PARKS PATON HOEPFL & BROWN

ENERGY INVESTMENT BANKING, LP

MUSINGS FROM THE OIL PATCH
December 27, 2006

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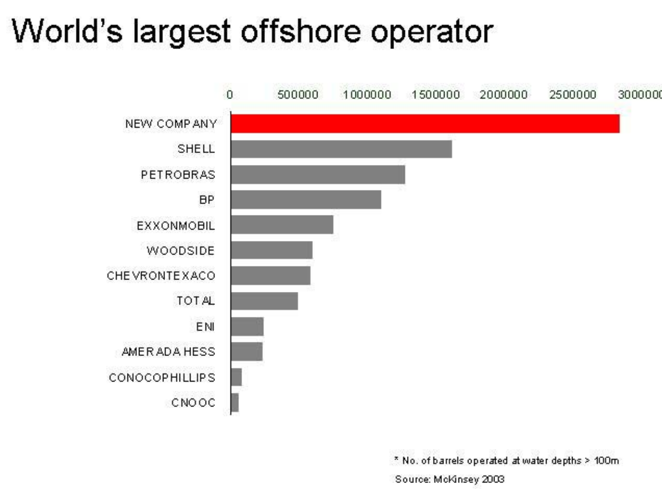
Note: *Musings from the Oil Patch reflects an eclectic collection of stories and analyses dealing with issues and developments within the energy industry that I feel have potentially significant implications for executives operating oilfield service companies. The newsletter currently anticipates a semi-monthly 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

Implications of the Statoil and Norsk Hydro Merger

Statoil ASA and Norsk Hydro will merge to form the world largest offshore oil operator based on number of barrels of production

On December 18, Statoil ASA (STO-NYSE) and Norsk Hydro (NHY-NYSE) announced plans to merge their offshore oil and natural gas units in a $30 billion deal. The transaction, which is likely the last mega merger to be announced in 2006, will create the world largest offshore oil operator based on number of barrels of production. It will create the fifth largest European oil company based on stock market capitalization. The big question is will this merger be the first of many over the next several years in response to changing industry conditions, or is this deal unique and driven primarily by internal company and Norwegian government considerations?

Exhibit 1. The New Combined Statoil



Source: Statoil, Norsk Hydro

Norway's Prime Minister Jens Stoltenberg called the deal "the start of a new era" for Norway's petroleum industry. He also said that the Norwegian government plans to increase its ownership in the new company to two-thirds from its currently estimated 62.5% share. The current ownership percentage arises from the state's respective ownership in each of the two companies and their respective shares in the new company. At the present time, the state owns 71% of Statoil and 44% of Norsk Hydro. Under the terms of the deal, Statoil shareholders will hold 67.3% of the new company while Norsk Hydro shareholders will hold the remaining 32.7%.

The companies operate in almost every major petroleum region of the world excluding the Middle East and Southeast Asia

Combined, the two companies expect to produce 1.9 million barrels per day of oil equivalent in 2007. They also should have proved reserves equal to 6.3 billion barrels of equivalent oil. The bulk of the reserves and production of the new company are in the Norwegian sector of the North Sea. Over the years, at the direction of the government, both Statoil and Norsk Hydro embarked on international oil and gas exploration and development programs. Currently, combined, the companies operate in almost every major petroleum region of the world excluding the Middle East and Southeast Asia.

Exhibit 2. Combined Statoil and Norsk Hydro Operations

Source: Statoil, Norsk Hydro

The merged company will control roughly 70% of the oil and gas production on the Norwegian shelf

Why this deal, and why now? There are many possible reasons, but in our mind the principal ones are the increasingly competitive nature of the global search for new hydrocarbon reserves, cost pressures in the companies' existing exploration and development projects and the need to jump-start reserve and production growth on the Norwegian continental shelf. The merged company will control roughly 70% of the oil and gas production on the Norwegian shelf. Norway, due to its small population and economy, is the world's third largest crude oil exporter and a growing supplier to

European natural gas markets. However, the Norwegian basin, home to a number of large, world-class fields, has become mature and is experiencing declining production. Reversing that trend is a major focus for the government.

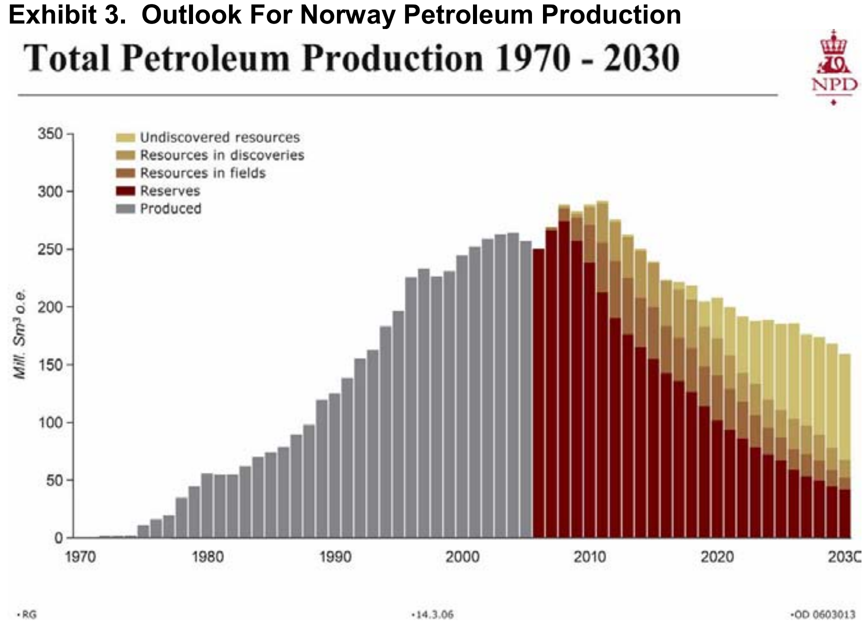
Over the past few years, the Norwegian government has been pushing to open up its waters to increased oil industry participation beyond the state-influenced firms

We examined the information about drilling in the Norwegian sector of the North Sea during 1999-2005 available on the Norwegian Petroleum Directorate's web site. Combined, Statoil and Norsk Hydro accounted for 69.5% of the 197 wells drilled during the time period, including wildcats, appraisal wells and re-entered wells. Individually, Statoil accounted for 99 total wells, or 50.3% of activity, while Norsk Hydro drilled 38 wells, or 19.3%. Over the past few years, the Norwegian government has been pushing to open up its waters to increased oil industry participation beyond the state-influenced firms. Those efforts have produced few tangible results, but emerging trends suggest changes are underway.

The large Norwegian oil companies (the parties to the merger) have demonstrated a declining spending profile in Norway over the past six years

The profile of total petroleum production for the Norwegian shelf shows a near-term peak last year with the possibility that production may be elevated to a new peak over the next several years, but then the basin embarks on a steady decline beginning about the end of this decade. The large Norwegian oil companies (the parties to the merger) have demonstrated a declining spending profile in Norway over the past six years, which is contributing to falling production. Even when other large petroleum companies are included, the total spending share has not grown over this period. Fortunately, the new entrants in Norwegian waters, in response to changes in the government's petroleum taxing scheme, are taking up much of this slack.

Exhibit 3. Outlook For Norway Petroleum Production

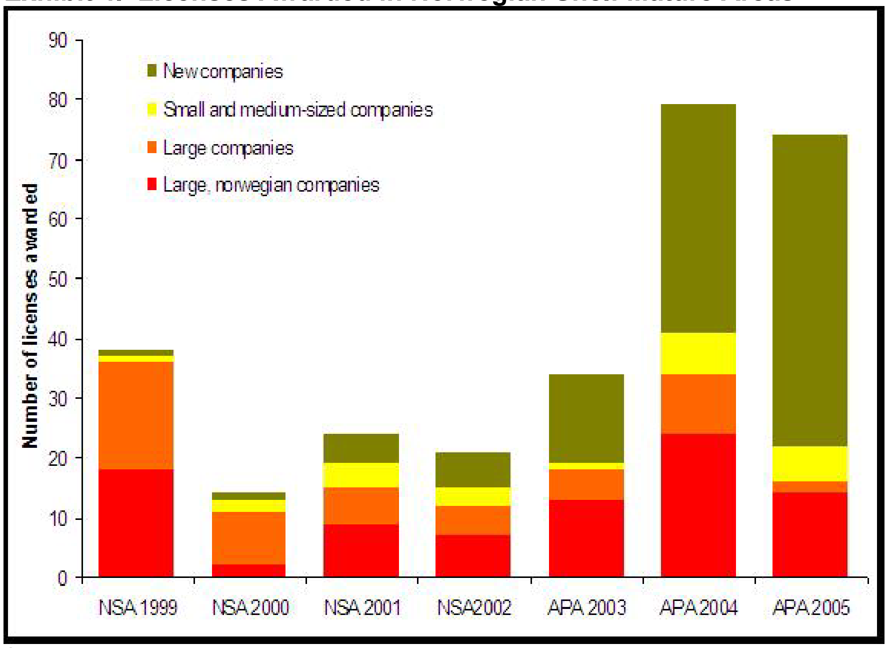


Source: Bente Nyland, NPD presentation, March 29, 2006

The petroleum tax law changes the Norwegian government has implemented have improved the attractiveness of oil and gas exploration for new entrant companies

The petroleum tax law changes the Norwegian government has implemented have improved the attractiveness of oil and gas exploration for new entrant companies. The primary changes include providing for the reimbursement of the tax value of uncovered losses from exploration activities, the ability to carry forward the tax value of losses when a company stops operating and the acceleration of the credit against the special tax for new petroleum investments. These changes have improved the certainty of the fiscal regime for these new entrants along with boosting the profitability of investments, especially for increased oil recovery efforts. The changes also have enhanced the value of licenses that should make them easier to trade.

Exhibit 4. Licenses Awarded in Norwegian Shelf Mature Areas

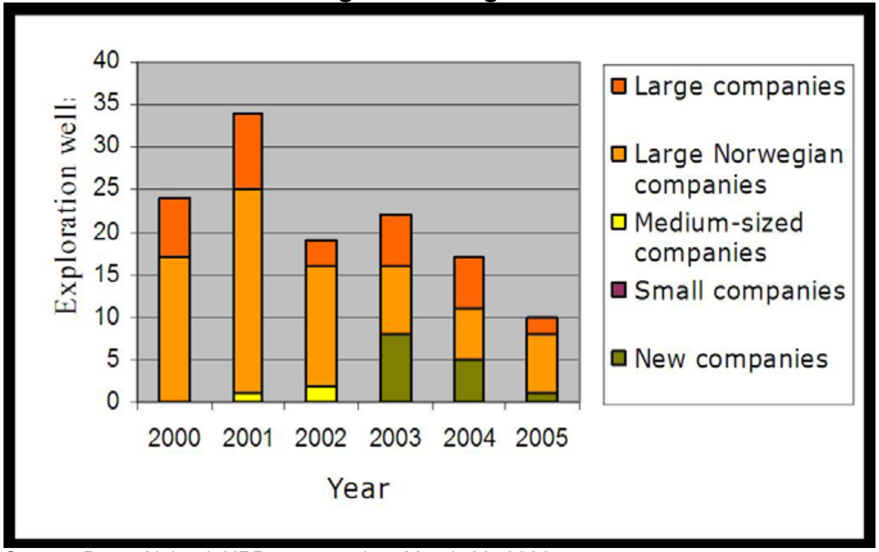


Source: Bente Nyland, NPD presentation, March 29, 2006

Attracting new companies is important to revitalizing the Norwegian petroleum sector, especially if the government hopes to boost future production

The impact these tax changes have had on new activity is best demonstrated by the increase in new licenses in mature producing areas by new entrants and small and medium-sized companies. The success of the effort is further demonstrated by the fact that new entrant companies are stepping in and drilling more, thus helping to pick up some of the slack in drilling by other companies. Attracting new companies is important to revitalizing the Norwegian petroleum sector, especially if the government hopes to boost future production. One has to wonder, given the emerging trend of greater participation by new entrant companies, whether the government will push for the new Statoil to disgorge some of its unexplored acreage holdings and even existing field ownership interests. Those moves could help accelerate the push for greater new entrant involvement in the Norwegian sector.

Exhibit 5. New Well Drilling on Norwegian Shelf

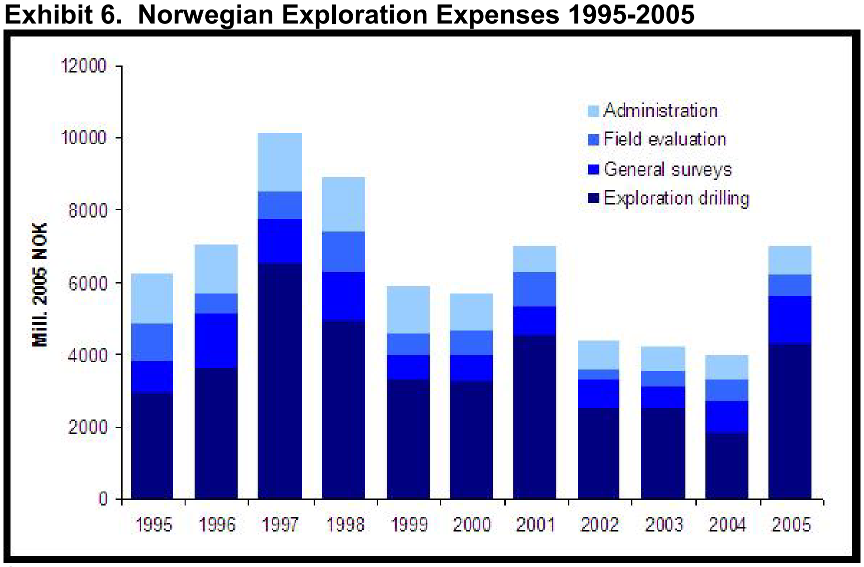


Source: Bente Nyland, NPD presentation, March 29, 2006

We suspect cost reductions will come from the elimination of non-Norwegian employees and consultants, plus cost savings from eliminating inefficiencies that arise from the duplication of resources

One of the reasons given for the Statoil/Norsk Hydro merger is the ability of the new company to reduce future operating costs. The companies are careful not to make too much of this point because of the sensitivity in Norway to possible layoffs. We suspect cost reductions will come from the elimination of non-Norwegian employees and consultants, plus cost savings from eliminating inefficiencies that arise from the duplication of resources.

Exhibit 6. Norwegian Exploration Expenses 1995-2005



Source: Bente Nyland, NPD presentation, March 29, 2006

The history of costs in the Norwegian sector are tied to the generally industry activity cycle. As shown in Exhibit 6, the cost of exploration has risen and fallen in concert with the overall ups and downs of the global petroleum industry. Exploration costs were extremely high in

Getting costs out of the system has to be an objective of the merger, along with improving the ability of the new company to compete internationally

the recent boom years of 1997-8 only to decline in the following years as the industry went through a mini-recession. Costs were up in 2001, again in response to a tighter E&P market and they jumped significantly in 2005. While we have not seen the data for 2006, we suspect costs have risen further as drilling rig contracts day rates are up substantially along with the prices for almost all other oilfield products and services. Getting costs out of the system has to be an objective of the merger, along with improving the ability of the new company to compete internationally in basins with greater potential that require lower cost structures to be profitable.

Countering the pressure to reduce costs will be the thrust of the oilfield service companies. Other producers in the Norwegian sector will be fighting the market dominance of the new company. By controlling roughly 70% of production and having accounted for nearly 70% of all the wells drilled over the past six years, the new Statoil has a disproportionate share of the Norwegian offshore market. If the company is allowed to continue to operate as it has in the past, then Norway may begin to look very much like other national oil company-controlled markets – limited opportunities and higher costs. That could force the oilfield service companies to re-examine how they work in this market.

The Norwegian oil workers union has weighed in against the merger, largely because of the exclusion of worker representatives on the board from the negotiations over the terms of the deal. The leader of SAFE, the onshore and offshore worker union, Terje Nustad, said. “This is a coup; it is a new oil revolution and a new development. Statoil should focus on the NCS.” Arild Theim, a spokesman for the Industry and Energy Union said he was concerned about the status of the new company with respect to the number of new exploration and production licenses awarded compared to the number the companies would have received individually. He said, “The land-based supply structure should be kept on as it is today…so that the merger does not lead to job losses.” However, he did say that the union viewed the deal positively, especially the increased state ownership as it should help to prolong the life of the Norwegian shelf. In addition, the new merged company will be a stronger player in the international oil industry.

The dilemma posed by union concerns versus the government’s concern about stimulating E&P activity on the Norwegian shelf shows the challenge of making this transaction a success

The upshot of these comments suggests the sensitivity the unions have to possible job losses due to cost considerations, but what they are also concerned with is the potential for a reduction in the market position of the new company within the Norwegian sector. The dilemma posed by union concerns – possible job losses and reduced future work opportunities – versus the government’s concern about stimulating E&P activity on the Norwegian shelf shows the challenge of making this transaction a success.

A recent article in *The Wall Street Journal* suggested that the merger of the two Norwegian companies is a sign of the times and that big oil companies are preparing for a new wave of consolidation. The premise of the article was “that bigger companies will better compete in the world's increasingly crowded oil fields." According to the article, the big oil companies are struggling to add oil and natural gas reserves and production and are facing increased competition and tightening access to hydrocarbon resources around the world. By getting bigger, these large oil companies will be better able to handle those pressures. The article then went on to postulate that a merger wave could result in less industry capital spending dimming the outlook for the oilfield service industry.

The introduction of more state-owned and state-sponsored oil and gas companies into the industry struggle to acquire hydrocarbon reserves and production has unleveled the playing field

We agree with certain aspects of that thesis, but not all. Clearly the global hydrocarbon market has become more competitive. The introduction of more state-owned and state-sponsored oil and gas companies with access to their government's coffers into the industry struggle to acquire hydrocarbon reserves and production has unleveled the playing field. Unfortunately, that genie is out of the bottle and not likely to be put back in, so the competitive landscape is different this time, and more importantly will remain different.

Interestingly, the issue of reserve and production growth for the major oil companies has been largely ignored by Wall Street and investors who appear to be more focused on stock valuations based on per share metrics. By repurchasing shares and achieving modest E&P success, oil companies have been able to maintain, or even increase, their per share metrics, which has led to higher stock prices, although higher commodity prices have been a driver, also. Most of the big oil companies have not meaningfully stepped up their capital spending efforts. Rather, they have used their huge cash flows to boost dividends, buy back shares and pay down debt. Despite these expenditures, most company cash flows have overwhelmed this spending leading to buildups of cash on the balance sheets.

While the oil companies appear to be well-positioned to finance acquisitions, we doubt the upcoming wave of industry consolidation will resemble previous ones. The acquisition wave experienced in the 1970s and early 1980s was driven by company efforts to get bigger, or to fend off takeover attempts. The deals done in the late 1980s and 1990s, however, were almost all driven by cost-reduction needs.

What are being talked today are deals driven by growth considerations

What are being talked today are deals driven by growth considerations. While a different strategic reason for consolidation, an important consideration that may shape this merger wave, at least for U.S.-based oil companies, will be the attitude of the new Congress. The initial thrusts from the anti-profit, new congressional leaders will likely be increased pressure on the oil companies to lower their refined product prices, i.e., cut their profit margins, and to boost their spending on alternative energy investments. We suspect that any moves by major oil companies to buy other U.S. oil and gas companies will be greeted with uproars of indignation and threats of punishment.

What is likely not to happen is the takeover of mid sized U.S. oil companies by foreign oil companies

Given our view of the M&A landscape for oil and gas companies, we think the thrust of consolidation efforts by U.S.-based oil companies will focus on foreign companies. Canada's Finance Minister recently improved the odds of increased acquisitions of his country's hydrocarbon resources by his move to eliminate the tax provisions that fostered the creation of income trusts. Additionally, small oil companies that have successfully discovered oil and gas reserves internationally may also become targets of the big oil companies. What is likely not to happen is the takeover of mid sized U.S. oil companies by foreign oil companies. These companies will benefit from the strong protectionist views of influential Democrats who will be ruling Congress for the next two years. Remember what happened when the Chinese tried to take over Unocal.

At the end of the day, the shifting petroleum industry landscape will further pressure oil company executives to step up their capital spending as the only realistic way to deal with their ballooning cash flows and growing cash hoards. Financial engineering steps (boosting dividends, buying back stock and paying down debt) can only address this cash issue at the margin. Reinvesting in the business is critical, but most managements fear opening the spending spigot just at the wrong time. Shaking that fear will be difficult, but the pressure to do so will likely grow as we move through 2007.

A Changing Industry Landscape

Our antenna should be attuned to a changing industry landscape as we move into 2007

Without betraying or compromising our sources, we thought the anecdotal information we have learned over the past two weeks suggest that our antenna should be attuned to a changing industry landscape as we move into 2007. Some of the information suggests that people swept up in the "boom mentality" stimulated by high oil and gas prices may be paying the price for having bet on those prices continuing in the face of weaker prices and signs of a softer economy next year. Other data suggests that managements are re-examining their company business strategies in light of actual or perceived changes in the industry and/or political landscape.

We understand several small U.S. E&P companies are close to defaulting on bank loans and have held discussions with bankruptcy lawyers as a result.

We also have been told that several Canadian oil and gas income trusts have laid off employees to deal with lower commodity prices, escalating oilfield costs and the higher cost of capital due to the tax law changes.

Some energy company lead tenants for new real estate projects in Calgary reportedly have pulled out putting those projects on hold.

Certain international oil companies are re-examining prospects in geographic regions they have shunned for years because their access to more attractive global E&P markets is being restricted.

Change is underway

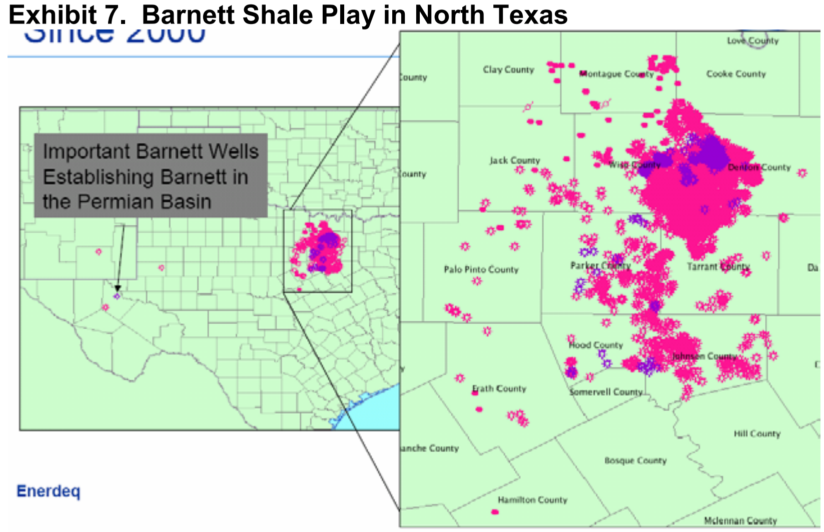
Is any one of these data points the equivalent of the canary in the coal mine? No. But collectively, they raise warning flags and signal that anyone predicting a continuation of recent industry trends will probably be wrong. Change is underway. Figuring out how much change, and in what ways it will happen becomes our challenge.

"A Beautiful Sight, We're Happy Tonight…"

These were drilling rigs working on the southern edge of the Barnett Shale play

Last Wednesday night, my wife and I drove to our daughter's home in Keller, which is northeast of Ft. Worth, for an early Christmas celebration. Our route from Houston took us north on I-45 to Ellis, which is above Corsicana, where we catch Texas 287. We then head northwest to I-820 and around Ft. Worth to Keller. Route 287 takes us through Waxahachie, Midlothian and Grand Prairie. The route is through Ellis County and into Tarrant County, the home of Ft. Worth. As we came over one hill on Route 287 we began to see lighted spires on the horizon. We recognized that these were drilling rigs working on the southern edge of the Barnett Shale play that extends primarily from Denton County to the north of Ft. Worth and south through Tarrant County (the Ft. Worth area) and then westward. This exploration play has been largely responsible for the increased drilling activity in Texas over the past several years.

Exhibit 7. Barnett Shale Play in North Texas



Source: IHS, ConocoPhillips

At one point on the road there were lighted drilling rigs on the horizon all around us. The view took me back to a time in the early 1980s when I hosted an investor energy conference in Oklahoma City where the deep gas drilling boom in the Anadarko Basin was underway. After dinner with Parker Drilling's (PKD-NYSE) management, we headed out with a number of investors for a ride that produced a similar scene of lighted drilling rigs everywhere one looked on the horizon. For anyone involved in this industry, it is a beautiful sight, and we certainly were happy that night to see it.

Capex Survey Suggests a Tale of Two Markets in 2007

Recently the Lehman Brothers' oil service and drilling research team, headed by Jim Crandell, reported the results of their survey of oil industry exploration and production spending for 2007. The results were in line with what many analysts had been expecting – the end of the run of double-digit annual spending percentage gains.

The regional spending trends suggest that international markets will be considerably stronger than North American markets next year

According to the study, Lehman Brothers' estimate of worldwide spending, based on its survey of 299 oil and gas companies, calls for spending to increase in 2007 by 9% to $292 billion. By region, international spending leads with an increase of 13% to $196 billion, while U.S. spending should grow by 5% to $73 billion. Canadian E&P spending is projected to decline by 7% to $22 billion. The projections reflect the more conservative spending outlook by companies given that they are anticipating a decline in North American natural gas prices. In addition, the survey does not tap the thinking of the major national oil companies in the Middle East and Africa where spending and activity gains have been robust and are likely to continue so next year. Therefore, it is possible that this initial spending survey for 2007 could prove conservative. However, the regional spending trends suggest that international markets will be considerably stronger than North American markets next year.

In reading through the study, we were drawn to several issues behind the thinking of the oil and gas companies as they approach setting their budgets for 2007. The two issues we found most interesting were: 1) the key determinants for E&P spending; and 2) the most important technologies. Each of these topics were measured over the 2000 to 2007 period and the changes in their importance points to shifts in oil and gas company thinking about their businesses and what they should be doing about it.

Exhibit 8. Key Determinants for E&P Spending 2000-07

	2007	2006	2005	2004	2003	2002	2001	2000
Natural Gas Prices	53%	61%	52%	73%	55%	67%	66%	68%
Prospect Availability	42%	53%	58%	51%	55%	39%	60%	45%
Oil Prices	39%	51%	50%	44%	43%	51%	47%	59%
Drilling Costs	37%	40%	41%	38%	35%	49%	35%	31%
Cash Flow	42%	36%	60%	54%	53%	59%	65%	68%
Drilling Success	35%	34%	43%	43%	30%	30%	44%	41%
Capital Availability	28%	23%	32%	39%	36%	37%	43%	52%

Source: Lehman Brothers

As Lehman Brothers pointed out in its narrative, natural gas remains the key determinant of E&P spending in 2007 reflecting the heavy concentration of North American independent producers in the survey. Because of this bias, cash flow, prospect availability and drilling costs are also important considerations. What we find interesting is to look at the ranking of these determinants and how the percentages have changed over time. For example, natural gas prices, at 53% of respondents, are barely above the 2005 level when this driver was ranked third on the list behind cash flow and oil prices. Over the period 2000 to 2004, natural gas prices led or were tied for the lead on the key determinant list. While the importance of natural gas prices has declined somewhat, they have been the prime driver for E&P spending for virtually all of this decade.

The figure suggests oilfield inflation has peaked

For all the concern expressed by producers about oilfield services inflation, the ranking of drilling costs at 37% for 2007, and its relatively low ranking throughout the period suggests that high commodity prices way outweigh cost concerns. Interestingly, drilling costs were rated higher in both 2005 and 2006 and was much higher in 2002. This year's figure suggests oilfield inflation has peaked.

We were also intrigued by the low percentage for capital availability. That determinant stands at 28% for 2007, which has to reflect the growing cash flows from high oil and gas prices and the vast amounts of public and private capital available. Bank loans to oil and gas companies has begun to grow significantly as lending officers believe the outlook for the industry is solid for the long-term. Historically, when commercial bankers fall in love with an industry because of its solid fundamentals, we are often close to a tipping point in the outlook. Will it be different this time? No one knows.

First time in the eight-year time period, 3-D/4-D seismic lost its premier position to fracturing/stimulation

Turning to the most important technologies survey question, for the first time in the eight-year time period 3-D/4-D seismic lost its premier position to fracturing/stimulation. This change reflects the growth in developing unconventional gas reserves and their need for fracturing and stimulation to improve the hydrocarbon flow from these reservoirs. In third and fourth places are horizontal drilling and directional drilling technologies, respectively. To our way of thinking, these two technologies are so similar that they should be combined, which would put them in second place behind fracturing and ahead of seismic technology.

Exhibit 9. Most Important Technologies

	2007	2006	2005	2004	2003	2002	2001	2000
Fracturing/Stimulation	109	91	61	88	52	74	24	30
3-D/4-D Seismic	90	102	110	121	106	146	129	155
Horizontal Drilling	57	64	60	62	54	58	39	31
Directional Drilling	42	35	33	48	42	44	9	12
Reservoir Recovery Optimizatio	38	27	30	39	35	NA	NA	NA
Drill Bit Technology	21	31	34	22	16	15	7	6
Intelligent Well Completions	18	17	16	23	20	25	3	2
Wireline Logging	15	14	12	17	8	13	3	10
Measurement-While-Drilling	15	10	5	6	10	10	3	4
Underbalanced Drilling	9	13	6	17	13	10	4	7
Expandable Products	1	1	2	3	1	NA	NA	NA
Deepwater Technology	0	4	4	6	9	10	3	11

Source: Lehman Brothers

Reservoir recovery optimization technology is still quite low in overall importance

What is very interesting is the position of reservoir recovery optimization technology. As can be seen, it has come from nowhere in 2002 to effectively fourth place on the list of most important technologies. However, this technology is still quite low in overall importance. But then again so are almost all the other new technologies ranked lower on the list, some of which appear to have significant future potential. Once again, the dominance of small North American producers among the surveyed group probably has skewed the answers to the most important technologies question since they are more heavily focused on exploiting unconventional gas resources. Also, fewer companies are targeting deepwater technologies and intelligent well completions. This bias does not invalidate the responses to the survey questions, it's just that the bias needs to be remembered when reading the results.

Employees Want More Than Dollars

Cheryl Collarini of Collarini Energy Staffing recently appeared on a panel at Hart's Energy's first Recruiting and Retention conference and discussed the results of a survey her firm conducted on non-monetary issues important to energy company employees. She was surprised by some of the findings. The survey assumed competitive compensation for all those surveyed. The universe of employees surveyed tended to be largely professionals that may have swayed some of the results.

The number one issue across all ages and genders surveyed was the company's reputation

According to the survey, the number one issue across all ages and genders surveyed was the company's reputation. This is an important consideration for management and should be factored in to all corporate decisions. Following that as the next most important issue was challenging work. This is not totally surprising as workers enjoy and are stimulated by challenging and varied work rather than monotonous and boring tasks.

The next group of important issues all involved the people and the culture at the company. These issues included the team, the supervisor, the ability to influence decisions and the openness to new ideas. These are important considerations, but are very personal issues. The next most important issue had to do with personal time, which included the length of commute and flexible work hours. These two issues would seem to go together as the ability to manage one's hours may improve commuting time. These issues also explain why companies are often more willing to consider relocation when their existing office lease terms expire, even though there is a huge cost associated with a shift. We are aware of companies that when considering relocating conducted employee residence surveys to aid them in their relocation decision.

The least important employee issue was assistance with child and elder care

Surprising to Cheryl Collarini, the least important employee issue was assistance with child and elder care. This result may be due to the level of professionalism of those surveyed. Those employees probably believe they can and should be able to handle these issues outside of their work environment. Another panel member who represented an industry with many more lower paid positions found that it was able to improve retention of employees by adding child care facilities. In this age of tight energy labor markets, paying attention to the non-monetary concerns of employees may make for more stable labor forces, which clearly is a cost-saving strategy.

Connecticut Electricity and NIMBY

Politicians are much more optimistic about Connecticut's electricity supplies through 2015 than the manager of the regional wholesale electric market, but that should not come as a surprise. The Connecticut Siting Council, an appointed board by the state legislature, wrote its initial report early this spring and revised it in early November. The council was scheduled to review and vote on the report at a mid November meeting, but no results are reported on its web site, although an email suggested an unchanged report.

The politicians expect electricity growth of only 1.2% per year while the electricity pros see a 1.8% growth rate

The council is charged with determining the rules and regulations for power and telecommunications services in the state. As part of its charge, the council is to review long-term electric power forecasts and recommend actions to ensure adequate future supply. In the new 2006 report, the council forecasts that Connecticut's total peak electricity usage in 2015 will be 7,654 megawatts, assuming normal weather conditions and no major retirements of electric generators. That peak represents an annual growth rate of 1.2% over the ten year period. On the other hand, the Independent System Operator (ISO-New England), which prepares its forecast using more stringent projection methods, projects demand to grow by 1.8% per year to a peak of 8,535 megawatts by 2015. It estimates peak summer loads, when demand is the highest due to air conditioning loads, at 9,120 megawatts. The implications from the difference in these two forecasts are significant.

In preparing its forecast, the council considers the forecasts prepared by the three major electric power companies operating in the state and examines their plans for maintaining and expanding power generation capacity during the forecast time period. Additionally, the council also has to consider the potential retirement of generating facilities due to their age.

A consideration within the forecast is the diversity of fuel sources in generating power supplies. Currently, Connecticut relies on fuel oil for 36.6% of its generating capacity with 30.1% coming from nuclear plants and 20.2% from gas-fired plants. Coal, hydro and refuse and methane make up the balance of the fuel sources. By 2015, the fuel source mix will shift dramatically. By then, natural gas will fuel 50% of the power generating capacity, while nuclear will increase to 34.7% and coal will account for 9.4%. The 2015 fuel mix assumes the operation of three new natural gas-fired power plants that have currently not been built and/or completed. It also assumes the retirement of all oil-fired plants that reach 40 years of age.

Connecticut is the least able to import power to supplement its internal supply resources and to access lower-cost supplies

The more telling point of the analysis is the council's review of the ability of Connecticut to import electricity from outside the state without compromising the grid voltage and system operating stability. The council assessed the state's situation with the following language: "…of all the New England states, Connecticut is the least able to import power to supplement its internal supply resources and to access lower-cost supplies located in other states. For example, New Hampshire, Vermont, and Rhode Island have enough import capacity to support 100% of their peak load. Massachusetts and Maine each can import slightly less than 50% of their peak load. Connecticut can only import approximately 33% of its peak load."

Connecticut can only import approximately 33% of its peak load

The council concludes: "To adequately address Connecticut's growing electric demand over the next ten years, Connecticut must expand its transmission infrastructure to increase its import capability and the ability to move imported power within the state."

Dominion Nuclear Connecticut Inc., the operator of the Millstone Unit 2 and Unit 3 nuclear power generation plants, recently made some modifications to the plants that have increased their generating output by 16.4 megawatts, or 0.8%, without increasing their fuel consumption. Earlier this year, Connecticut Attorney General Richard Blumenthal had proposed a "windfall profits tax" on the Millstone plants. This misguided attack came in response to the ratcheting up of electricity costs in the state due to most of the power plants experiencing rising fuel costs. The beauty of nuclear power plants is that their operating costs are very low, however the capital investment to build them is huge and the construction time is long.

Earlier this year, Connecticut Attorney General Richard Blumenthal had proposed a "windfall profits tax" on the Millstone plants

Connecticut is facing a tough future for electricity, both in availability and in cost. Residential electric rates are the third-highest in the country at 17.4 cents per kilowatt, which is well above the national average of 10.9 cents. Hawaii at 24.5 cents is the highest cost residential power in the country with New York State the second-highest at 17.5 cents. New Jersey ranks eighth at 14.8 cents. Power rates are scheduled to increase in January as Connecticut regulators are preparing to approve requested rate hikes.

A recent article in *The New York Times* highlighted the rise in Connecticut residential power rates, but pointed out that customers of municipal electricity companies were being spared these hikes. There are seven municipally-owned electricity companies all with rates ranging from 11.8 cents to 16.3 cents, well below the state average. Municipal power companies enjoy some cost advantages since they can issue tax-exempt bonds and do not pay local property taxes. As a result of their lower costs, they can pass the savings on to their customers. The cost differential has spurred the city of Norwalk to explore starting a municipally-owned utility for the part of the city not covered by the two existing commercial utilities.

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What we find most fascinating about the Connecticut situation is that when faced with high electricity costs and a possible capacity shortage, the state's politicians elect to paint a rosy picture of the supply outlook. At the same time, they are trying to figure out how to get more power into the state without irritating citizens by building lots of new generating plants, yet they attack the owner of the lowest-cost power plants in the state for "excessive profits" at a time when it is trying to expand their capacity. Also, Connecticut and its politicians have been among the leaders in fighting the siting of LNG receiving terminals along its coast and in neighboring Long Island Sound, while also fighting the construction of new natural gas pipelines to bring additional supplies into gas-starved New England.

Ever escalating electric power costs will harm the Connecticut economy, and someday the politicians will pay for their NIMBY attitudes

The preferred solution for Connecticut politicians seems to be to boost the capacity to import electricity from neighboring states as this can be done with the least amount of public disturbance. Unfortunately, their reliance on imported power makes them more susceptible to escalating power costs over which they have little control. Ever escalating electric power costs will harm the Connecticut economy, and someday the politicians will pay for their NIMBY attitudes and head-in-the-sands approach to economic management.

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