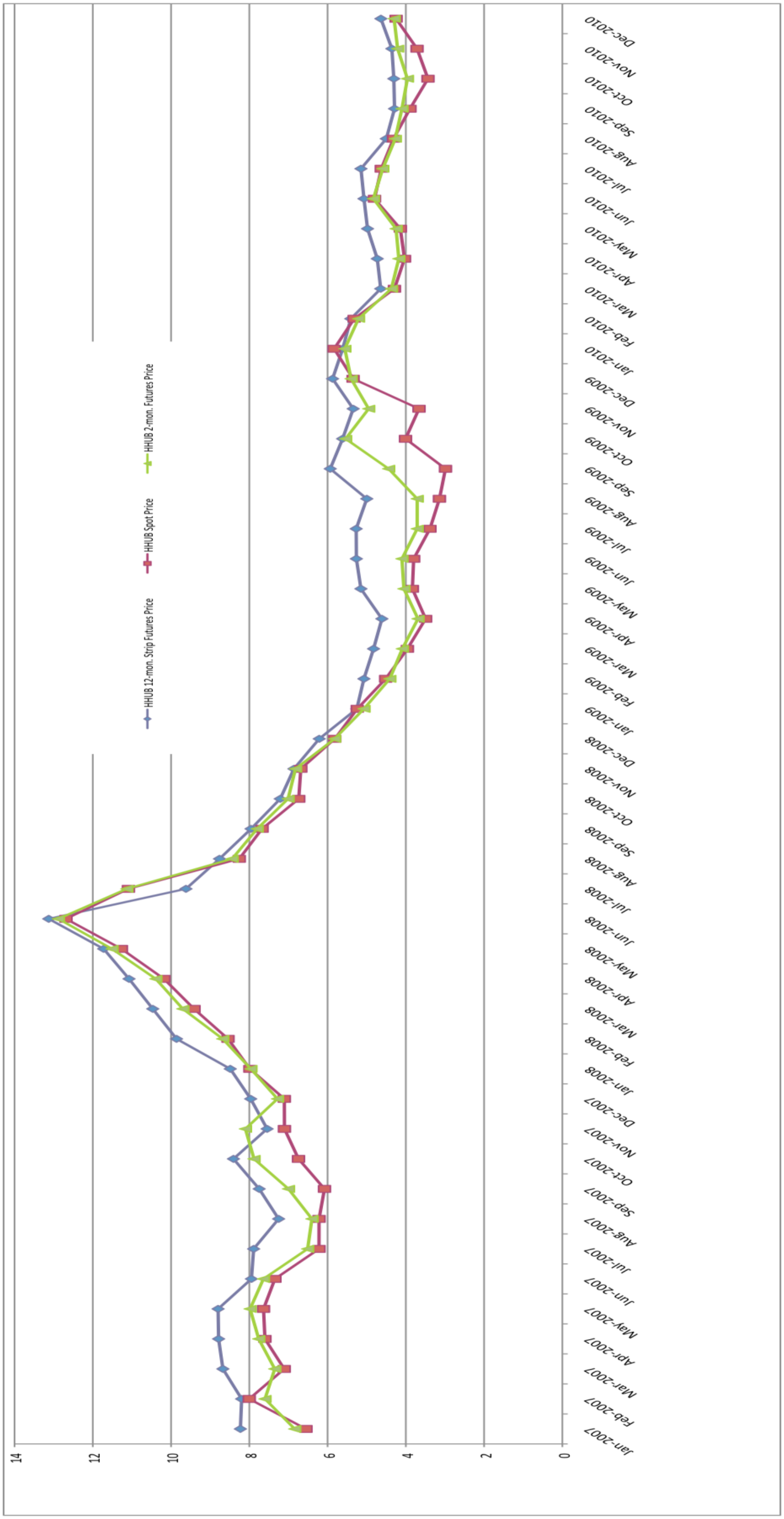
Exhibit 11: Comparison of HHUB Futures Prices and Spot Prices

$ per Mbtu



A similar, yet expanded graph is displayed on the next page.

Source: Energy Information Administration


HHUB 12-mon. Strip Futures Price
HHUB Spot Price
HHUB 2-mon. Futures Price
0
2
4
6
8
10
12
14
Jan-2007
Feb-2007
Mar-2007
Apr-2007
May-2007
Jun-2007
Jul-2007
Aug-2007
Sep-2007
Oct-2007
Nov-2007
Dec-2007
Jan-2008
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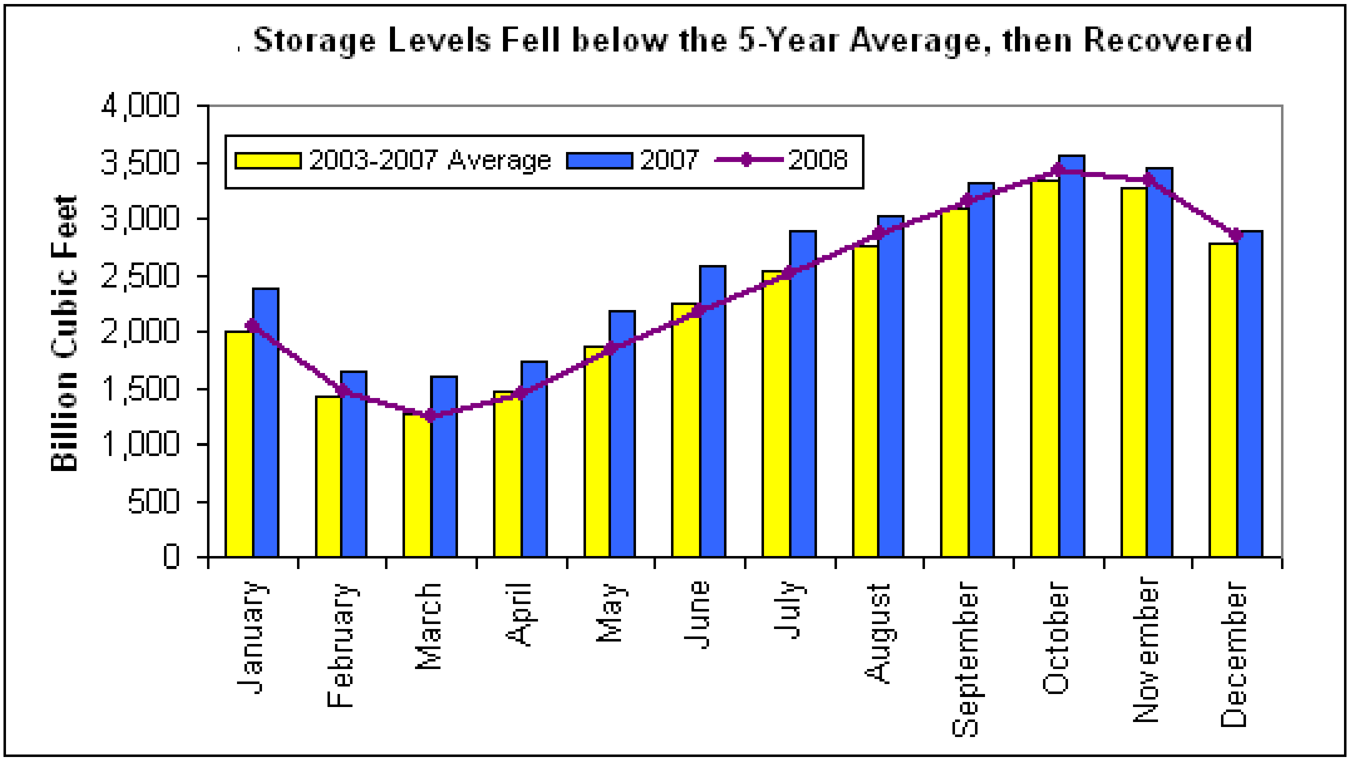
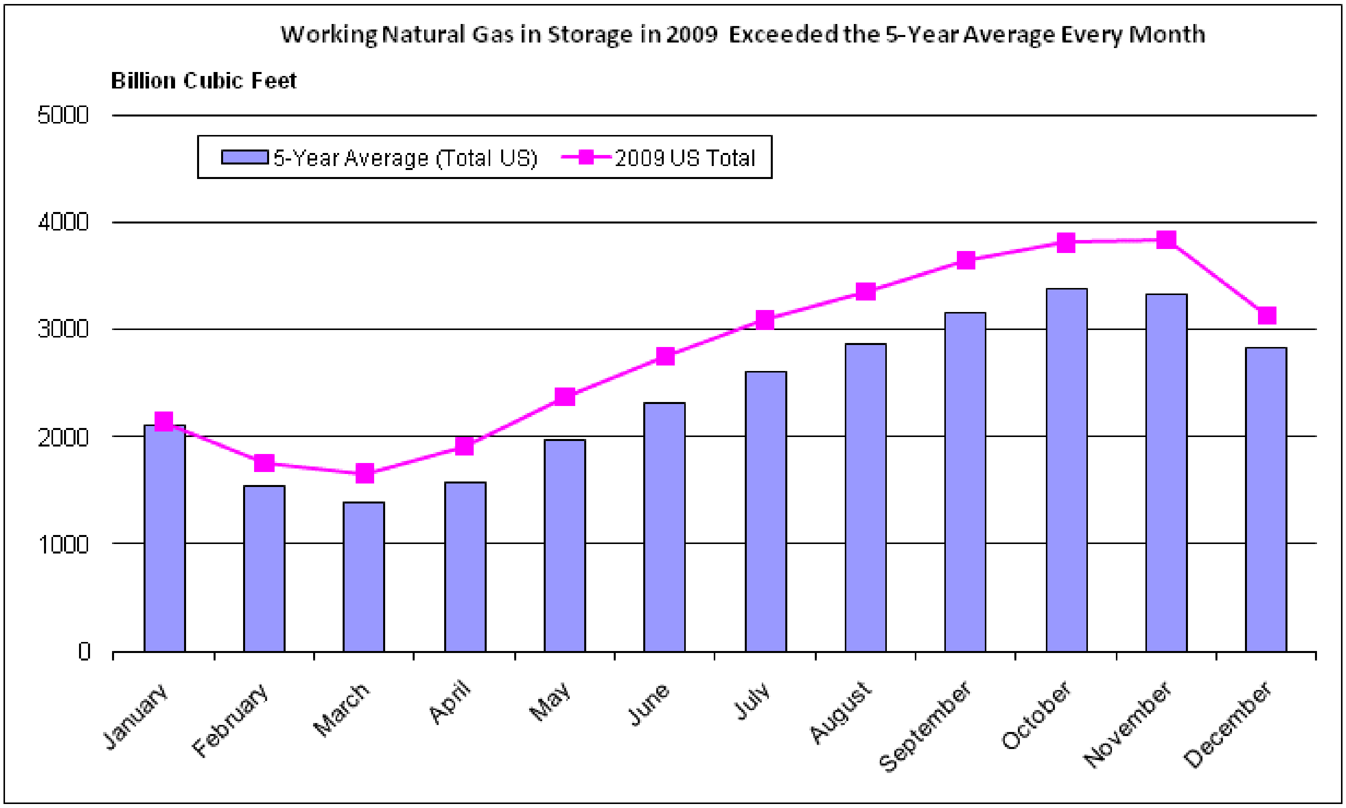
Oct-2010
Nov-2010
Dec-2010

Exhibit 12A: Working levels of inventory for 2008



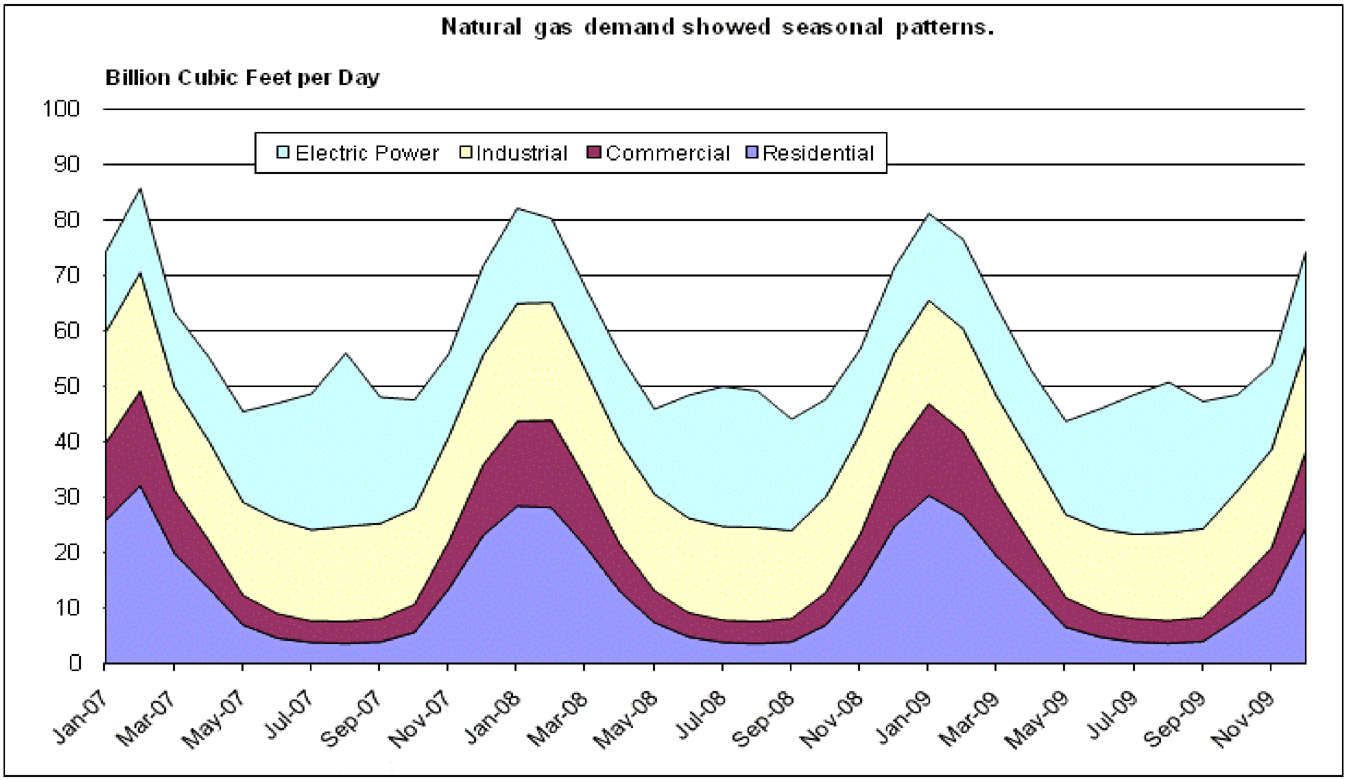
Source: Energy Information Administration

Exhibit 12B: Working levels of inventory for 2009



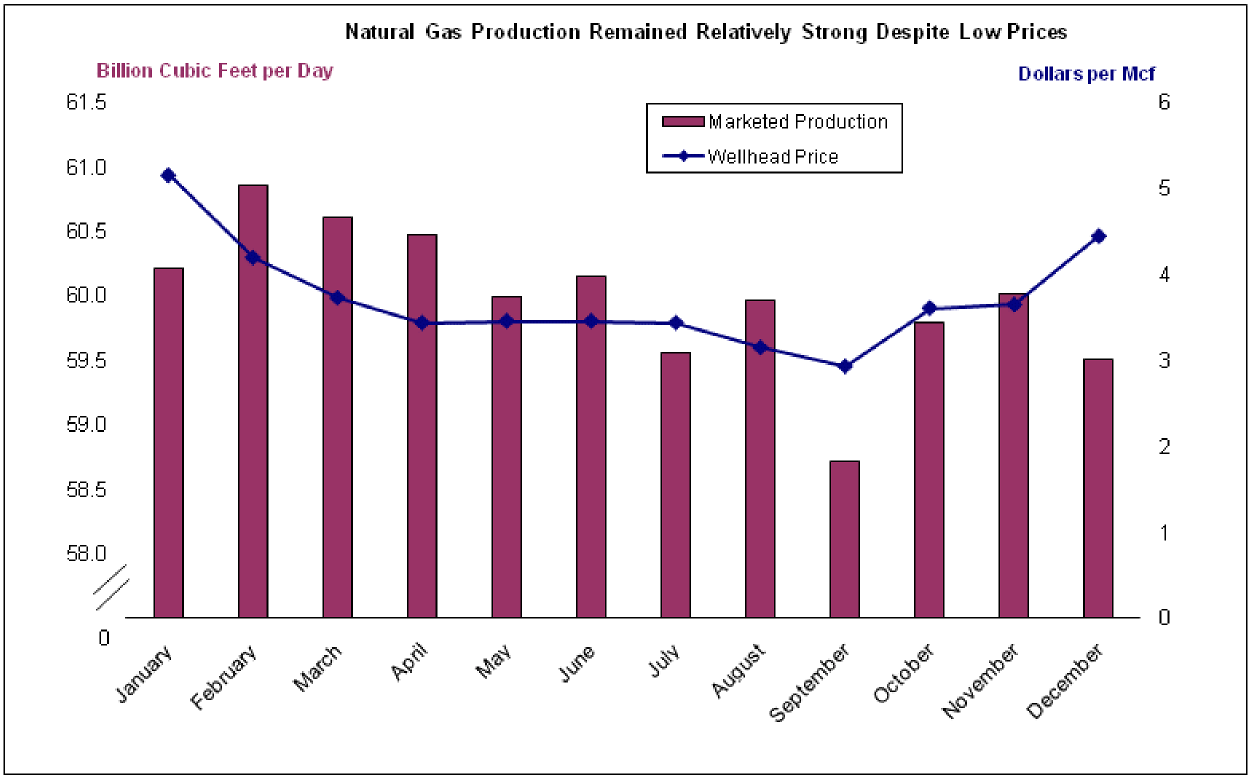
Source: Energy Information Administration

Exhibit 13: Seasonal Natural Gas Demand from 2007 - 2009



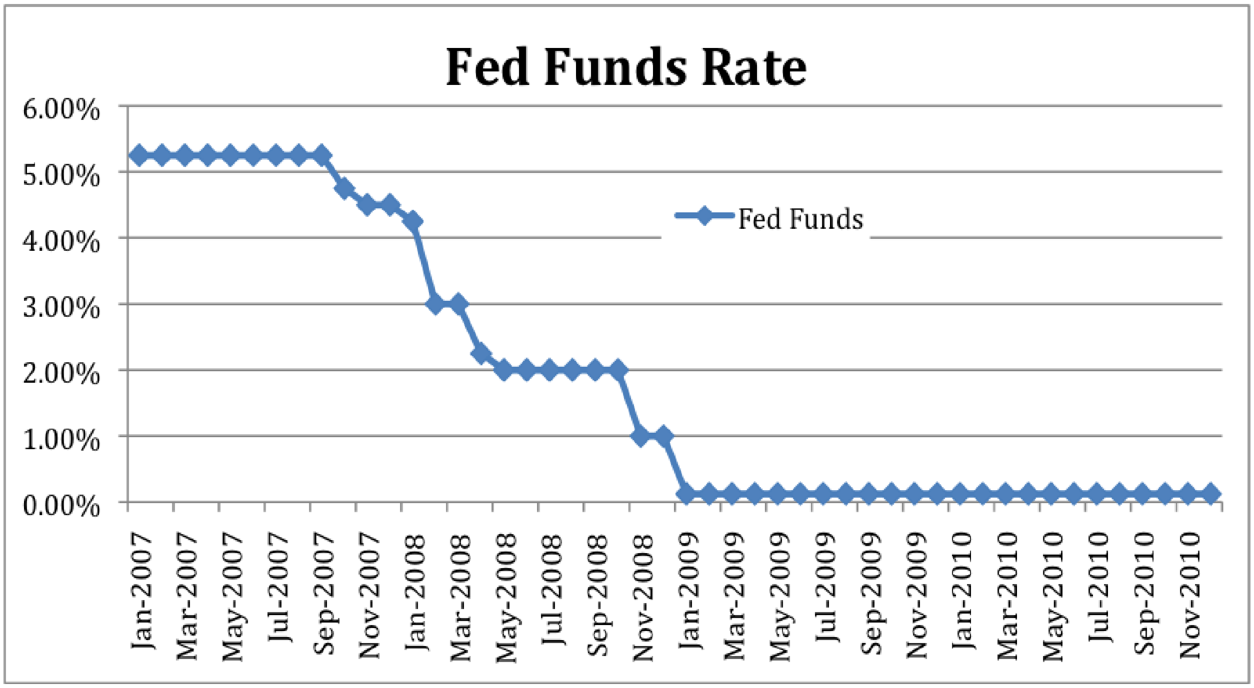
Source: Energy Information Administration

Exhibit 14: Natural Gas Production Remained Strong Despite Lower Prices in 2009



Source: Energy Information Administration

Exhibit 15: History of Federal Funds Rate (Proxy for Cost of Storage) from 2007 – 2010



Source: http://www.moneycafe.com/library/fedfundsrate.html

Exhibit 16: Regression of Average Temperature in Louisiana vs. HHUB 12-month Futures

Table of Sample Statistics

Sample Statistic	**USA Monthly Heating Days**	**HHUB 12- month Future Prices**
Mean	284.81	6.87
Median	225.50	6.07
Standard Deviation	263.56	2.19
Minimum Value	4.00	4.29
Maximum Value	767.00	13.13

Regression Statistics

Multiple R	0.07532997
R Square	0.005674604
Adjusted R Square	-0.015941165
Standard Error	265.6514954
Observations	48

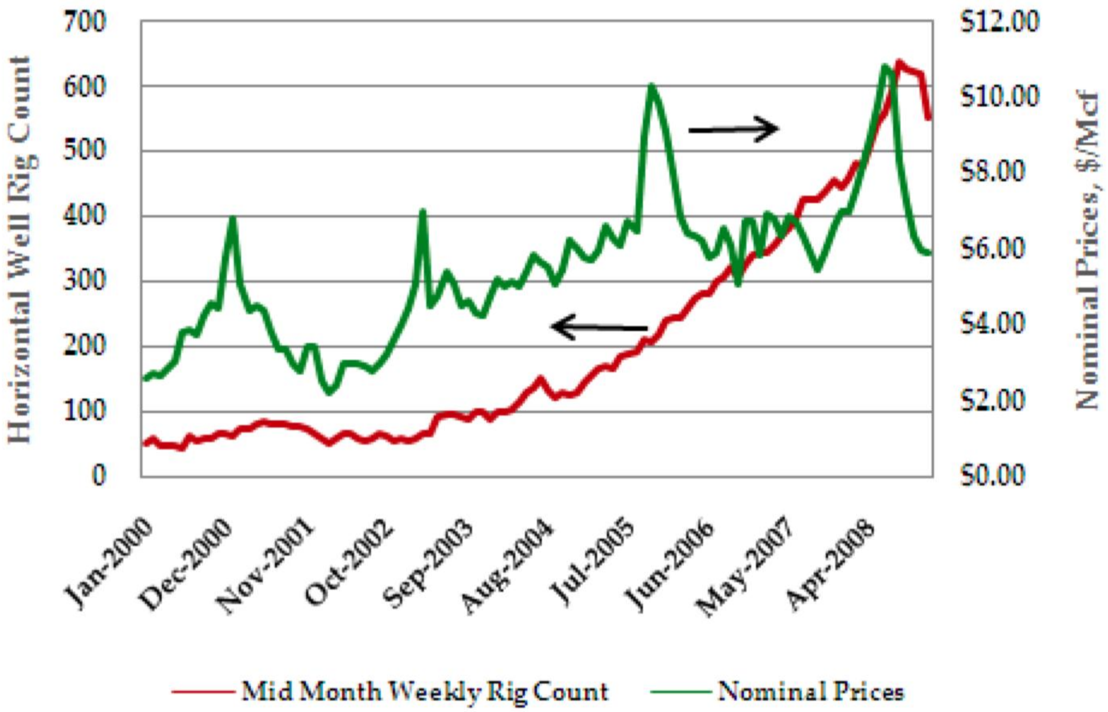
ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	18526.33087	18526.33087	0.262521505	0.610844618
Residual	46	3246252.982	70570.71699		
Total	47	3264779.313			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	347.1606688	127.584285	2.721030014	0.009156959	90.34682708	603.9745105
X Variable 1	-9.077929989	17.71757933	-0.512368525	0.610844618	-44.74156689	26.58570691

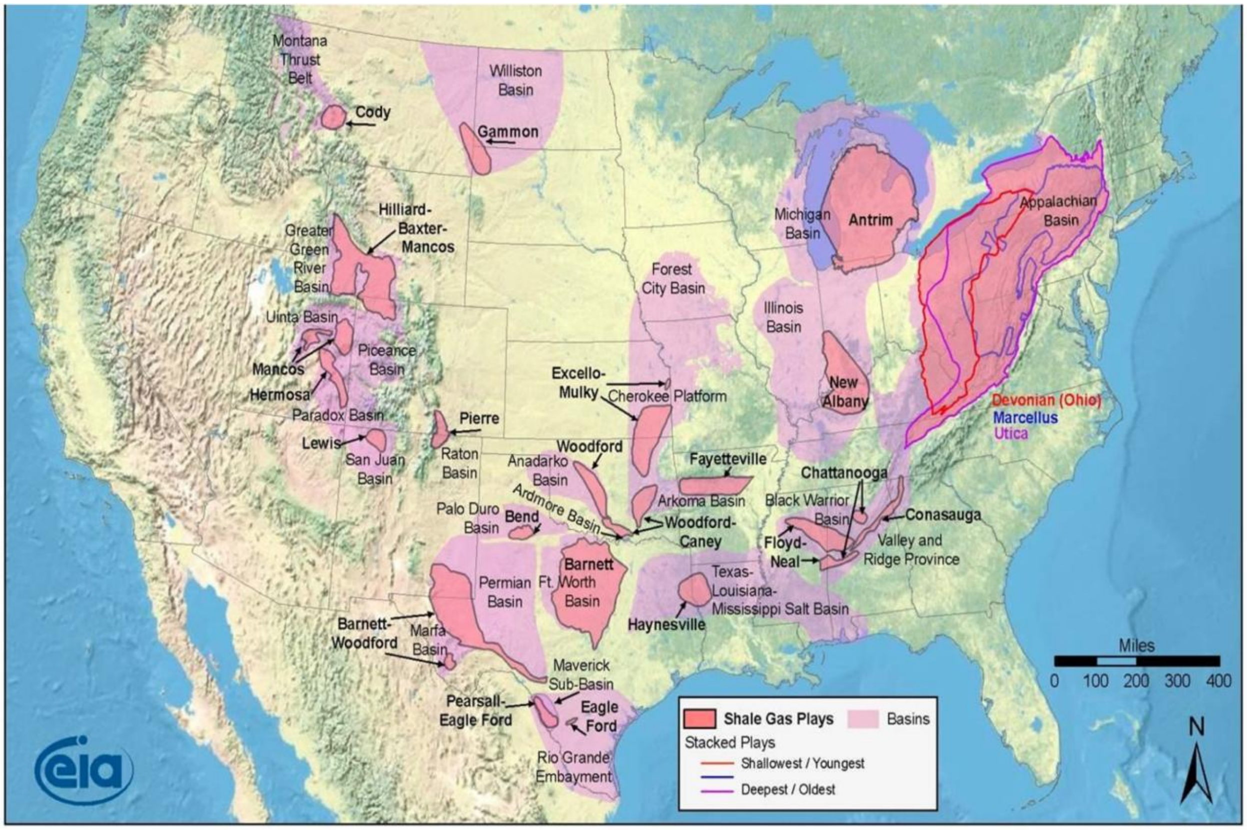
Source: National Oceanic and Atmospheric Administration (NOAA) and EIA

Exhibit 17: Horizontal Well Rig Count and HHUB Spot prices



Source: http://www.energy.ca.gov/2009publications/CEC-200-2009-005/CEC-200-2009-005-SD.PDF

Exhibit 18: Shale Gas Fields Throughout the United States



Source: Energy Information Administration