Gas Shales: Industry Savior or Value Destroyer?

BP says proven natural gas reserves around the world have risen to 1.2 trillion barrels of oil equivalent, enough for 60 years’ supply.

An article in the UK’s *Daily Telegraph* newspaper two weeks ago, written by its international business editor Ambrose Evans-Pritchard, highlighted the hype surrounding the natural gas resources contained in shale formations throughout the world and how this resource holds the key to meeting the world’s energy needs for decades to come. The article seized on comments from Tony Hayward, BP’s chief executive officer (BP-NYSE), at the recent 24th World Gas Conference 2009 where he pointed out that proven natural gas reserves around the world have risen to 1.2 trillion barrels of oil equivalent, enough for 60 years’ supply.

Mr. Hayward stated, “There has been a revolution in the gas fields of North America. Reserve estimates are rising sharply as technology unlocks unconventional resources.” His comments were echoed by Rune Bjornson of Norway’s Statoil Hydro (STO-NYSE) who observed that exploitable reserves are much greater than supposed just three years ago and may meet global gas needs for generations. His statement to *Petroleum Economist* was, “The common wisdom was that unconventional gas was too difficult, too expensive and too demanding. This has changed. If we ever doubted that gas was the fuel of the future – in many ways there’s the answer.”

The key to unlocking this vast natural gas resource that appears to exist around the world has been the application of 3-D seismic imaging, horizontal drilling and hydraulic fracturing technologies.

Texas A & M University has calculated that these technologies could increase global gas reserves by nine times to 16,000 trillion cubic feet (Tcf). In the U.S., the Energy Information Administration (EIA) has estimated that gas-shale production will meet half of the nation’s
Gazprom is not going to be the perennial cash cow selling natural gas to a desperate Europe and funding Russia’s great power resurgence

Gazprom is not going to be the perennial cash cow selling natural gas to a desperate Europe and funding Russia’s great power resurgence. While gas shales promise to be the savior for the U.S. and global energy businesses, there is clearly one big loser—Russia’s Gazprom (OGZPY.PK). If these new global gas supply forecasts prove accurate, Gazprom is not going to be the perennial cash cow selling natural gas to a desperate Europe and funding Russia’s great power resurgence. But there is truth to the statement by Deputy Chairman of the Management Committee of Gazprom, Alexander Medvedev, when he said, “There are a lot of myths about shale production.”

What are these gas shales and what are the myths? Gas shales are strata lying in the earth below many known basins containing oil and gas where substantial amounts of organic matter were deposited thousands of years ago and then under extreme pressures and temperatures were transformed into natural gas. In contrast to the more conventional deposits of natural gas—such as those associated with oil accumulations or found in structural or stratigraphic gas accumulations—these gas shales are almost solid rock formations that have absorbed the gas resource. Significantly, these gas shale formations often extend over very large distances.

Exhibit 1. Gas Shales Are Source Rock Of Petroleum Basins

Shales are highly compact and have little or no pore spaces where free-gas molecules can reside

The challenge in dealing with gas shales has been developing the cost-effective technology to open up the solid rock and free up the absorbed gas held there. In contrast to the more conventional gas producing formations such as sandstone, shales are highly compact and have little or no pore spaces where free-gas molecules can reside. It is only after the shales are broken and the shale turned into rubble that the absorbed gas molecules can detach from the shale and return to their free-gas state and thus be extracted from gas demand within 20 years, if not earlier. This prospect suggests that when coupled with wind and solar power, a smarter electric grid and a switch to electric cars, the U.S. could approach becoming energy self-sufficient, a goal of the Obama administration and others before it.
Notice how solid the gas shale is compared to the more porous sandstone.

Gas shales are found in many areas around North America as the chart of prospective basins and known producing shales shows.

Exhibit 2. Shales Are Often At The Bottom Of The Reservoir

Exhibit 3. Shales Are Dense While Sandstones Are Porous
The challenge for the E&P industry is to figure out just how large these basins are and how prolific they may become.

While gas shales tend to be homogeneous in their makeup there are significant variations that impact the ability of the shales to hold and release free-gas molecules. With the successful development of technologies to cost effectively extract the natural gas trapped in the gas shales, the challenge for the E&P industry is to figure out just how large these basins are and how prolific they may become.

Exhibit 4. Gas Shales Are Extensive In North America

The greatest impact on the reserve estimate increase comes from improved knowledge about gas recoverability from the highly prospective Haynesville and Marcellus shales.

The Federal Energy Regulatory Commission (FERC) prepared an analysis of potentially recoverable gas reserves from the known U.S. gas shale basins. Their chart shows dramatically higher estimates of this resource in 2008 compared to its estimate made in 2006. The increase in the reserve estimate reflects the impact of the new drilling and production technologies and higher natural gas prices on the estimated recoverability from the various shale basins. As shown in the table, the greatest impact on the reserve estimate increase comes from improved knowledge about gas recoverability from the highly prospective Haynesville and Marcellus shales.

The success of these new gas shale basins is the primary reason the Potential Gas Committee in its study released earlier this year boosted its estimate of the amount of natural gas resources available in the country to 1,836 Tcf. That estimate represents an increase over the estimate made two years ago by 515.5 Tcf, or a
The Potential Gas Committee saw shales accounting for 616 Tcf, or one-third of all the potential gas resources.

With an energy playing field tilted in its favor and the prospect of potentially huge new domestic resources, a golden era for natural gas is now envisioned by producers and investors.

After hitting a low of $2.50/Mcf barely a few months ago, gas prices have rallied back to the $5/Mcf level.

Soaring crude oil prices in 2007 and the first half of 2008 pulled natural gas prices higher. When the first significant signs emerged in the early summer of 2008 of the developing recession and credit crisis, oil prices peaked and began dropping precipitously. Just as natural gas prices had followed oil prices higher, they also dropped in lockstep. In actuality natural gas prices dropped faster than crude oil prices probably reflecting the regional market nature of gas. The big difference lately between the two fuels has been their relative price performance since the spring of 2009 as oil prices have recovered with growing signs of the ending of the economic recession, while gas prices have continued to struggle due to higher production and growing storage volumes. After hitting a low of $2.50 per thousand cubic feet (Mcf) barely a few months ago, gas prices have rallied back to the $5/Mcf level.

The promise of the gas shales has lead to a significant increase in drilling in these basins and a sharp increase in the nation’s natural gas production in the past three years following many years of either flat or declining domestic production. Because of its reduced CO₂ content, natural gas in recent years has become the preferred hydrocarbon resource for environmental reasons. While coal remains the cheapest fossil fuel available, its higher pollution quotient has made it the target of environmentalists and the current administration. With an energy playing field tilted in its favor and the prospect of potentially huge new domestic resources, a golden era for natural gas is now envisioned by producers and investors.

Soaring crude oil prices in 2007 and the first half of 2008 pulled natural gas prices higher. When the first significant signs emerged in the early summer of 2008 of the developing recession and credit crisis, oil prices peaked and began dropping precipitously. Just as natural gas prices had followed oil prices higher, they also dropped in lockstep. In actuality natural gas prices dropped faster than crude oil prices probably reflecting the regional market nature of gas. The big difference lately between the two fuels has been their relative price performance since the spring of 2009 as oil prices have recovered with growing signs of the ending of the economic recession, while gas prices have continued to struggle due to higher production and growing storage volumes. After hitting a low of $2.50 per thousand cubic feet (Mcf) barely a few months ago, gas prices have rallied back to the $5/Mcf level.
The E&P industry has been able to boost gas production with fewer rigs by targeting gas-shale wells.

The recent gas price recovery has come largely due to a reversal in the extremely bearish outlook for gas demand as forecasts for a record cold winter have emerged and there is a growing belief that the fall in gas-oriented drilling will meaningfully reduce gas production sooner rather than later. This scenario suggests substantially higher gas prices sometime in 2010. The problem in forecasting the timing of a fall in natural gas production, and a subsequent rise in gas prices, has been the success of gas-shale drilling. The E&P industry has been able to boost gas production with fewer rigs by targeting gas-shale wells in contrast to the historical trend that necessitated increased drilling efforts to grow production. We have looked at this topic before but the data is not as dramatic as that in the nearby chart. It shows how the growth of gas production for one producer active in the Barnett shale, the oldest and highly successful gas-shale exploitation effort, has increased without a commensurate rise in drilling. Since late in 2008 and so far through 2009, gas production for this producer from the Barnett has grown while the rig count has fallen by two-thirds.
Gas-shale formations have moved from being junk zones to golden calves, and they are now the target of billions of dollars of drilling and fracing expenditures.

The new gas shales are expected to leapfrog the performance of the Barnett because the industry has gained significant technological knowledge about shales and the higher initial production rates from wells in these basins supports that conclusion.

The history of the E&P industry has generally been one of creating wealth, but there have been numerous times in the past when the industry has been a serial destroyer of capital.

The key to the E&P industry’s success in growing gas-shale production has been the increased use of hydro-fracturing (fracing) technology, especially in horizontal wells where significant amounts of the shale formation are exposed. Historically when the E&P companies were drilling vertical wells seeking natural gas and they encountered shale formations, they were considered junk zones and problem areas that needed to be drilled through as quickly as possible to reduce the risk of drilling failures. In the past 20 years since George Mitchell of Mitchell Energy first began experimenting with Barnett shale wells, the E&P industry’s focus has been turned upside down. Gas-shale formations have moved from being junk zones to golden calves, and they are now the target of billions of dollars of drilling and fracing expenditures.

As the U.S. gas-shale frenzy has spread from the Barnett, and new exploration regions have benefitted from the knowledge and technology developed in that central Texas field, initial well production in new shale basins has set record after record. These drilling successes have fueled further excitement about the long-term potential of gas-shale plays. A problem, however, is that other than the Barnett, all the shale plays are early in their development and do not have extensive production track records. As noted by the industry forecasters, the new gas shales are expected to leapfrog the performance of the Barnett because the industry has gained significant technological knowledge about shales and the higher initial production rates from wells in these basins supports that conclusion. On the other hand, as analysts are now beginning to examine in greater detail the extensive well data available from the Barnett, they are beginning to question exactly how productive and profitable these wells are. As a result, doubts are emerging about how much of the hype about these gas shale plays can be believed. The analysts are questioning whether each new gas-shale play in reality will prove more prolific and more profitable than prior ones. For analysts, a healthy degree of skepticism is appropriate as charts of the performance of some Barnett wells are not matching the forecasts and hype.

As with any new exploration play, it takes the geologists and geophysicists time to determine out how best to unlock the hydrocarbons trapped in the underground rock in an economic manner. Therein lays the challenge for the gas-shales. Can these resources be developed in an economic manner, especially in a low-gas price environment, while still meeting the goals and aspirations of E&P executives and their shareholders?

The history of the E&P industry has generally been one of creating wealth, but there have been numerous times in the past when the industry has been a serial destroyer of capital. The wealth created by the industry has been due to a combination of skill, discipline and a certain amount of luck. The history of the petroleum industry is replete with tales of men who were gifted at knowing exactly where to seek oil and gas. Of course, for years the industry’s track record was one successful well out of every 10 drilled, certainly not a record.
Over the past 20-25 years, the petroleum industry has become more professionally staffed and managed, largely in response to the destruction of capital that came with the 1980s’ recessions and oil price collapse. The industry has also had its cast of characters – some successful and others not. Some were lucky and others unlucky. Some were educated, while others worked by “gut feel.” Many observers would say that these qualities characterized the wildcatters that populated the industry in its early days, but these were also the qualities that characterized many E&P leaders during the industry’s periods of extreme commodity price volatility such as in the 1970s. But over the past 20-25 years, the petroleum industry has become more professionally staffed and managed, largely in response to the destruction of capital that came with the 1980s’ recessions and oil price collapse. The industry’s performance during the 1990s and 2000s suggests companies have developed a well refined set of management tools and capital allocation disciplines that have contributed to its success. That view, however, is being called into question by the growing number of E&P companies currently going out of business – either through voluntary or involuntary actions.

For an E&P company, virtually all its assets are located down a hole in the ground. No one really knows what is down there, and in fact the final tally will only be known when the well is plugged and the field abandoned. The key principle of accounting is to match period expenses with revenues providing a clear picture of current profitability. In the case of the E&P industry, the bulk of the investment (expense) is expended in finding and developing oil and gas resources. Over time a small amount of money is spent producing the oil and gas along with the expense for corporate overhead. Unless a company borrows money to fund its exploration and development activities, it will have no other costs except for income taxes, assuming it makes a profit.

For accounting purposes, the large capital outlay for finding and developing (F&D) oil and gas has to be amortized over the number of barrels of oil or Mcf of gas expected to be produced from the field. If more oil and gas is found than initially estimated, then the venture turns out to be hugely successful as some of the later production has minimal F&D costs assigned to those units produced. On the other hand, if there is less oil and gas produced, then the un-amortized F&D cost needs to be written off when the well is plugged and abandoned.

E&P executives have to make judgment calls about the volume of oil and gas resources discovered and how long it will take to produce them. The challenge is to estimate as accurately as possible how large the reservoir is (i.e., the size of the bread box) and how much of the hydrocarbons contained in it will ultimately be produced (i.e., how many slices will be eaten). If we take the total amount of capital spent to find and develop the reservoir and divide it by the estimated number of barrels of oil or Mcf of gas to ultimately be produced, we
Those companies with low or falling F&D costs are perceived by investors to be more profitable and thus their shares will be worth more in the stock market.

The technologies for exploiting the gas-shale resources create a somewhat different process but essentially the same objective of exploiting the best parts of the reservoir first.

The initial production (IP) rate of the wells is a good indicator of the estimated ultimately recoverable (EUR) gas.

Arrive at the per-unit F&D cost. That unit cost figure then must be charged against the per-unit-income to determine the firm’s operating profitability. Obviously, the more barrels you have in the reservoir or the greater the percentage of them you can produce will influence the per-unit F&D charge. For public companies that depend upon high and growing earnings and cash flows for their stock valuations, or companies that need to raise capital to continue their exploration and development efforts, the more reserves and potential production you can establish, the lower your F&D cost per unit produced. Those companies with low or falling F&D costs are perceived by investors to be more profitable and thus their shares will be worth more in the stock market.

The E&P industry, like most businesses, tends to reap its most profitable opportunities first and then works on the less profitable ones later. Management is hopeful that over time, new technology will be developed or greater efficiencies will evolve making these initial marginally profitable opportunities more profitable over time. In the oil and gas business, the typical pattern is to drill the “sweet spot” of the field first and leave the less productive areas (the edge) of the field until the end, if they are ever drilled. The technologies for exploiting the gas-shale resources create a somewhat different process but essentially the same objective of exploiting the best parts of the reservoir first.

The only gas shale reservoir in the U.S. with an extended production history is the Barnett. It is located in central Texas, encompasses an estimated 5,000 square miles and underlies the cities of Dallas and Ft. Worth. This field was discovered years ago but the shale was thought to be primarily a cap rock to contain conventional deposits of oil and gas. It wasn’t until the 1980s that Mitchell Energy began trying to exploit the shale formation by using fracturing technology, but success didn’t really arrive until the late 1990s when natural gas prices rose and newer technologies became available.

The complexity of gas-shale formations presents a challenge. Depending upon the composition of the shales – brittle or porous; organic-rich or not; low stress or isotropic horizontal stress – understanding which technologies will prove most successful in unlocking the absorbed gas may require extensive drilling and fracturing efforts. As Marc Bustin, professor of petroleum and coal in the Department of Earth & Ocean Sciences at the University of British Columbia, Canada, put it recently, “We’ve drilled 8,600 wells in the Barnett and we still don’t know all the answers.” But based on the record of these wells, certain precepts have been accepted. Among them is that the initial production (IP) rate of the wells is a good indicator of the estimated ultimately recoverable (EUR) gas. These two variables are tied together through the use of a hyperbolic decline curve for each producing well that predicts the rate at which gas production will drop over time.

A problem with gas-shale wells is that the rock is so solid it needs extensive fracturing to become productive. We earlier showed the
There is a direct relationship between the number of areas in the well that are fractured and the gas flow rate.

The problem with these cost estimates is, if accurate, they will do little to encourage gas producers to cut back on their drilling activity as natural gas prices fall.

Because a well’s IP can be influenced by the number of fracs employed, and if the IP is truly a predictor of EUR, then by aggressive deployment of technology the new gas-shale plays can become very productive translating into low F&D costs making them very profitable, at least initially, in today’s low gas price environment. The problem becomes the production decline rates that tend to be very rapid. There are numerous estimates of F&D costs for the various shales, and one was recently presented in a Chesapeake Energy (CHK-NYSE) presentation to investors. The problem with these cost estimates is, if accurate, they will do little to encourage gas producers to cut back on their drilling activity as natural gas prices fall. Why stop drilling if you believe your F&D cost will be sub-$2/MCF while gas prices are close to $5/Mcf? As more wells produce more gas, there eventually has to be downward pressure on gas prices unless there is a sharp upturn in gas demand. Or unless it turns out that gas-shale productivity is not as great as trumpeted and the decline curves are sharper than plotted.
He has been examining whether the Barnett has proven economically successful and whether the success, or lack thereof, can be extrapolated to other gas shale plays throughout North America as the E&P industry claims.

One consulting geologist, Art Berman, now with the help of a geophysicist, Lynn Pittinger, is examining the production history of the Barnett shale wells looking for lessons about gas-shale production. He has been examining whether the Barnett has proven economically successful and whether the success, or lack thereof, can be extrapolated to other gas shale plays throughout North America as the E&P industry claims. He started looking at Barnett well data in 2007. Using the production history for one well and plotting a hyperbolic decline curve to match its initial data, he arrived at an EUR estimate of 1.15 billion cubic feet (Bcf). This appeared to be a reasonable and economic outcome at the time.
The exponential decline curve resulted in cutting meaningfully the estimated EUR for the well. However, when he revisited the production data for that well through the middle of 2009, he found it had fallen off much more sharply than was suggested by the hyperbolic decline curve he plotted in 2007. This time he decided to fit an exponential decline curve to the production data and found a much closer fit. However, the exponential decline curve resulted in cutting by a significant amount the estimated EUR for the well. From his initial estimated EUR for the well of 1.15 Bcf, he is now at 0.44 Bcf, or only 38% of his original estimate. He has subsequently examined the production history of about 2,000 Barnett wells and has found that they match exponential decline curves better than hyperbolic curves.

Exhibit 11. Exponential Curve Fits Better – Outcome Worse
Overly optimistic decline models: 2009 projection

The difference in using a hyperbolic versus an exponential decline curve can be significant. In fact, it can dramatically alter the forecast of the well’s EUR and its productive life. The reason is the impact of small curvature changes over time for hyperbolic curves, which are shown in the accompanying chart.

Mr. Berman has been making his conclusions available widely to the E&P industry and the investment community. He has published them in his columns in *World Oil* magazine throughout the year. He has also been making presentations at a wide range of industry and technical society meetings, including speaking recently at the Association for the Study of Peak Oil’s (ASPO) international conference in Denver, Colorado. Importantly, Mr. Berman has welcomed, and in fact encouraged, critical analysis of his methodology and conclusions and has gone out of his way to facilitate opportunities for people to do so.
Many of the criticisms remind us of the defenses for the dot-com and tech stocks after their collapse in the 1999-2000 timeframe.

For the E&P industry, this would not be the first time it has embarked on a course that ultimately destroyed more capital than it created.

As one would expect, there are people critical of Mr. Berman’s conclusions. Most of them are with companies actively involved in gas shale plays or at Wall Street investment banking firms that stand to benefit from capital-raising efforts for the E&P industry. Most of the criticisms we have seen, in our view, carry little substance. In fact, many of them remind us of the defenses for the dot-com and tech stocks after their collapse in the 1999-2000 timeframe. Those defending the stocks that had just blown up costing investors billions of dollars made statements to the effect that the analysis was solid, the models couldn’t have been wrong (they were prepared on Excel spreadsheets) and by the way, look at the billions of dollars “smart” investors were putting into the companies right up until the downturn. There must be something wrong with everyone else that we just don’t understand was their conclusion.

Of course, a number of investors could have said that about their accounts with Bernie Madoff and R. Allen Stanford. Understand, we are not implying that E&P industry executives and Wall Street energy analysts are committing fraud or have constructed ponzi schemes, but rather that there is sufficient room to interpret the data (legally) in such a way that it gives the appearance that companies are more profitable than they really are. For the E&P industry, this would not be the first time it has embarked on a course that ultimately destroyed more capital than it created. Equally important for the industry is that the misallocation of capital in the gas shales may also lead to misallocation of capital in other E&P ventures.

The following two charts best summarize the challenge the industry faces in refuting Mr. Berman’s analysis.
If the technology for dealing with gas shales is improving, then the onus would appear to be on the E&P companies to show data that substantiates their claims. Why are newer wells in the Barnett producing less than older wells? Does this mean we have exhausted the sweet spot in the field? That would be in keeping with the development pattern of most other E&P projects, and it would work against the concept that gas-shale exploitation is a factory-like drilling process. Likewise, why is the historical record of...
One has to question why we should expect gas prices to rise next year. The gas shale play is beginning to smell like a bubble and as we have learned during the past few years, bubbles have a way of ending in a bad way. One thing we have learned over the years of researching the energy business is that some investors will win big while many others lose. The question is whether the winners are the first movers or those who wait for the inevitable collapse and then pick up the pieces?

The greatest challenge for the E&P industry is to develop capital discipline and to then exercise that discipline. The gas-shale play is beginning to smell like a bubble and as we have learned during the past few years, bubbles have a way of ending in a bad way. We certainly hope we are wrong, but we cling to Mr. Bustin’s observation that even after 8,600 Barnett wells we don’t know everything there is to know about gas shales. We will continue to follow this debate closely because its outcome is important to the nation, the industry and investors.

Does October Snow Portend A Hard Or Mild Winter?

The October 15th snowfall in the U.S. Northeast was a surprise to most people. Given the stories about the weather and the pictures of the tree damage as a result of the heavy snow on trees still holding their leaves, we were happy not to have been driving back from Rhode Island then. Our usual travel route takes us across part of Pennsylvania from the New York line to Scranton where we connect with a primary north/south highway that extends to Tennessee. When we reach Scranton, we are not too far from State College, home to Penn State University, which was the epicenter of the snowfall, recording about nine inches total. By that Friday evening, Penn State had banned tailgating for its Saturday homecoming football game because of the problem of parking vehicles on grass fields that university officials knew would likely turn into mud.

The question that immediately came to our mind after seeing the early reports of the October snowfall was whether this weather event portends the start of a hard winter, or is it merely a one-time weather anomaly? Our curiosity was heightened after remembering the
There have been seven early October snows and during the following winters only two experienced below normal precipitation, one was normal and three were above normal.

September 28th forecast from Matt Rogers of Commodity Weather Group that the U.S. Northeast could experience its coldest winter in a decade. That forecast was responsible for natural gas futures prices jumping by more than a dollar per thousand cubic feet, from $3.73 to $4.88, in a single trading day.

For a quick answer to our question, we turned to the AccuWeather.com web site. AccuWeather, a leading weather forecasting service, happens to be based in State College as Penn State has an excellent meteorological program and the people behind the firm matriculated there. Since State College seemed to be at the center of the storm, it seemed appropriate to turn to this web site to check for an interpretation of the longer term impact of the early snowfall.

On the blog written by AccuWeather.com meteorologist Jesse Ferrell, he referenced a “quick” analysis he and another senior meteorologist at the firm did on winter precipitation following early October snowfalls. According to their analysis, there have been seven early October snows and during the following winters only two experienced below normal precipitation, one was normal and three were above normal. The quick answer to our question seems to be that you cannot draw any firm conclusion about the amount of snow to fall this winter based on this particular weather event.

In postings on Mr. Ferrell’s blog, there was an interesting item from a Don Brown who lives in the White Mountains of New Hampshire. He said he was in his 60s and had been a weather enthusiast for most of his life. His observation was that when there is a 5-day hot spell in April, the rest of the summer never experiences temperatures that are much above normal. (That happened this year.) Likewise, he
He said Philadelphia did not have any snow that winter.

While this recent snowstorm is the earliest to hit State College, it was not the earliest to ever hit Pennsylvania.

There were three winters that were cooler than the prior winter and two that were warmer – hard to draw any conclusion from this pattern.

said, when there is a 5-day cold snap in October, the following winter never has temperatures that are much below normal. We’ll wait to see if this correlation holds.

Another posting reminded Mr. Ferrell to check out the experience following an early snowfall in Redding, Pennsylvania during the 1972 World Series (an October event). He stated the only snow Redding saw the following winter were “snow showers.” He said Philadelphia did not have any snow that winter. So what can we expect for this upcoming winter? Of course we are less interested in the amount of snowfall than the temperature since that will influence natural gas and heating oil prices and, by association, the price of a barrel of crude oil.

Trying to find data on winter weather temperatures for Pennsylvania proved somewhat daunting. What we did find was a chart on the long-term record of winter weather temperatures for the entire U.S. Northeast (Pennsylvania, New Jersey, New York, Connecticut, Rhode Island, Massachusetts, New Hampshire, Vermont and Maine) from 1900 to 2006. While not perfect, it allowed us to do examine the quick analysis reported by Mr. Ferrell.

In the accompanying chart we show five of the seven early snow events in Pennsylvania. While this recent snowstorm is the earliest to hit State College, it was not the earliest to ever hit Pennsylvania. The five cities listed are located largely in the central part of the state with all of them north or west of Harrisburg. For people who want to study the geography, we have included a map of the State of Pennsylvania with many of its cities, including all those with early October snowfalls so you can locate them.

Exhibit 16. Early October Snowfalls Not A Winter Indicator

<table>
<thead>
<tr>
<th>Station</th>
<th>Date</th>
<th>Snowfall (Inches)</th>
<th>Temp °F</th>
<th>Chg from Prior Year</th>
</tr>
</thead>
<tbody>
<tr>
<td>Williamsport</td>
<td>October 16, 1977</td>
<td>1.0</td>
<td>24</td>
<td>Lower</td>
</tr>
<tr>
<td>Harrisburg</td>
<td>October 19, 1972</td>
<td>1.2</td>
<td>28+</td>
<td>Higher</td>
</tr>
<tr>
<td>State College</td>
<td>October 18, 1901</td>
<td>0.1</td>
<td>23-</td>
<td>Lower</td>
</tr>
<tr>
<td>Altoona</td>
<td>October 12, 1988</td>
<td>0.2</td>
<td>27</td>
<td>Higher</td>
</tr>
<tr>
<td>Johnstown</td>
<td>October 10, 1925</td>
<td>0.2</td>
<td>26</td>
<td>Lower</td>
</tr>
</tbody>
</table>

Source: NOAA, PPHB

In the table, we show the town, the date of the October snowfall, how much snow was measured, the average Northeast winter temperature (read from the chart in Exhibit 18) and the change in that average winter temperature from the prior winter. As can be seen, there were three winters that were cooler than the prior winter and two that were warmer – hard to draw any conclusion from this pattern.
Weather forecasting plays an important role in trading commodities. The investment community spends considerable amounts of money on weather forecasting as it plays an important role in trading commodities. Weather – temperatures and precipitation – influences the development of crops and their yields. It is also important for trading petroleum product, natural gas and electricity futures as their demand rises and falls with changes in temperatures. Thus, temperature forecasts of upcoming winters and summers receive considerable attention from investors.

In predicting consumer heating bills this winter, the Energy Information Administration (EIA) estimated they would be 8% below last winter due to lower fuel prices and 1% warmer average temperatures. There was considerable surprise at the trend in the components of the EIA’s forecast since the government’s weather agency, the National Oceanic and Atmospheric Administration (NOAA) has been talking about this being a normal winter, temperature wise. Given the surprise in the EIA’s winter prediction,
The key difference between the two winter forecasts is the interpretation of the impact of the El Niño weather phenomenon that developed earlier this summer.

Mr. Bastardi suggests this winter's weather will be cooler and snowier than normal, with the hardest hit area being southern New England through the Appalachians and mid-Atlantic regions.

When we look at the latest NOAA forecast for this winter released October 15th and compared it to the AccuWeather.com forecast released a day earlier.

The key difference between the two winter forecasts, as pointed out in a report issued by AccuWeather.com, is the interpretation of the impact of the El Niño weather phenomenon that developed earlier this summer and that has contributed to a lower number and reduced intensity of hurricanes that formed in the Atlantic Basin. In reviewing Mr. Rogers’ gas-price-boosting weather forecast we found it too hinged on his view of El Niño’s impact on winter weather trends.

Exhibit 19. A Colder And Snowier Forecast By AccuWeather

![AccuWeather.com 2009-2010 Winter Forecast Overview](image)

Source: AccuWeather.com

When we look at the overview of this winter’s weather as forecast by AccuWeather.com’s chief meteorologist, Joe Bastardi, we find he believes a “fading” El Niño will not play as much of a role in the overall weather pattern as one would expect from a typical El Niño year. Thus, Mr. Bastardi suggests this winter’s weather will be cooler and snowier than normal, with the hardest hit area being southern New England through the Appalachians and mid-Atlantic regions. Northern areas of New England should see normal snowfall with slightly below normal temperatures. Mr. Bastardi believes the major cities in the Northeast and mid-Atlantic region could see 75% of their expected snowfall in just two or three large storms. He also expects the Midwest and Great Plains regions to get a break from winter this season with below-normal snowfall and average to a bit milder temperatures than in recent years.

What seems obvious in comparing these two forecasts, based only on their temperature projections, is that NOAA has a much smaller geographical area it predicts will experience cooler than normal temperatures. Based on the charts, one can see how the EIA
arrives at a forecast for a slightly warmer temperature this winter compared to last year.

**Exhibit 20.  AccuWeather Forecast Says Higher Heating Bills**

![AccuWeather Forecast](image)

Source: AccuWeather.com

**Exhibit 21.  NOAA Sees A Slightly More Mild Winter This Year**

![NOAA Outlook](image)

Source: NOAA

Mr. Rogers’ winter temperature projection is consistent with Mr. Bastardi’s outlook based on a fading El Niño.

When we went back and reviewed Mr. Rogers’ winter temperature projection, we found his forecast to be consistent with Mr. Bastardi’s outlook based on a fading El Niño. Mr. Rogers stated, “About 70 percent to 75 percent of the time a weak El Niño will deliver the goods in terms of above-normal heating demand and cold weather.
It’s pretty good odds.” Because NOAA expects El Niño to remain prominent and drive winter weather, they expect the winter to be more like a normal or possibly slightly warmer season. We now know what to watch for to make our own projections.

Exhibit 22. El Niño Results In Warmer Winter In North America

The chart shows the expected pattern during a typical El Niño year with northern regions of both North and South America, Australia and southern Africa tending to be warmer than normal.

To understand the impact of El Niño on global weather patterns, we found the accompanying chart from the Meteorological Institute of the Netherlands showing global temperatures during the winter helpful. The red circles on the map show where temperatures during the winter months of December through February are warmer than normal while the blue circles show where they tend to be cooler. The chart shows the expected pattern during a typical El Niño year with northern regions of both North and South America, Australia and southern Africa tending to be warmer than normal.

What is interesting is the similarity of this global temperature map with the regions of North America identified by both NOAA and AccuWeather.com to be cooler this winter. If NOAA proves correct in its view that El Niño will be stronger and produce more mild winter weather then we should expect natural gas and heating oil prices to be trending lower as we move into the January through March period next year. On the other hand, if the judgments of Mr. Rogers and Mr. Bastardi are correct, then fossil fuel prices are likely not heading lower any time soon, and actually could be trending higher throughout the winter season. Just how much higher fuel prices climb will depend, at least for natural gas, on what happens to domestic production in light of the sharp fall-off in gas-oriented drilling this year.

If the judgments of Mr. Rogers and Mr. Bastardi are correct, then fossil fuel prices are likely not heading lower any time soon, and actually could be trending higher throughout the winter season.
And You Thought Wind Power Was Cheap?

Wind power - it's clean, it's domestic, it will create new jobs (although potentially destroy others) and it's cheap – nearly free as some believe.

Last year at the height of the oil price, Block Island customers were paying 65¢/KWh, four times the charge for onshore customers and the highest charge in the continental United States.

Off the coast of Rhode Island lies Block Island, home to 800 citizens who live there year-round. The residents of this little island, only 9.7 square miles in extent, depend on diesel generators for all their electric power at a premium cost to that charged onshore residents. The current power charge is 38.6¢ per kilowatt-hour (kWh) comprised of a 19¢ fixed charge from Block Island Power Company (BIPCO) and a 19.6¢ fuel-cost charge. Last year at the height of oil prices, Block Island customers were paying 65¢/KWh, four times the charge for onshore customers and the highest charge in the continental United States. Some local businesses were receiving $45,000 per month electric bills that almost put them out of operation.

At the present time, the National Grid wholesale power cost in Rhode Island is 7.5¢/KWh, which if added to the BIPCO fixed charge would result in customers saving about 12¢/KWh. It is likely that there would be an additional charge for the cost of the cable connecting the offshore wind turbines to the island and to recover BIPCO’s stranded power costs. Estimates are that these...
The demonstration project is estimated to cost $160-200 million while the larger wind farm will require upwards of a $1.3 billion investment.

Deepwater Wind, a start-up offshore wind farm developer, has two sanctioned projects on the drawing boards for Rhode Island. One is the demonstration project involving the installation of six to eight turbines three miles off the southeastern coast of Block Island by 2012, which would be followed by a much larger wind farm project involving as many as 100 turbines located 15 miles from the Rhode Island shore. To undertake these projects, Deepwater Wind needs to secure a contract with National Grid to sell it the electricity in order to secure financing for the projects estimated to cost a total of $1.5 billion. The demonstration project is estimated to cost $160-200 million while the larger wind farm will require upwards of a $1.3 billion investment.

The rules require National Grid to first work out a contract to supply alternative energy to Block Island and then sign a more far-reaching contract to supply alternative power throughout the state.

According to media reports, there is a wide gap between the cost estimates of the proposed power contract. Three weeks ago last Thursday, National Grid filed documents with the Rhode Island Public Utilities Commission stating that its negotiations with Deepwater Wind had failed to reach a “commercially reasonable” power-purchase agreement. The filing was necessitated by the provisions in a recently enacted law designed to encourage greater use of green-fuels in the state and to help push the development of these offshore wind farms. These changes came as a result of a new law signed by Gov. Carcieri last June. The law mandates National Grid enter into power supply contracts with green-energy companies. The rules require National Grid to first work out a contract to supply alternative energy to Block Island and then sign a more far-reaching contract to supply alternative power throughout the state. National Grid is allowed to earn a 2.75% markup on any green-power it sells to consumers.

The principal reason for the failure for Deepwater Wind and National Grid to reach a contract was the projected cost of the electricity to be supplied from the wind farm. According to media reports, there is a wide gap between the cost estimates of the proposed power contract. Deepwater Wind estimates the sale price at 20¢ - 25¢/KWh, although the company is also seeking a 3.5% per annum price increase over the life of the contract. What we don’t know is when the price escalation would commence. National Grid, on the other hand, calculates the cost at closer to 30.7¢/KWh over the 20-year contract. This compares to a current cost of 9.2¢/KWh for electricity derived from other sources, including natural-gas facilities and nuclear power plants.
There are certain costs that have to be spread over the small number of turbines such as the price for renting a ship to install the turbines and the expense for renting a facility from which to assemble and stage the offshore project.

William M. Moore, chief executive of Deepwater Wind, said the estimated cost for the Block Island wind farm is higher because of several factors. First is that there has been a surge in investments in offshore wind in Europe, which has raised the price of turbine components. Second is this would be the first development of its kind in the United States, so Deepwater Wind is moving into unknown territory and is taking on significant risks.

The small size of the Block Island project also hurts its economics. There are certain costs that have to be spread over the small number of turbines such as the price for renting a ship to install the turbines and the expense for renting a facility from which to assemble and stage the offshore project. Mr. Moore admits the cost of power from the 100-turbine project would be cheaper, but they can't get to build that one until they develop the demonstration (smaller) project. National Grid says it remains flexible and has not drawn a line in the sand, so future negotiations are likely. But in the meantime, it appears the first offshore wind farm development is moving along a slower-than-expected track.

If offshore wind is going to be slower arriving in the marketplace, what about onshore wind? Wind is the government's preferred power source for the future. They are working hard to increase its contribution and the record of installed wind power capacity shows clearly that we are installing more wind generating capacity every year since 2003. But as shown in Exhibit 24, the sharp declines in installed wind capacity in 2000, 2002 and 2004 show the impact of suspending the federal government tax credits that foster its competitive advantage.

Exhibit 24. Wind Power Growing, But Still Relies On Subsidies

While wind power is growing its electricity generating capacity, it is
becoming obvious that wind is gaining market share. That is not surprising given the tax credits for installing new green-power electricity capacity plus the mandates for electric utilities to purchase upwards of 20% of its total power supply from green-energy sources.

Exhibit 25. Wind Power Is Taking Generating Market Share

<table>
<thead>
<tr>
<th>Year</th>
<th>Wind</th>
<th>Natural Gas</th>
<th>Coal</th>
<th>Petroleum</th>
<th>Dual-Fired</th>
<th>Other</th>
</tr>
</thead>
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<tr>
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<td>38%</td>
<td>24%</td>
<td>14%</td>
<td>14%</td>
<td>5%</td>
</tr>
<tr>
<td>2003</td>
<td>8%</td>
<td>32%</td>
<td>26%</td>
<td>18%</td>
<td>12%</td>
<td>7%</td>
</tr>
<tr>
<td>2004</td>
<td>10%</td>
<td>29%</td>
<td>28%</td>
<td>22%</td>
<td>11%</td>
<td>9%</td>
</tr>
<tr>
<td>2005</td>
<td>12%</td>
<td>26%</td>
<td>29%</td>
<td>21%</td>
<td>10%</td>
<td>10%</td>
</tr>
<tr>
<td>2006</td>
<td>15%</td>
<td>23%</td>
<td>28%</td>
<td>20%</td>
<td>8%</td>
<td>13%</td>
</tr>
<tr>
<td>2007</td>
<td>18%</td>
<td>21%</td>
<td>28%</td>
<td>18%</td>
<td>6%</td>
<td>16%</td>
</tr>
<tr>
<td>2008</td>
<td>21%</td>
<td>19%</td>
<td>30%</td>
<td>17%</td>
<td>5%</td>
<td>17%</td>
</tr>
</tbody>
</table>

Source: AWEA

Renewables as a class still account for only 3.0% of total electric power generation capacity in the United States

The environmental aspects of renewable power sources have begun to draw the ire of citizens who question whether the land sprawl associated with wind and solar power installations wouldn't be better addressed by using nuclear power.

After the recent four-year boom in wind power generation construction, it represents the largest component of the renewable fuels share of the electric power generation market. But renewables as a class still account for only 3.0% of total electric power generation capacity in the United States. Thus, although progress is being made, it is not likely that renewable power supplies will account for more than a small share of the total power market for the foreseeable future.

The environmental aspects of renewable power sources have begun to draw the ire of citizens who question whether the land sprawl associated with wind and solar power installations wouldn't be better addressed by using nuclear power. Several months ago Lamar Alexander, Republican Senator from Tennessee, wrote an op-ed article in the The Wall Street Journal criticizing the sprawl associated with wind and solar installations. He specifically pointed to proposals from energy developers to erect wind turbines along the mountain tops along the Appalachian chain, from Maine to Georgia. Mr. Alexander pointed out that a 300-mile line of mountain-top wind turbines stretching from Chattanooga, Tennessee to Bristol, Virginia...
According to the study, wind is more land-intensive than coal, but nuclear power is the least land-intensive.

The best prospects for U.S. wind power lie offshore.

In response, Denise Bode, CEO of the American Wind Energy Association (AWEA), said, “…only 2% to 5% of that land is actually disturbed for turbines, service roads, etc., which means that for America to generate 20% of its electricity from wind, the amount of land actually used is about half the size of Anchorage, Alaska, or less than half the amount currently used for coal mining today.” The problem with Ms. Bode’s answer is that it is undercut by a study by the environmental group, The Nature Conservancy. The report asked the question: How much land is required for the different energy sources that power the country? According to the study, wind is more land-intensive than coal, but nuclear power is the least land-intensive.

Ms. Bode is partially correct about wind’s land-use as the actual footprint for a wind turbine is typically a quarter to a half an acre. The footprint, however, doesn’t include the 5-10 turbine diameter spacing required between wind turbines and the necessary service roads, but Ms. Bode says that farmers and ranchers can use most of the space between turbines for crops and/or animal herds. While land use is an important issue, proponents of wind power will argue that the turbines are not that intrusive, especially since they are likely to be located in the central part of the U.S. where there aren’t many people – only crops and domestic animals. As the nearby chart of wind resources for this country shows, the best prospects...
The biggest challenge for wind power is that it tends to blow at the wrong time of the day relative to electric power demand. When power use climbs, it is usually during the afternoon and early evening when winds tend to blow the least. Wind is strongest during the nighttime and early in the morning, but electricity consumption is lowest at these times. That is one reason why builders of electric and plug-in hybrid vehicles argue the country can refuel them all at night at a low cost and without having to dramatically expand the capacity of the nation’s electric grid.

Scientists are working on developing ways to store the surplus electric power generated by wind turbines during low-demand times of the day. For example, there are concepts to have electrically-powered pumps move water into storage tanks at elevated locations that would then be released during peak power demand periods to generate supplemental electric power.

We believe a less costly solution would be to turn the nation into a nocturnal society. Since we are into mandates, why does everything have to be done in daylight? Just think of all the benefits – we would be sleeping during the hottest times of the day (institutionalizing the siesta). We would be more productive since we would not be distracted by beautiful days or glorious sunrises or sunsets. But importantly, the amount of cheap power available would increase instead of being wasted or requiring that we make investments in trying to store it. Benjamin Franklin wanted to make the turkey the nation’s bird rather than the eagle. We think maybe the owl could be more important in today’s energy-challenged...

**Exhibit 27. Land Intensity Is Greater For Wind Than Coal**

Source: The Nature Conservancy

The biggest challenge for wind power is that it tends to blow at the wrong time of the day relative to electric power demand. When power use climbs, it is usually during the afternoon and early evening when winds tend to blow the least. Wind is strongest during the nighttime and early in the morning, but electricity consumption is lowest at these times. That is one reason why builders of electric and plug-in hybrid vehicles argue the country can refuel them all at night at a low cost and without having to dramatically expand the capacity of the nation’s electric grid.

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environment. Here’s to the owls rather than the roosters!

**Exhibit 28. Wind Power Is Strongest Offshore**

Source: Dept. of Energy

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