CANADIAN ENERGY INVESTMENT OPPORTUNITIES

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JUNE 2005

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FASTER THAN A SPEEDING PUCK

The pace of drilling for oil and gas and of energy financing activity in Canada's oil patch resembles watching a high-stakes hockey playoff. And it's just as exciting. At press time, the Canadian rig count was 287, a five-year high.

The good news? Oil and gas production appears to be increasing. Gas production from the Western Canadian Sedimentary Basin is already running about 200 million cubic feet per day ahead of last year's pace.

The Canadian Association of Petroleum Producers (CAPP) estimates that 23,000 wells will be drilled this year, another high-water mark. More than 22,000 wells were drilled in western Canada last year, with 16,000 of them targeting natural gas.

Likewise, the outlook for Canada's economy is favorable. The Bank of Canada estimates Maple Leaf economic growth of 2.5% this year and 3.25% in 2006.

In the oil patch, investors are enjoying some of the best returns of recent years due to rising commodity prices, greater production and a good stock market for E&P companies and trusts. A group of 18 integrateds and large-cap producers showed an average return of 22% in the first quarter, according to FirstEnergy Capital Corp. The investment-banking firm's universe of 12 mid-cap E&P companies posted average returns of 20%. The small-cap sector of 31 E&P firms reported returns of 17%, with standout Petrobank Energy & Resources Ltd. posting 66%.

Alberta marks its 100th anniversary this year. The oil and gas industry has played a major role in the province's economic development—and it will for years to come. Already, the province exports much of its oil and gas to the U.S. In the future, its heavy-oil output will be important as both the U.S. and Canada seek stable supplies not at risk from geopolitical events.

This special report brings you up to date on trends in Canada and shines a spotlight on the opportunities within conventional oil and gas plays, coalbed methane, royalty trusts and other aspects of the Maple Leaf oil patch.

—Leslie Haines
Editor-in-Chief

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A CENTURY OF GROWTH AND ENERGY

Alberta's centennial legacy is its monumental leap from Canadian backwater to an international powerhouse fueled by energy.

ARTICLE BY SYDNEY SHARPE

Alberta's energy industry is a heavy driver of Canadian growth. One-third, or C$7.7 billion, of Alberta's total revenue in 2003-04 was derived from energy-related sources, as did more than half of its C$66 billion in total exports. The province's multibillion-dollar surpluses pave a debt-free province whose social and economic expansion directly affects those beyond its borders.

"Over the past decade, Alberta's economy has consistently had the highest rate of growth in Canada," Alberta Premier Ralph Klein told a Harvard University audience in March. "The province leads the nation in job creation and employment. Alberta's salaries are the highest and its taxes are the lowest in Canada."

Klein added that Alberta produces 1.7 million barrels of crude oil and 5 trillion cubic feet of gas a year.

"Most of this production winds up in the U.S. Alberta provides 8% of the crude oil and 12% of the natural gas used in the United States," noted Klein. "Alberta's production is increasing and will continue to increase for the foreseeable future."

The amount of drilling planned is truly stunning, with 24,500 to 25,000 wells forecast for 2005, including 2,000 to 3,000 coalbed-methane wells. The contrast with the 1980s and 1990s is extreme, even though those were hardly dormant decades. About 5,000 to 7,000 wells were drilled annually and the industry celebrated a record high of 11,000—less than half the current total.

Early bitumen production in the 1930s near Fort McMurray. *(Photo courtesy of Canadian Association of Petroleum Producers)*

"Everything is running on all eight cylinders," says Wilf Gobert, the venerable analyst and vice chairman of Calgary-based investment-banker Peters & Co. "Oil prices are at a record high and production is growing."

Even as traditional oil and gas development explodes, industry players are racing to develop the world's most environmentally friendly and cost-effective technologies as well. Albertan companies are known around the world for their technological innovation, and they are expected to continue their impressive track record. The eco-energy companies will become the big winners in the sweepstakes to cut greenhouse gas emissions from carbon dioxide while increasing production.

Precision Drilling is targeting gas near Brooks, Alberta. *(Photo by Lowell Georgia)*

For a province roughly the size of Texas, but with a population of only 3 million people, these are heady times. The oil patch is awash in cash for expansion and production, with much of that investment going into oil extraction from the heavy-oil sands near Fort McMurray, as well as other non-conventional production such as coalbed-methane gas.

But it was conventional oil and gas that gave Alberta its energy start.

EARLY DAYS

The province was known to be a petroleum haven, based on stories of First Nations and early explorers who spotted the oil-sands outcrops in the northeast as well as the oil seeps in the southwest. As for natural gas, there were legendary vents running along the North Saskatchewan River east of Edmonton, and beside the mountain streams west of Turner Valley.

On May 14, 1914, the Dingman #1 hit wet natural gas just east of Calgary near Turner Valley. William S. Heron and his partner, Arthur W. Dingman, made the initial discovery. Their company, Calgary Petroleum Products, was also financed by Sen. James Lougheed and R.B. Bennett, who later became the prime minister of Canada. The find spawned a packed field of speculators, as more than 500 companies sprouted virtually overnight.

By 1917, that number had dwindled to 17. The First World War was raging and financial interest had dissipated. By 1921, Calgary Petroleum Products was forced to sell its Turner Valley gas-processing plant to Standard Oil's Canadian company, Imperial Oil, and its subsidiary, Royalite Ltd. The plant operated until 1985 and then became a provincial and national historic site.

The Turner Valley area again ignited excitement with a massive gas strike made by Royalite on October 14, 1924. Royalite had a pipeline to Calgary consumers, but other producers simply burned their waste gas in large flare pits, dubbed "hell's half-acre." The horizon lit up for hundreds of miles and damning articles appeared in publications from New York to London. Up to 90% of the entire field's resource was wantonly destroyed.

Only a few kilometers south of the original strike, Robert A. Brown rode an oil wildcat into a petroleum paradise. In 1936, his Turner Valley Royalties #1 found oil under all that gas, truly launching the

petroleum boom. Desperate for oil during World War II, the Canadian government pushed the Turner Valley Field into doubling its production.

"During 1942, the field produced 10 million barrels of oil—more than 27,000 barrels of oil per day. Total wartime production for the field accounted for 95% of total Canadian output," wrote Peter McKenzie-Brown, Gordon Jaremko and David Finch in *The Great Oil Age*.

As production at Turner Valley started to wane, Leduc leapt into the energy forefront. On February 13, 1947, Vern "Dry-Hole" Hunter decisively deep-sixed his nickname with an oil discovery. Imperial Oil had drilled 133 successive dry holes. Almost ready to cap its Leduc #1 well, Hunter's crew decided to push a further five feet—and drilled straight into the Canadian history books.

The gusher proved to be a 200-million-barrel discovery that propelled Alberta into the modern petroleum era.

On May 10, just three kilometers southwest of the original well, the Leduc #2 dove 100 feet further into the rock and tapped the rich petroleum juices of the Devonian reef formation. Alberta had cemented its spot as the prime Canadian source for oil and natural gas.

Soon international producers were spudding wells all over central Alberta with each of these finds proving more than 90 million barrels of oil reserves: Redwater in 1948; Golden Spike in 1949; and Wizard Lake, Fenn Big Valley and Bonnie Glen in 1951. Then, in 1953, the discovery of Pembina Field outdid them all.

The quarry was oil, but producers continued to snare natural gas even though prices and markets were elusive. They announced a string of major gas discoveries at Pincher Creek in 1948; Cessford in 1950; and Bindloss, Hussar, Minnehik, Duck Lake, Nevis and Olds in 1952.

The southeastern city of Medicine Hat was proclaimed to have all hell for a basement by none other than Rudyard Kipling, the great British writer who toured the area in 1907. A generation earlier, in 1883, men working for the Canadian Pacific Railway discovered that giant field of natural gas instead of water, which was what they really wanted and needed.

BUILDING PIPELINES

Petroleum was abundant but getting product to market was another matter. A massive underground highway of pipes carrying liquids needed to be built and mega-projects were the only way to do it. In November 1949, Interprovincial Pipeline Ltd., now Enbridge Inc., broke ground just east of Edmonton and its 1,800-kilometer trek began.

In December 1950, the first oil reached Superior, Wisconsin. The oil line ran to Sarnia, Ontario, in 1953 and on to Toronto in 1957, making it the world's longest pipeline. By 1976, all 3,680 kilometers stretched to Montreal. Today, Enbridge, headquartered in Calgary, operates 13,500 kilometers of pipeline, the longest system of its kind in the world.

Building a natural gas pipeline system from Alberta to eastern Canada and the U.S. fueled the great federal pipeline debate of 1956, which led to the demise of Prime Minister Louis St. Laurent's Liberal government a year later. The nationalistic debate focused on securing supply for Canadian customers first.

The TransCanada Pipe Line Co. eventually laid 3,500 kilometers of pipe east from the Alberta-Saskatchewan border to Toronto and Montreal. On October 27, 1958, Alberta gas finally flowed to Toronto. TransCanada, based in Calgary, boasts a 23,186-kilometer system that remains one of the largest natural gas carriers on the continent. TransCanada also controls the former Alberta Gas Trunk Line, created by the Alberta government to keep provincial gas and pipelines under its control.

Even though Alberta became a province in 1905, it still didn't receive ownership of its

Five pipelines converge here at the Alberta border, one of the largest centers of gas compression in North America. (Photo by Lowell Georgia)

own natural resources until 1930. That federal failure was a fateful precursor to Ottowa's imposition of the 1980 National Energy Program, which ultimately deprived the Alberta government of more than C$100 billion of royalty taxes (in today's dollars).

A third important pipeline developed in the 1950s also met with federal anger and a demand for a minimum five-year supply reserve. Undeterred, Frank McMahon built the appropriately named Westcoast Transmission Co., which carried Alberta gas to the Pacific Coast markets of British Columbia and the U.S.

All three pipelines opened markets and ensured the continuing development of the industry in Alberta. Yet the oil patch in the 1950s and 1960s was largely run by Canadian subsidiaries of foreign conglomerates. The "Big Four," as they were known, were Gulf Oil based in Pittsburgh, Imperial/Exxon from New Jersey, Texaco in New York and Royal Dutch/Shell from Europe.

A Canadian Foothills drill site. (Photo courtesy of Schlumberger)

Premier Ernest Manning's Social Credit government created the Alberta Gas Trunk Line in 1954 as a public-private partnership to transport natural gas within the province and to maintain prices and supply. It was led by Bob Blair, who eventually took the company into exploration and production as well as transportation.

Another Alberta-based company, Dome Petroleum, led by the formidable Jack Gallagher and Robert Wright, moved from a small start-up to take on frontier exploration in the Beaufort Sea. The federal government was financing frontier wells that even 30 years later were still not economic. Frontier development was another step in the federal plan to ensure energy control, security of supply and energy development on federal territory outside of provincial control. It was the same mentality that led to the pipeline imbroglio.

"In the end, it was proven that you couldn't afford to build a pipeline unless you had the U.S. market. You needed that to justify the size of pipe you put in the ground," says Gobert.

THE ISSUE OF CONTROL

The push for Canadian control of the industry dominated the 1950s, 1960s and 1970s. When Premier Peter Lougheed (grandson of James Lougheed) and his Progressive Conservatives won power in Alberta in August 1971, they wanted a better distribution of revenue from the energy companies and the federal government. Liberal Prime Minister Pierre Trudeau insisted on federal control and implemented the National Energy Program in 1980. The aftershocks reverberate in Alberta today.

In the 1970s and 1980s, when the OPEC cartel held sway over prices and supply, there was a national crisis over oil and gas that caused Ottawa to launch the National Energy Program. The NEP of 1980 had two key policy goals: to help Canada become self-sufficient, and to exploit oil and gas on federal lands, thus reducing provincial control.

After 1983, Conservative Prime Minister Brian Mulroney started to slowly dissolve the NEP through gas deregulation. He also ratified the North American Free Trade Agreement that led to the freer flow of oil and natural gas to American markets. While this was a significant watershed for the industry, it came just as world oil prices were plummeting.

"For the Alberta oil patch, however, deregulation unleashed a huge excess of gas reserves that the industry had been forced to stockpile," recalls Gobert. "We had over 30 years of supply in the late 1970s and early 1980s. To drill a well that was going to supply gas in 25 years was uneconomic."

Again, in the early 1990s, the oil patch was severely challenged with low energy prices and the departure or downsizing of the large majors. Conditions were ripe, however, for Alberta entrepreneurs to raise capital and start new E&P companies, the juniors. During the next decade, they would grow through mergers and the drillbit, or be taken over.

The most successful of the early starters is senior producer Canadian Natural Resources Ltd. In 1989, it was a nine-person company producing 1,400 barrels of oil equivalent (BOE) daily and capitalized at C$1 million. Today, Canadian Natural boasts 2,000 employees, produces more than 510,000 BOE daily and has an enterprise value of C$13 billion.

Other stalwarts of the Alberta oil patch were created when international producers left Canada. Talisman Energy Inc. was fashioned from BP Canada Inc. in 1992 and today has an enterprise value of C$15 billion. Nexen Inc. changed its name from Canadian Occidental Petroleum Ltd. in 2002. It ended its 30-year tie with Los Angeles-based Occidental Petroleum, which initially owned 80% of its stock. Nexen now has an enterprise value of C$8 billion.

In April 2002, Calgary-based EnCana Corp. became North

America's largest independent oil and gas producer, dramatically capping an unusual journey from its original status as a government-created midsize producer. It was known as Alberta Energy Co. and had been formed by Premier Lougheed's government in 1975 with an offering of 50% of its stock to the Alberta public. AEC, as it was known, was given the right to explore the gas-rich Suffield Block north of Medicine Hat in southeast Alberta, as well as a piece of the early oil-sands development.

The company eventually became fully public and in early 2002, it merged with Pan-Canadian Energy Corp. to form EnCana Corp., with an enterprise value of about US$34 billion. EnCana still drills hundreds of shallow gas wells every year at Suffield.

TODAY'S TRENDS

There are two important trends in the Alberta oil patch today: investment in oil sands and royalty trusts. The oil sands, with reserves second only to those of Saudi Arabia, began development in 1967 with investment from Great Canadian Oil Sands, now part of Suncor Energy. In 1978, a public-private partnership of producers as well as federal and provincial governments formed Syncrude Canada Ltd.

Today these companies, along with several others, produce more than 1 million barrels of oil a day from the oil sands near Fort McMurray.

The royalty trust form of company continues to grow in popularity and receive a majority of the energy capital raised in Canada. In April 2004, senior oil and gas producer Penn West Petroleum Ltd. underscored the trend by turning itself into a C$5-billion energy trust.

Analyst Martin King of investment-banker FirstEnergy Capital Corp. believes many more companies, especially juniors, will take this route. As their tax pools run down and they face larger taxes, "many more trusts will be formed to transfer the tax burden," he says.

The Toronto Globe and Mail's Dave Ebner calls Penn West's conversion "broadly reflective of the graying of Canada's oil patch, which was once a Wild West of ambitious exploration back in the days of Jack Gallagher and Dome Petroleum."

Yet there's still plenty of potential waiting to be tapped for the producer with tenacity, instinct and luck. In December 2004, Shell Canada proclaimed a massive discovery of 800 billion cubic feet of gas near Rocky Mountain House in west-central Alberta.

"New technology that allows scientists to see features that may have previously gone unnoticed is credited with the discovery," Shell reports.

Brian Prokop, an analyst with Peters & Co., points to higher natural gas prices coupled with lower costs as well as better technology.

"There is a lot more drilling for smaller accumulations, so there will be more chased and found. The technology for extracting difficult gas out of tight-gas reservoirs has advanced significantly," Prokop adds.

That's why it's difficult to estimate the amount of recoverable natural gas reserves left in Alberta. Gas that was considered completely uneconomic five years ago is seriously in the game. Conventional estimates, notes Prokop, are likely underestimating the overall remaining recoverable reserves.

That said, estimates today range from 54- to 84 trillion cubic feet and beyond. Unconventional natural gas from coalbed methane and other sources could contain between 200- and 500 trillion.

Alberta analysts expect prices to remain high. For 2005, Peters & Co. forecast gas prices to average US$6 per million Btu and to stay there in 2006. FirstEnergy Capital dramatically upped its gas price forecast for 2005 to US$7 per million, rising to US$7.50 for 2006.

"At this stage, we are treating our forecast to be a conservative view of the potential for natural gas prices in the next two to three years," writes King at FirstEnergy.

The firm's forecast for West Texas Intermediate oil is US$50 per barrel as is Peters & Co.'s. They differ for the longer-term outlook; however, as FirstEnergy expects US$52 per barrel in 2006 while Peters expects US$40.

All of this bodes well for Alberta's future. The estimated reserves of recoverable conventional oil are 4 billion barrels. As for non-conventional, the oil-sands story, with up to 174 billion barrels of recoverable oil, has only just begun.

Sydney Sharpe is a former energy journalist for the Calgary Herald, and a best-selling Canadian author working on her fifth book. She writes frequently about politics, energy and history.

CANADIAN JUNIORS

Last year, there were 82 publicly traded Canadian juniors, all but one based in Calgary, making for a rich stew of opportunity and deal-making.

ARTICLE BY PETER D. KNAPP

Building a junior oil and gas company in western Canada is harder than it looks. Despite historically high commodity prices, thousands of emerging explorers and producers will never even make it to the point where they would be considered juniors.

To break into the junior ranks, it takes the right combination of leadership, access to capital, technical skills and timing. Junior companies that combine these traits have a formula for success that has the potential to reward investors with hefty returns.

From 2003 to 2004, the number of publicly traded western Canadian juniors—defined as oil and gas companies that produced between 500 and 15,000 barrels of oil equivalent (BOE) per day in the third quarter—expanded 21%. In 2004, there were 82 public juniors focused on western Canada, up from 68 a year earlier. All but one are headquartered in Calgary.

Most of Canada's juniors gain their initial public listing on the Toronto Venture Exchange (TSX Venture). Many eventually graduate to the Toronto Stock Exchange (TSX) once they meet certain criteria. Junior oil and gas companies have enjoyed a great deal of market attention during the past year as retail and institutional investors have been able to make substantial profits on the sector. The gains have been fed by sustained high commodity prices that are part of an overall industry cycle.

In addition, many juniors are following an apparent formula that prescribes a defined company life-cycle, one that has proven rewarding to many investors from start-up phase to eventual exit strategy.

The life-cycle of a Canadian junior can be a short and exciting ride. This is especially the case in the current climate when oil and gas prices are relatively high, the market is bullish on energy and the intermediate sector is dominated by royalty trusts that are hungry to acquire additional production and reserves, often by acquiring the juniors.

GETTING STARTED

The first stage of a junior's life-cycle begins by assembling an experienced management team with a healthy reputation, which helps it raise the funds to get the ball going. Many companies are initially privately financed. A large portion of these companies becomes publicly listed early on to gain access to more capital. When companies conduct subsequent financings, they want to dilute initial shareholders as little as possible. This means gaining market recognition early.

What can a start-up company do to distinguish itself? The simple solution is to find and produce hydrocarbons. This can be done by searching where no one else is looking, extracting known reserves using new technologies that improve margins, or reviving an area for production that others have forgotten. One example of a start-up junior that is undertaking all three methods to distinguish itself is WaveForm Energy (TSX Venture: WE.A, WE.B).

Originally formed as a limited partnership in late 2003, WaveForm got started by acquiring the exclusive Canadian license for a proprietary seismic data analysis technology developed in the U.S. and having a trademarked name: Event Resolution Imaging (ERI). Designed to more accurately find new drilling locations through existing seismic data, the technology offers potential for the company to capitalize on the success and shortcomings of others.

Led by president and chief executive Don Rae, who has an extensive background in horizontal drilling, WaveForm went public in December 2004 to finance its strategy of drilling horizontal oil wells into the Bakken Shale formation. The Bakken is an oil-bearing geological structure that stretches from North Dakota across the border into southern Saskatchewan, also a part of the Williston Basin.

Rae and his team reassessed the area and identified two more depths of Bakken shale to target. They've parked themselves right in the middle of the highest-pressure zone. WaveForm sees the Bakken as a potential resource play, meaning any success is repeatable on a relatively large scale.

For start-up juniors, potential is everything. It's the intrigue of a prospective triple-digit capital gain that draws an investor's attention. Juniors are ideal for those who don't mind doing their homework and taking some risk.

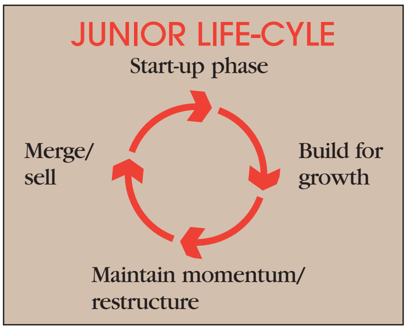
THE NEXT STEP

A start-up company can move into the next phase by establishing a solid base of production, and therefore cash flow, through drilling or acquisitions. Once this base has been built to support the company's overhead, the team must continue its search for innovative ways to grow larger and more profitable.

Sometimes creative measures are necessary to compete for production and reserves in the Western Canadian Sedimentary Basin. Many junior companies develop a niche where they can become experts, whether it is shallow-gas drilling in southern Alberta, enhanced oil recovery using waterflood techniques, coalbed-methane production, deep gas exploration or heavy-oil extraction.

Connacher Oil and Gas (TSX Venture: CLL) is one such company that has a base of production from which it is expanding, using a new focus. With conventional production of around 850 barrels of oil a day, the company is quietly establishing itself as one of very few juniors playing the Alberta oil-sands game.

Connacher recently added some financial clout with a positive cash position and a clear operating line of credit. Now president and CEO Dick Gusella is happily telling the story of how his company snuck in and accumulated 101 sections of prime oil-sands leases in an area dubbed the Great Divide, approximately 60 miles south of Fort McMurray.



Connacher plans to use steam-assisted gravity drainage to produce crude oil from the property. With a 10,000-barrel-per-day production rate anticipated for the first of several pods, this project has the potential to multiply Connacher's current production base by several times.

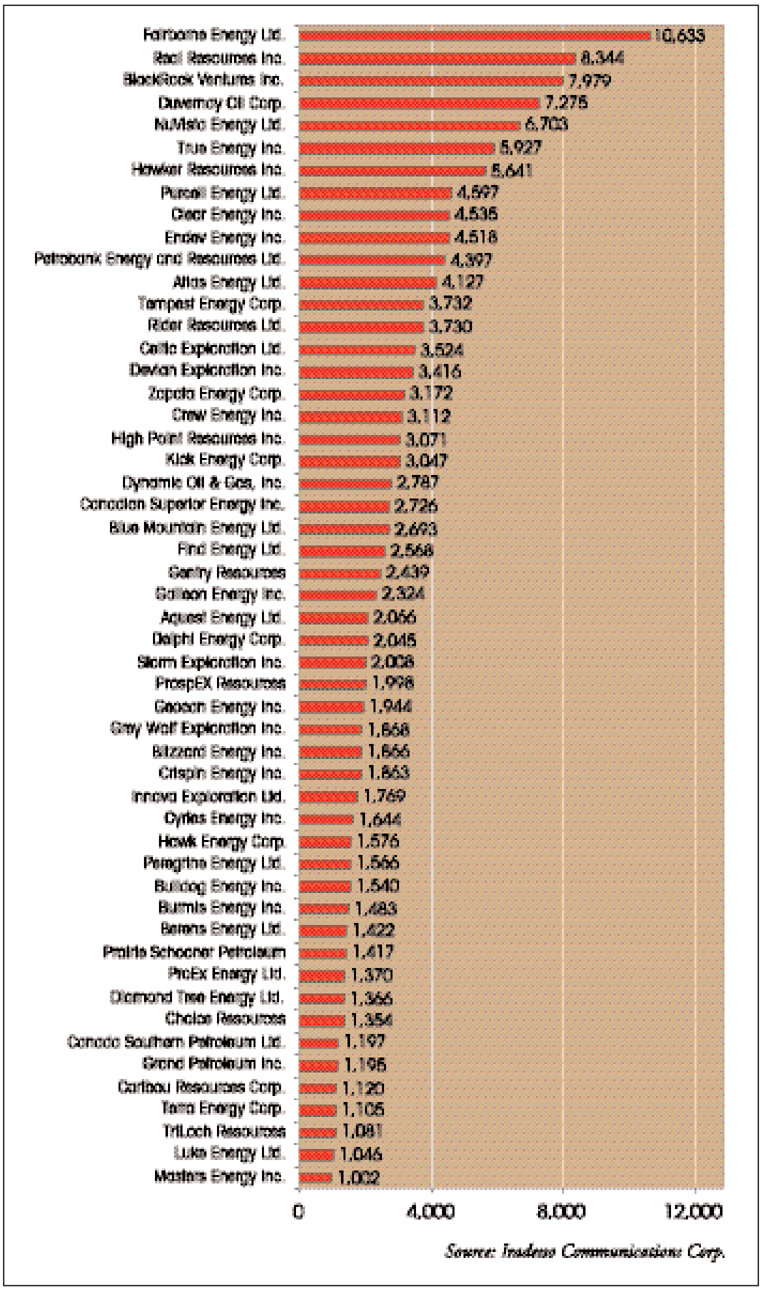
With its conventional production providing the cash flow to cover overhead, Connacher's next big step hinges on the success of the potential company-maker at Great Divide.

THE MATURE JUNIOR

Relying on one major success isn't enough to maintain a strong position in the market. Whether a company-maker comes in the form of an acquisition, an exceptional development-drilling program or a discovery, it is essential for a junior team to show it can turn success into a habit. If a company doesn't get acquired after a major success, it must find ways to maintain the momentum and grow.

For some, circumstances make this very difficult. In 1999, for example, Purcell Energy (TSX: PEL) found that elusive company-maker where no one else was looking, at Fort Liard in the Northwest Territories. Going in with a production base of approximately 1,000 barrels per day from other properties, Purcell's net production from Fort Liard alone ballooned to more than 4,000 barrels a day in 2001. This phenomenal growth made the company the toast of the junior oil and gas sector.

Fast forward to 2005. Now investors are asking, "What have you done for me lately?" Difficulties at Fort Liard during the past three years have sent the property's production down to less than 1,000 barrels a day net to Purcell. In the meantime, Purcell has been trying to follow up on its exploration success. Although it has been able to maintain production levels, the lack of growth made many shareholders impatient.



Canadian juniors' fourth quarter 2004 production (BOE/d).

Despite the headaches, president and CEO Jan Alston has remained persistent in pointing out that Fort Liard still has much untapped potential, while Purcell has gained the capability of also driving forward to gain production elsewhere.

Purcell was finally able to announce another large gas discovery this winter at Tenaka in northeast British Columbia. With the success in Tenaka, Purcell has righted itself and can once again boast strong potential moving forward.

Purcell is now in its 12th year of operations. This in itself is something of which to be proud, but the company is having trouble gaining market recognition in a sea of new juniors with short life expectancies. The market shows a preference for restructured, refinanced and rebranded companies.

THE RESTRUCTURING JUNIOR

Most successful juniors end their run within five years of inception. Some companies get acquired, leaving the management team to begin the cycle again, while others merge with peers and create larger, restructured entities.

If a board of directors thinks the time is right for a junior to be sold, it may simply entertain the most recent offer since there is constant communication between potential buyers and sellers in this sector. Alternatively, the board could decide to enter a formal process to "maximize shareholder value." This often means a third-party agent that specializes in mergers and acquisitions will try to solicit bids for the company while examining other options.

As of April 2005, Zapata Energy (TSX Venture: ZCO) was still in this process, originally announced in September 2004. Meanwhile, Rock Creek Resources (TSX Venture: RCR.A, RCR.B) announced such a process in April.

An alternative method whereby a management team can restart the cycle is through a merger or reorganization. Earlier this year, Argo Energy and Lightning Energy announced they would do both. The merger and subsequent reorganization produced Sequoia Oil and Gas Trust (TSX: SQE.UN) and White Fire Energy Ltd. (TSX: WF), both of which began trading in April 2005. Sequoia was created to be a growth-oriented trust with a diversified asset base and significant potential in the development of coalbed methane in central Alberta. As with most energy trusts, the business model is to provide unit-holders with sustainable distributions from cash flow by growing production and reserves on a per-unit basis.

Meanwhile, the former Argo and Lightning shareholders also gain an initial position in a new focused junior, White Fire Energy. The latter has established the Pembina Nisku exploration trend near Edmonton, Alberta, as its focal point. This play has attracted significant attention with the success of fellow junior Vaquero Energy coming almost completely from this area. Vaquero recently was sold to Highpine Oil and Gas (TSX: HPX) in a share deal valued at just under C$400 million.

Whether through a restructured company or a completely new entity, this is where the junior oil and gas company cycle begins again, with the hopes of making substantial returns the next time the cycle is completed.

Peter Knapp is president of Iradesso Communications Corp., a Calgary-based research, investor-relations and corporate-communications firm. The firm represents some of the companies mentioned in this article.

The Canadian Association of Petroleum Producers' (CAPP) annual Oil & Gas Investment Symposium takes place each June in Calgary, Alberta. It provides an unrivalled opportunity for institutional investors to meet senior management from Canada's leading oil and gas producers as well as the emerging companies that generate so much interest in the sector. Next year's event will take place over three days, June 12 to 14, 2006.

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ONE, TWO, THREE DAYS…

The invitation-only event expanded to a three-day format in 2005 to ensure that investors have the opportunity to see senior management from as many of the 85 participating oil and gas producers as possible.

CAPP launched a two-year overhaul of Symposium in 2004 that included the introduction of informal round table sessions for investors with integrated and senior producers as well as royalty trusts. Our biggest modification in 2005 was to devote two days to the fast-growing junior and emerging companies.

CAPP represents 150 companies that explore for, develop and produce more than 98 per cent of Canada's natural gas and crude oil. CAPP also has 125 associate member companies that provide a wide range of services that support the upstream oil and natural gas industry. Together, these members and associate members are an important part of a $75-billion-a-year national industry that affects the livelihoods of more than half a million Canadians.

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CAPP CANADIAN ASSOCIATION OF PETROLEUM PRODUCERS

GEARED UP FOR GROWTH

The world's third-largest natural gas producer and ninth-largest oil producer, Canada is growing upstream activity and output to record levels.

INTERVIEW BY BRIAN A. TOAL

While concerns abound in the U.S. about the tightness of North American natural gas supply and steep gas-production decline curves, Canadian operators have been increasing their drilling activity and daily output in the Western Canadian Sedimentary Basin (WCSB) to record levels.

If anything, Canada has become more of a safe harbor for the U.S. than ever before, in terms of addressing domestic energy-supply shortfalls. During 2004, more than 22,000 wells were drilled in western Canada, 16,000 of them for natural gas. The result: Canadian gas output climbed by 200- to 300 million cubic feet (MMcf) per day versus 2003, to a daily level of 17.4 billion cubic feet (Bcf).

The good news is that the benchmark level of drilling is expected to be eclipsed this year, as the number of wells spudded jumps to 23,000—16,500 of those targeting gas. Indeed, 2005 gas production out of western Canada already is 200 MMcf per day ahead of last year's pace.

Moreover, although the remaining gas-resource potential in Canada is estimated at 371 trillion cubic feet (Tcf), this includes 144 Tcf of proved gas reserves in the WCSB and 67 Tcf in the Mackenzie Delta. What is not included in this picture is an estimated 167 Tcf of unconventional resources such as from coalbed methane (CBM).

Meanwhile, as the U.S. wrestles with concerns about the certainty of crude supplies in uncertain geopolitical times, Canada is important as a reliable source of North American supply. Aside from its 4.9 billion barrels of conventional oil reserves, Canada also has 175 billion barrels of oil sands—a roughly 400-year supply at current production levels. Indeed, with its oil sands, Canada is second only to Saudi Arabia in global oil reserves.

Canada produces 2.7 million barrels of crude oil a day. When combined with refined products, Canada exports a total of 2.1 million barrels a day to U.S. markets. With oil-sands production surpassing 1 million barrels per day and expected to reach 2 million in 2015, Canada is one of few countries with growing oil production.

To find out more about Canada's current and future hydrocarbon supply picture and its plans for upstream activity, Oil and Gas Investor *recently sat down in Calgary with Pierre Alvarez, president of the Canadian Association of Petroleum Producers (CAPP).*

Three points he emphasizes are that Canadian oil production is ramping up, contrary to impressions; Canadian gas supplies have not peaked—there are abundant conventional and unconventional sources of gas remaining in Maple Leaf country; and upstream spending in Canada is on the rise.

Pierre Alvarez

Investor What is the 2005 Canadian drilling outlook?

Alvarez Drilling in Canada continues to set new record highs, with 2005 on track to surpass the benchmark established in 2004. One-quarter of the world's rigs are working in the WCSB with the majority of wells targeting natural gas.

In 2004, more than 22,000 wells were drilled (16,000 gas) in the WCSB. In 2005 the expectation is that 23,000 wells (16,500 gas) will be drilled, but seasonal weather in Canada, in particular "spring break-up," will always play a significant role in rig activity.

For comparison, Canadian producers drilled about 10,000 wells per year in the WCSB in the 1990s. Industry spending on conventional oil and gas is expected to hit a new record high of C$24 billion in 2005.

Investor What will drive growth in oil production this year?

Alvarez In 2004, Canada produced 2.6 million barrels of crude oil a day, an increase of 100,000 barrels from 2003 and is expected to reach 2 million by 2010 and 2.7 million by 2015.

In 2005, Canadian oil production is likely to average 2.7 million barrels per day. In addition to western Canada, crude oil from offshore Atlantic Canada will increase as the White Rose project (potentially 90,000 barrels per day) comes onstream later this year or in early 2006 to join current operations at Hibernia (203,000 barrels per day) and Terra Nova (110,000).

This makes Canada the world's ninth-largest oil producer, and with the vast oil-sands potential, poised to move quickly up this list.

Investor And growth in gas production?

Alvarez Canada produced 4 Bcf of gas per day in 2004—6.3

Tcf for the year, which was slightly higher than in 2003. Canada is the world's third-largest gas producer.

Daily production climbed by between 200- and 300 MMcf in 2004 over 2003, and already 2005 production is up about 400 million per day during the same period in 2004.

Investor Where is most of the gas drilling taking place?

Alvarez The largest number of gas wells (65%) is drilled in the shallow-gas regions of southeastern Alberta and southwestern Saskatchewan. Unconventional gas production is also taking off as CBM wells accounted for 13% of all wells licensed in Alberta from January through April of this year. Wells also are being drilled in the foothills on the eastern slopes of the Rocky Mountains in west-central and northwestern Alberta and northeastern British Columbia.

Foothills plays hold much deeper gas than traditional wells in the basin. Northeast British Columbia has produced a series of significant discoveries in recent years, and there was also a major gas discovery in central Alberta late last year. These successes ignited further exploration in these areas.

Canada exported 3.6 Tcf of gas to the U.S. in 2004. (Photo courtesy of Burlington Resources Canada Ltd.)

Investor Where is most of the oil drilling taking place?

Alvarez Crude oil production growth in Canada is focused on the oil sands where capital spending on both in-situ and mining projects will total close to C$8.5 billion in 2005. We are seeing technology advances in areas such as steam-assisted gravity drainage or cyclic-steam stimulation being applied in the oil sands and making the resource more economic. Technology is driving the increases in oil-sands production.

Investor Is CBM drilling a growing part of the picture?

Alvarez As conventional sources of gas mature and production stabilizes, producers in Canada are increasingly looking to unconventional gas—such as CBM, tight-sands and shale—to maintain and grow supply.

While there are wide ranges of this resource in place—as much as 500 Tcf or more—a reasonable estimate of 167 Tcf of CBM in Canada makes this resource just slightly smaller than the Potential Gas Committee's estimate of 169 Tcf of CBM in the U.S.

While CBM accounts for 10% of total gas production in the U.S., it is in its infancy in Canada, with production at 18 Bcf a year coming mostly from Alberta and British Columbia. Indications are that most of the CBM wells in Canada—particularly in Horseshoe Canyon coals—tend to generate less produced water than CBM wells in the U.S. Technology will play an integral role in determining how much of Canada's unconventional gas will be economically viable to develop.

Investor What about Canadian oil and gas exports?

Alvarez After meeting domestic energy needs, the U.S. is Canada's biggest export market, and, in turn, Canada is the largest single supplier of natural gas, crude oil and refined petroleum products to the U.S. Canada exports a little more than half of its crude oil and natural gas and virtually all of it goes to U.S. markets. Canada exported 1.6 million barrels per day of oil to the

U.S. in 2004 and 3.6 Tcf of gas. Those figures are likely to grow moderately in 2005.

Oil and gas account for 12.6% of all Canadian exports.

Investor What about export-pipeline projects?

Alvarez Producers and pipelines are studying a number of options to increase oil capacity out of western Canada to accommodate the increase in production from the oil sands. Beyond meeting Canada's needs, there is the potential to increase export to traditional markets such as the U.S. Midwest and California and move into new markets such as the U.S. Gulf Coast as well as Asian markets.

Key decisions need to be made in 2005 on new oil-pipeline capacity from the WCSB as it takes up to five years to approve and build new capacity.

Canadian producers and pipeline companies also are developing plans to transport natural gas from the Northwest Territories to tie into the North American pipeline grid. There is also potentially a significant portion of an Alaskan natural gas pipeline that would be built through Canada as it connects into the continental grid.

Investor What is the Canadian capex level?

Alvarez Total capital investment was C$31 billion in 2004 and is expected to rise to C$35 billion in 2005. Canadian producers are also significant players in the international field and will spend more than C$5 billion outside Canada. In all, Canadian companies produce more than 1 million barrels of oil equivalent outside of Canada.

Investor Will Canadian M&A activity continue to increase?

Alvarez It is continual and driven by a variety of factors, including cash flow, exploration success, consolidation in core areas, opportunities to reduce costs, etc.

Investor What is the future of Canadian royalty trusts?

Alvarez The oil and gas income trusts have taken an important role in the industry by tending to focus on extending the life of mature properties. They bring on additional production while opening opportunities for different kinds of investors.

Investor What is the biggest challenge facing the Canadian industry?

Alvarez The industry must compete for global investment-capital scale, and Canadian costs are rising relative to other areas of the world. Companies now must seek oil and gas pools that are more remote, deeper and geologically challenging; new, high-cost technologies are necessary to take advantage of these opportunities.

As well, with the record activity in both conventional and oil sands, the availability of well-educated and skilled labor that is fundamental to finding and developing Canada's resources is tight and will be stretched further in the next five years. Industry growth also means remaining competitive through increased investment in research and innovation.

Access to the resource base is also a major issue. There is significant effort by CAPP and its member companies to work with governments and regulators to eliminate overlap and duplication in the federal and provincial regulatory regimes to improve the certainty and timeliness of the processes.

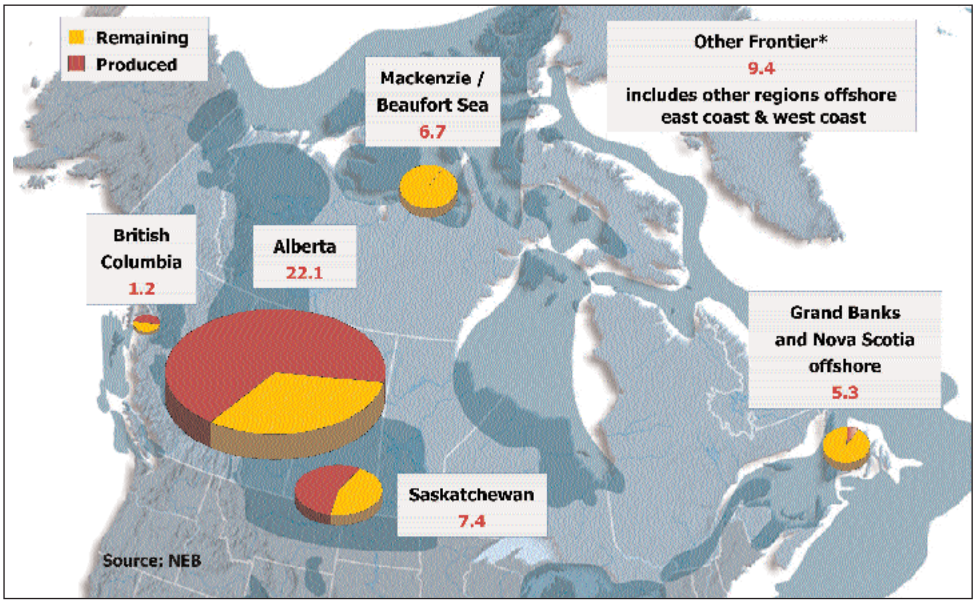
As an industry, we look for three policy priorities from governments—reasonable and timely access to resources, secure access to markets and economic competitiveness—to maintain a successful Canadian oil and gas industry. As always, we work cooperatively with government and stakeholders to meet the challenges.

Investor What should North American producers and investors understand about the Canadian oil and gas industry?

Alvarez One of the biggest misunderstandings is that Canadian gas supplies have peaked and are on their way down. The other false assumption is that oil-sands projects will use any new supply of natural gas that is being produced in northern Canada. In both cases, this is simply not true.

Canadian gas production is unlikely to double again, as it did during the 1990s, but nor is gas production declining. Spurred by high prices, producers are drilling at record rates and seeking out deeper, natural gas in the WCSB. Canadian companies are also looking to unconventional, promising sources of supply such as CBM and tight gas, and also continue to produce gas in non-traditional areas like northern and Atlantic Canada.

Oil-sands projects are, in fact, consuming less gas than in the past. And, as expected since higher gas prices equate to higher costs for oil sands, companies are constantly developing and implementing new technologies to reduce or eliminate use of natural gas.



Ultimate conventional oil resources in Canada in billions of barrels.

CBM 101

Coalbed-methane activity in Canada is set to grow rapidly as new drilling and completion techniques bear fruit.

ARTICLE BY JIM JARRELL and SAMIR KAYANDE

The province of Alberta has significant amounts of coal that contain methane. However, thickness and depth, coupled with production testing, have revealed that not all of the province's coalbed methane (CBM) has the potential to be commercial at this time.

Admittedly, it is still early in CBM development. Alberta's CBM production, now approximately 160 million cubic feet a day, accounts for a sliver of Western Canadian Sedimentary Basin (WCSB) gas production, which totals approximately 16 billion cubic feet (Bcf) a day. However, CBM has the potential to become a significantly larger part of the basin's production.

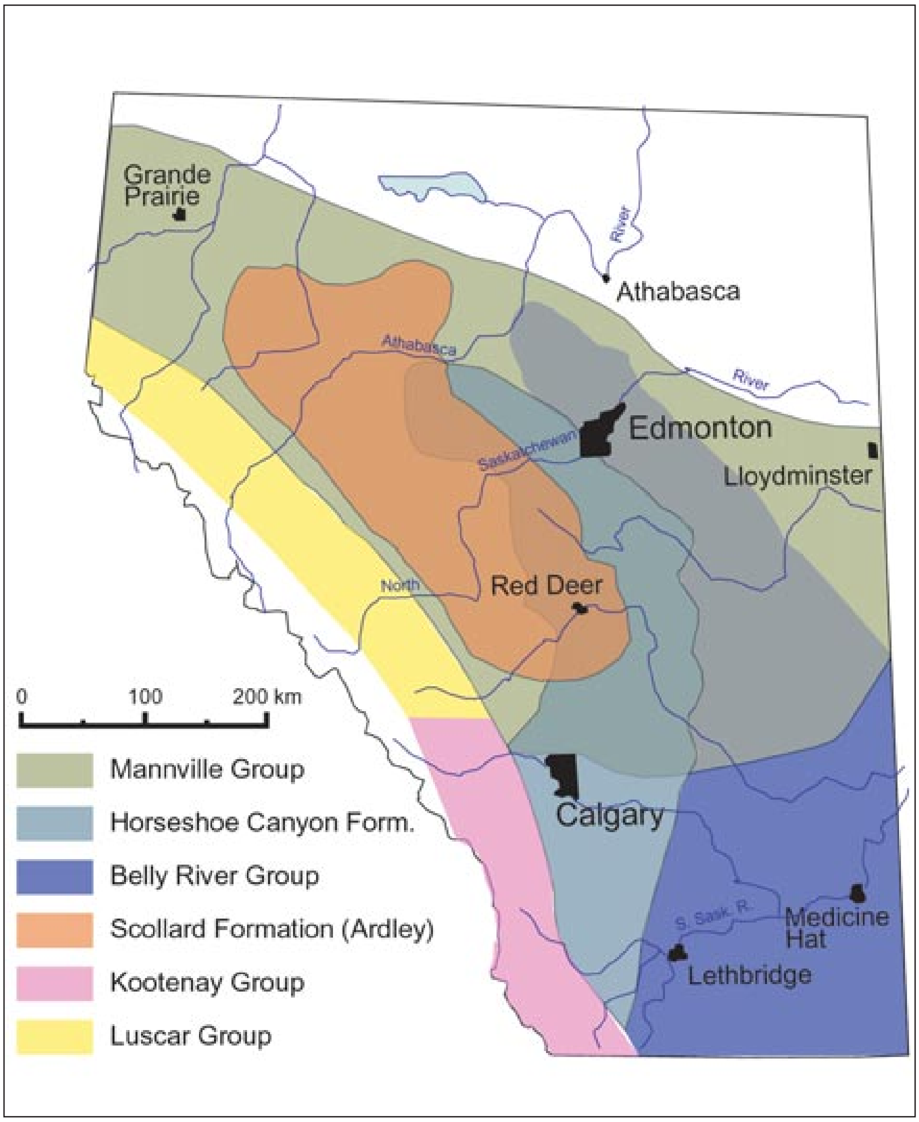
The coals in central Alberta dip from shallower in the east to deeper in the west. Ross Smith Energy Group believes some Horseshoe Canyon projects along the flanks of its fairway will generate lower returns due to lower gas rates. MGV Energy has drilled approximately 50% of all flank-area producing wells. The average daily initial production is about 90,000 cubic feet per well per day in the flank, versus 135,000 in the fairway.

Of the three main prospective CBM horizons—the Ardley, Horseshoe Canyon and Mannville—only the Horseshoe Canyon has been declared commercial. Ross Smith estimates development costs of C$0.66 per thousand cubic feet (Mcf) and about C$4,000 per flowing Mcf per day for current Horseshoe Canyon production.

Numerous pilot projects in the Mannville coal seams have yet to show commerciality. The Mannville is the deepest coal and offers the most significant resource potential of the three horizons. Recent successes with horizontal drilling may affect future development significantly.

Here's a look at the pros and cons of the three main coal targets in western Canada.

Ardley. As the shallowest formation, the Ardley coals contain the lowest gas content of the three. Testing to date has shown low and variable gas and water production rates. The produced water is potable, which has created concerns and opposition from communities, ranchers and regulators.



Alberta coalbed-methane distribution potential. (Source: EUB, Alberta Geological Society)

Predicting well performance has thus far been a challenge, as results vary not just between operators, but even within individual projects.

In response to these concerns, and the relatively low resource potential, most of the industry has stayed away from serious development of the Ardley. We expect this trend to continue.

Horseshoe Canyon. The Horseshoe Canyon coals of Alberta are unique because the coals produce gas with essentially no water production. All other documented CBM projects in North America have water production associated with at least the initial depressurizing/dewatering stage. Because of immediate gas production, and absence of water handling and disposal requirements, Horseshoe Canyon projects require significantly less capital and have significantly higher investment returns than conventional CBM projects.

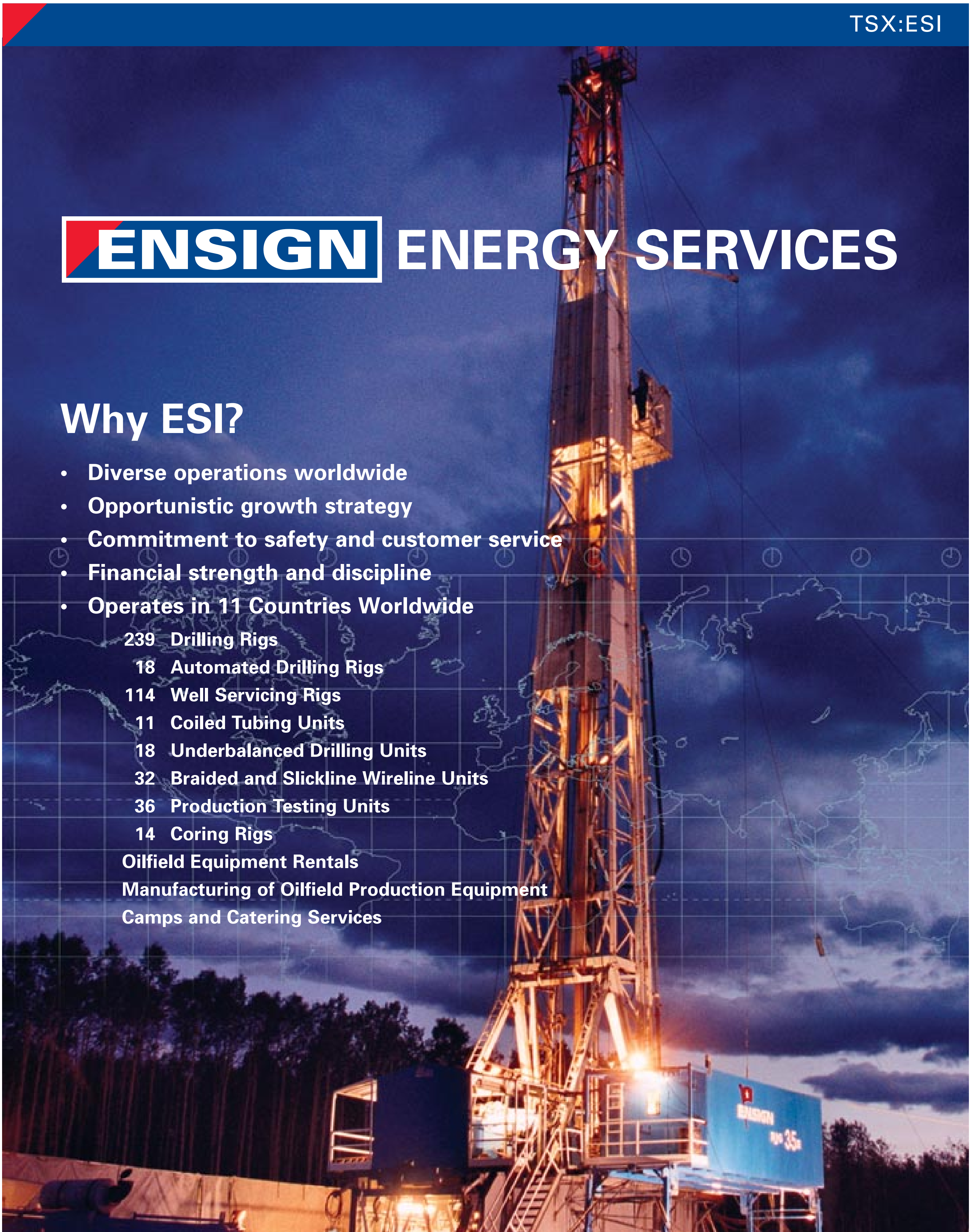
The Horseshoe Canyon coals consist of up to 30 seams, 0.1 to 1 meter in thickness, interspersed over several hundred vertical meters. As a result, new and innovative drilling and completion techniques have been developed specifically for this play. Operators commonly case and perforate each prospective seam, then stimulate with high-rate nitrogen injection.

The technology is becoming widely understood; consequently, many non-CBM players are getting into the Horseshoe Canyon game. The current average initial production rate from the Horseshoe Canyon is approximately 115,000 cubic feet of gas per day.

Mannville. The Mannville coals are more typical in that they have associated water production—similar to U.S. Rocky Mountain CBM plays. Unlike the Ardley, these deeper coals produce saline water which, according to Alberta Energy Utilities Board regulations, must be disposed of in an approved manner. In most cases, this means reinjection into deep underground formations and somewhat higher costs.

The vast majority of Mannville CBM wells drilled have been vertical. Numerous pilot projects, a few as large as 40 wells, are under way. Some have been on production for more than three years. Results have generally been poor as gas production has not climbed to economic rates during the dewatering phase.

One recent exception has been the horizontal well drilled by Talisman south of Edmonton, which is currently operated by CDX Canada. The well averaged 1.2 million cubic feet of gas per day for its first three months of production through the end of January 2005. Equally important, the well has produced an insignificant quantity of water during this period.



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Driving to Zero

CBM ECONOMICS*

	Horseshoe Canyon	Mannville (Vertical Wells)	Mannville (Horizontal Wells)
Development Capital Cost/Well*	C$290,000	C$500,000	C$2,500,000
Gross Production Estimate			
First Yr (Mcf/d)	87	34	1,000
Avg./First Three Yrs (Mcf/d)	75	70	500
Water (Bbl/d)	-	41	N/A
Gross Reserves/Well (MMcf)	438	500	2,000
Development Cost (C$/Mcf)*	C$0.66	C$1.00	C$1.25
3-Yr Cost of Addition (C$/Mcf/d)	C$3,867	C$7,143	C$5,000

* Excludes land acquisition and exploration costs. Notes: Gross production (before application of royalty interest) is shown.

Source: Ross Smith Energy Group

The industry has taken notice. Many operators—including Apache, APF, EnCana, MGV, Nexen, Talisman and Trident—have licensed wells, acquired land and otherwise made their intentions known to drill their own horizontal Mannville CBM wells in 2005. CDX's U.S. parent has a history of horizontal CBM development expertise. The question remains for the other operators: can they achieve similar results?

CURRENT STATUS

Ross Smith Energy Group's review indicates that almost 1,700 wells have been licensed and were producing CBM, largely from the Horseshoe Canyon, as of January 2005. The firm believes there are a number of additional producers originally licensed to deeper zones that have been recompleted and are producing CBM.

The CBM pioneers in Alberta were EnCana and its former joint-venture partner MGV Energy, a subsidiary of Dallas-based Quicksilver Resources. EnCana possesses the largest CBM land position in the province because of its ownership of heritage Canadian Pacific Railway rights. MGV received its foothold in the Horseshoe Canyon fairway through its partnership with EnCana and other joint ventures. EnCana plans to drill 1,000 net CBM wells in Alberta in 2005; MGV plans 275 net wells. Apache and Trident are also significant Horseshoe Canyon players.

Predicting well performance has been challenging, as results vary not just between operators, but even within individual projects. Among the many factors that cause low production per well, gas-gathering constraints are important. CBM gathering requires pipeline systems that operate at ultra-low pressures. Increased infrastructure investment likely will result in increased CBM well productivity.

As noted earlier, lack of commercial success in a number of vertical-well CBM pilot projects has led to horizontal drilling in the Mannville. However, thicker zones are required to justify the feasibility of the higher well costs.

Investors need to be mindful of risks surrounding rights ownership. Royalty ownership remains murky for so-called freehold lands (those lands for which the Alberta government does not own all of the mineral rights); specifically, for the subset of freehold for which the coal right and natural gas right are held by different parties (split title).

Two scenarios are possible. In one case, the Alberta government holds the coal right, and the natural gas right is freehold. In this case, the government will not demand an additional CBM royalty. Therefore, the producer will pay a royalty to the freehold natural gas right-holder only. This situation is simple.

In the other case, the coal right is freehold, and the natural gas right is either freehold or owned by the government. In this case, the natural gas right-holder will demand its royalty—the question is whether the coal right-holder will also demand a royalty for CBM production.

A CBM producer might find itself in the middle of a tug-of-war between the coal right-holder and the natural gas right-holder. This could be resolved in court based on the provenance of the rights ownership under each specific piece of land. The current uncertainty around this issue is likely holding up development of certain split-title lands.

Commercial results from the Horseshoe Canyon, plus the potential for horizontal Mannville drilling, lead us to expect continued growth of Alberta's CBM.

Jim Jarrell is president of Ross Smith Energy Group, an independent buyside research firm in Calgary. Samir Kayande is analytics manager for the firm's Energy Investment Handbook.

DIFFICULT QUESTIONS

Certain questions often emerge when Ross Smith Energy Group analyzes a new play. Investors gain by asking oil and gas company managers specific questions regarding their plans.

- How do you plan to tie in your CBM wells? How much will it cost and how long will it take?
- Why do you believe that your production per well is above/below average? Is this trend sustainable?
- What is your opinion of the performance of Mannville coals? Do you plan to drill horizontal wells to exploit the Mannville?
- Are you exposed to freehold coal owners' royalty claims?

SUNNY TIMES

Investors, bankers and E&P companies are making hay in Calgary.

ARTICLE BY LESLIE HAINES

These are heady times in Canada's oil patch. High oil and gas netbacks at the wellhead, a boom in drilling activity and well completions, and a surge in corporate financing of all types mark the past two years.

"Clearly the energy sector is providing superior returns to the overall Toronto Stock Exchange (TSX) Index," says Art Korpach, managing director and head of energy banking for CIBC World Markets in Calgary. "I think if you back the energy sector out, the TSX return would be flat or even negative, depending on the time frame you measure."

As in the U.S., more than enough capital is available to fund start-up companies, emerging juniors, new energy trusts and the mergers and acquisitions that will fuel growth for all. E&P initial public offerings are coming to market again after a drought.

Seven private-equity funds specializing in energy have recently closed or are in the process of closing this year, and have started to deploy dollars, according to Lane McKay, managing director for Cosco Capital Management LLC in Calgary.

"Underwriting is very competitive now, but people are maintaining their integrity. They are selective on the management teams they'll back and the deal structures they'll do," McKay says. "The smart ones wait until the right business plan comes along."

Since January 2005, Cosco has helped raise mezzanine capital for Action Energy in a C$40-million, follow-on placement, C$23 million in private equity for Bunker Energy Corp., and C$25 million of equity for Energy 51. All are early-stage, private E&P companies in Calgary.

"Five years ago there was little money available to the energy sector and now there is too much," says Wayne Deans, a partner in Deans Knight Capital Management Ltd., a Vancouver-based private-equity fund that typically takes a 5% to 10% stake in financings for private E&P companies. "There were fewer 'crazy' deals two years ago compared with some of the ones coming out of the woodwork now."

The firm has invested in 11 E&P and two oil-service firms through its first equity fund and a half-dozen in its second fund. It has broadened its scope to consider uranium, biomass and other energy ideas as well, Deans says.

Rapid growth through acquisitions and higher stock prices are commonplace in Calgary. In late 2003, Deans Knight invested in tiny West Energy Ltd., a blind pool start-up whose stock was about C$1 per share at the time. Now that company, which went public in 2004, is the second-largest player in the Pembina region's Nisku reef play and has a market cap approaching C$250 million.

PRIVATE CAPITAL SOURCES

Traditionally, start-up E&P firms have faced few roadblocks to getting financing or a public listing on one of the Canadian stock exchanges as a means of gaining capital. But during the past two or three years, private-capital sources have become more visible and more active in Canada, also doing deals to fund early-stage E&P companies.

According to Cosco Capital Management's Lane McKay in Calgary, there are three Maple Leaf private-equity fund managers with active funds that are out raising money today. Another four managers have so-called inactive funds—that is, funds that have closed and from which they are now gradually placing capital with E&P, service or alternative energy companies.

Here's a summary of some private-equity funds focused on energy.

- ARC Financial Corp. raised C$403 million in ARC Energy Venture Fund 4 in the summer of 2004. Contact Lauchlan Currie, (403) 292-0431.
- Kern Partners Ltd. has so far raised C$160 million on its way to a possible C$200 million at press time. Some capital has already been placed in E&P companies. Contact Pentti Karkkainen at (403) 517-1507 for more information.
- JOG Capital raised C$40 million in its second fund and is in the process of raising a third fund that may go as high as C$120 million. Contact Don Cowie at (403) 232-3307 for information. (JOG stands for junior oil and gas company, the target investment size of the fund.)
- Oleum West Capital Ltd. is in the process of raising its second fund, targeting C$75 million. Contact Darryl Rudichuck at (403) 294-9111 for more information.
- Canadian Energy Equities has raised C$20 million. Contact Clarence Chow at (403) 571-0692 for more information.
- Deans Knight Capital Management Ltd., Vancouver, is placing capital from two small funds that raised an aggregate C$45 million. Contact Wayne Deans or Craig Langdon, (604) 669-0212, for more information.
- Camcor Capital Inc. has raised C$100 million in its third private-equity fund, which is being invested this year. Contact Cameron McVeigh, (403) 508-2950, for more information.

Another investment, Highpine Oil & Gas Ltd., teamed with West Energy, and after a series of private financings for both companies, they made a C$100-million purchase at Pembina. Highpine went public in April 2005 in a C$72-million IPO.

No wonder energy is popular with retail and institutional Canadian investors. One new trend is that companies are starting to spin out specialized energy assets—coalbed methane (CBM), oil sands, unconventional gas—away from broader energy companies to form smaller, specialized E&P firms, Korpach says.

CIBC is the strategic advisor to Thunder Energy Inc., which along with Mustang Resources and Forte Resources, plans to combine assets and create these new public entities: an energy trust, two exploration companies and a pure-play CBM company.

"The theory is that you create better value by creating better structures. The market values the trust structure now and sees future development value in CBM companies," Korpach says. CIBC led the recent C$78-million IPO of Grey Wolf Exploration, which had been owned by Texas-based Abraxas Petroleum.

Private-equity players also are busy. Kern Partners Ltd. in Calgary has raised C$160 million so far for Kern Energy Partners Fund I. The target was C$150 million. The fund is still open because one limited partner may increase its commitment to the fund "and a couple other folks are still deliberating, before we formally close it. Our maximum is $200 million Canadian," says Pentti Karkkainen, a Kern partner.

A variety of North American institutions have contributed, 55% Canadian. This fund has the capacity to invest up to 25% of its capital outside Canada. It will target energy technology and services as well as conventional and unconventional E&P investments.

"Our sweet spot is C$10- to C$15 million in E&P, but if we see an opportunity to ultimately commit that amount later, we are OK taking a smaller amount initially, say C$5 million, and then moving up.

"There's lot of capital available, both public and private, so you have to be patient and disciplined," Karkkainen says. But deal-makers are moving fast in Canada today. Kern has already placed 20% of the fund "on things we worked on coincident with the closing."

Kern is the largest institutional shareholder in Gibraltar Exploration, started in November 2003 as a deep-basin gas exploration company. It also advised MEG Energy, a heavy-oil player, through three private-equity placements to raise C$275 million. Chinese oil firm CNOOC bought 16% of MEG's stock recently to get a toehold in Alberta's oil sands.

A NEW WAY TO GROW

Tristone Capital of Calgary has greatly expanded its capabilities through its recent merger with Petroleum Place of Denver. Through that deal, the full-service firm now offers, in both countries, M&A and strategic advisory, negotiated asset and corporate sales, and investment banking. The final piece of the puzzle is that it will bring the upstream-asset auction to Calgary later this year in live and Internet format.

Through its Houston subsidiary, The Oil & Gas Asset Clearinghouse, the firm hopes to repeat its U.S. auction success in Canada, helping buyers and sellers of undeveloped land and producing wells to achieve value.

The auction concept has matured in the U.S. marketplace and is no longer seen as a means of unloading "unwanted" assets with liabilities, says president Ken Olive, who formed the Clearinghouse more than a decade ago. In 2004, the firm sold US$320 million in eight auctions.

"The more telling statistic is that our sales are averaging US$40 million per auction," he says.

Some small producers that want to aggregate meaningful properties with upside attend the auctions almost monthly and have built good companies on that basis, he says. Sellers get better value more quickly through the auction format as well.

The average price per transaction has grown and this year, is averaging about US$306,000 per lot, up from US$179,000 per lot in 2003. A lot is any operating component, whether a single well, multiple wells, or a unit with hundreds of wells. The largest sale at auction was US$14.7 million for a Mississippi oil field.

A Burlington Resources drill site in Wapiti, Alberta. *(Photo courtesy of Burlington Resources Canada Ltd.)*

HEAVY-OIL POTENTIAL

Alberta is sitting on a world-class heavy-oil deposit that will be producing 2 million barrels a day by 2010.

ARTICLE BY SYDNEY SHARPE

When Alberta Premier Ralph Klein calls the oil sands the eighth wonder of the world, the nabobs in the local oil patch nod their agreement. The amount of recoverable oil is extraordinary, up to 174 billion barrels. The amount of investment is exceptional too, at C$97 billion. Both these numbers will almost certainly rise as the world's second-largest reserve of oil revs up its engines.

The oil sands in northern Alberta are home to the biggest field of petroleum on the planet. The Alberta Energy and Utilities Board calculates that the Athabasca region, in the Fort McMurray area, contains 1.3 trillion barrels of crude bitumen. To the east, the Cold Lake area has 201 billion barrels and, to its west, the Peace River Field has 129 billion barrels.

The Albertan oil sands represent 15% of the worlds proven reserves and could actually surpass those of first place Saudi Arabia—if producers are able to capture all of the oil spread throughout the gooey bitumen mass. The Canadian Energy Research Institute in Calgary estimates there are between 1.7- and 2.5 trillion barrels of heavy oil bonded into the sands.

Besides sand, the oil sands contain clay, water and between 11% and 12% bitumen, which must be separated from the sand, upgraded into synthetic oil and shipped to markets. About 80% of the oil sands are buried deep enough that it cannot be mined, but can only be recovered in-situ (in place). The most popular method injects steam through horizontal or vertical wells. The heat and pressure force the bitumen to separate from the sand, where it migrates to the wells and is pumped to the surface.

While steam-assisted gravity drainage (SAGD) and cyclic steam stimulationare the most common processes used to get at the deeper oil sands, other technologies are being tested. Burning bitumen rather than natural gas to produce steam to extract bitumen makes all kinds of economic sense.

Researchers are examining technology that reduces the amount of water used or replaces it entirely. They're also dedicated to minimizing the environmental impact of such massive projects.

The shallow Athabasca deposit holds reserves so close to the surface that they can be mined. Massive open-pit mines and hot-water separators are used to capture the molasses-like substance from the sands. For every barrel of synthetic crude oil produced, two tons of oil sand must be mined. To visit the Fort McMurray mines is to be taken into a labyrinth of colossal pits where trucks as tall as two-story buildings shuttle loads of bitumen back and forth.

"These are mining and upgrading operations that are as big as any in the world," Klein told a Harvard University conference in March. "They're made possible by technological advances that have surmounted incredible obstacles. The oil-sands operations have collectively been called the biggest engineering project in the world."

Suncor's Millennium Mine upgrader can process 225,000 barrels per day. (Photo by Lowell Georgia)

Syncrude's vast North Mine sprawls over hundreds of acres, where bitumen is mined. (Photo by Lowell Georgia)

Conventional Canadian oil reserves are dropping, and this puts the monumental potential of the oil sands in perspective. In 2003, the U.S. Department of Energy added reserves contained in oil sands to its Canadian estimate of total resources, boosting the number to 180 billion barrels from 4.9 billion barrels for the previous year.

"The production of crude oil from Alberta's oil sands has the potential to close the U.S. energy gap, meaning that the United States would never have to buy more offshore oil than it does today," explained Klein. "This is a strong statement to make, but it's true."

He added that the 2% yearly increase in consumption for the U.S. is the same as the forecast rise in production from the oil sands, or about 200,000 barrels a day.

Alberta's oil-sand operations currently produce 1 million barrels a day and that figure is expected to double during the next decade. Producers seem to be tripping all over each other to finance new projects.

Crucial to oil-sands development was the generic royalty tax regime launched by the provincial and federal governments in 1996, allowing companies to recover capital and operating costs first. This was a massive incentive for producers to increase their commitment through further investment.

"It was a watershed year in the expansion of oil-sands production," says veteran analyst Wilf Gobert, vice chairman of Calgary-based investment-banking firm Peters & Co. "As you expand with additional phases, the capital being spent could be deducted from the cash flow of the first-phase production. In 25 years we'll look back at the oil-sands development as a huge factor in the Canadian industry."

AMBITIOUS PLANS

The multibillion-dollar oil-sands extravaganza jump-started the year in February when Canadian Natural Resources Ltd. gave the go-ahead for its C$10.8-billion Horizon project north of Fort McMurray. Within weeks, Petro-Canada and UTS Energy Corp. announced their Fort Hills plans to the northeast that are expected to cost at least C$4- to C$5 billion. Suncor Energy Inc., which already produces synthetic crude from its nearby mine, formalized the regulatory filing for its Voyageur venture, likely to cost the same.

Athabasca Oil Sands Project, which is owned by Shell Canada Ltd., Western Oil Sands Inc. and ChevronTexaco Corp., could double its oil-sands production during the next decade with a C$17-billion investment. If this goes ahead, it will become the biggest oil-sands mega-project to date.

Many producers already have received provincial and federal regulatory approval and their expansions are well on their way to completion. On the mining/extraction side, they include Syncrude Canada Ltd.'s Stage 3 plans for C$7.8 billion and Alberta Oil Sands' Jackpine project for C$5.7 billion.

In-situ (steamflood) investments include Suncor's C$1-billion Firebag project; ConocoPhillips/Total/Devon's C$1.4-billion Surmont; Nexen/Opti's C$3.5-billion Long Lake; Canadian Natural's C$130-million Primrose Lake extension; and EnCana's C$400-million Christina Lake venture, as well as its projected C$1.24-billion Foster Creek project.

Synenco Energy Co. is designing a C$3.5-billion project using an innovative technology called asphaltene gasification, which turns asphalt into a synthetic gas and then burns it. It has, however, a few hurdles to overcome such as finding a partner and receiving regulatory approval.

Imperial Oil Ltd., a unit of ExxonMobil, is planning its C$5- to C$8-billion Kearl Lake endeavor. Meanwhile, Husky Energy Inc. is considering options for its entire oil-sands division, which includes the C$400-million Tucker Lake and the C$1.6-billion Sunrise thermal projects (formerly the Kearl in-situ project).

Global interest in oil sands seems unabated, with China National Offshore Oil Corp. coming onboard in April. It paid C$150 million for a 17% stake in MEG Energy Corp., a small oil-sands player.

The action is dramatic, considering that capturing the elusive bitumen has taken years of discovery and technical innovation. The oil sands were well known to the First Nations peoples, who used the gooey substance to caulk their canoes.

It wasn't until 1967, however, that the Great Canadian Oil Sands developed the Fort McMurray-based Athabasca oil-sands mega-project that is today part of Suncor Energy Ltd. The hot-water technology that converts the mined bitumen into synthetic crude had been discovered in the 1920s by Karl Clark of the Alberta Research Council.

In 1978, the federal and provincial governments joined a consortium of companies to form Syncrude Canada Ltd., becoming the second massive mining and upgrading venture in Fort McMurray.

ECONOMICS

The cost to develop the oil was not for the faint of heart. Today's lower per-barrel cost of between C$10 and C$15 owes its very profitability to those first producers who took the plunge.

Trying to peg a billion-dollar number to the amount of expansion and the projected flow by the end of the decade is a risky game. Most of the projections are based on crude oil averaging between US$20- and US$25 per barrel (West Texas Intermediate). With prices hovering between US$50 and US$55 WTI, the staggering amount of investment already announced will likely only increase.

"None of these numbers are set in stone, and there is no right number when it comes to estimated capital expenditures. The current amounts will likely rise, not fall, with the widening confidence in rising oil prices," says Gobert. "You can set the budget and then get in trouble. The good news is that reserves are so large that cost overruns haven't impaired the economics."

All these projects become profitable when WTI oil is at US$25 per barrel and Nymex natural gas is US$4 per million Btu, according to the Canadian Energy Research Institute and a study led by Gobert at Peters & Co.

The Peters study notes that the mining projects are far less vulnerable to natural gas prices, compared to in-situ SAGD projects, which use more energy.

Analyst Steven Paget of FirstEnergy Capital Corp. estimates that by 2010, the Albertan oil sands will produce 1.93 million barrels of oil per day. By 2015, that number is expected to rise to 2.68 million a day.

"It's the one place in the world where you can see over a million barrels a day of growth in the next decade, all in friendly Canada," adds Paget.

Paul Ziff, chief executive of consulting firm Ziff Energy Group, says that the region itself is a small community that can only absorb a finite amount of spending before it creates inflation.

"Every now and then you get a blowout in costs, which has been salvaged by high oil prices," he says.

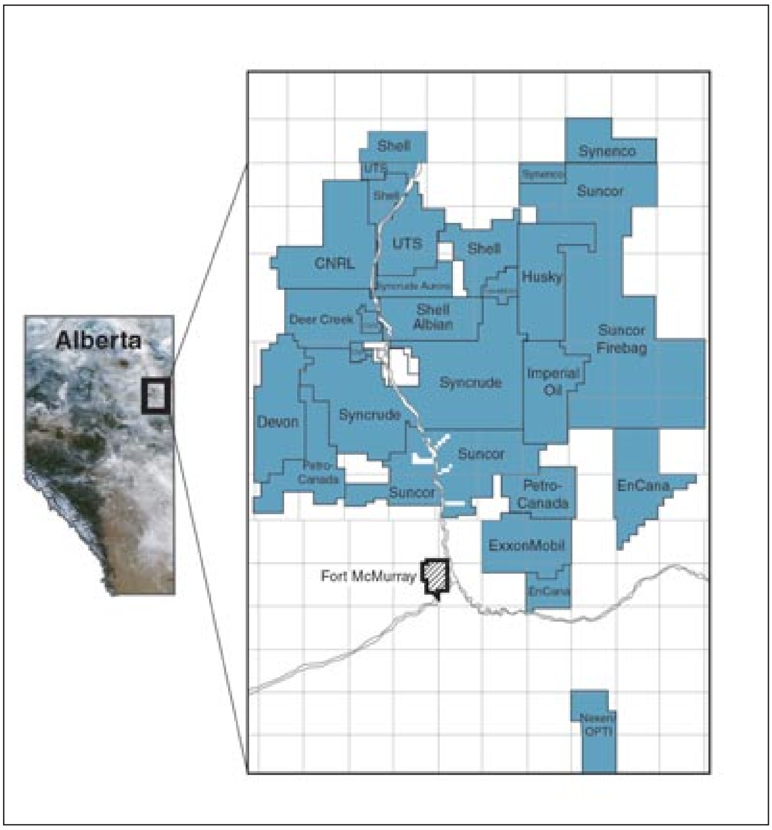
Ziff points out that the oil sands have become the favorite home for spending by virtually all the major producers in Canada, as well as the large independents and even some start-ups.

"The technology is accessible," notes Ziff. "Where there's a supply, people will find a way to open up markets. The long-term prognosis is more investment. The overview is that Canada is one of the very few areas in the Western world where production is increasing. That is highly unusual."

OIL-SANDS FACTS

- Total Albertan bitumen is about 1.6 trillion barrels in place, of which about 300 billion barrels are potentially recoverable under currently anticipated technology and economics.
- Of the 300 billion barrels, approximately 59 billion are shallow enough to be mined, leaving about 80% of the resource to be exploited using in-situ (steamflood) technologies.
- Western Canadian production of light, sweet synthetic crude oil (made by upgrading bitumen) is expected to reach 1 million barrels a day by 2010.
- Of this total, Canada will export 600,000 barrels a day by 2010.

Sources: Alberta Energy & Utilities Board, Purvin & Gertz



Oil-sands projects in northern Alberta. *(Source: FirstEnergy Capital Corp.)*

PRINCELY PERFORMANCE

Oil and gas royalty trusts continue to rule based on their returns. Many have altered their strategy, and are starting to consolidate and drill more wells.

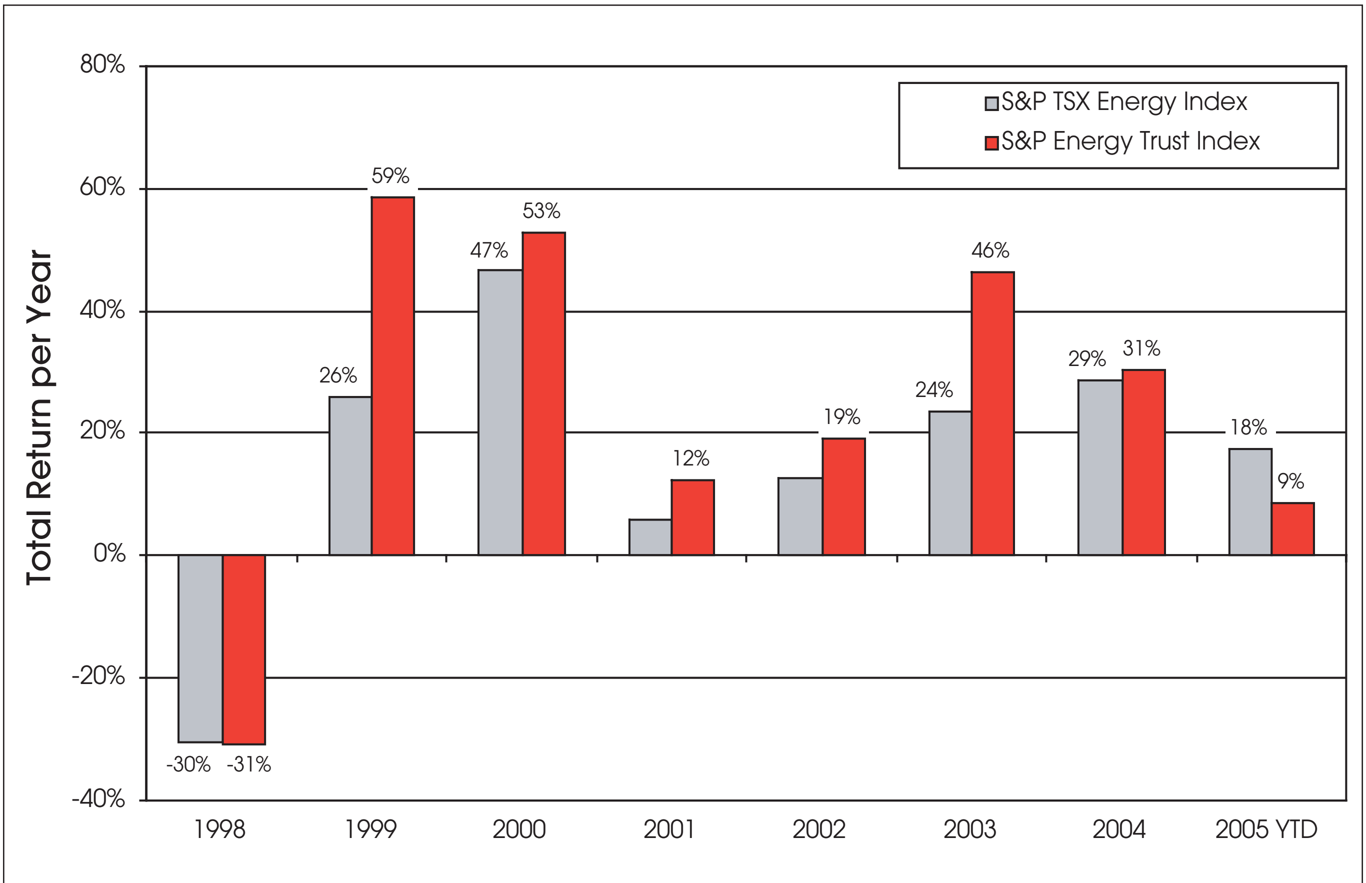
ARTICLE BY JILL T. ANGEVINE and WILLIAM J. LACEY

The Canadian energy trust sector has grown quite diverse, offering investors a wide range of choices in reserve-life index, asset quality and strategy among some 35 of these publicly traded trusts. The field of choice has grown, as in 2002 there were only 11 such trusts. In aggregate, the royalty or income energy trusts now produce close to 540,000 barrels of oil equivalent (BOE) per day, not counting oil-sands production.

The overall Canadian income trust market grew in 2004 to an aggregate market capitalization of about C$120 billion, with oil and gas trusts representing about 34% of that total.

The energy trusts that can provide continual increases in production and reserves per unit should stand strong among the group in terms of total return performance. The trusts followed by FirstEnergy Capital Corp. produced a total return of 9% for unit-holders in first-quarter 2005. The forecast is for continued strong returns for the group of approximately 15% during the next 12 months, but it is important to be selective in choosing an energy trust in which to invest.

One reason for the optimism? The FirstEnergy commodity-price deck is moving up, to US$52 in 2006 and US$54 in 2007 for West Texas Intermediate oil, and to



Until just recently, and for six years, the S&P Energy Trust Index has outperformed the S&P TSX Energy Index, although the two move up and down with fluctuating oil prices. *(Source: FirstEnergy Capital Corp. and Bloomberg)*

US$7.50 in 2006 and US$7.75 by 2007 for Nymex gas. Additionally, the trusts continue to attract strong management from the E&P sector, bringing capital discipline and a greater focus on internal prospect generation. Under the current FirstEnergy price deck, the market appears to be efficient, with the trusts trading at 108% of their net asset value.

To analyze the trusts, FirstEnergy used metrics similar to those it uses for reviewing E&P companies that the firm covers: finding, development and acquisition costs; cash-flow netbacks; and recycle ratios. These are key measures of a trust's sustainability. FirstEnergy views both debt-adjusted production per unit and debt-adjusted reserves per unit as key measures in comparing the trusts.

Bonavista Energy Trust and Peyto Energy Trust are FirstEnergy's top picks in the sector, with 10 other trusts rated Outperform.

TOP PERFORMERS

One reason the trust format is so popular with energy executives who form them, and with investors, is that the Energy Trust Index on the Toronto Stock Exchange (TSX) has outperformed the TSX Energy Index of E&P companies for the past six years. However, year to date, the TSX Energy Index takes first place over the Energy Trust Index with an 18% total return versus a 9% total return for the trust index.

Harvest, Peyto and Paramount have been the strong performers during the past 12 months, with both Harvest and Peyto returning a total of more than 70% to unit-holders. In first-quarter 2005, Harvest and Peyto performed just above the group average while Crescent Point, Baytex and Petrofund produced the top three returns, all above 15%. Bonterra, Pengrowth, Ketch and Advantage all showed negative total returns in the first quarter.

The net asset values (NAV) for each of the various trusts are ultimately a conservative representation of the value of producing assets, if management goes from being an active manager to effectively letting the production decline, with investors harvesting the cash flows generated from the producing assets. Though this is not necessarily representative of the value, since these businesses are actively managed, it does help to frame out the downside protection in value versus where the units are currently trading.

Based on FirstEnergy's 2004 year-end price scenario, the firm saw the trust group trading at an average 159% of NAV at the end of the first quarter of 2005. With the acceleration of commodity pricing during the past several months, the firm felt it was prudent to outline the premium for the trusts using a much higher price deck (2005 current scenario). Under this frame of reference, the premium being paid in the market is significantly compressed at just 8%, and 10 trusts were trading at or below NAV at the end of first-quarter 2005.

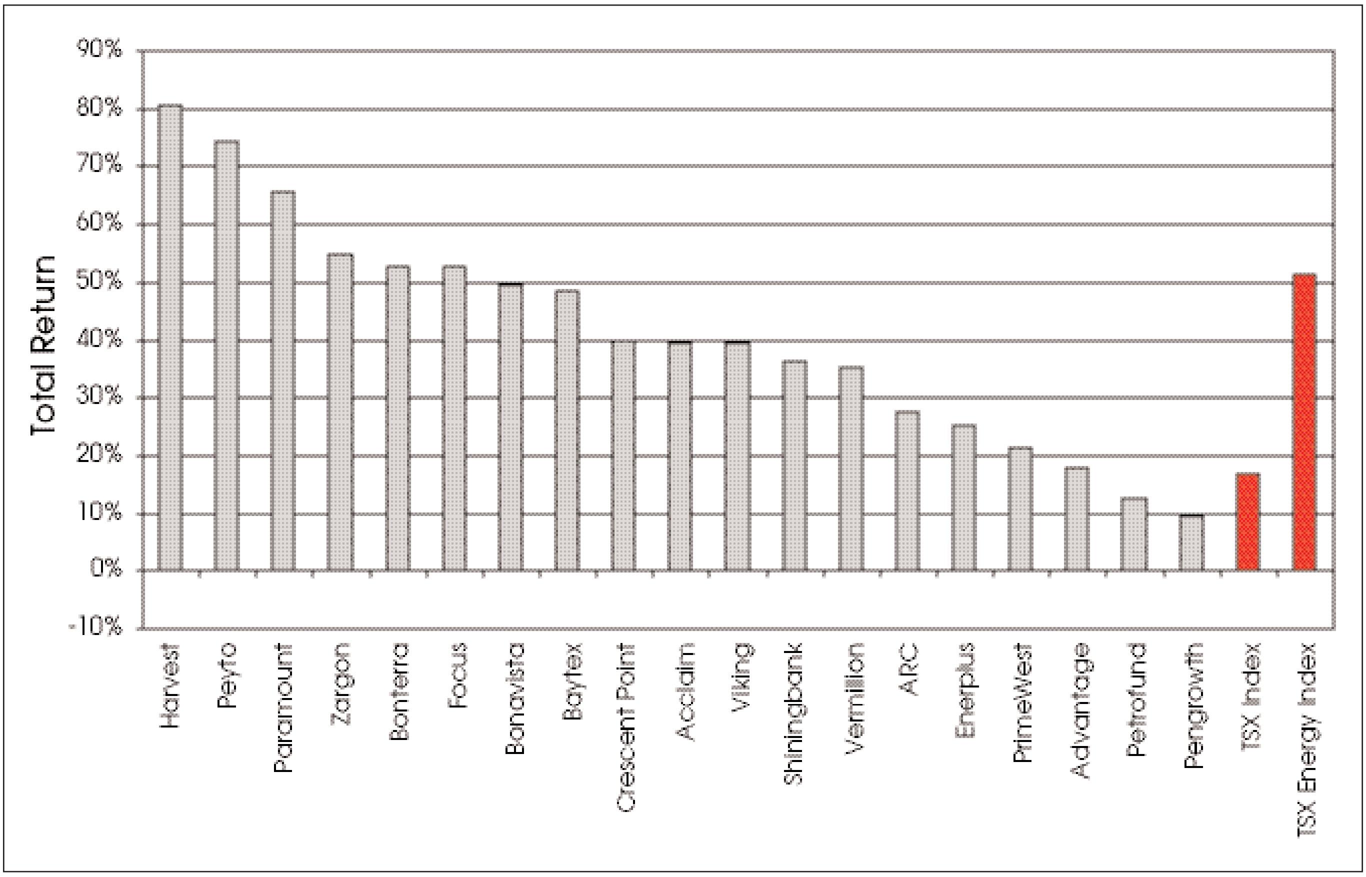
Despite some investors expressing trepidation regarding the valuations of the energy income trusts, the market has been efficient in its pricing of units. Looking forward, understanding which management teams can unlock longer-term, unit-holder value will be a key to providing better-than-average performance.

RESERVES PER UNIT

When looking at the trusts versus other equity investments in energy, the common criticism is the value creation equation that many believe to exist does not apply within the energy trusts. Two metrics FirstEnergy uses include debt-adjusted production per unit and debt-adjusted reserves per unit.

FirstEnergy compared the income trusts that have existed since year-end 2003 with the senior Canadian producers and the ability to add reserves per unit while taking changes in the broader capital structure into consideration. There is a natural tension between these two business models in that trusts are typically oriented toward lower-risk drilling opportunities and acquisitions, while the seniors place greater emphasis on exploration, while also continuing to pursue other development and acquisition opportunities.

Those businesses that undertake a "riskier" strategy of exploration within their overall model should also be able to add reserves at a greater rate than those who buy them,



Returns for trusts vary as each new trust shows different traits. Harvest, Peyto and Paramount have returned more than 60% to investors. The above graph shows trust performance for the 12 months ending March 31, 2005. *(Source: FirstEnergy Capital Corp. and Bloomberg)*

as exploration barrels should inherently be "cheaper" than ones bought off the shelf.

When reviewing the annual change in reserves and taking the change in capital structures into account, the average debt-adjusted reserves per unit declined for the trusts 3%, whereas the Canadian senior E&Ps saw an average decline of 3.5%. To be fair, those E&Ps that were subject to SEC reserves-disclosure requirements saw significant downward revisions to bitumen (heavy oil) reserves based on year-end pricing. Should one add back those bitumen-reserve adjustments, the reserves per share increased year-over-year 7.9%, or an absolute outperformance of 10.9% versus the trusts.

However, within the trust model one also has to remember the debt-adjusted reserves also reflect payment of distributions to unit-holders that averaged 69.4% of cash flow and resulted in an average yield of 13.8% for 2004.

On an absolute measure, the change in reserves per unit for the trusts (once cash distributions are taken into consideration) is nominal. More important, we could ask whether the higher degree of risk associated with exploration really generates adequate returns, or is a model of exploitation and optimization and the distribution of cash flow the greater creator of unit-holder or shareholder value?

PRODUCTION PER UNIT

Next, FirstEnergy looks at the exploration, exploitation and development (E&D) capital deployed within the two models and the ability for them to maintain overall production. The firm has taken the broader view that it's important to consider the capital structure in aggregate versus just looking at per-share values, as the addition of debt to the balance sheet can inflate values on a per-share basis, but may not reflect underlying changes in capital structures.

Looking at capital allocation, in 2004, the trusts on average spent 54.5% of cash flow on E&D, while the senior producers spent much more, averaging 85.2%.

Both the trusts and E&Ps were active in the 2004 acquisition and disposition markets, often with the seniors selling their more mature properties into what was viewed as an overheated acquisition market. A number of the trusts made acquisitions, sometimes at lofty prices that left many in the market wondering how any value was being created.

On a debt-adjusted, production-per-unit basis, the results were varied, with some trusts seeing production per unit decline in excess of 10%, while two of the trusts posted very respectable results with debt-adjusted growth in excess of

A rig at daybreak drills a coalbed methane well for MGV Energy Inc., a subsidiary of Quicksilver Resources. (Photo by Alberta Photo Co. courtesy of Quicksilver Resources)

Skyscrapers abound in Calgary, the center of Canadian energy finance. (Photo by Lowell Georgia)

resulted in an average yield being received of 13.8%.

What we hope to show through these examples is not that one model is better than the other, rather that both models serve a broader purpose depending on the requir-ements of the investor, namely a nearer-term income focus versus longer-term investment horizons.

A variety of returns have been demonstrated, which shows the potential diversity of investments within this highly competitive landscape. This business is highly dynamic and as such, just because one company shows poor reserves growth or production-per-unit growth in one year, the broader context of sustainability of distributions, hedging models, future prospectivity and capital structures must also be taken into consideration.

FD&A COSTS

How do trusts make money? By exchanging present cash in property purchases and development drilling for improved future cash flows that come from oil and gas sales.

Which trusts are making the best tradeoffs? Finding, development and acquisition costs (FD&A), together with cash flows and recycle ratios (netback per BOE/FD&A cost per BOE), are the best measure of a trust's ability to continue distributions to unit-holders.

With NI 51-101 standards implemented, proved plus probable (P+P) reserve estimates are now the best estimate of recoverable reserves, while proved reserves alone are now the conservative estimate.

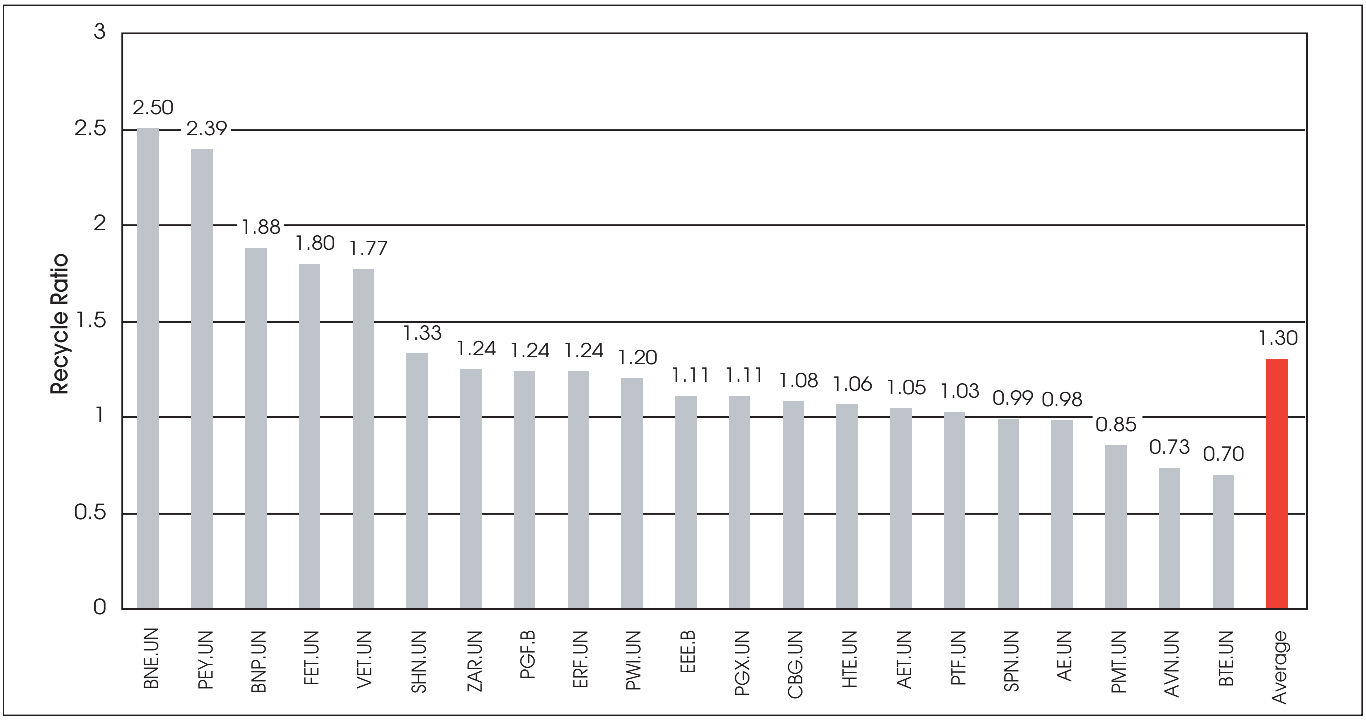
Leaders in P+P FD&A costs for 2004 were Bonterra, Peyto, Bonavista and Vermilion. Leaders in Proved FD&A were Peyto, Bonterra, Vermilion and Bonavista, in that order.

FD&A costs for trusts are comparable to these costs for E&P companies. The data shows the trusts have a competitive recycle ratio. Multiplying this recycle ratio by the capital-expenditure-to-cash-flow ratio shows how financial leverage can increase the recycle ratio.

10%. In aggregate, the trusts showed overall declines of 5.5%, a result that is in line with a model that is oriented toward mature assets with little exploration upside.

What was more surprising was that the senior producers' average debt-adjusted production per unit actually declined 1.4% versus 2003, even though they are spending more than the trusts on E&D.

Many of these companies are undertaking longer-term initiatives to add production and create value for shareholders, but as in the case of the reserves per unit, it is important to remember that the trusts also paid out a distribution that



Cash-flow netbacks vary widely among the trusts, depending on their finding and development costs and hedging positions. The above shows 2004 proved finding costs including changes in future development capital, divided by cash-flow netback per BOE. (Source: FirstEnergy Capital Corp. and company reports)

As a group, the trusts converted each BOE of production into 2.8 BOE of proved reserves by spending 215% of cash flow, while also providing distributions to unit-holders.

HEDGING STRATEGIES

Because the trusts are active price-hedgers, their cash flows per BOE suffered in the rising market of 2004. Some of the trusts took a severe hit from hedging, with the 2004 average proven recycle ratio at 1.3 times with hedging, but 1.48 times before hedging.

We have also compiled a unique look at recycle ratios using the formula: D = (three-year average recycle ratio for the trust minus the three-year average recycle ratio for all trusts)/standard deviation of the recycle ratio during the past three years.

Statisticians will recognize this as a modified Sharpe ratio. This formula rewards companies that consistently post an above-average recycle ratio. The best trusts by this measurement are Vermilion, Focus and Peyto.

With hedges, many of the trusts were not able to generate strong proved recycle ratios. We estimate that a proved recycle ratio of at least 1.1 times is necessary for long-term sustainability. With nine trusts below this line, investors need to remain selective.

This article is adapted from a report by Jill T. Angevine and William J. Lacey, vice presidents, institutional research, for FirstEnergy Capital Corp., Calgary. Both are chartered financial analysts.

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