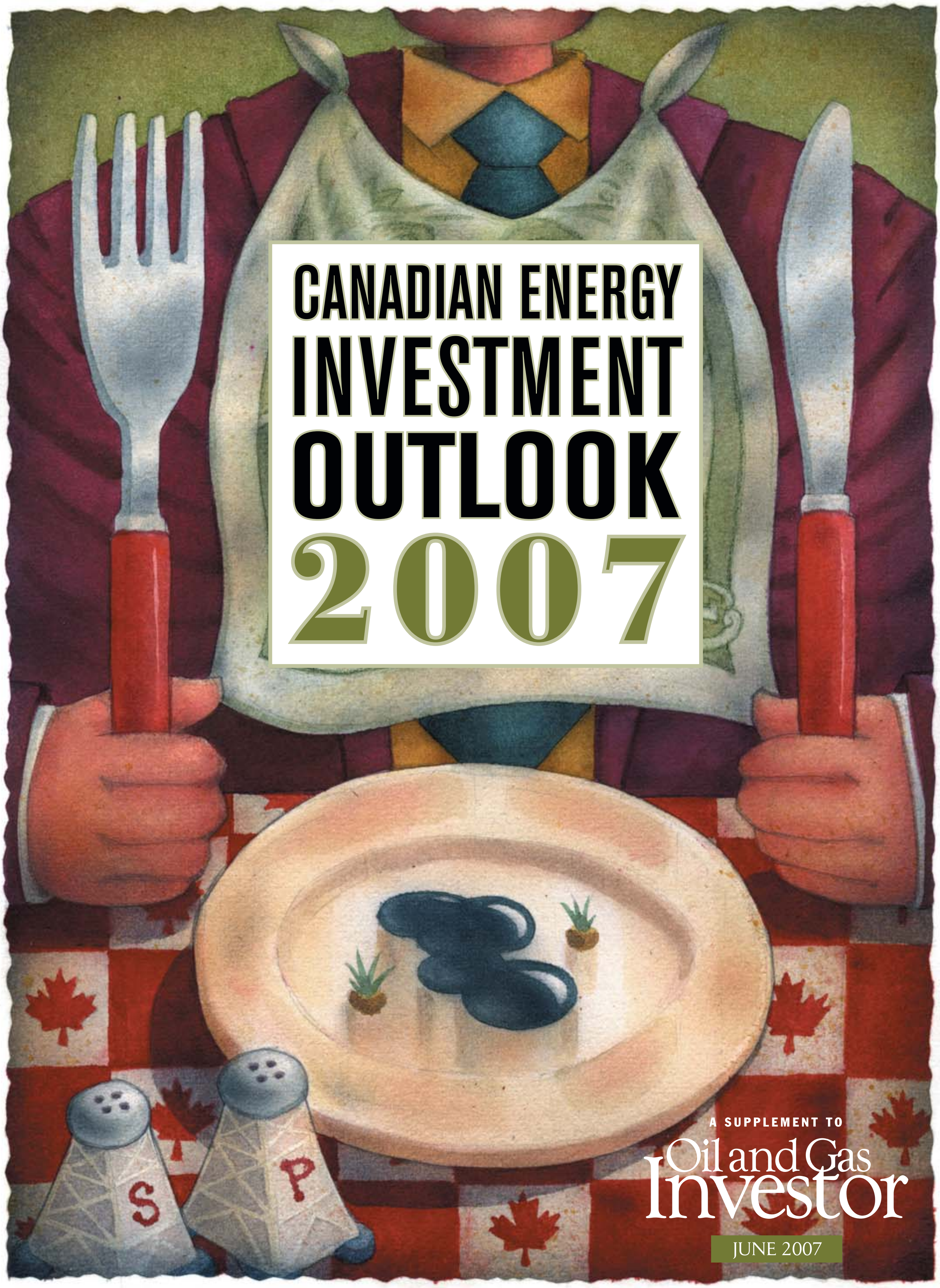
CANADIAN ENERGY INVESTMENT OUTLOOK 2007



A SUPPLEMENT TO

Oil and Gas Investor

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CANADIAN ENERGY INVESTMENT OUTLOOK 2007

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Cover illustration by David Wink

Challenges and Opportunities Ahead

Drilling activity and oil and gas production in Canada are taking a bit of a breather this year after the high-flying scene of 2005 and early 2006. This gives investors a better chance to analyze opportunities and make clear-eyed choices for the future.

In 2006, Canada surpassed all other suppliers of crude oil to the U.S. It continues to provide about 16% of our natural gas supply as well. Significant gas reserves continue to be drilled in the Deep Foothills play that straddles the border between Alberta and British Columbia.

There is opportunity if one knows where to look. What's more, energy equities are, in general, trading at a discount today, according to noted analyst Martin P. Molyneaux, managing director and head of institutional research at FirstEnergy Capital Corp. in Calgary. Here, he shares his views about the industry's direction and provides his list of top stock picks from large-cap companies to the fast-growth juniors.

Although worried about rising drilling and operating costs, he is fairly sanguine for the long term.

"FirstEnergy is very bullish on oil and gas prices. Our fundamental view is that demand keeps on increasing, and supply is going nowhere quickly," he says.

But supply is rising in the heavy oil sands of northern Alberta. The area is attracting heightened interest from politicians, oil companies and environmentalists around the globe, with increased acquisition activity a natural outcome of that petro-allure.

By 2025, heavy-oil production will increase from about 1 million barrels per day currently, to at least 4 million—some say as much as 4.65 million.

And yet, changing royalty schemes and the Canadian government's new emissions plan that starts July 1, 2007, threaten to alter the margins on this important source of energy for North America.

What about the juniors? In light of last year's gas-price decline, they are newly focused on higher-margin gas projects, and many have changed their production weighting to oil from gas. Most are steering clear of debt. In all, say our experts, they will end up being much stronger companies this year, whether they grow to become intermediates or are acquired by another E&P company.

This special report brings you up to date on these and other major trends within various sectors of the Canadian oil patch.

—Leslie Haines
Editor-in-Chief
Oil and Gas Investor

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A Pause in the Action

After running in place for several years despite more drilling, natural gas production may slump in 2007 as activity slackens.

BY GARY CLOUSER, CONTRIBUTING EDITOR

After years of increased drilling activity just to maintain a production plateau, western Canadian natural gas output appears headed for a dip in 2007 thanks to a drilling slump that began in third-quarter 2006.

Most of the industry organizations that follow activity have revised downward their drilling predictions made last fall, and they are calling for a dip in gas exports to the U.S. as well.

The average rig count in March 2007, about 268, was a drop of more than 50% from the same period a year ago, a steeper decline than is usually seen during the muddy spring break-up season, when rigs and trucks cannot move because of road bans.

This year, the number of gas wells expected to be drilled could fall for the first time since 1998, warns Roger Soucy, president of the Petroleum Services Association of Canada, based in Calgary.

In a presentation at the end of April, he said PSAC forecasts oil and gas drilling activity for 2007 will be about 18% lower than a year ago, with gas wells accounting for the drop. That means some 19,200 oil and gas wells will be drilled in 2007.

What's more, this is a reduction of 11% since PSAC's November 2006 forecast, with the decline "particularly evident in natural gas regions."

The proportion of wells intended for gas versus oil is also falling. Western Canada has a high proportion of shallow gas wells targeting small reserves that deplete quickly and aren't profitable to drill at times of lower prices. Gas wells accounted for about 75% of Canada's producing wells in 2005, slipping to about 70% in 2006. PSAC forecasts that for 2007, the percentage of producing wells that are gas will drop to 59%.

The slowdown poses several potential problems. Can the trend be reversed, or at least slowed, as volumes from conventional wells continue to decline, and greater emphasis is placed on non-conventional wells, particularly coalbed methane?

Is the drilling decline short-lived and poised to reverse itself as gas prices that fell to about half their peak levels begin to rise again?

A Bear drilling rig drills for gas in British Columbia. (Photo by Lowell Georgia)

CANADIAN OUTPUT

Much of the decline from earlier projections is in coalbed-methane drilling. Is this a short-term trend or is it more revealing of Canada's dilemma? What impact will changes in tax structure have on production from marginal wells? The answers will profoundly affect the U.S. as it gets about 16% of its gas supply from Canada, according to the U.S. Energy Information Administration.

Exports are already slipping. In 2006, Canada exported to the U.S. 3.6 trillion cubic feet of natural gas, or 9.9 billion cubic feet (Bcf) a day, compared with 10.2 Bcf a day in 2005.

Some industry forecasts say that Maple Leaf gas volumes available for export in 2007 could drop by as much as 1 Bcf per day.

Total Canadian production in 2006 was an estimated 17.2 Bcf a day, of which 16.8 Bcf was produced in western Canada, says Greg Stringham, vice president, Canadian Association of Petroleum Producers. CAPP now projects that for 2007, total production will fall to 16.7 Bcf a day, with 16.3 Bcf from western Canada.

Total gas completions in 2006, including coalbed-methane wells, totaled 14,500. That number is expected to drop to 13,700, according to the CAPP.

Other Canadian observers see the same trend.

"Conventional gas production was at a relatively steady plateau from 2002 to mid-2006," says Ken Martin, gas supply analyst for Canada's National Energy Board. "Since mid-2006, conventional gas production has declined slightly. At the same time, CBM deliverability has been increasing, partially offsetting the slight decrease in conventional gas production.

RIG ACTIVITY

Softening gas prices, changes in tax structure regarding royalty income trusts and rising production costs have been major factors in the falloff in the rig count.

"Rig activity began to fall around August/September of 2006, and the lower activity seen in 2007 is a continuation of that trend," says Martin of the NEB. "For 2007, evidence to date suggests that the actual gas drilling level for 2007 will likely be lower than was projected" in the 2006 NEB Energy Market Assessment published in October 2006.

"The 2006 conventional gas-intent drilling came in at approximately 13,900 wells—about 83% of our original projection," he says. "But, if you are looking for a measure of drilling efforts in 2006, well counts are somewhat misleading, as a larger share of the downturn occurred in areas where shallow gas drilling dominates. Using our estimate of drill days as a measure of drilling effort, actual 2006 conventional gas

COALBED METHANE

Development of coalbed methane is relatively new in Canada, growing from basically zero wells drilled five years ago to as many as 3,200 drilled in 2005, according to the Canadian Association of Petroleum Producers (CAPP).

The National Energy Board estimates there were about 2,600 CBM wells drilled in 2006.

"With the general downturn in drilling that is now underway, it is more likely that CBM-intent drilling in 2007 will be lower than what happened in 2006," says Ken Martin, NEB gas supply analyst.

"We estimate the actual number of conventional gas connections in 2006 to be 15,760 and the number of CBM connections to be approximately 2,900," he says. Tight gas is included as conventional gas in the NEB's short-term deliverability analysis.

The NEB has forecast CBM production could be 1 Bcf per day in 2008, but CAPP vice president Greg Stringham says, "While we may not reach the full 1 Bcf a day in 2008, it may be reached shortly thereafter, depending on price."

The impact on activity from softening prices affects producers differently depending on the areas they are active and the costs associated with those areas.

"The low prices of fall 2006 (below $4 per thousand cubic feet) really put a chill on CBM development. While current higher prices may bring it back, it will likely be lagged a bit," he says. "Approximately half of the most recent estimate of conventional gas resources in the WCSB (Western Canadian Sedimentary Basin) have been produced, and the industry must shift its focus to other sources, such as coalbed methane."

Canada's conventional gas reserves at year-end 2005 (the most recent estimate) are 57.9 trillion cubic feet, and marketable CBM resources are estimated at 167 Tcf.

Canadian CBM well counts continue to be dominated by wells drilled in the Horseshoe Canyon play. But, Horseshoe Canyon development is occurring at a slower pace than most people originally anticipated, due in large part to the recent downturn in gas prices and rising development costs. CBM drilling projections for 2007 had been about 3,700 wells, but that figure likely will be revised downward when NEB updates its projection this fall.

Production from conventional gas wells has been declining since 1999, and while increases are expected from CBM and tight gas, the size of those increases has been overstated because technical and economic recovery will result in just a small portion of the CBM and tight-gas resources being produced, Ziff Energy's Bill Gwozd says.

The CBM resource is estimated at 660 Tcf in-place, but only about 20 Tcf, or 4%, will be economically and technically recoverable, unless there are major technical improvements, he says. The total tight-gas resource is about 565 Tcf, but just 10 Tcf can be technically and economically recovered. Ziff estimates that CBM and tight-gas production will each ultimately top out at about 2- to 3 Bcf a day.

drilling was approximately 93% of the projected level."

Martin says there is potential for 2007 to still be a fairly strong year for drilling even though winter drilling was below the record levels of 2006.

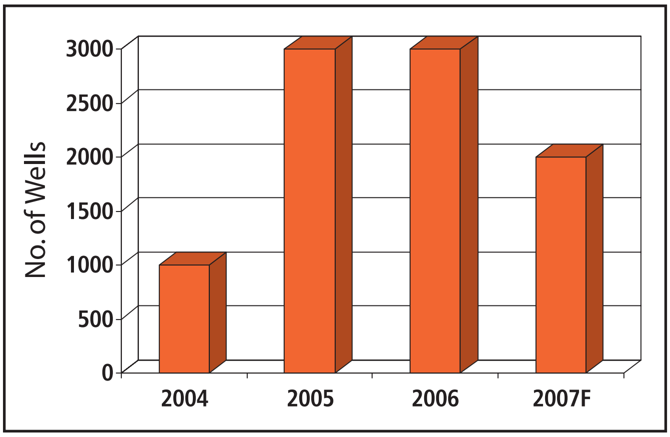
The questions for this year: would increases in gas prices relative to service and drilling costs be sufficient to drive increased spending? And, to what extent will producers be able to scale up existing drilling programs for the remainder of 2007?

Late 2006 and carrying into the first half of 2007, drilling activity decreased, which will result in about a 3% to 5% slippage in production, says George Eynon, vice president, business development and external relations, Canadian Energy Research Institute in Calgary.

The active rig count dropped from 600-plus to just more than 500, and that drop will have a lag effect on production for 2007. Unconventional gas production is currently at about 4.5 Bcf a day, or 27% of Canada's total production, Eynon says.

With prices rebounding to more than $7 per thousand cubic feet, there will be some pressure for companies to resume a more robust drilling program.

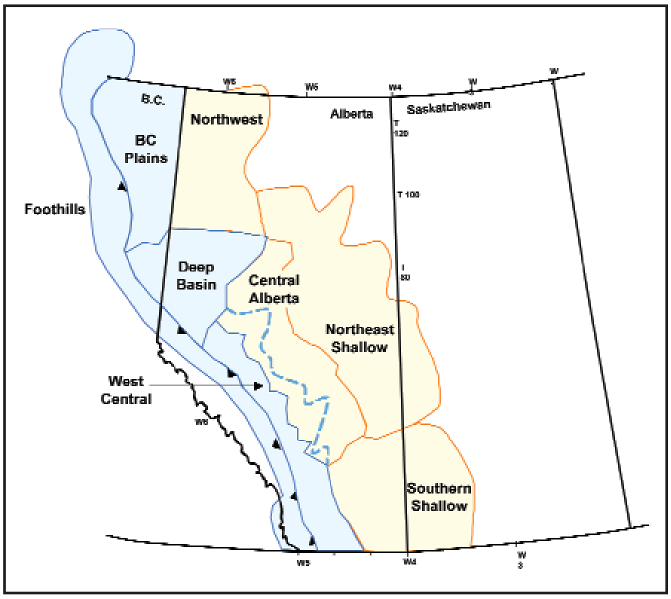
"It is important to understand the seasonality of the drilling season in western Canada," Stringham says. "Rig utilization rates are the highest during the winter drilling season, sometimes approaching 100%. As we get into spring, the western provinces institute road bans restricting the movement of heavy vehicles, including rigs. This, in turn, impacts the level of drilling leading to fewer wells being tied-in and lower production."



Coalbed-methane activity is forecast to decline.

(Source: Petroleum Services Association of Canada)

The seasonality of drilling activity means gas production picks up in the first quarter of each year, moderates somewhat in the spring-break period, then gradually increases in the second half of the year as drilling levels somewhat recover.



Canada's gas strategy areas. (Source: Ziff Energy Group)

"However, in 2006, with the slowdown in gas drilling both conventional and CBM production tapered off toward the end of last year," Stringham says.

OTHER CHALLENGES

Even with a rebound in prices, concerns about the fate of the income trusts, rising production costs, competition for labor and equipment continue to be hurdles for gas production, Eynon says.

It is difficult to quantify the impact on income trusts as the removal of their tax incentive is being phased in over four years. But the trusts accounted for about 21% of the Western Canadian Sedimentary Basin's gas production. More important, they accounted for a significant portion of the industry's development activity, Eynon says.

The main niche for such companies was developing marginally economic resources. The income trusts companies are not all reacting the same. Some have immediately stopped development activities, others plan to phase it out, and still others are operating as business as usual with the hope or expectation that federal tax policy can be changed. Still, projections are that the change in the tax structure could initially result in production declines of half a Bcf per day.

Regarding costs, part of the problem for Canadian gas producers is the success and huge potential from Alberta's oil sands. They have to compete for skilled labor and capital equipment, which is causing costs to rise by as much as 50%. The situation in Alberta is made worse by the overall heightened economic activity, which is having upward pressure on all prices, he says.

Delays on the proposed Mackenzie Valley Pipeline have served as a disincentive for gas exploration in the extensions of the WCSB into northern Canada, Eynon says. Current projections are that the earliest that pipeline can be operational is 2012.

Meanwhile, Canada's internal gas consumption continues to rise at an annual rate of about 1% to 2% and could spike, if and when Ontario implements its ban on coal-fired power generation.

Increased internal consumption and a drop in production will make less gas available for Canada to export, Eynon says. Perhaps a bigger uncertainty is the impact that Canada's compliance with Kyoto protocol limits will have on fuel choices and thus gas demand.

Bill Gwozd, vice president, Ziff Energy Group, a consulting firm with offices in Calgary and Houston, says its analysis tells this story: increases in gas production from CBM and tight gas will not be enough to offset the decline from conventional wells. There will be a net decrease in Canadian gas production as early as 2007, and that net decrease will accelerate.

Canadian gas producers are facing a "double whammy" of higher costs for smaller, less-productive wells, amid a slip in commodity prices, even as their costs soar, Gwozd says.

The average Canadian gas well is becoming less productive. Gwozd says the average well production in 2005 was 220,000 cubic feet a day, down 37% from 2000. Since 2005, that has slipped by more than 10%.

Ziff Energy expects exports to the U.S., which had been about 10 Bcf a day in 2005, to fall 8%, or to about 4.7 Bcf a day by 2014 (the date Mackenzie Delta's 1 Bcf a day is forecast to arrive).

The supply problem is made worse by an increase in Canadian gas consumption, which had been rising about 1% to 2% annually, but will jump to more than 3% annually because of increased consumption for power and use in producing Alberta's oil sands, Gwozd says.

DRILLING PROJECTIONS

The consensus is that drilling activity for late 2006 and early 2007 will prove to be less than had been forecast, making the mid-year updates to be issued by the PSAC, the CAPP and the Canadian Association of Oilwell Drilling Contractors eagerly anticipated.

Even before further downturn in activity, the PSAC in its latest predictions (released in January) said it expects drilling activity in 2007 will be about 10% less than the 2006 final tally of 23,431 wells and that the reduction will be particularly evident in natural gas regions.

The CAODC in its most recent forecast, issued in October 2006, said it is projecting 19,023 well completions, or a 15% decline from 2006.

"Virtually all of the anticipated decline, 3,275 wells, is focused in shallow-deliverability gas areas, as well as coalbed methane."

The NEB's Martin says, "With lower drilling levels than what was projected, Canadian gas production can be expected to also fall short of the projected volumes. As the projection in the 2006 Energy Market Assessment amounted to roughly flat Canadian deliverability, the downturn in drilling is expected to result in a drop in Canadian gas production in 2007."

Gary Clouser writes on natural gas and midstream topics. He can be contacted at gdclous@sbcglobal.net.

The Oil Sands

Canada's oil sands are a global flash point. Whether you want to increase your supply of oil or your supply of environmental finger-pointing, look no farther than the Athabasca tar sands.

BY SYDNEY SHARPE, CONTRIBUTING EDITOR

Just as Canada became the top supplier of crude oil to the U.S., Al Gore was getting ready to supply the North Country with a little crude of his own. The former American vice president brought his well-oiled message to the energy heartland of Calgary, Alberta, where he applauded the local community for inviting him.

Then, in a respectful way, Gore denounced the carbon dioxide emissions from the oil sands, where domestic and global companies are investing $125 billion in heavy-oil projects during the next 15 years to produce 3.5 million barrels per day. Even a media star like Gore can't take away the reality that heavy oil is surpassing conventional production—but bringing with it challenges, including increased greenhouse gas emissions.

By 2025, Alberta's heavy oil production will more than quadruple to 1.7 billion barrels, from 388 million barrels in 2005, Neil McCrank, outgoing chairman of the Alberta Energy and Utilities Board, told a University of Calgary audience in mid-March.

The province produces a little more than 1 million barrels of bitumen per day compared with 570,000 barrels of conventional crude. That will drop to 219,000 barrels a day in 2025, while bitumen will boom to 4.65 million barrels daily.

FirstEnergy Capital Corp.'s oil sands analyst, Mark Friesen, pegs 2025 bitumen production a little under that estimate, at 4 million barrels a day.

Phil McPherson, director of research at Irvine, California-based C.K. Cooper & Co., noted in a research report that Canada is "rapidly becoming more important to U.S. supplies than some of our hostile foreign suppliers" and "will potentially have a greater impact on the price of oil than OPEC's inability to maintain production quotas."

With Venezuela taking over operational control of its multi-billion-dollar Orinoco Belt on May 1, 2007, it's no wonder the Canadian oil sands have attained such worldwide petro-allure. Canada's political stability lies in sharp contrast to the sabotaging of Nigeria's oil fields, Iraq's endemic terrorism and Russia's continuing confiscation of profitable private energy operations.

The Canadian Energy Research Institute estimates 175 billion barrels of bitumen are recoverable with current technology. Given the vast technological changes during the past two decades of oil-sands research, that number could rise incrementally with constantly evolving innovation.

Still, "oil sands investment is not for the faint of heart," explains ARC Financial Corp.'s chief energy economist, Peter Tertzakian. "It's not for small players, generally speaking." Projects require massive amounts of capital and long-term sustainable access to that capital.

"Companies must have the ability to deal with governments in a sophisticated manner," he adds.

Rising costs coupled with provincial and federal climate change initiatives, a provincial royalty review and the phasing out of the federal accelerated capital-cost allowance have added a level of uncertainty not normally associated with Canadian energy investment.

"When we look into the future, there will be more policy action," adds Tertzakian. "It will be layered between fiscal and environmental policy and will impact marginal players."

GREEN ECONOMICS?

In late April 2007, the federal government introduced a green plan Gore quickly denounced "as a complete and total fraud." Yet EnCana Corp. CEO Randy Eresman said during the company's recent annual meeting that "there will be a point where you start shutting down new project development. It's really a question of when do you choke." He noted that when you add up all the financial burdens associated with project developments, the "returns . . . are skinny."

Nexen's chief executive, Charlie Fischer, was just as concerned during the company's annual meeting.

"All of us are in the same boat. If we don't have the rates of return shareholders expect, we'll wait," he explained to reporters after the meeting.

The federal green plan calls for an 18% reduction in emissions per unit of production by 2010 and a 26% drop by 2015. Those unable to achieve intensity targets can purchase credits from domestic emissions trading or donate to a technology fund at C$15 a ton, jumping to C$20 in 2013. The Canadian government believes this will stabilize greenhouse gas emissions by 2010 and help reduce them by 150 megaton, to 2006 levels, by 2020.

In July 2007, the Alberta government will begin charging CO_2 emitters C$15 a ton if they can't reduce emission intensity immediately by 12%. This measure, essentially a carbon tax, will supply money into a technology fund to research measures such as carbon sequestration. No companies with existing plants are expected to meet the July 1 target.

Given that the provincial and federal climate plans call

HISTORICAL OIL SANDS TRANSACTIONS

	Date	Acquiror	Target (Company - Project)	Transaction Type	Total Consideration ($MM)	Recoverable Resource (Net MMbbls)	Implied Valuation ($/Bbl)	Mining/ In-Situ	Working Interest (%)	Expected First Production
1	2/1/2003	Canadian Oil Sands	EnCana - Syncrude interest	Working Interest	$1,070.0	819	$1.31	Mining	10.0%	Current
2	7/11/2003	Canadian Oil Sands	EnCana - Syncrude interest	Working Interest	$417.0	307	$1.36	Mining	3.75%	Current
3	7/2004	Shell Canada	EnCana - Lease 9 & Lease 17	Asset	<$100.0	1,000	<$0.10	Mining	100.0%	N/A
4	7/9/2004	UTS	True North - Fort Hills & Lease 14	Corporate	$125.0	2,184	$0.06	Mining	78.0%	2008
5	3/1/2005	Petro-Canada	UTS - Fort Hills	Working Interest	$300.0	1,680	$0.18	Mining	60.0%	2010
6	4/8/2005	CNOOC	MEG - Christina Lake	Working Interest	$150.0	334	$0.45	In-Situ	16.69%	2007
7	5/31/2005	Sinopec	Synenco - Northern Lights	Working Interest	$149.7	600	$0.25	Mining	40.0%	2011
8	8/2/2005	Total S.A.	Deer Creek	Corporate	$1,667.0	2,012	$0.83	Mining/ In-Situ	100% (84% of Joslyn)	2006 & 2011
9	9/6/2005	Teck Cominco	Petro-Canada & UTS - Fort Hills	Working Interest	$250.0	280	$0.89	Mining	10.0%	2010
10	9/6/2005	Teck Cominco	UTS - Fort Hills	Working Interest	$225.0	140	$1.61	Mining	5.0%	2010
11	5/8/2006	Shell Canada	Blackrock - Seal & Orion	Corporate	$2,058.0	603	$3.41	In-Situ	100.0%	Current
12	7/24/2006	KNOC	Newmont Mining - Black Gold	Asset	$310.0	305	$1.02	In-Situ	100.0%	2010
13	10/5/2006	ConocoPhillips	EnCana - Christina Lake & Foster Creek	Joint Venture	$4,423*	3,250	$1.36	In-Situ	50.0%	Current
14	11/29/2006	Canadian Oil Sands	Talisman - Syncrude interest	Working Interest	$475.0	106	$4.49	Mining	1.25%	Current
15	11/29/2006	Suncor	Talisman - Lease 23	Gross Overriding Royalty	$107.5	35	$3.07	Mining/ In-Situ	2.0%	2017+
16	1/23/2007	Royal Dutch Shell	Shell Canada	Corporate **	$8,700.0	858	$5.00	Mining/ In-Situ	22% of Shell Canada not already owned by Royal Dutch Shell	Current
17	3/22/2007	Enerplus	ISH - Kirby	Asset	$182.5	220	$0.83	In-Situ	100.0%	2011/2012
18	4/19/2007	Teck Cominco	UTS - Lease 14	Asset	$200.0	200	$1.00	Mining	50.0%	N/A
19	4/26/2007	Statoil	NAOSC	Corporate	$2,200	1,700 ***	$1.29	In-Situ	100.0%	2009

* FCC Estimate based on average U.S. downstream transaction metrics

** FCC Estimates. See Western Oil Sands FACTs dated October 24, 2006 for details

*** Resource estimate based on GLJ Best Estimate. Management Best Estimate of 2,100 MMbbls would imply a value of $1.05/Bbl Source: FirstEnergy Capital Corp. & Company Reports

for specific greenhouse gas targets, CEOs want to know how the two plans will operate together and whether there will be recognition for targets achieved under one plan but not another. Federal and provincial governments are working intensely to "harmonize" the regulations. In the interim, the challenge is to calculate costs when the plan's fine lines aren't yet written.

"It's very complicated, and the costs are going to be very company-specific," says Greg Stringham, vice president of markets and fiscal policy, Canadian Association of Petroleum Producers (CAPP).

ACQUISITIONS

Even though the federal plan was sparse in details, a UBS Securities Canada report quickly pegged operating costs going forward at 44 cents per barrel of bitumen. Peters & Co. estimated that the impact "appears to be relatively modest" at 19 cents to 65 cents per barrel of oil equivalent.

At the height of the green plan uncertainty, Norway's Statoil announced a C$2.2-billion plan of its own: the acquisition of privately held North American Oil Sands Corp. Statoil had been looking for an entry into the oil sands, and NAOSC majority owners (Paramount Resources, ARC Financial and Ontario Teachers' Pension Plan), were pleased to comply with the all-cash, $20-per-share offer.

NAOSC's recoverable reserves of 2.2 billion barrels of bitumen make the offer C$1 per barrel, which is similar to the C$1.6 billion Total paid for Deer Creek Energy in 2005.

As the oil sands continue to attract global energy giants, some high-cost producers are so stretched that they're reviewing their options. Those hurt most by the government green plans are companies that don't yet have any production.

In early May 2007, Synenco Energy, which holds 60% of Northern Lights Partnership, announced its planned C$6.3-billion upgrader is on hold as it discusses "strategic alternatives" with investment bankers. A likely fit is China's Sinopec, which already has a 40% stake in NLP. Another possibility is Italy's ENI.

Western Oil Sands is also for sale, although its Athabasca-area partner, Royal Dutch Shell, could take it home to mother.

"The oil sands are the focus for a number of social and economic issues," says Suncor Energy's vice president, sustainable development, Gordon Lambert.

"Political uncertainty and demand doesn't seem to be

U.S. REFINERS TO TAKE CANADIAN OIL

Canada plans to ramp up its production of heavy oil from the oil sands by nearly 2.5 million barrels a day during the next decade. That ultra-heavy oil-sands production will place an estimated 1.54 million barrels a day into the North American Market from 2006 to 2020, and an additional 1.35 million barrels a day of synthetic crude, according to Hart Energy Consulting's World Refining & Fuels Service, the downstream consulting affiliate of Hart Energy Publishing.

U.S. refiners will be tasked with processing more of that crude.

On the West Coast, most of the refineries with capacity for handling heavy crude will continue to process California heavy crudes, not Canadian supplies. Along the Gulf Coast, most of the refiners will have all they can do to handle increasing supplies of heavy crude from Mexico and Venezuela.

The bulk of the heavy oil coming from Canada will end up being processed in the U.S. Midwest. By 2015, some 60% to 65% of the crude processed in the Midcontinent will be from the oil sands, according to the report.

Many of the oil-sands crudes have high acid characteristics that require refinery metallurgy modifications to protect piping and vessels.

BP has announced a $3-billion revamp of its Indiana refinery, and ConocoPhillips has announced a joint venture with EnCana to revamp two U.S. refineries, one in Illinois and one in Texas, to process Canadian heavy crude. Marathon also is re-engineering refineries in Detroit and Kentucky for the same reason. Construction will start this year on its Grayville, Louisiana, refinery expansion.

diminishing for transportation fuels. In addition, climate change is front and center. The level of public concern is much higher than ever in the last decade. We're concerned about the potential for a patchwork quilt environmental policy."

When Suncor started its millennium project in 1997, crude oil was trading about $12 a barrel. Now it's $60 and rising, but so are costs.

"With these higher crude prices, it's quite predictable that you end up with this kind of circumstance—revenues become so large that the old rules get revisited," he says.

TECHNOLOGY GAINS

Lambert stresses Suncor's renewable energy investments and its continued technological innovations, even as its cost-per-barrel has risen to between $20 and $25. "We're the pioneers. We've got a lot of skin in the game and a lot of incentive to tackle the challenges and sort them out. Our truck and shovel technology was a big breakthrough. We think our next mine face slurry technology will take us to a better spot as well."

The equipment works at the face of the mine where the ore is exposed and the oil sands are removed and then conditioned on the site. Through hydro transport, a slurry to the extraction facility eliminates the need for giant trucks, shovels and the associated emissions.

Technology is what put the oil sands on the global map, as innovators gradually found ways to transform the gooey molasses-like mass into profitable fuel. Today, all the major players are working on proprietary technology that will lower their costs and emissions. But costs have soared as iron, copper, nickel, zinc and steel rise alongside a tight and pricey labor market.

"Oil prices spurred activity in the sector, so labor costs have increased enormously. Raw material costs have risen more dramatically than oil prices and those two (labor and raw material) make up two-thirds of the cost of oil-sands projects, which have gone up two-, three- or even four-fold in some cases," says FirstEnergy Capital's Friesen.

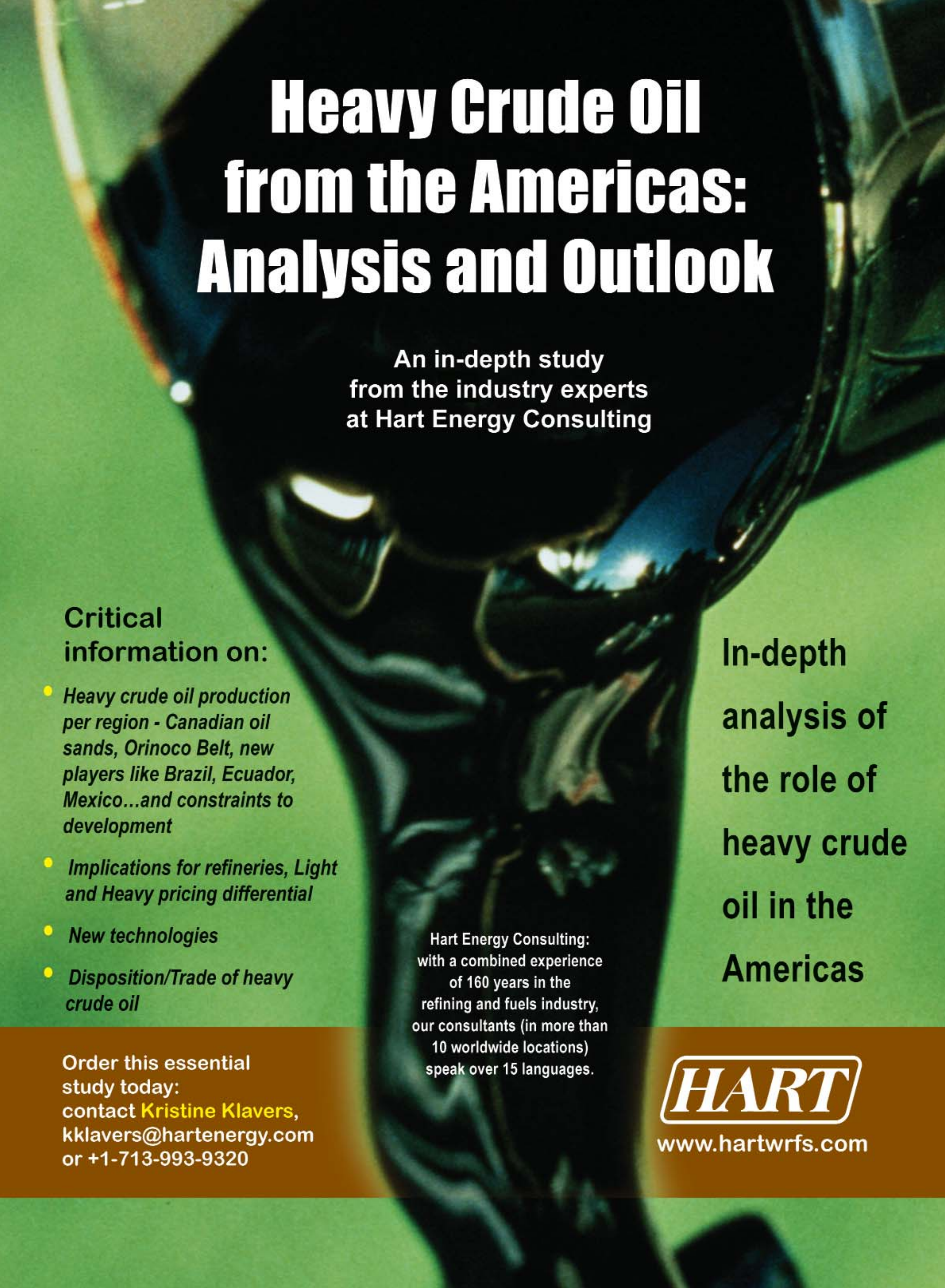
Cost inflation is not unique to the oil sands or even the oil industry, and any project risks cost hikes over time. But analysts stress that it is especially evident with mega projects. Increased project costs coupled with government green plans, plus a royalty review now being undertaken by the Alberta government, all cumulatively add up.

"While some of the shine has come off the sector, there are still lots of opportunities," adds Friesen.

"Growth in this industry will be pretty dramatic if investment isn't chased away. Industry is prepared to deal with the situation and willing to act. They aren't environmental bad guys. They want to be responsible. We need a framework to conduct business and we're lacking it. Right now it's the biggest uncertainty over the sector," he says.

There's already some push-back timing. Canadian Natural Resources' planned upgrader at its Horizon project is in deferral mode. Total has postponed its Joslyn Creek project for a couple of years. Imperial's Kearl Lake project could be rescheduled from 2009 to 2010 or 2011.

See **HEAVY OIL ECONOMICS** on pg. 24


Heavy Crude Oil from the Americas: Analysis and Outlook
An in-depth study from the industry experts at Hart Energy Consulting
Critical information on:
Heavy crude oil production per region - Canadian oil sands, Orinoco Belt, new players like Brazil, Ecuador, Mexico…and constraints to development
Implications for refineries, Light and Heavy pricing differential
New technologies
Disposition/Trade of heavy crude oil
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People Are the Biggest Asset

Martin P. Molyneaux, member of top-ranked energy-focused investment bank FirstEnergy Capital Corp., shares his views of the future of Canada's energy industry.

INTERVIEW BY SYDNEY SHARPE, CONTRIBUTING EDITOR

Martin P. Molyneaux

Martin P. Molyneaux is one of an elite group of Canadian energy research analysts whose depth, insight and judgment are sought by investors and media alike. He's a frequent commentator, panelist and advisor whose observations are bang-on, often coupled with catchy phrases that aptly describe a company's performance.

In each of the past nine years, Molyneaux has been ranked among the top five oil and gas analysts out of a field of about 60 in the Brendon Wood Survey of Canadian institutional investors. During that period, he has been ranked No.1 twice and No. 2 twice. He maintains in-depth coverage of 17 Canadian oil and gas producers, including the integrated companies and international explorers based in Canada.

As a founding member of FirstEnergy Capital Corp., Molyneaux is managing director of institutional research for this leading energy-focused, full-service investment bank in Calgary. Since 1997, FirstEnergy has been rated as a top-ranked research team in Canada overall and in terms of research quality.

Molyneaux has worked in the securities industry for the past 17 years and has been involved in the oil and gas industry for 23.

His analysis of a particular company is instructive for anyone planning to invest: "It's how you're spending that's the real key here, and it's what you're spending on to create value per share; big company or small, it doesn't make any difference."

Finally, his ultimate tip: "If something's at the bottom of your portfolio, then get rid of it. It boils down to get rid of the distractions."

Molyneaux enjoys a variety of sports and has completed nearly 40 triathlons, including the Ironman World Triathlon Championship in Hawaii in 1986. During the past few years, he has chased his goal of cycling the highest 25 paved roads in Europe, with 17 of these passes completed to date.

Oil and Gas Investor *sat down with him recently to get his sense of where the Canadian energy industry is going next.*

Investor How would you describe the oil and gas sector going forward?

Molyneaux Everyone is very concerned about the increasing cost structure. This includes reserve addition costs on the front end of the value chain all the way through the various costs of operations. Certainly people costs and retention are the paramount managerial issues, with a significant inflation in salaries along with bonus and stock option expectations. Everybody sees the revenue effect of higher energy prices, whether oil or natural gas. The question is, what is the margin looking like between sales price versus cash flow and earnings from those price levels?

Investor There's dramatic inflation in all cost structures within the energy world.

Molyneaux No question; it's a worldwide issue, not just a Canadian one. Rising steel prices to rising people costs to rising lease costs for office space—you name it. But do oil and natural gas prices keep inflating on the same kind of trajectory? For example, there was a pretty significant meltdown of natural gas prices entering the winter of 2006-07, which dramatically changed how capex programs were executed.

Investor You've been analyzing the industry for more than two decades. Have you seen this level of concern and industry challenge before?

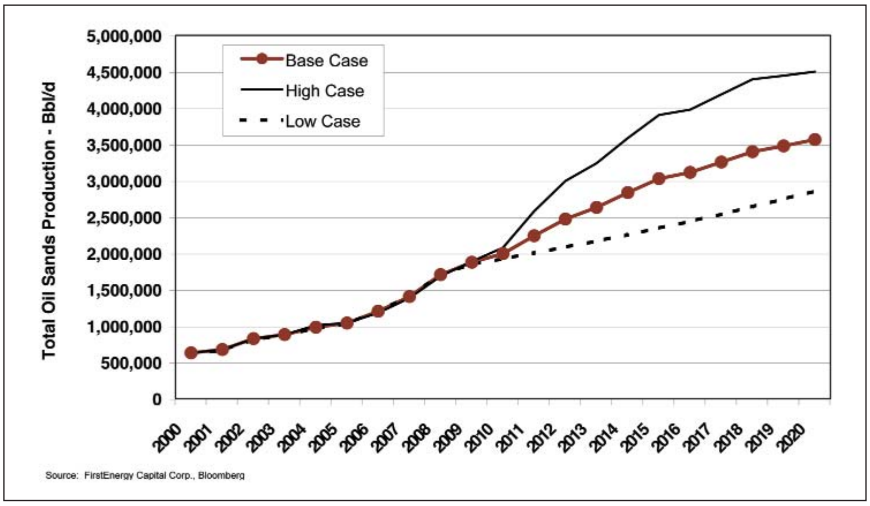
Molyneaux I think producers are very concerned—I have never seen concern to this level. Producers are being asked to spend more and more and are really worried about margins. Cost structures are going up, but inflation of oil and gas prices has kept things onside to date. The issue is: can you flatten out increases in cost structure if oil and natural gas prices stop increasing?

Investor Where do you predict petroleum prices will go?

Molyneaux FirstEnergy is very bullish on oil and gas prices. Our fundamental view is that demand keeps on increasing and supply is going nowhere quickly. We see ongoing, but not as dramatic, inflation in cost structures. We can see margins being maintained and potentially even expanded. This makes us bullish on the sector. It's much more challenging being bullish on the sector when we have $65 oil and $7.50 or $8 gas prices than when they were $40 and $5, respectively.

Investor Do you see the challenges leveling off and any sense of economic rationality returning?

Molyneaux No. The challenges keep on getting greater from a supply point of view. In terms of economic rationality, it all depends on what the sales prices are going to be. There are lots of hands up wanting their share of economic rent. The latest is the royalty review that the province of Alberta is



By 2020, the oil sands could be producing up to 4.5 million barrels per day.

undertaking amid concern over its share of the pie. Adding another level of uncertainty to the equation is not a good thing from either a corporate or investor point of view.

Investor How do we allay the fears of investors and the oil patch generally?

Molyneaux What we really need are relatively stable oil and natural gas prices so that all parties can get their economics rebalanced. Oil prices have gone from $30 to bordering on $70, and trying to judge what everyone's fair share of the pie should be has been extremely challenging to date. Everyone has fairly lofty expectations.

Investor Is Canada's role much more significant now that it is the main exporter of oil and natural gas to the U.S.?

Molyneaux There's absolutely no question with the Canadian oil sands volume growth happening that we are, and will continue to become, a more material supplier to the U.S. Do we want so much of our output going into that marketplace, especially when it comes to heavy and synthetic crude oil? There are lots of good arguments being made for pipelines to the West Coast to diversify our markets to include Pacific Rim consumers.

Investor Which factors lead to successful investing?

Molyneaux It is still about strong management teams identifying quality assets and opportunities. In a rapidly increasing commodity price atmosphere, lots of poor decisions get covered up by the upward shift in energy commodity prices.

Investor Which companies are consistently good bets?

Molyneaux It's those companies that allocate capital most stringently, where they can invest incremental dollars with the highest returns. Canadian Natural Resources is one very good example. Suncor is certainly there and it's almost a pure oil-sands exercise. Nexen, with Charlie Fischer at the helm, is very stringent in how they allocate capital.
Investor Does diversity seem to help?
Molyneaux If you've got the ability to compare and contrast domestic versus international opportunities, along with oil versus gas versus synthetic oil, then you have the portfolio to pick and choose the opportunities you want to pursue. When all is said and done, this business still requires very strong execution skills within the organization. It is all well and good to visualize a project, but it is critical to get it to a cash flow-positive position economically.
Investor Do you see all this activity leveling off, especially the influx of tiny oil-sands companies stalking the golden calf?
Molyneaux Activity levels will level off if oil prices stabilize. The rapid increase in oil prices over the last couple of years absolutely attracts more competitors.
Investor Even the dubious kind?
Molyneaux There are all kinds of ideas floating around covering an unprecedented range of project execution risk. Whereas historically, it would take 12 or 18 months to raise debt and equity capital, now there are some projects being partially financed that are nothing more than ideas. The big leveler in the evolution of the Canadian oil sands will be directly linked to project execution ability. That will be the key in our way of thinking.
Investor Al Gore and other environmentalists have strongly criticized oil-sands development for the level of carbon dioxide emissions. What impact are they having?
Molyneaux Certainly emissions in their broadest definitions are causing sources of capital to rethink how they're exposed worldwide to energy. Whether it's upstream, transportation, refining and marketing, to the absolute end-users, we need to do a lot more science on these issues. I'm not a believer in CO_2 being the boogey man.

In other environmental areas, ethanol for example, is it really the saving grace, or is there more than meets the eye? Are other emissions more important than CO_2? We have come a long way in the last decade, but there remain many, many environmental challenges ahead.
Investor And all solutions come at a cost.
Molyneaux That is for sure. We think the costs will be considerably higher than most energy consumers perceive currently.
Investor Do you expect to see any shifts in M&A action?

See **THE BIG PICTURE** on pg. 24

Challenges Make Junior E&Ps Stronger

How the juniors react to adversity can set them apart from their peers.

BY PETER KNAPP, BRYAN MILLS IRADESSO CORP.

I'm fortunate to get to work closely with the executives of numerous Canadian junior oil and gas companies. Although these companies appear to have many similarities, especially to the outsider, it's some of their differences that I find most interesting. These differences become apparent when companies are faced with adversity, as the sector was last year.

In 2006, their challenges included volatile natural gas prices, high costs for oilfield services, shortages of experienced management and technical staff, and the removal of the option to create an income trust as an exit strategy. These challenges led to waning investor interest and lower stock prices for the group.

For the 83 publicly traded juniors with production between 500 and 15,000 barrels of oil equivalent per day, the average stock price declined 14% in 2006 and a further 14% in the first quarter of 2007. In comparison to their peak stock prices achieved in spring 2006, many juniors dropped by 50% or more before starting to move back up this past April.

The accompanying table shows the five biggest junior oil and gas share price increases and decreases for 2006, along with subsequent performance during the first quarter of 2007.

Because the average junior oil and gas company has a life span between two and four years, the past year was the first time many of them faced a declining market. Experienced management teams that held key positions during the low oil-price cycle of 1998 or the low natural-gas-price cycle of 2002 maintained an advantage if they could apply the lessons they had learned. Meanwhile, many management teams are stronger now than they were a year ago, based on the adage that whatever doesn't kill you makes you stronger.

Commodity price volatility is one of the trickiest external factors for junior oil and gas companies to manage. The direction oil and gas prices are heading has a major impact on investor interest in the sector. Also, the economics of oil and gas projects can swing all over the place depending on the revenue expectations at different prices.

The current pricing environment is robust in relative comparison to oil and gas prices of the past 10 years. However, both commodities have dropped significantly from highs reached in 2005 and 2006. Meanwhile, the Canadian dollar continues to be strong against the U.S. dollar, translating to lower relative Canadian pricing than in the past. The market tends to pay more attention to the direction of commodity prices, not to the actual price itself. Concern is legitimate for exploration and development drilling plans that were developed during

JUNIORS SHARE PRICE CHANGES—TOP 5 BEST AND WORST PERFORMERS

Company	2006 share price change	Q1 2007 share price change
Culane Energy Corp.	547%	-2%
Bulldog Resources Inc.	228%	2%
Questerre Energy Corp.	135%	2%
RSX Energy Inc.	85%	-17%
Alberta Clipper Energy Inc.	57%	-28%
Cinch Energy Corp.	-63%	15%
C1 Energy Ltd.	-65%	-62%
Caribou Resources Corp.	-69%	-79%
Berens Energy Ltd.	-69%	-6%
Flagship Energy Inc.	-75%	-65%

the highs, which may no longer provide the same potential return on investment.

REACTING TO PRICE CHANGES

The manner in which a junior chooses to deal with commodity price fluctuations, particularly weaknesses, can set it apart from its peers. During the past year, many companies made a conscious effort to change their production weighting to oil or gas. With the latter prices dropping comparably more than oil prices did, many companies shifted their focus to oil, where they can bring in comparably more revenue.

However, some companies saw this as an opportunity to acquire out-of-favor gas production. There are still companies focused entirely on oil, those that are completely natural gas and everything in between. The median junior went from having 69% gas production in first-quarter 2006 to having 66% gas production in the fourth quarter of the same year.

Other ways juniors reacted to lower gas prices were to focus efforts on higher-margin properties and move lower-margin properties to the backburner for future development. Some companies were in a position to take advantage of lower prices by acquiring a financially weak company with attractive oil and gas assets.

Other juniors insisted on steering clear of debt or maintaining low debt levels in relation to cash flow, so they have a lot of leeway in the case of continually falling commodity prices. Only three of 83 juniors finished 2006 with a net cash position. These companies were Tusk Energy Corp. (TSK-TSX), Bulldog Resources Inc. (BD-TSX) and Culane Energy Corp. (CLN-TSXV).

Because of lower commodity prices, certain companies had to swallow a balance sheet write-down for their year-end reserves. Write-downs can often spell disaster for investors and can cause problems for lenders who have provided funds based on the previously recorded value of reserves. However, once a company has done a write-down, it can take advantage of the associated losses to reduce or eliminate taxes. It is often a matter of finishing the write-down.

With some relative price stability since the beginning of 2007, companies are finding it possible to move forward once again and are gaining more traction in terms of attracting investor interest and making money from oil and gas activities.

In 2006, drilling and service rigs were in such high demand that prices for these services rose and became a challenge for many juniors. Fortunately, this issue has since been resolved, with supply and demand being at a better balance whereby rigs are now available and costs have dropped.

Companies adjusted their commodity production mix, focused on projects with the best margins and held off on certain projects where the economics became problematic. Juniors only drilled their best prospects and waited on others. Other creative solutions were to acquire or build their own drilling rigs, negotiate in association with peer companies and negotiate long-term rig contracts.

The frenzied Canadian oil and gas sector in 2006 gave some companies the motivation to look internationally for opportunities where they would not need to compete for services and resources as much as in Canada.

Some juniors also dealt with a shortage of experienced management and technical people to fill out their teams. Some were forced to be creative in terms of offering an attractive work environment to employees, along with high compensation, bonuses and incentive plans. Alternatively, some chose to make do with fewer people rather than overpaying new additions to the team.

JUNIORS RESPOND TO TRUST WOES

The fate of juniors and energy income trusts is intertwined. On October 31, 2006, the Canadian government announced tax changes that would mean existing income trusts would only be able to operate with favorable tax treatment of their distributions until the year 2011; and no new income trusts would be taxed favorably.

At the time of this surprise announcement, many investors jumped ship from their energy trust investments, assuming they were better off with smaller positions. Any juniors planning a conversion to a trust were stopped in their tracks.

Investors in the junior sector also wondered how this change would influence juniors, with many opting not to stick around long enough to find out.

But now, perceptions may have changed. Many energy trust unit prices are back up to the levels they were around the time of the October announcement. Trusts are still acquiring juniors, albeit at a slower pace. One of the latest such deals occurred when Provident Energy Trust offered $508 million in cash for all of the shares of Capitol Energy Resources—showing there can still be an attractive exit for successful juniors and their investors.

Whether junior acquisitions are still happening, investors can take confidence in the fact that the Canadian junior sector was alive and well long before income trusts became a prominent factor during the past five years. It isn't difficult for juniors to fall back on the same strategies for growth and exit used before the trusts became such eager buyers of the juniors.

As a result of the change to trust taxation, the juniors are now more focused on longer-term planning instead of looking for a quick takeover. This is a positive development as it means there will be more healthy companies that are independently successful.

The continually changing junior oil and gas sector has successfully navigated significant challenges during the past year. The next year will also present challenges, but the sector seems better prepared for them and upside potential is strong from where the sector now stands.

Peter Knapp is president of Bryan Mills Iradesso Corp., a Calgary and Toronto-based research, investor relations and corporate communications firm.

Service-Company Returns

An analysis shows that U.S. service companies have higher systemic risk than Canadian firms.

BY SAMIR KAYANDE, ROSS SMITH ENERGY GROUP

Service-company pricing is competitive information and not easy to find in the public domain. However, examination is possible of the reaction of service-company valuations to changes in oil and gas prices as a proxy for their returns. In Canada, research shows that service-company returns have lagged those of producers. Meanwhile, in the U.S., service-company returns have beaten those of producers.

It is reasonable to hypothesize that service-company stock valuations depend on three factors: the price of oil, the price of gas and the excess return of the broad market index. To test this hypothesis for Canadian and U.S. energy-service companies, a regression model was built with the excess log percentage change of the relevant energy-services index during a four-week period as the dependent variable. The log percentage change of the spot West Texas Intermediate price, spot gas price and excess broad-market index (e.g. the S&P 500) were independent variables. In this case, "excess change" is the change of the index less the return on a risk-free Treasury security.

Regression Coefficients

Coefficients are significant unless otherwise indicated.

	ln Change (Spot Gas)	ln Change (Spot Crude Oil)	ln Change (Market Index)	R^2
RSEG Canadian Energy Service Index	0.170	Not Significant	0.858	0.44
S&P Energy Equipment and Service Index	0.118	0.293	0.994	0.41

Note: The market index for Canadian service companies is the S&P/TSX Composite. The market index for U.S. service companies is the S&P 500.
Source: Bloomberg, Federal Reserve, Bank of Canada, RSEG

Three key observations surfaced. First, the RSEG Canadian Services Index does not depend on spot crude oil changes. This is a surprising result, especially when contrasted with the strong crude oil dependence of the S&P Energy Equipment & Service Index. Oil drilling accounted for similar percentages of all wells drilled in both countries, so the difference is likely related to the more international and offshore U.S. service sector.

Secondly, Canadian service companies are more affected by changes in gas prices than U.S. service companies. This makes sense if Canadian service-company prices are independent of crude oil: gas-price dependence has to take up the slack.

U.S. companies have a higher association with the S&P 500 Index than Canadian companies' association with the S&P/TSX Composite Index. This implies that U.S. service companies have higher systemic risk, or market betas. The more diversified, international U.S. service companies trade more like higher-beta industrials than like lower-beta energy companies.

INDICES, METHODOLOGY

The S&P Energy Equipment & Service Index consisted during the study period of Baker Hughes, BJ Services, Core Labs, Diamond Offshore, Ensco, Haliburton, Helmerich & Payne, Nabors, Noble Drilling, Pride International, Rowan Cos., Schlumberger and Tidewater. Since 2002, its performance has exceeded that of the S&P Energy Index and the S&P 500.

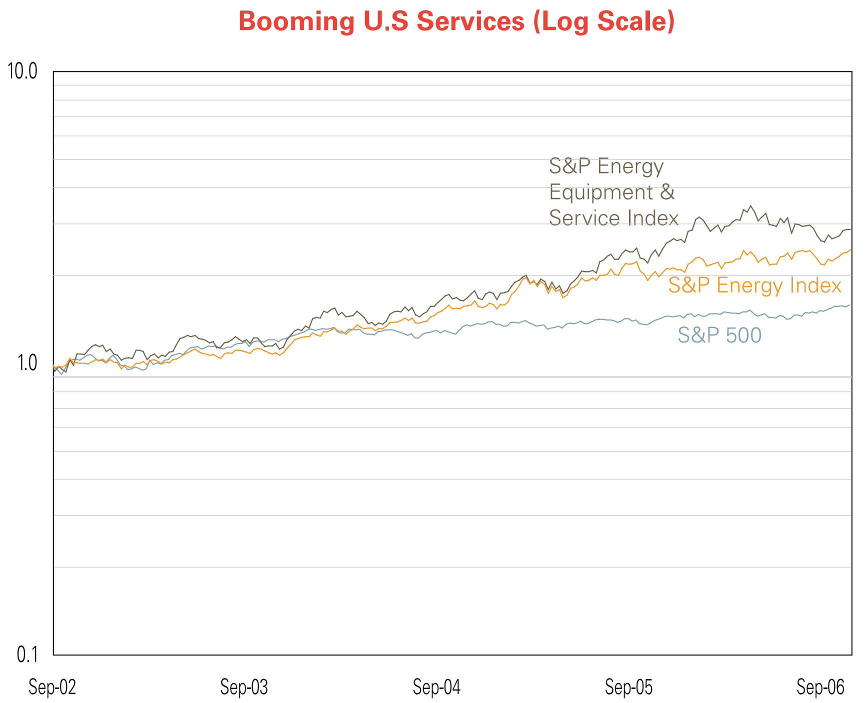
Ross Smith Energy Group created the RSEG Canadian Energy Service Index because the TSX, formerly known as the Toronto Stock Exchange, does not publish an energy-services index. The RSEG index includes service companies in the S&P/TSX Composite: Calfrac, CCS Income Trust, CHC Helicopter, Enerflex, Ensign, Pason, Precision Drilling, Shawcor, Tesco, Trican and Trinidad.

Since 1998, total return for the RSEG index has exceeded that of the S&P/TSX Composite Index, but lagged the S&P/TSX Energy Index. This is unusual, because capex escalation whipsawed producers in 2006. Presumably, much of this escalation should have ended up in the pockets of the service companies and increased their stock values. While Canadian service companies did enjoy pricing power, energy companies still posted better returns.

An RSEG peer group of independent oil and gas producers increased capital expenditures by 42% in 2006. This has increased finding and development (F&D) costs for the peer group. In 2005, by contrast, historically high reserve replacements industry-wide drove a surprising drop in F&D costs in Canada and the U.S., according to Energy Information Administration and other data.

Last year's capex increase stemmed from two related factors: high commodity prices increased the incentive to explore and develop, and the increased activity led to escalated costs in the service sector.

Looking ahead, cost escalation will certainly be a factor in 2007, though to what degree is uncertain. In Canada, the giant oil-sands labor vortex should provide support for



Note: Comparison begins September 2002 because that is the first avaliable date for the S&P Energy Index.
Source: Bloomberg

service-sector costs regardless of the activity level in the rest of the industry. In the U.S., cost-containment measures and increased capacity in the cyclical drilling sector could mitigate cost escalation to a greater extent.

Industry-wide figures for capital expenditures and reserve additions in 2006 won't be known until year-end 2007. However, scenarios for cost escalation and reserve replacement in 2006 were evaluated to estimate industry-wide F&D costs.

There would have been downward price-related reserve revisions in 2006, but these would have been offset by organic additions. Because net reserve additions are unknown, a sensitivity analysis was performed to determine a range of potential 2006 F&D cost outcomes. Capex increases were varied between 30% and 70%, while reserve replacement was varied from 80% to 150%. In the rosiest scenario—30% capex escalation and 150% reserve replacement—2006 F&D costs still exceeded 2005 costs by 27%.

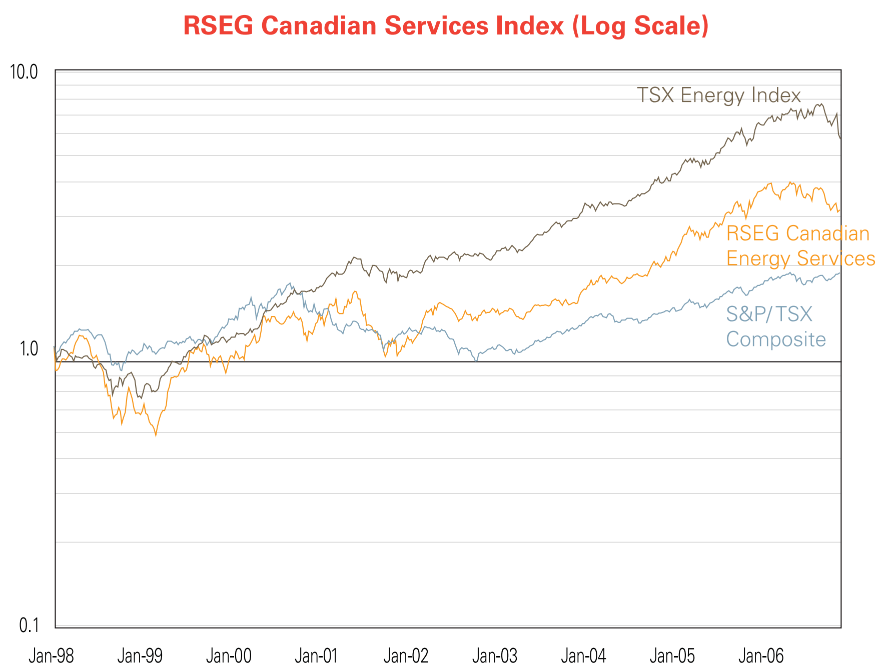
Oil-sands operations were excluded from F&D costs in the analysis because the business model is quite different. Higher initial capital costs are amortized over 40 years or more for oil-sands projects, meaning their lower capex per barrel of added reserves cannot be compared with conventional costs of additions. As some of the barrels are produced 40 years in the future, their present value is reduced to nearly nothing.

With 2006 scenarios looking unpromising, 2007 is shaping up to be a challenging year. F&D costs will likely be at historically high levels, even if capex is held flat at 2006 levels and reserves are added at a breakneck pace as in 2005.

While the reserve-additions side of F&D cannot be easily forecast, the capital-cost side is easier to predict. Costs are up, but Canadian service companies have not reaped the benefits of pricing power to the same extent that producers have reaped the benefits of higher oil prices: after all, service companies are facing higher costs, too.

U.S. service companies, more international and diversified, have performed better than U.S. energy companies, but our analysis shows they also have more systemic risk.

Samir Kayande is analytics manager, Energy Investment Handbook, for Calgary-based independent energy-research firm Ross Smith Energy Group. This report is an excerpt from a larger work he wrote on the topic.



Source: Bloomberg, RSEG

HEAVY OIL ECONOMICS, continued from pg. 12

"The industry is trying to manage its costs better by deferring and to manage engineering by more definition with greater modularization and preplanning to make sure they are as efficient as possible," says Tom Ebbern, Tristone Capital's managing director, institutional research.

Despite all this, the volume of projects coming during the next year is impressive, and there's no question the sector will experience significant growth. Husky Energy has its Tucker steam-assisted gravity drainage project; EnCana's Foster Creek is building on its production; and Nexen-Opti's Long Lake project should be steaming and bitumen production should start to flow slowly over the next few months prior to the upgrader starting up.

An increase in heavy-oil production coincides with a significant rise in synthetic crude. Many U.S. refineries are reconfiguring to take a heavier and higher sulfur-content crude. The lag in the equation is the downstream side where higher costs are delaying projects

"It's not how fast you can develop the heavy-oil resource, but how fast you can build the refinery and the pipeline to accompany the oil," says Ebbern.

Companies building a new green-field facility face the most challenges. Adding incrementally to an existing facility is an easier proposition, but not as cost-effective as in the past. The problem is no longer made-in-Alberta, as costs are a global issue.

"We've had excess capacity for 20 years now. Every incremental barrel coming into the market requires downstream infrastructure," notes Ebbern.

Consequently, companies are looking for third-party solutions to upgrading, either in Alberta or the U.S. EnCana has established its $15-billion partnership with ConocoPhillips, in which EnCana operates the upstream production and ConocoPhillips the downstream refining. In early May 2007, Husky scooped up Valero Energy's Ohio refinery, with a refining capacity of 165,000 barrels per day, for $1.9 billion. Marathon Corp. and BP have billion-dollar plans to adapt their refineries to add Canadian bitumen.

"Oil-sands projects have such investment momentum they have to go forward," says CAPP's Stringham. "But this is probably the highest level of uncertainty I've seen in the industry since prices went low in 2002."

Still, Friesen wrote in a research report: "In spite of the challenges of the current environment, we conclude that double-digit rates of return on long-life projects with no production decline should be viewed as attractive from both an investment and strategic perspective."

As Tertzakian says, "Companies need backbone." So do investors. "Look for good assets and good sophisticated management," he adds. "Costs are still a big issue, though for now, they don't appear to be rocketing out of control."

Analysts advise those who like investing in oil-sands plays to stick with the larger, more established players who know how to run the business and understand the pots and pans of extraction and production.

The dreamers, and there are many, will be weeded out with the complexities, including cost increases. The risk of small oil-sands players is simple: do they have the expertise and the track record?

In 2002, the marginal costs of getting the oil sands were justified at $27 per barrel of oil. Now, Tertzakian notes, the price must be above $50 a barrel, before "anyone gets excited about the oil sands."

The industry is nervous. It needs to find a quiet balance between energy security, affordability and the environment. That will be some time coming even though the markets demand the oil, and security of supply is still a vital concern.

THE BIG PICTURE, continued from pg. 17

Molyneaux That's a very interesting question. Accessing debt capital has never been so easy for energy players. No question there is tons of money around to do these types of transactions. But if you talk to any of the major energy players, they would clearly rather do sizeable property acquisitions than corporate deals. To do large corporate deals is challenging, especially from a people point of view. Clearly, with energy players in overdrive currently, to take their eye off their main business to undertake a material corporate transaction has to be compelling in the extreme. Combining organizations into a new highly competitive enterprise is very, very challenging.

Investor You've consistently said that one plus one must equal three to make it a go.

Molyneaux In the current economic climate, that's far from easy to do. Clearly there are lots of financial incentives to do M&A transactions. Really, the key question is: are the equity markets properly valuing assets or are they trading at a discount? In our view, energy equities are, in general, trading at a discount.

Investor What is your biggest concern in future M&A activity?

Molyneaux In our view, it's the people assets or intellectual assets. It's interesting that the value of your intellectual assets does not appear on any balance sheet.

If you are going to buy another enterprise, front and center questions for any acquirer are these: can I retain all the people, and how long will it take for the combined organizations to perform efficiently as one? Everyone realizes that retaining people is critical. In our view, the human resources departments have been under-appreciated, and they are a critical part of business and will be even more so in the future.

You want the best people doing the most value accretive work in your organization every day.

For example, why is EnCana building a brand-new building in Calgary and putting everyone in one location? They have realized that to have their people spread over a number of different buildings is not optimal from a per-share value creation point of view. Today the world of energy is all about people.