MUSINGS FROM THE OIL PATCH

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Note: *Musings from the Oil Patch reflects an eclectic collection of stories and analyses dealing with issues and developments within the energy industry that I feel have potentially significant implications for executives operating oilfield service companies. The newsletter currently anticipates a semi-monthly publishing schedule, but periodically the event and news flow may dictate a more frequent schedule. As always, I welcome your comments and observations.* Allen Brooks

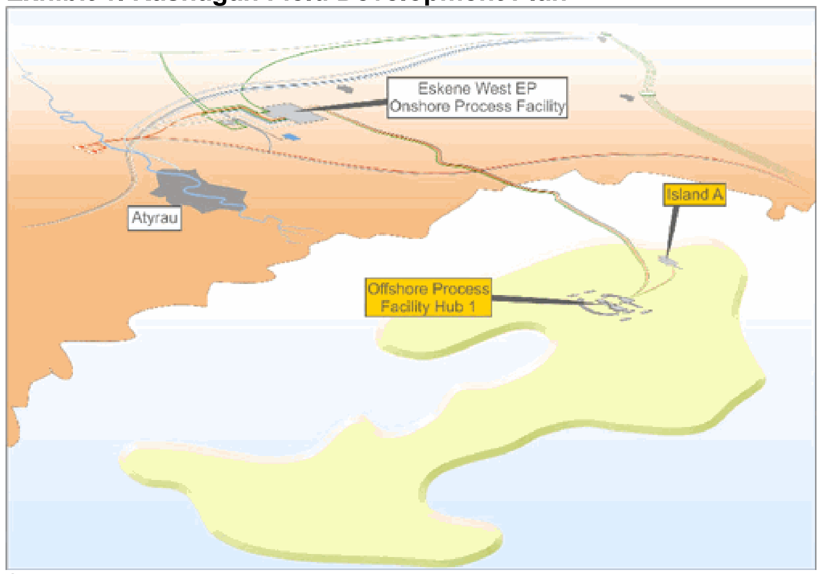
New Oil Field Woes and Peak Oil Impact

The mammoth Kashagan oil field development in Kazakhstan will be later coming on stream and cost substantially more

Just over a week ago, Italian oil company Eni SpA (E-NYSE) announced that its mammoth Kashagan oil field development in Kazakhstan would be considerably later coming on stream than previously projected and would cost substantially more. The company confirmed what some investors had already surmised, which is that Kashagan would begin pumping oil sometime in the second half of 2010, fully two years behind schedule. Equally disappointing was the company's disclosure that the cost to develop the field would be substantially greater. In actuality, Eni did not disclose the exact amount, but it signaled the magnitude of the hike when it disclosed plans for capital investment in the 2007-2010 period of EUR44.6 billion ($58.9 billion), a 27% increase over the previous spending for the 2006-2009 period. There are estimates floating around the industry suggesting that Kashagan's cost has risen from $29 billion into the mid- to upper-$30 billion range. If the amount to be spent on Kashagan were to increase in line with the overall capital spending growth projected by Eni, then the new cost estimate for the field would be in the $36.8 billion range. The fact that the cost estimate has increased should not come as a surprise. The cost of all oilfield services has increased, along with inflation in raw materials such as steel and cement. The cost increase was telegraphed by the recent experiences of Royal Dutch Shell (RDS.A – NYSE) and ExxonMobil (XOM-NYSE) with their Sakhalin Island projects.

Kashagan was initially discovered in 2000. The field lies about 50 miles offshore Atyrau and is described as being 47 miles long by 22 miles wide. The 480 square mile field was the largest oil discovery anywhere in the world since 1980. Some explorationists thought that Kashagan could be the fifth largest field in the world. The initial reserve guesses were that the field held somewhere between 8 and 50 billion barrels.

Exhibit 1. Kashagan Field Development Plan



Source: RigZone.com

By 2004, the additional drilling and seismic work narrowed the reserve estimate to about 13 billion barrels. Initial plans had been to bring the field into production in 2005 at 75,000 barrels per day (b/d), but that target date was pushed back to 2008 to 2009 due to political issues in Kazakhstan and geopolitical issues in Central Asia along with the technological challenges of bringing the oil into production given the harsh environment and remote location. The revised development plan was to start the production at 450,000 b/d but ramp it up to a peak of 1.2 million b/d sometime between 2015 and 2020.

As a result of the size and importance of Kashagan's reserves and production, this field has been an important ingredient in the analysis surrounding the Peak Oil hypothesis for global oil supply. In its January 2004 issue, *Petroleum Review* magazine published an analysis of the mega oil field projects under development in the world including the estimated date of their commencement, their subsequent production buildup and their impact on global oil supplies. At that time, Chris Skrebowski, the author of the study, projected Kashagan's Phase I coming on stream in 2006 at the rate of 450,000 b/d. Phase II of the project was scheduled on stream in 2008 and would boost annual production to 900,000 b/d. The final phase of the project would increase production to 1.2 million b/d and would be operational in 2010.

In January 2004 *Petroleum Review,* Kashagan's Phase I projected to come on stream in 2006 at the rate of 450,000 b/d

By *Petroleum Review's* April 2006 review article, Kashagan's development timetable had slipped. Now Phase I was scheduled to be on stream in 2008, followed by Phase II in 2010 and Phase III in

Peak production of Kashagan has been raised to by 300,000 b/d to 1.5 million b/d and can be sustained for at least 10 years

2012. The estimated production rates remained the same as initially projected. In the interim between the 2006 forecast and the recent Eni announcement, the peak production of Kashagan has been raised by 300,000 b/d to 1.5 million b/d, and management is confident that the peak production level can be sustained for at least 10 years. While Eni says that the field's start-up will begin during the second half of 2010, it says that the peak production will now be attained in 2019, some three years behind the prior peak production target date. What is unknown is whether the Phase II production hike (originally from 450,000 b/d to 900,000 b/d) projection remains in tact and on schedule - some two years following initial production, or whether there has been slippage in that timetable, also. There is also a question as to whether there is another phase in the field's development that sees production going up from 900,000 b/d to the new peak of 1.5 million b/d with an interim step.

In Exhibit 2, we have reproduced the global oil capacity increase profile that *Petroleum Review* published in conjunction with its 2006 article. Below the two projections that Chris Skrebowski published – the Net new capacity and Net Net estimates – we have added our projections for those two scenarios reflecting new production schedules that account for the delay in Kashagan's startup.

Exhibit 2. Kashagan's Delay Magnifies Peak Oil Debate

	2005	2006	2007	2008	2009	2010
Opec new capacity	1,160	1520*	1420*	1320*	2240*	2235*
Non-Opec capacity	1,416	1865*	2320*	1886*	1710*	1035*
Total new capacity	**2,576**	**3385***	**3740***	**3206***	**3950***	**3270***
Capacity erosion	1,226	1,400	1,600	1,750	1,800	1,850
Net new capacity	**1,350**	**1,985**	**2,140**	**1,456**	**2,150**	**1,420**
Gulf of Mexico loss	300					
Net Net	**1,050**	**1037****	**1300****	**1866****	**1622****	**1189****
With Kashagan adjustments						
Net new capacity				**1,231**	**1,925**	**1,195**
Net Net				**1,686**	**1,442**	**1,009**

** assumes no slippage and no capacity shortfall; ** assumes 20% slippage and 10% capacity shortfall*

Source: Petroleum Review, April 2006; PPHB

In making our revisions to the *Petroleum Review* 2008-2010 forecasts, we have presumed that the initial estimates assumed Kashagan would come on stream at the middle of the year, and that the increased production scheduled in 2010 would also come on at mid-year. Based on these assumptions, after a robust increase in global oil capacity in 2007, new supplies added in 2008 might fail to match global oil demand growth if the rate of increase in demand is similar to this year's projected growth rate. Oil capacity growth would jump higher in 2009, but then moderate to a lower growth rate than forecast for 2008.

The adjusted Net Net scenario, which reflects a 20% slippage in production and a 10% capacity shortfall, projects anemic 2008-2010 capacity growth

When we look at adjustments to the Net Net scenario, which reflects a 20% slippage in production and a 10% capacity shortfall, the capacity growth for 2008-2010 is rather anemic. While the Net Net scenario for 2008 is better than the unadjusted estimate, that better growth reflects the fact that 2007's capacity growth is projected to be very strong. However, the growth estimates for 2009 and 2010 are low. This scenario would seem to support the latest estimates by Peak Oil enthusiasts that 2010 will mark when the world's oil supply truly stops growing. The Kashagan news is certainly not welcomed by either its developers or the world's population.

Oops! Kyoto and Oil Sands Redo?

Canada is wrestling with two, what appear to be immovable forces – the Kyoto Agreement and the development of its oil sands deposits. On Valentines Day, the lower house of the Canadian Parliament passed a resolution that calls for Canada to rededicate itself to environmental commitments made when the country signed the Kyoto Protocol in 2002. This legislation has pressured Canada's Prime Minister Stephen Harper, a Conservative with a long history of support for the development of Canada's energy resources, to potentially shift his allegiance if he hopes to be re-elected.

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In May 2006, the Canadian government announced that the level of the country's emissions was 34.6% above its Kyoto target of an average of 563 million tons annually between 2008 and 2012. Emissions last year probably soared higher reaching possibly as high as 780 tons. The bad news about this emission record is that if every existing operation in the Alberta oil sands region were shut down, the move would save only 30 million tons a year, which barely dents Canada's reduction goal of 220 million tons a year. The failure to meet the Kyoto Protocol targets carries significant future economic consequences for Canada.

Future development of Canada's energy resources may clash with the growing mood of the populace that wants a more "green" country

The political dilemma for Stephen Harper revolves around his long-standing advocacy for development of Canada's energy resources, which may clash with the growing mood of the populace that wants a more "green" country, and possibly the development of fewer energy resources that help the United States and attract the attention of terrorists. On the same day that the environmental resolution was passed, al Qaeda's branch in Saudi Arabia issued a call for jihadists to attack energy industry assets in Canada due to the country's important supplier role for the United States.

Throughout Canada's history, it has recognized the potential of its oil sands deposits, which were referred to as "tar sands" in earlier days, which carries a pejorative image today. The problem was that these assets were unprofitable unless crude oil prices were sustained at levels well above then prevailing world prices. In the past few years, as oil prices crossed the $30 per barrel threshold, the financial viability of these oil mining projects improved. Growing world oil demand also suggested that future oil prices would likely go higher and, importantly, be sustained at these new, higher levels. Prior to the world oil price advance, Canada responded to the challenge of making oil sands developments economic by enacting a tax break in 1996 that allowed an accelerated capital cost allowance for energy companies, thus enabling their oil sands developments to move forward.

It appears, based on Stephen Harper's attempt to shift to the political center in anticipation of an early election call (possibly in April), this tax break may be revoked, partly as a sop to the environmental movement given the belief that current world oil prices provide sufficient incentive for the energy companies to move forward with their oil sands developments. If this happens, it would be similar to the U.S. Democratic Party's call for rescinding the Clinton-era "royalty relief" tax breaks for U.S. energy companies. But maybe the more challenging issue is the potential economic fallout from Canada's failure to meet its Kyoto Protocol targets.

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Recently, revelations about the thinking and knowledge of the Liberal Government about Canada's ability to meet the Kyoto goals have come to light. Eddie Goldenberg, the most trusted policy advisor to then Prime Minister Jean Chrétien, disclosed in a speech recently that the government agreed to Kyoto with complete knowledge that Canada could not meet the targets. Mr. Goldenberg said, "I am not sure that Canadian public opinion – which was overwhelmingly in favor of ratifying Kyoto in the abstract – was then immediately ready for some of the concrete implementation measures that governments would have to take to address the issue of climate change." Further, he said, "Nor was the government itself even ready at the time with what had to be done. The Kyoto targets were extremely ambitious and it was very possible that short-term deadlines would at the end of the day have to be extended." So why was the Chrétien government willing to sign the Kyoto Protocol in full knowledge of the potential economic risks the country could be facing?

Mr. Goldenberg explained that the government signed the protocol because it felt it was in the best interests of the people. He declared that the simple act of signing the protocol was beneficial in the long run because it galvanized public opinion in favor of climate change. But as an editorial in *The Globe and Mail* argued, "In effect, the Liberals signed a deal – complete with financially onerous penalties – that the nation could not meet, and did so because the mere act of signing would capture public support. It seems that the high-minded talk in 1998 was a very expensive marketing ploy, and taxpayers will be stuck with the tab."

To meet its Kyoto goals, the Canadian government will likely have to go abroad to buy emissions credits or sponsor carbon-reduction initiatives in other countries

In order to meet its Kyoto goals, the Canadian government will likely have to go abroad to buy emissions credits or sponsor carbon-reduction initiatives in other countries. The market for emission credits it tight and they would likely get more expensive with Canada competing for them. This would mean billions of dollars heading abroad. Worse for the country is that countries that meet their targets are able to carry their surplus credits forward beyond 2012. Any country that does not meet its targets must carry its deficit, multiplied by 1.3, on its post-Kyoto balance sheet.

If Canada does not meet its Kyoto targets and does not buy credits from other nations after 2012, the country's exports could face sanctions under global trade rules from countries that have met their targets. The 27 nations of the European Union are already collectively 14% below their quota, but meeting their target has been helped by the admission of lesser developed Eastern European countries into the group. Whether the European Union can remain in compliance with its Kyoto targets remains to be seen. To comply with Kyoto, Canada may be forced to make some significant political and economic moves that could carry huge costs for the country.

Will Canada be willing to forgo oil sands development with its attendant labor and tax implications, or is it willing to risk potential trade sanctions in the future?

Will Canada be willing to forgo oil sands development with its attendant labor and tax implications, or is it willing to risk potential trade sanctions in the future? A cleaner environment is highly desirable, but as Mr. Goldenberg pointed out at the time of the government's signing of the protocol, which it knew it could not meet, people were not prepared for the economic costs of complying – something they are just now beginning to face. Canadians, as others around the world, are confronting Robert Frost's dilemma in "The Road Not Taken" http://frost.freehosting.net/coll1.htm. We make choices, but seldom ever get a chance to revisit those decisions.

Aubrey McClendon: Trail Boss or Moses?

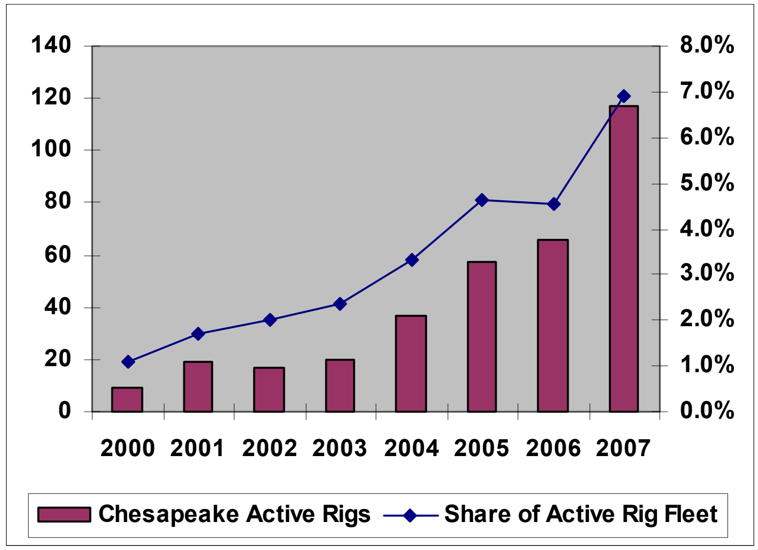
On February 22, Chesapeake Energy Company (CHK-NYSE) announced its fourth quarter financial results that significantly beat the estimates of Wall Street analysts. More important, the underlying performance of the company, both for the quarter and the full year, as measured by its growth in fourth quarter production, increase in annual proved reserves, production replacement ratio and finding and development costs, was outstanding.

Chesapeake achieved much of its reserve replacement with a finding and development cost for organic growth (by the drill bit) of $2.00 per mcfe

For the full year of 2006, Chesapeake increased its proved reserves by 19% to 8.956 billion cubic feet of gas equivalent (bcfe). The company' fourth quarter production increased almost 17% above the year-ago quarter at 1.653 bcfe per day. Chesapeake replaced its 578 bcfe of production with 2.013 trillion cubic feet of gas equivalent (tcfe) for a replacement ratio of 348%. And amazingly, Chesapeake achieved much of its reserve replacement with a finding and development cost for organic growth (by the drill bit) of $2.00 per thousand cubic feet of gas equivalent (mcfe).

On the company's earnings conference call with investors and analysts, Mr. McClendon, Chesapeake's CEO set forth expectations that the company should end 2007 with proved reserves of about 10 tcfe that would further grow to 11 tcfe in 2008. His confidence in the projections is a function of the company's land position in the major non-conventional natural gas plays of the United States and the company's aggressive drilling program. Chesapeake is the number one company in the country in wells operated along with ranking as number one in non-operated wells. In other words, Chesapeake is the 800-pound gorilla in the land drilling business in the United States.

Exhibit 3. Chesapeake's Rig Market Share Has Grown



Source: Smith International; PPHB

Chesapeake has often executed an investment strategy in the oilfield service sector that helps the company reduce, or at least control, its well drilling and completion costs, while often generating significant investment returns over time

Given the company's importance to the oilfield service industry, Mr. McClendon's observations about oilfield service trends and his strategy for capturing value for his shareholders within this cost envelope carry substantial weight among energy investors. Chesapeake has often executed an investment strategy in the oilfield service sector that helps the company reduce, or at least control, its well drilling and completion costs, while often generating significant investment returns over time. For example, the company invested about $10 million in drilling rigs in 1997 that eventually yielded a return of about $90 million. More recently, Chesapeake harvested a $73 million gain on the $40 million it had earlier invested in small land driller Pioneer Drilling (PDC-AMEX) to help that company expand its fleet.

According to Mr. McClendon, Chesapeake recognized in 2001 that its business plan could be at risk if the traditional cyclical development of the oilfield service industry unfolded in subsequent years. Mr. McClendon recognized that as the oil and gas industry stepped up its exploration and development activity, the oil and gas and oilfield service industries would encounter problems as they used up their spare capacity. Specifically, he expected the industry to be short of skilled people, attractive land holdings and rigs and other oilfield service equipment. Chesapeake could not afford to allow industry choke points to prevent the exercise of the company's business plan. For that reason, Chesapeake elected to re-enter the drilling rig business with its Pioneer Drilling investment.

That decision to get into the drilling business became more focused as Mr. McClendon realized that the drilling contractors were not prepared to add new rigs to their fleets until utilization of existing fleets had reached high levels, lifting contract day rates and profits that would provide the funding for building new rigs. The result of that strategy, from Chesapeake's perspective, was to insure that rig shortages developed. With that in mind, Chesapeake elected to start buying and operating its own rig fleet. Today, that fleet consists of 70 rigs and is programmed to expand into the low 80s. According to Mr. McClendon, the Chesapeake rigs perform better than contractor rigs, and he can measure this by the company's data on its own wells – both company drilled and contractor drilled, along with the information on well costs and drilling performance on wells in which Chesapeake is a non-operator. Mr. McClendon expects this better performance because, as he puts it, these are "our" rigs operated by "our" employees drilling on "our" projects. This better performance is a significant contributor to the low finding and development cost Chesapeake has established.

Chesapeake rigs perform better than contractor rigs, and he can measure this by the company's data on its own wells

Last year, as oilfield service inflation was ramping up and gas prices were falling, Mr. McClendon began an aggressive program to counter this profit squeeze. He elected to slow drilling activity, partly by shutting in uncontracted gas production as gas prices fell to the $5 per mcf level, and he began to lobby against cost pass-throughs for fuel costs, etc. by the service companies. He also lectured the oilfield service industry that it needed to control, and in fact reduce, its service and rig rates to ensure the continued financial viability of the domestic natural gas industry. It seems that his efforts have paid off as the rig count flattened out its advance late in 2006 and utilization rates softened leading drilling contractors to start reducing day rates in selected rig markets.

As Mr.McClendon described the current oilfield market on the conference call, drilling rig rates began falling in the fourth quarter and with the prospect of 300 additional land drilling rigs scheduled to enter the fleet over the next 18 months, he expects further pressure on rig day rates. Pressure pumping service costs have also stopped rising as more capacity has entered the market. He commented that current pressure pumping bids are reflecting 10% lower prices. With lower steel costs, the major components for drilling and completing wells are on the down trend. Mr. McClendon believes that 2007 may mark the first year since 2002 that oilfield service costs are lower than the previous year. His goal is for costs to decline by 10-15%, but he acknowledges that achieving that goal will depend on natural gas prices.

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Mr. McClendon was questioned about the profitability of Chesapeake's investments in drilling rigs and pressure pumping equipment given the highly profitable opportunities the company possesses in its exploration and development portfolio. According to management, its oilfield service equipment generated $14 million of gross profit in the fourth quarter and had generated a $33 million credit against its full-cost pool by using its own rigs and service equipment on its own wells. The company said that this $47 million of value, if annualized and capitalized at 5.5 times would provide a value to Chesapeake shareholders for these oilfield businesses of approximately $1 billion.

An additional point made by Chesapeake about its oilfield service investments was that the company currently owns sufficient gas compression assets to rank as the fifth or sixth largest company in that industry sub-sector. The company is achieving three-year payouts on its investments, which if properly maintained have a 50-year life. Management believes that if it wanted to monetize this investment, it could achieve a three-to-one return on its investment. Management was also not shy in saying that they look at their oilfield service investments as ones that will help create value for the company, and they see no reason why they should not capture some, or all, of that value for Chesapeake shareholders. This was specifically true with its investment in a fleet of pressure pumping equipment. All told, management speculated that the value of all its non-E&P assets could be worth upwards of $2.5 billion. Lastly, Chesapeake believes it is helping to drive down oilfield service costs for the entire oil and gas industry.

Management was not shy in saying that they look at their oilfield service investments as ones that will help create value for the company, and they see no reason why they should not capture some, or all, of that value for Chesapeake shareholders

As we listened to Mr. McClendon discuss his strategy and the role Chesapeake is playing in the oil and gas and oilfield service industries, we pictured him as a trail boss atop his steed overlooking a broad Western plain punctuated by a meandering herd of independent oilmen heading to market after they stopped at a local watering hole for a drink. But then, when we heard Mr. McClendon describe his goal for cutting oilfield inflation by 10-15% in 2007, and how he was helping to drive down oilfield service costs for the industry, we pictured him on the banks of the Red River parting its waters as the independent oilmen moved out of captivity by oilfield service companies and into the land of nirvana. Whichever image captures your fancy, there is no mistaking the huge role Aubrey McClendon plays in the domestic oil and gas business.

The Oscars, Al Gore and TXU: The Tipping Point?

At the Hollywood spectacle known as the Oscars, Former U.S. Vice President Al Gore not only won an Oscar for the best documentary feature in 2006, but he shared the stage with actor Leonardo DiCaprio to announce that the Oscars had gone “green” by buying carbon credits to offset the emissions associated with the show. Even if some of the attendees arrived in hybrid limousines, the power needed for all the cameras, lights and sound had to be substantial, and by purchasing carbon-credits, the Oscar’s was able to offset the carbon footprint of the show.

Quite possibly, though, half a continent away a more significant environmental victory was being negotiated – the purchase of the Texas utilities company TXU (TXU-NYSE) by a couple of private equity (PE) firms with the blessing of two leading environmental groups. TXU became an enemy of environmentalists last year when it proposed to build 11 new coal-fired power plants in Texas both to replace aging and environmentally disastrous existing plants and to add electricity generating capacity in a state that is rapidly running out of spare power. Before sealing the buyout deal, the two private

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equity firms contacted and secured the support of leading environmental opponents to the coal plant expansion plan by agreeing to scrap eight of the proposed plants, agreeing to support mandatory emissions caps and agreeing to an overall reduction in TXU's CO_2 emissions by 2020.

While environmental groups such as Greenpeace, which stages publicity events to protest environmentally unfriendly corporate and government actions, continue to speak out, the impact of private equity firms supported by environmental movements such as the National Resources Defense Council and Environmental Defense, may signal a more powerful, and effective movement to alter the growth of carbon emissions. What remains to be seen, however, is whether this combination can develop real solutions to the emissions challenges that are better than the plan proposed by the company the PE firms are buying.

The PE firms buying TXU are planning on investing more money in wind and solar power and less in coal

We understand that the PE firms buying TXU are planning on investing more money in wind and solar power and less in coal. They also are counting on restoring to operation mothballed gas-fired power plants. A challenge for the use of more wind and solar power is that these sources are located in areas quite removed from TXU's operational base and thus will require the construction of huge transmission lines to bring the power to market. Under Texas' recently de-regulated electricity industry, transmission lines remain one area with significant state regulation, which could put the new owner's strategy at risk. In addition, just as this new strategy is being unveiled, the debate over wind power in Texas is heating up. There have been a number of articles in the local media about West Texans who are upset with the visual pollution and land disruption created by the huge wind turbine projects being proposed. One of the most recent high visibility wind power battles involves the heirs to the famous South Texas King Ranch and its equally historic Kenedy Ranch neighbor. The managers of the Kenedy Ranch want to install a 400-unit wind farm on the ranch, but they are being challenged by the King Ranch heirs who are opposed. While part of this struggle is over economic development of the two ranches, the battle is being fought over wind turbines at the moment.

There are a number of conditions under which TXU would apply or reapply for permits to build the coal-fired power plants

Recent revelations from TXU's earnings conference call and media reports about the negotiations behind the environmental deal suggest that the terms of the agreement may not be as meaningful as initially thought. That is because there are a number of conditions under which TXU would apply or reapply for permits to build the coal-fired power plants. According to the transcript of the call, as reported by *The Wall Street Journal*, TXU CEO John Wilder said that TXU would not build the coal-fired plants "unless our customers face reliability issues, shortages leading to higher prices, or our competitors propose plants that are expected to have a meaningful impact on market dynamics." According to a report from the Texas grid operator (ERTOC), power reserves could slip into a danger zone as early as 2009, given the recent spurt in power demand, which would produce conditions that would allow TXU to move forward with its plants. Whether the agreements with the environmental groups are modified to tighten up those permissible conditions or not may determine what opposition the buyout encounters. If there is opposition, it might signal that the tipping point for the environmental movement hasn't been reached. But at the moment, it is hard not to believe that the confluence of the Oscars and the TXU deal marks that tipping point. What follows the tipping point is likely to have a meaningful impact on the long-run future of the energy business.

Building Shareholder Value in a Short-term World

Two new studies from Wall Street investment firms on either side of the Atlantic highlight the challenge for management in building value in a short-term oriented investment world. One firm focused on the impact of how managements are returning cash to investors while the other highlighted the challenge of influencing stock prices when investment holding periods are shrinking. The question poised by these studies is whether it is possible to evolve a strategy for creating shareholder value before the venture vultures descend on underperforming companies.

Citigroup (C-NYSE) in London estimates that UK companies have returned $231 billion to investors in the form of share buybacks and special dividends since 2003. This total amount of money returned accounted for 63% of total dividends paid to shareholders over the period. Across Europe, the amount returned to shareholders totals $384 billion, which represents the equivalent of 56% of all regular dividends paid.

Investors are pressuring managements to return surplus cash to shareholders because they are less trusting of managements to invest the cash wisely

Investors are pressuring managements to return surplus cash to shareholders because they are less trusting of managements to invest the cash wisely. To some degree that attitude is a reflection of the last bear market (1999-2000), which destroyed significant shareholder wealth, coupled with the fear that the current stock market ebullience may be "long in the tooth" and poised for a major correction – such as partly experienced last week. Given this investor attitude, company managements have responded by paying special dividends and buying back their stock.

A stock buyback sends a message to the financial community that management believes its stock is undervalued

In its study, Citigroup argues that these techniques have an inherent advantage over boosting regular dividends because they provide management with greater financial flexibility. A special dividend does not have to be repeated and stock buybacks can be terminated at any time. Additionally, a stock buyback sends a message to the financial community that management believes its stock is undervalued. But then again, when have you met a management that doesn't think its stock is undervalued?

As a result of these trends, Citigroup estimates that ordinary dividends have failed to keep up with earnings growth in both the UK and the rest of Europe. Since 2003, European corporate earnings have increased 101% but dividends have only risen by 45%. In the UK, earnings have risen 55%, while dividends have gone up 30%. As a result, the payout ratio is at a 15-year low in Europe and an all-time low in the UK. The most interesting point, however, is that stock buybacks have failed to boost companies' share prices.

European managements have started to employ the old value-creating technique of boosting dividends

The conclusion from these trends is that European managements have started to employ the old value-creating technique of boosting dividends. Last year, Vodafone (VOD-NYSE) stopped its stock buyback and instead raised it dividend. Other European companies are starting to boost dividends, although not all are stopping their buyback programs. Citigroup's conclusion about how best to create shareholder wealth fits with recent academic studies of the subject in the United States. Most of these studies show that increased dividends yield a more sustained benefit for shareholders than either special dividends and/or stock buybacks.

Since Diamond Offshore's stock price has so closely followed that of its peers, it is hard to state that the company's policy of awarding special dividends has contributed to better stock performance

One of the most recent examples in the stock market of a special dividend announcement is Diamond Offshore's (DO-NYSE) declaration of a $4 special dividend on January 30. The special dividend, in addition to the company's quarterly $0.125 ($0.50 annualized) per share dividend, was to be paid on March 1 to shareholders of record on February 14. As can be seen from Exhibit 4, Diamond's stock price jumped at the time of the announcement, but it appears that the bump after the announcement was limited. Based on the trading pattern from mid-January to early February, either everyone expected a dividend announcement, or the stock was being driven higher by other factors such as investors believing that the company would outperform analyst earnings estimates for the fourth quarter of 2006 and that its outlook for 2007 and beyond was growing brighter. Since Diamond's stock price has so closely followed that of its peers, it is hard to state that the company's policy of awarding special dividends (it awarded a $1.50 special dividend in 2006) has contributed to better stock performance.

Exhibit 4. Diamond's Stock Not Helped by Special Dividends

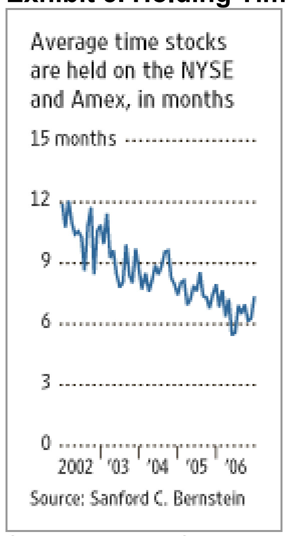
Source: BigCharts.com

Compounding the challenge of how best to create shareholder

Average holding period for stocks on both the New York Stock Exchange and American Stock Exchange in 2006 was less than seven months

wealth, managements are also wrestling with the phenomenon of short-term shareholders. As reported by *The Wall Street Journal*, a new study by the chief investment officer of Sanford C. Bernstein shows that the average holding period for stocks on both the New York Stock Exchange and American Stock Exchange in 2006 was less than seven months. By comparison, the average holding period in 1999 was more than a year. The study pointed out that the last time the average holding period was this short was in 1929.

Exhibit 5. Holding Time Falls



Source: *The Wall Street Journal*

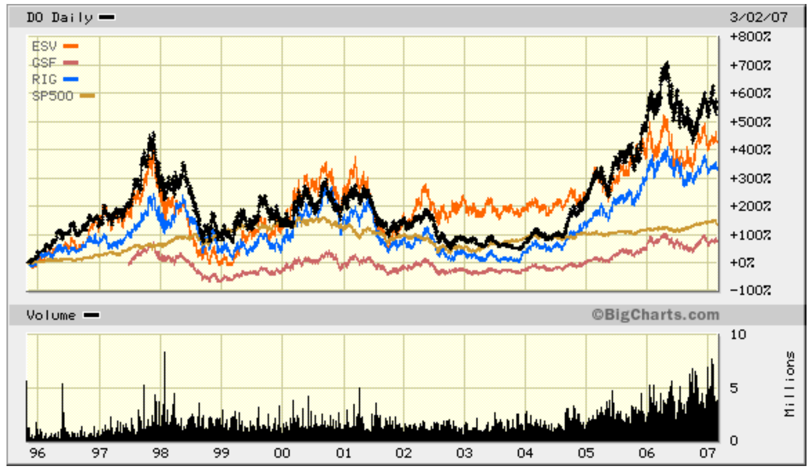
Over extended time periods, well managed companies, even in cyclical industries, have been able to create significant shareholder wealth

This falling holding period results from the numerous changes in the investment and trading worlds, but since these factors are beyond the scope of company management actions, the question becomes what should managements do. The range of actions extends from ignoring the short-term gyrations in the stock price due to short-term-oriented shareholders moving in and out of positions to becoming fixated on, and paranoid about, the volatility. Neither of these actions is appropriate. What is appropriate is to understand that over extended time periods, and especially true for companies operating in cyclical industries, well-managed companies have been able to create significant shareholder wealth – it is just hard to see it while it is happening.

Notice in Exhibit 6, that for most of the offshore contract drillers, a highly cyclical industry, even with $10 oil in 1998 and the global recession after 9/11, companies have been able to create significant shareholder wealth through conservative stewardship of capital and sound contracting strategies. In reality, even though a growing component of executive compensation is tied to the performance of the share price (aligning management with shareholder interests), managements should continue to focus on long-term considerations because there is really little they can do to influence the short-term. Meaningful shareholder wealth is ultimately created through sound long-term capital investment decisions and tight operational control.

Management's attitude should be to let the day-traders have at it and instead focus on those actions and decisions they can control.

Exhibit 6. Diamond and Drillers Created Shareholder Wealth



Source: BigCharts.com

North Sea Gas Industry at Risk from Taxes and Prices

The current 17 pence per therm rate which UK gas producers receive is roughly equivalent to $17 per barrel

The British government is rumored to be considering another tax hike on the oil and gas industry as its profitability continues to expand. Unfortunately, there is a huge disparity in profitability depending upon whether you are a gas producer or an oil producer. The latter are basking in the glow of $60 per barrel oil futures prices once again after a brief respite at $50 in January. But even at that depressed level, natural gas is still not receiving the equivalent BTU value. According to Malcolm Webb, the chief executive of the UK Offshore Operators Association, the current 17 pence per therm rate which gas producers receive is roughly equivalent to $17 per barrel. That price level is believed to be not too far from the level at which the North Sea's oil production begins to become uneconomic.

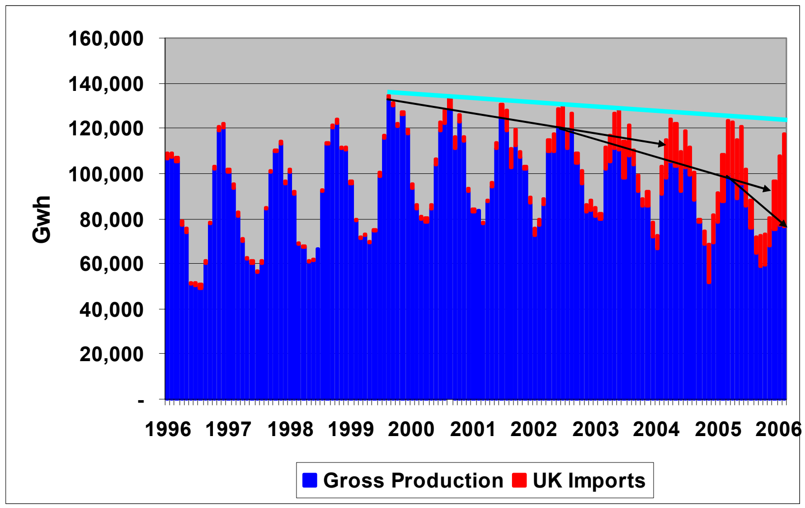
Mike Simpson, the UK business manager for Tullow Oil (TQW.IR), commented that the gas industry is dealing with high taxes and low gas prices, which has forced operators to cut back on projects. Part of the problem is that all oil and gas producers, whether oil- or gas-focused, have to pay the same 50% corporate tax rate. With current crude oil prices about 3.5 times the equivalent natural gas price, the tax burden for oil-focused producers is more manageable. Mr. Simpson revealed that Tullow planned to cancel a production program in one of its North Sea fields because it had become uneconomic.

According to Mr. Simpson, "The Chancellor set his tax increase on the basis of oil at dollars 50 a barrel." He went on to say, "The price of gas is nowhere near the equivalent of that. If this continues, the infrastructure will be gone. We think there is a case for gas to be made a special case and to develop indigenous resources for the

Offshore drilling rigs are being contracted by oil companies at day rates of approximately $200,000, which can be justified on the basis of $50 to $60 per barrel oil prices

good of the country." That is an important point as the gas industry produced GBP9 billion of the fuel at wholesale prices last year and it supports thousands of jobs. At the heart of the dilemma for the gas industry is that offshore drilling rigs are being contracted by oil companies at day rates of approximately $200,000, which can be justified on the basis of $50 to $60 per barrel oil prices. If the gas industry is unable to compete for offshore drilling rigs and other offshore equipment, important investments necessary to sustain, or boost, current production will not be made. The result of those capital investment delays will be falling gas production.

Exhibit 7. UK North Sea Gas Production Falling



Source: Dept. of Industry and Trade; PPHB

When one examines the recent history of UK gas production and imports, it becomes increasingly clear what impact aging fields, escalating costs and non-competitive investment incentives are having on the business. Exhibit 7 shows the monthly gross gas production figures for the UK and the country's monthly net gas import volumes since 1996. The supply of gas from indigenous resources was growing up to and through winter's end in 2000, at which time gas production volumes peaked. A slight decline rate set in at that time, which continued through to winter's end in 2002. The decline rate then accelerated through 2005, and it then began to plummet in 2006. From the 2000 peak supply point, total available gas supply (measured demand) declined at a modest rate through last year, with the shortfall in domestic gas production made up by growing volumes of imported gas.

Without some fiscal relief, the UK gas industry will be challenged to obtain more supplies to offset the normal natural gas production decline curve

Without some fiscal relief from the British government or the discovery of significant and easily developed new gas resources, the UK gas industry will be challenged to obtain more supplies to offset the normal natural gas production decline curve. On the face of it, it doesn't appear that either of the former conditions will be met, which signals an increasingly bleak outlook for UK natural gas producers.

Unless gas consumption falls, the UK will have to import increasingly more gas in the future, and the geopolitics of securing that supply make for some interesting and challenging scenarios.

The Challenge of Canada's Labor Market

In order to attract workers to this desolate outpost and keep them, energy and oilfield service companies are reinventing the work camp

The far north region of Alberta, Canada can be formidable. Not only is the weather wretched in the winter, but living in a modern-day gold rush community generates other pressures. Ft. McMurray, in the heart of the Canadian oil sands play, has struggled for a number of years with the pressure of hiring and housing the thousands of workers necessary to both build and operate these mammoth oil mining extraction facilities. In order to attract workers to this desolate outpost and keep them, energy and oilfield service companies are reinventing the work camp.

For most of the 150-year history of the oil industry, living conditions for roughnecks and tool-pushers were utilitarian at best. According to Shane Stampe, president of Horizon North Logisitics Inc. (HNL.V-CDNX), crews hauling drilling rigs and supplies to well locations along the shore of the Arctic Ocean in the Northwest Territories in the 1970s and 1980s slept six to a room in old trailers atop sledges hauled across the tundra by bulldozers. Meals were served in a mess hall next to the toilets. But now the drafty old trailers and community showers are yielding to resort-style housing that includes private rooms with flat-screen televisions and gourmet meals.

While food and accommodations on offshore drilling rigs and production platforms have traditionally been at the top of the industry's scale for comfort, there are limits as to how lavish conditions can be due to logistics and space restrictions. However, energy and oilfield service companies are recognizing that the care and feeding of these human cogs in the industry's wheels of progress is extremely important, especially when competitors are ready, willing and able to hire them away.

A work camp for 2,500 people costs about $120 million or the equivalent cost to drill a well in deepwater in the Gulf of Mexico

In Canada, the focus has been on the work camps associated with the oil sands due to the explosion in new projects in the region, the magnitude of the investment energy companies are committing and the numbers of workers needed for construction and operation of the plants. The increased cost of these facilities is adding to the general cost pressures oil and gas producers are confronting. A work camp for 2,500 people costs about $120 million or the equivalent cost that ExxonMobil or Shell spends to drill a well in deepwater in the Gulf of Mexico. Shell is building a camp for 2,500 employees complete with an indoor hockey rink and an oak-paneled pub in the heart of the oil sands. ExxonMobil is planning soccer fields and indoor basketball courts for 1,300 workers at its Kearl oil sands project, where construction is scheduled to kick off later this year. Oil States International's PTI group has hired a Québécois pastry chef to make *tarte au sucre*, a traditional dessert favored by engineers and geologists hailing from that province.

For energy companies, learning to compete in non-traditional ways (wages, fringe benefits, etc.) is a new requirement

Feeding people is a very real challenge. Oilfield workers tend to be mostly men with a few women. They won't tolerate mediocre cuisine and bad cooks lead endangered lives. Roughnecks drilling wells above the Arctic Circle typically eat 7,000 calories a day, almost three times more than normal men. That high caloric intake is needed in order to perform 12 hours shifts of heavy labor outdoors where temperatures often fall to minus 45 C in winter months. For energy companies, learning to compete in non-traditional ways (wages, fringe benefits, etc.) is a new requirement. We can expect that this battle will continue to escalate with workers being the beneficiary. Life in the camp below looks quit acceptable.

Exhibit 8. Pictures of PTI Beaver River Executive Lodge

Source: PTI Group Inc. brochure

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