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Fernandez said the find “will make the country a more sustainable one” and could eventually help the government avert sporadic energy shortages. She stressed that the government would adopt special techniques to develop the gas field adequately and called on Argentine corporations to work together with energy companies.

The president added that the discovery “allows us to project gas reserves for the next 50 years” and investors looking at Argentina may now see energy resources that are worth developing.

Only a few years ago, the general perception was that Argentina’s geology had little to offer. But that appears to have changed with the recent discovery. “There is [now] a general perception that Argentina is attractive with shale gas and pipe gas, and at the right price, it will be viable,” said Daniel Kerner, an analyst with Eurasia Group in Argentina, quoted on December 7 by AP Newswires.

“The important thing will be to see what exactly the price mechanism is, and reducing some of the price distortions for producers ... Obviously the gas is going to have to be sold at a higher price or else this is not going to be profitable,” He added.

The discovery was made by YPF drilling in an area known as Vaca Muerte – which translates as dead cow – near the town of Loma La Lata, located about 1,150 km southwest of Buenos Aires.

YPF, clarifying that the find could not yet be classified as reserves, said exploration teams had drilled four wells,

each of which had yielded an initial daily output of 100,000 cubic metres per day.

It said “huge volumes” of both shale gas and tight gas had been found at the site, where a horizontal well will be required to tap the deposit. The company announced that it now plans to invest US\$140 million in 26 other drilling operations to find more such deposits – a campaign that increases the investment made by a 50:50 exploration and production venture YPF with Vale to US\$1 billion.

Vale plans

One winner in the process is Vale, which has been seeking to secure gas to develop its US\$4.3 billion Río Colorado potassium project in the nearby province of Mendoza.

The project is scheduled to begin production in the second half of 2013, with initial production capacity of 2.4 million tonnes per year and the potential for 4.4 million tonnes. But to get the gas it needed Vale appeared to be faced with the choice of digging out supplies from the tight Argentine market or importing cargoes from abroad. Under the deal with YPF, half of the gas unearthed near Loma La Lata will go to Vale.

YPF is also expected to benefit significantly. Argentina’s largest employer – which produces and processes about 50% of the country’s oil and controls around the same proportion of the domestic fuel market – plans to float 15% of its shares in an initial public offering (IPO).

YPF is also preparing a US\$600 million bond issue, and the Eskenazi family’s Petersen group is also preparing to exercise an option to raise its stake in YPF from nearly 15% to 25%. Eskenazi said his company “this year invested 51% more than last year in exploration,” and has referred to the ongoing shale gas developments as “the biggest investment in the history of Argentina.”

Argentina’s unconventional gas resources have attracted interest from a handful of global energy companies, including Apache Corporation, Total and Wintershall, among others. Although YPF’s deposits remain unproven, and will be more expensive to extract than natural gas because of the horizontal drilling and hydraulic fracturing processes that will be required, it is reasonable to expect that a fresh influx of other overseas hydrocarbons investors will begin to scan the market for new opportunities.

Their efforts will be aided by the government’s Gas Plus programme, which allows companies producing unconventional gas to sell the fuel at far higher prices than is the case of traditional gas, which is subject to strict price controls.

As Argentina’s consumption of 1.5 tcf (42.5 bcm) per year of gas continues to rise in tandem with economic growth forecast at around 6.5% in 2010, the premium on shale gas, coupled with local demand, should ensure that explorers will be well rewarded for further successes. ■

Project costs on the rise in Alberta

The award of construction contracts for the Sunrise oil sands project suggests a ramp-up in activity and costs in Alberta’s oil sands industry

By Ashok Dutta

A consortium of Husky Energy and BP has awarded two construction contracts for the first phase of the 60,000 barrel per day Sunrise oil sands project in Alberta.

Worth a combined value of around C\$1.25 billion (US\$1.24 billion), the awards are the largest to be made in the post-economic downturn era in the

province’s energy sector and point to a significant resurgence in project activity after a hiatus of around two years. ►►

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Hectic negotiations

According to sources in Calgary's engineering, procurement and construction (EPC) industry, negotiations prior to the award of the contracts were "hectic," with bidding companies offering last-minute discounts as they battled to trump each others' offers.

"There was talk of a leading contender booking two floors of office space in downtown Calgary even before being awarded the contract," an official from a leading EPC firm told *UOGM* on condition of anonymity. "Another firm was seen visiting the client's office more frequently than is the accepted norm."

Neither Husky Energy nor the bidding companies have confirmed such rumours. Nevertheless, what is clear is that it was a tight race and indicates that EPC firms in Alberta are hungry for new contracts.

Rising costs

From a commercial perspective, the contracts awarded for the Sunrise scheme are likely to set a benchmark for the capital costs of oil sands schemes. And the early signs are that projects costs are on the rise again.

In one of its latest reports, Boston-based think-tank IHS-CERA said the cost of building a large oil sands processing facility had risen by 3% since the start of 2010 to a level that was just 4% below the 2008 peak.

"A combination of higher oil prices, a weaker US dollar and a stronger global economy is resulting in rising costs," it said. "Activity is increasing and prices are rising, albeit with a healthy dose of caution. Overall things are getting busier, but it is much more sustained. There are still going to be challenges. However, it will not be as much as it was during the boom."

Labour issues

Assuming an upturn in oil and gas project activity in China, India and the Middle East will impact raw material prices (the cost of steel in particular), the IHS-CERA report said: "In Alberta, the province's capacity to supply labour is

once again nearing its limit, but we do not expect a return to the overheated boom times."

Nick Olds, senior vice-president with ConocoPhillips Canada, confirmed that labour costs continued to be a sticking point for oil sands operators.

"Labour availability is still an issue and this is driving up costs," he said. "We are willing to work with the government to find a solution. Keeping projects on schedule and costs in place is of great importance to us."

Commenting on the wider situation, Jeff Young, a principal and estimation manager with Calgary-based Vista Projects, said the capital costs of oil sands projects had remained "flat" over the past few months, but there were now indications of an upward trend.

"During the mid-2009 to first-quarter 2010 period, costs dipped 15-20%. But of late we have seen them rising by 10%," he said. "Labour is still a bottleneck and in the coming few years we anticipate there will be a fight to get the best workforce."

Young said the C\$100 (US\$99.03) per day "retention bonus" – money paid by companies to keep staff on site – was not

in vogue at the moment, but it might be rolled out again if the market started to overheat.

Overcrowding

A key problem in the 2006-08 period of boom and bust in Alberta was that there were too many schemes on the drawing board, which resulted in oil companies competing for the same pool of resources.

This time round, both the industry and the government are cautious that projects are implemented more judiciously, thus reducing the pressure on available manpower and materials.

Several major schemes are currently getting under way. The most notable are Imperial Oil's 110,000 bpd Kearl Lake project, Phase Two of ConocoPhillips' 85,000 bpd Surmont scheme and the third, fourth and fifth stages of Suncor Energy's Firebag venture, which will have total production capacity 187,500 bpd. However, an emerging trend in Alberta's oil patch is the emergence of several small-scale oil sands projects with production capacity of around 5,000-25,000 bpd.

"The attitude is of acceleration and there is a steady diet of project activity," pointed out Alex Campbell, founder of engineering consultancy Vista Projects. "Established players are going ahead with their mega-projects, but several smaller ones are kicking off."

Clearly, the proliferation of new schemes will translate into a growing demand for engineers.

"Next year, there will be a lot of competition for engineering personnel as projects ramp up. We are looking at our rates and offering a variety of incentives to ensure good people stay back. We are also being competitive from a wage perspective," Campbell said.

The industry appears to have accepted that project costs are on the rise. The key question now is by how much. ▶▶



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“An SAGD [steam-assisted gravity drainage] project now costs C\$60-70 [US\$59.42-69.33] per barrel, while the capital cost of a mining venture is C\$80-90 [US\$79.23-89.14] per barrel,” said Bob Dunbar, president of Strategy West. “There has been a drop in the price of

steel, rebar and concrete and this is reflected in the new projects being mounted on the drawing board. Also, some companies like Cenovus Energy are showing signs of cost efficiency by replication.”

With demand and costs rising, the

pressure on Alberta’s oil sands patch looks poised to ramp up in the coming months. The industry will hope it is better prepared to handle that pressure this time around compared to how stretched things became during the last boom period. ■

POLICY

New York applies partial fracking ban

The New York state governor has signed an amended bill, which will see the fracking of high-volume horizontal wells in the state banned until July 1, 2011.

On December 13, the Post Gazette said that the: “Outgoing Democratic governor vetoed a bill on [December 11] that would have suspended all new natural-gas drilling permits until May 15. Instead, he issued an executive order prohibiting high-volume hydraulic fracturing of horizontally drilled wells, such as those in the Marcellus shale region of southern New York.”

Critics would have preferred the broader ban that had already been approved. However, Paterson’s decision was met by celebration from both pro-drilling proponents and

environmentalists. The licensing of gas wells in New York’s section of the Marcellus shale has been frozen since 2008, while the New York Department of Environmental Conservation (DEC) reviewed the potential environmental impact. Last week, Jim Smith, a spokesman for the Independent Oil & Gas Association (IOGA) of New York, said: “This legislation will adversely affect a sector of New York’s economy because of unsubstantiated fears. There continues to be no evidence that the one sector of the industry that this legislation will most certainly affect has done anything to warrant a forced closure of new wells.” On December 13, the IOGA stated that it praised Paterson “for [his] courageous veto of the moratorium bill.”

Rig data

Weekly data released by Baker Hughes on December 10 has shown that the number of horizontal rigs in action in the US held steady at 966, unchanged from the report for December 3.

However, 966 horizontal rigs is a record in the US and represented an increase of 18 from the end of November 2010. Compared to 2009, the number of horizontal rigs in the US has increased by over 80% reflecting the ongoing boom in the country’s shale deposits.

The potential fall in horizontal rig count which could have resulted from a full memorandum in New York, will likely be somewhat diluted by Paterson’s version of the ban. ■

Halliburton to disclose fracking chemicals

Halliburton will disclose its hydraulic fracturing chemicals to the US Environmental Protection Agency (EPA) under a new agreement. Halliburton had been subpoenaed by the EPA in November over the contents of its fracking fluid, which is often used when drilling for shale oil and gas.

The company will provide the data to

the EPA, by the end of January 2011.

In its subpoena, the EPA said that the Texas-based company had not been providing adequate data. The regulatory agency is in the process of a major study of the environmental impact of fracking.

“Over the past few weeks, we have provided more documents and will continue to work diligently with the EPA

to provide the documents,” a Halliburton spokeswoman told the Wall Street Journal.

Another eight oil services companies had already complied with EPA’s voluntary request in September for information on the chemicals used. ►►