Petroleum news

page 5 TransCanada to reactivate Alaska right-of-way lease

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North America's source for oil and gas news

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ANS spur line might be cheaper

JUDY PATRICK

A study of Cook Inlet gas for DOE's Arctic Energy Office suggests that piping North Slope natural gas to Southcentral Alaska might be cheaper than exploring for and developing new sources of gas in Cook Inlet. See story on page 17.

Imperial ready for Mac attack

> *"Eventually, Alaska gas will come and we need to make sure we're first."*
> **—Tim Hearn, Imperial Oil**

A mounting "sense of urgency" as Alaska moves ahead with plans to develop its North Slope gas resources should see the first regulatory application filed for a Mackenzie Valley pipeline this summer, Imperial Oil Chief Executive Officer Tim Hearn said April 21.

"Eventually, Alaska gas will come and we need to make sure we're first," he told reporters in Toronto.

"Our challenge is to file (applications) by mid-year and we'll

see **IMPERIAL** *page 20*

Thunder Hawk prospect could hold up to 400 million barrels

A Thunder Hawk is hovering near the largest and perhaps most dynamic oil and gas discovery in the Gulf of Mexico, the BP-ExxonMobil Thunder Horse complex in deepwater Mississippi Canyon.

After two years of planning, operator Dominion Exploration & Production and partners Spinnaker Exploration and Murphy Oil have commenced drilling on their Thunder Hawk prospect on Mississippi

see **PROSPECT** *page 20*

COURTESY OF TRANSOCEAN

The exploratory well, situated in 5,724 feet of water, is being drilled from Transocean's Cajun Express.

BREAKING NEWS

COOK INLET, ALASKA

New model needed

Lower Cook Inlet geology differs from upper, developed area, says Boyd

By KRISTEN NELSON

Petroleum News Editor-in-Chief

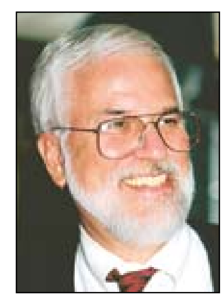
The Minerals Management Service has a lower Cook Inlet oil and gas lease sale scheduled for May 19 in Anchorage.

Whatever happens, it probably won't be what happened in October 1977.

At the 1977 sale, the first in lower Cook Inlet, 27 companies bid some $400 million for 87 of the 135 leases offered, and started exploring the next year, drilling 10 wells and three redrills from drillships, jackups and semi-submersibles by 1985.

Ken Boyd told Petroleum News that he doesn't expect this year's sale to be that kind of a barn burner.

For one thing, the drilling ended, the leases are gone and there is no production from the lower inlet.



KEN BOYD

In addition to the oil price bubble bursting, the companies who drilled wells variously named Guppy and Coho (Marathon), S. Arch and Bede (Phillips), Hawk, Ibis and Raven (ARCO Alaska) and Falcon and Shelikof (Chevron), discovered that lower Cook Inlet doesn't have the same geology as upper Cook Inlet.

Boyd said the price of oil, which was high and expected to stay high, was a driver in the 1977 sale. "I think the expectation was that the oil prices were never going to go down," he said.

So were the big structures in lower Cook Inlet, structures like those that yielded major finds in upper Cook Inlet in the 1960s — "these big reverse faults,

see **MODEL** *page 23*

ALASKA

Alaska LNG may be too costly

By LARRY PERSILY

Petroleum News Government Affairs Editor

An Alaska Department of Revenue memo says proponents of a state- or municipally owned North Slope natural gas project could be basing their pipeline tariff estimates on faulty assumptions, missing the real cost of service by more than $1 per thousand cubic feet.

A leading advocate of a publicly owned project strongly disputes the memo's numbers.

But, if true, such a significantly higher tariff could seriously damage the project's chances for success in the highly price-competitive Pacific Rim market for liquefied natural gas.

The memo said the economic models used by advocates of a publicly owned project could be

see **COSTLY** *page 22*

State memo questions assumptions of LNG project proponents

An Alaska Department of Revenue memo released in late March reviewed several assumptions underlying the feasibility models used by proponents of a publicly owned North Slope natural gas pipeline project.

Many of the issues are already on the Alaska Natural Gas Development Authority's assignment list for consulting contracts, as the authority works to put together its development plan for a state-owned natural gas pipeline.

see **MEMO** *page 22*

CANADA

Oil sands newcomers UTS and OPTI revive hopes

By GARY PARK

Petroleum News Calgary Correspondent

The Conference Board of Canada delivered what it called a "unique" economic forecast last month, declaring that the Alberta oil sands will show the way to Canada's other energy resources over the next decade.

The report came at a time when anxiety was at a high level, following another massive cost overrun and a one-year delay in bringing a Syncrude Canada expansion on line.

But the last week has seen two junior companies, who are hoping to make their debut in the oil sands, raise the spirits of those who feared potential investors in a 300 billion-barrel resource might be getting cold feet because of the sector's shaky trends.

OPTI Canada, created by Ormat Industries, an Israeli-based power and technology company, completed a C$1.8 billion financing to cover its share of the 50-50 joint venture with Nexen to build the C$3.4 billion Long

see **HOPES** *page 24*

OPTI President and CEO Sid Dykstra

● COOK INLET, ALASKA

Unocal drilling fifth natural gas well at Happy Valley

Production from field scheduled to begin in November; company may also drill step-out at field

By KRISTEN NELSON

Petroleum News Editor-in-Chief

Unocal Alaska is drilling a fifth natural gas well at its Happy Valley pad in the Deep Creek unit southeast of Ninilchik on the Kenai Peninsula, and will connect the field by pipeline to the Kenai Kachemak Pipeline at Ninilchik this fall.

Unocal Alaska's onshore gas exploration and development is focused at the Deep Creek and Nikolaevsk units, Chuck Pierce, vice president of Unocal Alaska, told Petroleum News April 19, and the company continues to "invest at Ninilchik with our partner Marathon as well, and we're drilling two to three wells there this year" as development continues.

1 2 SERIES

Two wells were drilled at the Happy Valley pad in the Deep Creek unit last year, two more have been completed this year and a fifth is under way. One more well will probably be drilled there this year, Pierce said, bringing the total to six wells at that field.

"By the time we're finished, we'll have five to six development wells on the pad. Then we'll have facilities and a pipeline, and the pipeline will come right back down Oilwell Road, essentially using a DOT right of way that goes beside the road."

Nov. 1 is the scheduled startup for gas delivery from Happy Valley, and Pierce said Unocal is "on schedule to get started on or before Nov. 1 right now, and that way we'll have gas before the winter … which we need to meet our Enstar contract requirements."

Three units on same trend

The three units, Ninilchik, Deep Creek and Nikolaevsk, are all on the same geologic trend, Pierce said.

JUDY PATRICK

Chuck Pierce, Unocal's top executive in Alaska

"The Nikolaevsk unit is just the next step to the south, same trend," he said. At Nikolaevsk Unocal has permitted an exploration well called Red, which the company plans to spud in June.

And Unocal is "evaluating drilling another exploration well in the Deep Creek unit to the south of Happy Valley," he said, depending on how other work goes, "so in the second half we might do a step-out away from Happy Valley inside the Deep Creek unit."

The Ninilchik, Deep Creek and Nikolaevsk developments are all targeted to providing gas under Unocal's contract with Enstar, he said.

Traditional gas business

The company's older gas fields are dedicated to supplying gas to the Agrium fertilizer plant.

There is ongoing work at Swanson River, Pierce said, "and we're looking at drilling two new wells there."

These are infield wells, he said, part of ongoing development. The field was discovered in the late 1950s, and so this is just getting "the last bit of the development done there," he said.

On the west side of Cook Inlet Unocal has two small gas fields, Lewis River and Stump Lake. "All the gas from the west side properties, and from Swanson, and from Steelhead (in Cook Inlet)," goes to the Agrium fertilizer plant.

As at Swanson River, Unocal is doing work at Steelhead. "We're looking at some compressor work there," just typical ongoing work, he said. "And we may drill another well out there … that's under evaluation."

Nov. 1 is the scheduled startup for gas delivery from Happy Valley, and Pierce said Unocal is "on schedule to get started on or before Nov. 1 right now, and that way we'll have gas before the winter … which we need to meet our Enstar contract requirements."

The oil piece

The oil piece of Unocal's Cook Inlet business is primarily offshore, although Pierce said "we have a little bit of oil production from Swanson River." The oil comes from the McArthur River field and the Granite Point field on the west side, and that oil goes to the Drift River terminal and then across the inlet to the Tesoro refinery.

Unocal's oil business is "fully developed and what we're focused on there is optimization," he said: projects to optimize the wells, de-bottleneck the facilities. "So we really aren't looking at new wells, we're focused on optimization."

North Slope and Foothills

On the North Slope Unocal has about a 5 percent interest at ConocoPhillips-operated Kuparuk and about a 10.5 percent interest at BP-operated Endicott.

The company has exploration acreage in the Foothills area, "we took it back in May of 2001, and it's more gas-oriented than oil and it doesn't make sense to drill any exploration wells until such time as there's a pipeline so we can get the gas to market," Pierce said.

While the company isn't interested in frontier exploration in areas such as the National Petroleum Reserve-Alaska, "we are interested in what I'd call close-in exploration, step outs from the existing field structure. … So we are looking for satellite-type opportunities adjacent to the existing infrastructure and fields."

And, of course, he said, Unocal continues to participate in exploration within the Kuparuk unit. ●

Editor's note: See part II of this story in the May 2 issue of Petroleum News.

INTERNATIONAL

Output prices drive Apache's profit

Big exploration and production independent Apache, on the strength of increased production and strong commodity prices, weighed in April 22 with a record 2004 first-quarter profit of $1.06 per share or $348 million, up from the previous record established in the first quarter of 2003 of $1.05 per share or $338 million.

Houston, Texas-based Apache's first-quarter production averaged 430,400 barrels of oil equivalent per day, up 23 percent from 348,600 boe per day in the prior-year period. Liquid production alone averaged 228,300 bpd, up 37 percent, while natural gas production averaged 1.2 billion cubic feet per day, up 11 percent.

"Higher production and strong commodity prices drove our record first-quarter financial results," said Steve Farris, Apache's chief executive officer.

He said that strong prices for both oil and gas also are driving the acquisition market for producing properties continually higher.

"Although we are always looking for acquisitions which have the potential to bring added value, in the current environment, we intend to continue our active drilling program and to be patient," Farris said.

During the 2004 first quarter, Apache said it completed 422 wells worldwide compared to just 156 a year ago. "We were active in each of our core areas, and this activity should benefit our financial results in future quarters," Farris said.

Cash from operations before changes in operating assets and liabilities during the 2004 first quarter totaled $737 million, up from $645 million in the year-earlier period. Apache's debt-to-capitalization ratio declined to 24.2 percent at the end of the quarter, from 26.3 percent at year-end 2003.

—**RAY TYSON,** Petroleum News Houston correspondent

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Petroleum news

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INTERNATIONAL

Swift Energy reports record production

Swift Energy's production during the 2004 first quarter jumped 9 percent versus the year-ago quarter to 14.1 billion cubic feet of natural gas equivalent, the company said April 19, adding that production also rose at least 5 percent compared to the 2003 fourth quarter.

The exploration and production independent said U.S. production alone increased to at least 10.3 billion cubic feet of equivalent, 33 percent greater than the 2003 first quarter and some 17 percent greater compared to the 2003 fourth quarter. The increase was attributed primarily to increased levels of production from the company's Lake Washington operations in Plaquemines Parish, La.

New Zealand production in the 2004 first quarter totaled about 3.8 billion cubic feet of equivalent, a decrease of 26 percent from the first quarter of 2003 and a decrease of 17 percent from the fourth quarter of 2003, Swift said. The company said the increased use of hydroelectricity in New Zealand contributed to a short-term reduction in market demand, which is expected to continue at least through this year's second quarter.

—**RAY TYSON,** Petroleum News Houston correspondent

● INTERNATIONAL

Burlington profit soars

Big E&P independent says it has reached point of sustainable production growth of 20 percent over three years

By RAY TYSON

Petroleum News Houston Correspondent

Burlington Resources, which used to infuriate analysts with missed production targets, is dancing to a different tune these days.

The first of the major U.S. exploration and production independents to report 2004 first-quarter earnings, Houston, Texas-based Burlington saw its profit jump 32 percent from a year earlier on production that rose 14 percent to set a new quarterly record.

The big North American natural gas producer also said April 21 that it remains on pace to increase overall production 20 percent over three years, beginning this year.

In early March, the company upped its production commitment with a pledge to spend about $5 billion on developing its so-called "base of excellence" properties, located primarily in 10 core producing areas in the Rocky Mountains corridor between New Mexico's San Juan Basin in the United States and Western Alberta in Canada. The company said it plans to spend $1.5 billion in 2004 alone.

"These outstanding (first quarter) results confirm that we are entering what we believe will be a period of sustainable growth for our company," said Bobby Shackouls, Burlington's chief executive officer.

First quarter beats analysts' expectations

Burlington reported net income for the first quarter of 2004 of $1.78 per share or $354 million, beating analysts' expectations of around $1.63 per share. That compared to net income of $1.33 per share or $269 million for the year-ago quarter.

However, 2004 first-quarter net income was down from the $2.04 per share or $404 million earned in the 2003 fourth quarter, due in part to a $59 million, non-cash charge taken in this year's first quarter.

Net cash provided by operating activities increased to $742 million in 2004 first quarter from $589 million in the prior year's quarter. Discretionary cash flow increased to $812 million from $721 million during the prior year's quarter. In addition, at the end of the first quarter the company's balance sheet included more than $1 billion in cash and cash equivalents, an increase of $270 million during the quarter, Burlington said.

Burlington's daily production, about 90 percent weighted to natural gas, increased to 2.849 billion cubic feet of gas equivalent in the 2004 first quarter from 2.490 bcf in the 2003 first quarter. The company said it expects to produce 2.606-2.804 bcf of equivalent during this year's second quarter.

North America "performing strongly"

"Our North American core properties continue performing strongly, while the major international development programs are ramping up during a very favorable price window," Shackouls said. Burlington's 2004 first-quarter production growth included a 4 percent increase in daily natural gas production to 1.953 bcf per day from 1.872 bcf during the prior year's quarter.

Natural gas liquids output rose 5 percent to 66,900 barrels per day from 63,700 bpd during the prior year's quarter. However, oil production jumped a whopping 110 percent to 82,400 bpd from 39,300 bpd during the prior year's quarter. The substantially higher crude volumes were attributed to higher production from the Williston Basin in the United States and from start-ups during 2003 of fields in Algeria, China and elsewhere. Increases in natural gas and NGL production resulted primarily from higher volumes in the Barnett Shale trend in North Texas, and from properties in South Louisiana and Northwestern Europe, Burlington said. During the quarter, the company said it had ongoing development in virtually all its major properties.

Since coming under criticism in the late 1990s for consistently missing its own production goals, Burlington management has restructured the company, divesting costly non-core properties and focusing on its "keeper assets." While divestitures eliminated about 10 percent of Burlington's production base, output from these keeper assets also rose 10 percent. ●

JACKSON, MISS.

Mississippi Senate sends offshore drilling bill to governor to sign

The Mississippi Senate has sent to the governor a bill to permit offshore drilling in Mississippi waters.

On April 19, senators agreed to House changes to the bill, giving it final legislative approval. The legislation strips oil and gas lease authority from the Department of Environmental Quality and gives it to the Mississippi Development Authority, a move supported by the oil and gas industry.

About three-quarters of the tax and lease proceeds from drilling would go to the state education trust fund and the remainder to local county governments. Predictions have been that the state has reserves that could bring in $1 billion or more to state coffers over a couple of decades or so.

—**THE ASSOCIATED PRESS**

● ALBERTA

TransCanada to reactivate 23 year old Alaska gas line right-of-way

By LARRY PERSILY

Petroleum News Government Affairs Editor

In a move to ensure it is part of any venture that builds an Alaska North Slope natural gas pipeline, TransCanada Corp. will reactivate its 23-year-old state right-of-way lease application for the route.

The company also said it will apply for a state fiscal contract setting up a schedule of payments in lieu of taxes, which it would invoke if it ends up owning a stake in the Alaska portion of the project.

"It's not the technical design that's the problem but who will hold the shipping commitments for gas for 15, 20 or even 30 years." —TransCanada CEO Hal Kvisle

And while taking the two steps to show its strong interest in the project, TransCanada also acknowledges any deal will need to include as partners the North Slope producers to provide the financial guarantees necessary for building the line — and to provide the gas itself.

Calgary-based TransCanada joins pipeline operator Enbridge Inc., also of Calgary, in pledging to submit an application under Alaska's Stranded Gas Development Act. The law allows potential project owners to negotiate the certainty of a long-term contract for payments in lieu of state and municipal taxes on the proposed pipeline.

The three major North Slope producers submitted their own joint Stranded Gas Act application the third week of January, with negotiations continuing.

The state expects to receive Enbridge's application by the end of April, said Steve Porter, deputy commissioner at the Alaska Department of Revenue. TransCanada anticipates turning in its paperwork within a few weeks, Hejdi Feick, company spokeswoman, said April 19.

Want to know more?

If you'd like to read more about TransCanada, go to Petroleum News' Web site archives. These are just a few of the articles published during 2004 in which TransCanada is featured or plays a significant role.

Web site: www.PetroleumNews.com

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- **April 11** What went wrong?
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Partnership could emerge

With two pipeline companies and three producers looking at the project, and each willing to spend millions of dollars on fiscal negotiations with the state and their own planning work, it is appearing more likely the project could be a shared venture instead of under a single owner.

"TransCanada is clearly one key part of the equation for the project," Alaska Gov. Frank Murkowski said in announcing the company's new role in the state's efforts to promote construction of a pipeline to move North Slope natural gas to market — and to move new tax and royalty revenues into the state's declining-oil-production treasury.

"I think he refers to it as a partnership," Mike Menge, the governor's special assistant for oil and gas issues, said of the envisioned venture to develop the line. "Clearly, we have no idea what form that partnership will take."

In addition to the producers and pipeline companies, the partnership will need to include the state, provincial governments, and U.S. and Canadian federal governments, Menge said. The pipeline, as proposed, would run about 2,000 miles from the North Slope, through the Yukon Territory and into Alberta, where it would connect with either or both TransCanada's and Enbridge's existing North America distribution systems.

"This is a very large project that will require the cooperation of a number of parties," TransCanada's Feick said, adding the company "recognizes the importance of the state resolving the upstream issues."

She declined to elaborate on what upstream issues need resolving. "That's a good question for the governor and the state of Alaska," Feick said.

Producers likely to carry the risk

"To TransCanada, 'upstream issues' is always code for getting the gas," Menge said.

So while the state waits for TransCanada's and Enbridge's applications under the Stranded Gas Act, the administration will continue negotiating with the producers on royalty, production tax and other issues that are key to moving ahead on the project.

And just as the state's lead Stranded Gas Act negotiator Pedro van Meurs told legislators earlier this month, TransCanada also is aware the North Slope producers most likely will be the deep pockets covering the financial risk of the project by pledging to ship their gas.

Such ship-or-pay contracts — regardless of the spread between the pipeline tariff and destination market price — would provide the financial security needed to borrow money for construction.

"It's not the technical design that's the problem but who will hold the shipping commitments for gas for 15, 20 or even 30 years," said Hal Kvisle, TransCanada's chief executive officer.

"Everybody, historically, has looked around the table and asked whether the LDCs (local distribution companies), merchants or pipeline companies (would hold the risk) of building the pipeline," he said at a Washington, D.C., press briefing April 19, sponsored by the Interstate Natural Gas Association of America.

"Eventually, it's come down to the big producers. ExxonMobil, ConocoPhillips and BP PLC are the ones most likely to

see **TRANSCANADA** page 6

GULF OF MEXICO

Construction company hit by heavy loss

Gretna, La.-based Torch Offshore Inc., an offshore construction company for the petroleum industry, reported a big first-quarter loss April 15 and said it would have to raise capital over the next two years to continue operating.

For the three months ending March 31, Torch lost $6.8 million, or 54 cents per share, on revenue of $19.4 million, compared with a first-quarter profit last year of $544,000, or 4 cents per share, on revenue of $24.5 million. Much of the company's problem is due to the conversion of the Midnight Express, a vessel that lays deepwater pipeline. The conversion project, originally projected to cost $90 million, is being completed at a cost of $109 million, the company said. In addition, drilling in the Gulf of Mexico remains slow, despite high oil and natural gas prices, the company said.

"Raising additional capital during 2004 and 2005 is a requirement for the company to continue to conduct operations, meet its obligations and support the operations of the Midnight Express," Torch Chairman Lyle Stockstill said.

The company said it had entered negotiations with Mariner Energy for the first piping project for the Midnight Express. That project could take place in the fourth quarter of 2004, the company said.

—THE ASSOCIATED PRESS

● UNITED STATES

Panel urges new ocean protections, trust fund

Commission wants $4 billion of $5 billion in oil and gas royalty payments, cabinet-level National Ocean Council

By JOHN HEILPRIN
Associated Press Writer

The government should set up a trust fund with $4 billion annually from oil and gas royalties to protect and improve the health of the nation's oceans, Great Lakes and coastal areas, a presidential commission reported April 20.

"Will it be tough to sell? You better believe it. But we're going to go for it," said the chairman of the U.S. Commission on Ocean Policy. "Everybody wants to go after those revenues. Well, we do too. And we hope we can win it," said James Watkins, a retired admiral and former chief of naval operations.

The panel recommended a trust fund similar to one for highways that is financed by revenue from the federal gasoline tax. Watkins said ocean resources no longer can be thought of as limitless and that the oceans cannot continually clean themselves. Also proposed was a new Cabinet-level National Ocean Council. Some $5 billion annually in royalty and other payments now goes to the Treasury for offshore oil and gas drilling. The commission wants to use $4 billion of that; the other $1 billion would go for land and water conservation and historic preservation.

The first federal review of ocean policy in 35 years produced more than 250 recommendations, including some for states, in a nearly 500-page report.

Area studied larger than U.S. land mass

Commissioners spent 2 1/2 years studying coastal areas, the Great Lakes and 4.4 million square miles of ocean. That total area is nearly one-quarter larger than all 50 states combined because it includes the exclusive economic zone stretching about 200 miles from the continent in addition to Pacific and Atlantic islands.

The panel urged new ways of managing these waters so the needs of nature are placed ahead of political boundaries. But people's needs, too, must be considered, the report said.

The commission estimated the cost of all its recommendations at $1.3 billion the first year, $2.4 billion the second year and $3.2 billion annually after that.

But it pointed to annual ocean-related economic activity of $700 billion in goods that ports handle, $50 billion from fishing and trade, $11 billion from cruise ships and passengers, and $25 billion to $40 billion from offshore oil and gas production. The draft report went to governors and others for comment. A final one goes to Congress and the White House later this year. ●

continued from page 5

TRANSCANADA

hold the shipping commitments, so whatever kind of project is put together has to be one that works for the producers," Kvisle was quoted by Dow Jones Newswires. He is the first Canadian to hold the post as chairman of the gas association.

Costs make people nervous

"When you get a project of this complexity, with steel prices and construction costs going through the roof, people get nervous," Kvisle was quoted by Dow Jones. "Nervousness, more than anything else, is the reason this pipeline has never been built."

The project, proposed to carry 4.5 billion cubic feet of gas per day, could cost $20 billion, with total tariffs estimated at almost $11 million a day to Midwest markets.

Kvisle held his briefing the same day as Alaska Gov. Frank Murkowski announced TransCanada's news at an Anchorage Chamber of Commerce luncheon.

"TransCanada holds federal authorizations including the right-of-way lease to construct the line through Alaska, as well as the right to build the line through Canada," Murkowski said.

The company believes its 1977 U.S. regulatory certificate and 1978 Canadian certificate to build an Alaska gas line give it exclusive rights to the project. The certificates apply to the Alaska Natural Gas Transportation System, designed almost 30 years ago to carry an average 2.4 billion cubic feet per day from the North Slope into Alberta for distribution throughout North America.

Although some industry observers question whether TransCanada's rights would prevent a developer from building a different project — carrying more gas along a slightly different route — most agree it would create serious political problems to ignore the company's claims, especially in its home country.

"There are no simple answers to the legal questions posed," said a 2001 Federal Energy Regulatory Commission staff report on whether the 1977 U.S.-Canada treaty and subsequent operating certificates are the only way to get the line built.

TransCanada willing to share rights to project

After obtaining the gas line right of way, and putting together shipping contracts sufficient to finance the project, TransCanada said it would be willing to turn over the right of way to another developer for the Alaska portion of the project. The company would retain the Canadian portion of the line for itself.

The company is not looking to build or operate the gas treatment plant that would be needed on the North Slope, just the pipeline, Feick said.

The offer to turn over the right of way is contingent on the developer of the Alaska portion of the line acknowledging TransCanada's exclusive rights to the project and agreeing to connect with TransCanada's pipeline system to move the gas to Alberta for distribution to North American markets.

The company and its wholly owned subsidiary Foothills Pipe Lines Ltd. operate more than 24,000 miles of natural gas pipeline across Canada. TransCanada also holds partial interest in half a dozen other companies that own 4,500 miles of gas pipe in the United States.

In reactivating its state right-of-way lease application, TransCanada restarted a process it opened up in 1981. The company, through its Foothills subsidiary, applied that year for state right of way to accompany its federal right of way from the North Slope to the Yukon border. Foothills suspended its state application in 1982, citing low natural gas prices as the reason for shelving the project.

Right-of-work stopped again in 2002

Foothills reactivated its state application in July 2001, only to shut it down again in May 2002 to allow time "for other aspects of this project to catch up." The company said those other issues included federal tax incentives for the pipeline — still stuck in Congress almost two years later — and the need for a gas deal with the North Slope producers.

TransCanada's right-of-way application covers about 200 miles of state land between Prudhoe Bay and the Canadian border. The rest of the route is mostly federal, with some Native corporation holdings.

The company's decision to move ahead with its right of way will not change the state's plans to process its own rights-of-way applications for so-called spur lines to carry smaller quantities of natural gas from the main pipe south to Valdez and also to the Kenai Peninsula, said Menge of the governor's office. The state also wants to secure a right of way from the proposed Point Thomson oil and gas development west to the main line at Prudhoe Bay, in anticipation that Point Thomson gas will be needed to feed the gas line.

Murkowski is asking lawmakers to appropriate more than $3.5 million for the spur lines and Point Thomson rights-of-way work, with the intent that the state would hold the permits and later transfer them to whatever private or public venture may decide to build the lines.

TransCanada will reimburse the state for the costs of processing its right-of-way permits, and for the state's negotiating costs under the Stranded Gas Act. ●

TransCanada willing to drop issue of repayment of pre-2000 gas line right-of-way costs

TransCanada Corp. says it is willing not to seek repayment of the millions of dollars it spent more than 20 years ago on its first attempt to obtain state right of way for an Alaska North Slope natural gas pipeline.

Though seemingly a small amount when compared to the perhaps $20 billion it will cost to build the entire project, it's a significant step for historians of the long effort to build a pipeline to carry Alaska gas to market.

If the company had wanted to press its rights to recover all of its earlier costs in developing the project — with the compound interest that has accrued over the years — the added expense could have further burdened the tariff for the already financially iffy proposed pipeline.

Federal Energy Regulatory Commission rules would have allowed the company to seek recovery of its costs, though most observers in recent years have expected TransCanada to give up on trying to roll the expenses into the pipeline tariff. The hard-to-swallow, interest-bearing accumulated liability has been called the "meatball."

"TransCanada will not go after … those costs," spokeswoman Hejdi Feick said April 20. She said she didn't know how much the company was giving up.

Estimates of the total expenditures by the 16 original partners in the Alaska Northwest Natural Gas Transportation Co. during the gas line effort of the 1970s and early 1980s range up to $400 million. It's unknown how much of the money was spent on the Alaska right of way for the gas line vs. other planning and design costs more than 20 years ago.

One of 16 partners

TransCanada was one of the 16 partners, as was its wholly owned subsidiary Foothills Pipe Lines Ltd. TransCanada and Foothills, through mergers and acquisitions over the years, hold the rights to the project.

"TransCanada will not seek reimbursement … of any costs (including interest) associated with the state right-of-way lease that were incurred prior to January 1, 2000," the company said in a memorandum of understanding with the state. TransCanada and Alaska's governor announced the agreement April 19, as part of recent efforts to push development of the long-awaited gas line.

—LARRY PERSILY, Petroleum News government affairs editor

INTERNATIONAL

EIA report predicts crude oil will cost $51 a barrel by 2025

Crude oil prices will increase gradually and reach $51 a barrel by 2025 due to inflation and rising energy needs in developing nations, according to an Energy Department projection.

The report by the DOE's Energy Information Administration said strong economic growth in Asia will drive world energy prices in the next decade. The developing world's demand for energy will nearly double by 2025 with oil, coal and natural gas leading the way.

The report projects global energy demand to grow about 54 percent by 2025. But China, India and other developing countries will see a 91 percent jump as these countries continue rapid industrial development, said the EIA.

OPEC producers are expected to still be the major oil suppliers in 2025, the report said. They now account for about a third of the oil being pumped.

Crude oil prices have been steadily rising since the late 1990s. The price of light crude closed at $36.70 a barrel April 13 in trading on the New York Mercantile Exchange.

The sharpest jump in demand will come from China and other Asian countries. Demand in the United States also will continue to increase. "The United States, China and the rest of developing Asia account for nearly 60 percent of the projected growth in world oil use," the EIA said.

Coal and oil will remain dominant fuels despite concerns about climate-changing "greenhouse" gases, the report said. Emissions of carbon dioxide, the leading greenhouse gas, will increase from 23.4 billion metric tons in 2001 — the baseline used in the report — to 37.1 billion metric tons by 2025, according to the EIA projections.

—THE ASSOCIATED PRESS

CANADA

Wave of trust deals hits C$B

Deal-making in the Canadian energy trust sector has hit C$2 billion inside a month amidst an asset-buying binge.

Since March 31, the acquisition flurry has seen six separate transactions, with four junior E&P companies, one trust and a bundle of Murphy Oil assets snapped up in the process.

The latest occurred April 19 when Harvest Energy Trust bid C$189 million, including C$64 million of debt, for the bulk of properties held by Storm Energy.

Provided Storm shareholders approve the offer in June, Harvest will see its reserve life index climb to 6.7 years from 6 years as it adds proven plus probable reserves of 14 million barrels of oil equivalent to its existing base of 33 million boe and increases its output by 4,200 boe per day to an average 16,750-17,500 boe per day in 2004. The trust expects its exit rate for the year will be 18,750-19,250 boe per day.

The cash-and-shares offer marks the second time in two years that Storm has sold into the trust sector.

In a fall 2002 reorganization, Storm spun off some assets to create Focus Energy Trust, which has since expanded its production to

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● NORTH AMERICA

XTO Energy poised for large acquisition

Independent looking at deals, anticipates exceeding its acquisition budget

By RAY TYSON
Petroleum News Houston Correspondent

Fast-growing Fort Worth, Texas-based independent XTO Energy, which now anticipates exceeding its acquisition budget for 2004, says it is working on several property deals and might even buy a company outright before the end of the year.

"If we could do the size of a fairly large company this year through a direct acquisition, I would do it, if they were good numbers and good properties," said Bob Simpson, XTO's chief executive officer.

Simpson also told industry analysts in an April 20 conference call on 2004 fourth-quarter earnings that XTO is "very likely" to spend more than the $650 million it planned on acquisitions this year.

"We're two-thirds into that in the first quarter of the year," he said. "But I will tell you that we're working on multiple deals and it's very likely we'll exceed the $650 (million) in terms of budget."

Despite the high cost of quality properties today … "the risk is sitting out this market rather than participating in it."
—Bob Simpson, XTO Energy

Less than two months into 2004, XTO already had shelled out some $450 million for U.S. oil and gas properties and said then it planned to spend at least another $200 million on acquisitions this year. In its latest deals, XTO paid $120 million for its first Barnett Shale properties in East Texas, plus $80 million for additional properties in the Arkoma Basin, a major core area for the gas-weighted producer.

XTO not predicting it will buy a company

Simpson said that while XTO was not "predict-

see **XTO** page 8

● INTERNATIONAL

High crude oil prices trigger BP's share buyback

Company will use extra cash for stockholders, not increased exploration

By LARRY PERSILY
Petroleum News Government Affairs Editor

Rather than use some of the extra cash flow from high oil prices to boost exploration and production spending, BP p.l.c. will use all of the money to buy back more of its shares, transferring much of the windfall to its stockholders.

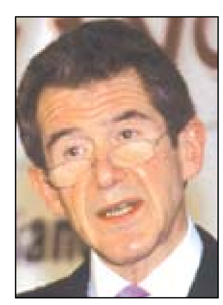
"There appears, at present, to be overwhelmingly more chance of the oil price being above $20 a barrel for the next few years, than not," John Browne, BP's chief executive officer, said in a statement on the company's web site.

Expecting prolonged high prices, the company intends "to distribute 100 percent of all excess free cash flow (from prices above $20 per barrel) to our shareholders, as part of our determination to provide them with additional returns," Browne said.

"It's a principle of disciplined cash flow," said spokesman Ian Stewart of BP's New York City office.

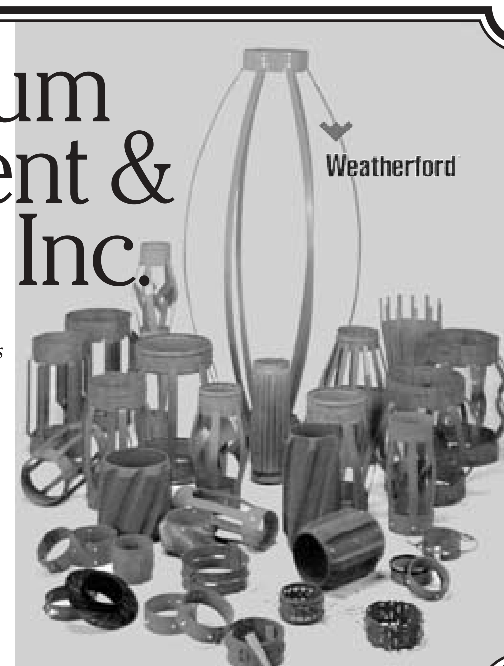
When asked why the company has decided to spend billions buying back shares instead of boosting spending even higher on exploration and production, Stewart answered: "We have chosen to go

see **BP** page 8



JUDY PATRICK

BP plans "to distribute 100 percent of all excess free cash flow (from prices above $20 per barrel) to our shareholders." —John Browne, BP



CANADA

Thunder Energy rolling into British Columbia on heels of Impact merger

Canadian junior Thunder Energy is set to extend its reach into northeastern British Columbia once its merger with Impact Energy is completed on April 30.

The company plans to spend C$40 million of its capital budget in British Columbia, C$30 million on its central Alberta activities and C$8 million on a summer coalbed methane program in Alberta, president and chief executive officer Doug Dafoe told analysts.

Thunder is counting on commercial coalbed methane from at least one of its Alberta projects this year as it steps up drilling to 125 wells from 110 in 2003.

With the merger, combined output will be 10,000 barrels of oil equivalent per day, with natural gas output targeted at 70 million cubic feet per day by this time next year, he said. Proved plus probable reserves will be 204 billion cubic feet of gas and 9 million barrels of oil and natural gas liquids.

Dafoe said that the new British Columbia properties hold a number of discovered resources that need to be in-filled and linked to processing facilities.

Once the deal is completed, Thunder will have a working interest of 50 percent on 58 sections of land and 95 percent over 85-150 sections of land in Alberta.

But, despite the accelerated activity, Thunder expects production will remain flat at 50 million cubic feet per day of gas and 1,700 boe per day.

—**GARY PARK,** Petroleum News Calgary correspondent

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XTO

ing" buying a company this year, "if we got out there as far a couple billion (dollars) during the year … I would do that as a large acquisition of a company. Again, we are on that pace."

Simpson said XTO likely would use company stock for a large acquisition, a strategy he concedes is out of character for a company that generally pays for its properties from cash flow.

Despite the high cost of quality properties today, he added, "the risk is sitting out this market rather than participating in it."

Production gained through property acquisitions, together with drill bit successes and high commodity prices, served to propel XTO's 2004 first-quarter profit to $94.1 million or 40 cents a share, compared to net income of $66.2 million or 31 cents a share for the same period last year. Excluding special items, the company's 2004 first-quarter profit was $119.1 million or 51 cents per share, which was on par with analysts' expectations.

Total revenues for the first quarter were $394.8 million, 56 percent above first quarter 2003 revenues of $253.5 million. Operating income for the quarter was $169 million, a 48 percent increase from first quarter 2003 operating income of $114.2 million. XTO also reported record first quarter natural gas production of 771 million cubic feet of natural gas per day, a 30 percent increase from the first quarter 2003 level of 591 million cubic feet per day.

The company said daily gas production of 790-795 million cubic feet is expected in the 2004 second quarter, 810-815 million cubic feet in the third quarter, and 830-835 million cubic feet in the fourth quarter. Over the three quarters, oil production is expected to average 13,000-13,500 barrels per day and natural gas liquids between 6,000 and 6,500 barrels per day.

"The company's consistent performance highlights our predictable growth profile substantiated by our rich exploitation inventory and disciplined focus on acquiring the right rock to develop," XTO President Steffen Palko said. "As a result, we are building on our successful programs by increasing current ownership positions and by expanding into new core areas." ●

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BP

this way." He declined to elaborate on the company's choice, although he said the share buybacks would continue "certainly for the foreseeable future."

$20 oil will cover all of BP's cash needs

The company said it expects to earn sufficient revenue from oil at $20 a barrel to cover all its capital needs — barring acquisitions it does not currently foresee — while also paying a growing dividend. It plans to use all of the extra cash generated at above $20 to buy back more of its shares, directly benefiting stockholders by, hopefully, driving the share price higher.

Putting the additional cash into share buybacks costs the company the same as paying it out in stock dividends, but buying up shares can be better for stockholders, Stewart said. Although income taxes are due the year a stockholder receives a dividend, shareholders can choose to hold on during periods of rising stock values and take their gains when it's to their advantage, he said.

And it's not like the company's dividends are lagging.

Higher-than-normal oil prices of the past few years have helped BP boost its payments to shareholders. The company sent out almost $5.8 billion in dividends last year, an increase from $5.38 billion in 2002 and $4.94 billion in 2001.

And while paying out larger dividends, BP purchased 775 million of its shares at a cost of $6 billion between 2000 and the end of 2003 in a move to boost per-share equity. During that time, its share price started at $50 and bounced around that level before ending 2003 at close to the starting price.

Share prices up this year

The results are different so far this year. The company purchased an additional 155 million shares in the first quarter, sending share prices higher. After starting the year just below $50, the price climbed to $54.72 on April 16.

The company has almost 3.7 billion shares outstanding, worth $200 billion at $54 each.

BP's strategy through the end of 2006 will be to move out of the acquisition and consolidation mode and into a time of focusing on performance, particularly building cash returns while still investing in exploration and development for long-term growth, Browne said in the March 29 statement.

The company's capital spending, which totaled almost $14 billion worldwide in 2003, will slip to $13.5 billion in 2004, Browne said, falling to between $12 billion and $12.5 billion in 2005 and 2006.

At those spending levels, Browne said, the company intends to maintain its five-year rolling average of between $4 and $5 a barrel for finding and developing oil and gas reserves.

BP's reserves, as of Dec. 31, 2003, totaled 18.3 billion barrels of oil and gas equivalent.

Even with less capital spending, BP's production is expected to grow by 5 percent a year between 2003 and 2008 — not counting production growth from its Russian joint venture, TNK-BP — the company reported. Its 2003 production averaged 1.9 million barrels of crude oil and 8.6 billion cubic feet of gas per day.

Profit centers scattered around the globe

Separate from its efforts in Russia, BP's "new profit centers" are oil and gas projects under way at Kizomba A field in Angola, the In Salah gas field in Algeria, the fourth liquefied natural gas train at Australia's North West Shelf, Holstein in the Gulf of Mexico and the Atlas methanol project in Trinidad, Browne said. All are due online this year.

Next year's start-ups will include the Mad Dog and Thunder Horse fields in the deepwater Gulf of Mexico, the Azeri field in Azerbaijan, a fourth LNG train at Trinidad and the In Amenas project in Algeria.

And while it is impossible to predict the price of oil, "BP's view is that it is quite reasonable to use $20 as a base case for balancing cash flows over the next couple of years," Browne said.

"Over time, as production rises and capital spending declines, we expect the oil price at which (BP's) cash flows balance to fall below $20," he added. ●

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DEALS

more than 8,000 boe per day.

Storm executives will start a new junior producer by inheriting production from their own company of 4.2 million cubic feet per day of natural gas and 210 bpd of natural gas liquids. They plan to drill for gas in west-central Alberta.

The expectation among analysts is that the buying spree is far from over.

Trusts, many of whom budgeted for 2004 oil prices of $25 a barrel, are flush with cash and under pressure to maintain production levels to support their monthly and quarterly distributions to unit holders.

Conventional producers in the junior ranks are the obvious target, with companies such as Purcell Energy, which has strong interests in the Northwest Territories, Real Resources and Zargon Oil & Gas among those labeled as takeover candidates.

—**GARY PARK,** Petroleum News Calgary correspondent

● DALLAS, TEXAS

Ensco accelerates plans to move drilling rigs out of Gulf of Mexico

Company says activity levels in Middle East and Pacific Rim improving, while North Sea, West Africa and Gulf remain sluggish

By RAY TYSON

Petroleum News Houston Correspondent

Contract driller Ensco International says that because of continuing market weakness it intends to act swiftly on plans to move some rigs out of the U.S. Gulf of Mexico.

"Given anticipated first half softness in some areas, we have elected to accelerate various undertakings," Carl Thorne, the company's chief executive officer, said April 20.

He said activity levels in the Middle East and Pacific Rim are improving, while the North Sea, West Africa and the Gulf of Mexico remain sluggish. Over the past year, companies have steadily moved rigs out of the Gulf. For the week ending April 16, the count stood at 89, down 12 compared to the same weekly period last year, according to rig monitor Baker Hughes.

In May, Ensco will relocate two 250-foot jackups from the Gulf to the Middle East, where they will undergo upgrades until late third and early fourth quarters, Thorne said.

In addition, he said, Ensco 67 will mobilize from the Gulf to a shipyard in Singapore for a major upgrade, including conversion from slot to cantilever configuration, with expected completion in late first quarter 2005.

"These actions will allow us to take advantage of strong international term-work opportunities, as well as to address enhancement cost efficiencies and fleet geographic balance," Thorne said.

He said that with the relocation of three jackups, and the exchange of Ensco 55 in connection with the construction of Ensco 107, U.S. domestic supply would be reduced, and international availability increased, by four rigs.

Average day rate up from year-ago quarter

Ensco now expects to incur about 40 rig-months of downtime in connection with its overall jackup rig enhancement program during the remainder of the year. The company also has elected to accelerate regulatory inspection and maintenance on Ensco 7500, a deepwater semi-submersible rig, which will result in shipyard time through May.

"While the actions we are taking will have short-term negative impact on earnings, we believe that these decisions will enhance intermediate and long-term positioning as the fundamentals of our industry continue to improve," Thorne said. "We continue to expect global activity to be stronger in the second half of 2004 than in the first half of the year."

Ensco reported net income of $21.0 million or 14 cents per share on revenues of $186.5 million for the 2004 first quarter, a slight decline compared to net income of $22.9 million or 15 cents per share on revenues of $192.9 million for the same period last year. First-quarter 2004 results met analysts expectations based on Thompson-First Call consensus estimates.

Excluding results from discontinued operations, Ensco's income from continuing operations actually was $21.3 million in the first quarter of 2004, compared to $26.7 million for the year-ago period. Discontinued operations include the company's marine transportation vessels sold in April 2003 and three rigs to be exchanged in connection with construction of Ensco 107, a new high-specification jackup rig, announced in February 2004.

The average day rate for Ensco's operating jackup rig fleet was $50,200 for the first quarter of 2004, compared to $48,500 in the year earlier period. Utilization for the company's jackup fleet decreased slightly to 85 percent in the most recent quarter, from 87 percent in the first quarter of 2003.

Diamond Offshore has first-quarter loss

Meanwhile, Diamond Offshore weighed in with a loss for the first quarter of 2004 of $11.0 million or 8 cents per share, compared with a loss of $21.6 million or 17 per share in the same period a year earlier, missing analysts' expectations by about 2 cents per share. However, revenues for the first quarter of 2004 were $184.2 million versus $146.1 million for the first quarter of 2003.

"Results for the (first) quarter were impacted by planned surveys as well as greater-than-anticipated idle time on several of the company's mid-water and deepwater units," said Larry Dickerson, Diamond's chief operating officer.

However, he said market conditions appear to be improving and that Diamond is realizing benefits from continuing cost control programs initiated in 2003. Moreover, survey work is expected to be completed in the 2004 second quarter, "and our goal is to resume the sequential quarterly improvements achieved last year as we move forward in 2004," he added. ●

GULF OF MEXICO

Noble Energy boosts interest to 60% in Gulf's deepwater Lorien discovery

Exploration and production independent Noble Energy has acquired an additional 40 percent interest from ConocoPhillips in the Lorien discovery well on Green Canyon block 199 in the deepwater Gulf of Mexico, the company said April 20.

Noble said the acquisition increases its working interest in Lorien from 20 percent to 60 percent, adding that it also will take over as operator of the block.

Of ConocoPhillips' 65 percent working interest, Noble Energy acquired 40 percent, with the remaining 25 percent acquired by Norsk Hydro E&P Americas and Davis Offshore. Norsk has a working interest of 30 percent, and Davis has a working interest of 10 percent.

The acquisition of ConocoPhillips' working interest in Lorien by Noble Energy and its partners is subject to approval by the U.S. Minerals Management Service.

A project team is working on plans for an appraisal of the Lorien discovery during 2004, Noble said. Announced as a discovery in July 2003, the Lorien well is in 2,177 feet of water. The well was drilled to a total measured depth of 18,703 feet and encountered more than 120 feet of apparent oil pay in a "high-quality" reservoir interval, Noble said.

—**RAY TYSON,** Petroleum News Houston correspondent

Technip, Mustang win key engineering contracts for U.S. Gulf's Tahiti project

ChevronTexaco has awarded two major engineering contracts for development of Tahiti's sub-sea systems and floating production facility, to be located in Green Canyon blocks 640, 641 and 596, about 190 miles southwest of New Orleans, La.

Tahiti, with 400 million to 500 million barrels of estimated oil reserves, is among the largest discoveries in the deepwater Gulf of Mexico.

Under the agreement, Technip Offshore will perform front-end engineering and design for the proposed truss spar floating production facility, ChevronTexaco said April 15, adding that Mustang Engineering will perform the same for the Tahiti topsides oil and gas processing facilities.

Under the agreement, Technip Offshore will perform front-end engineering and design for the proposed truss spar floating production facility, ChevronTexaco said April 15, adding that Mustang Engineering will perform the same for the Tahiti topsides oil and gas processing facilities.

Construction contracts are expected to be awarded in the second quarter of 2005, ChevronTexaco said.

"We are pleased to announce these key contract awards that move our Tahiti Project closer to first production," said Ray Wilcox, president of ChevronTexaco Exploration and Production Co. "Tahiti is a significant component of ChevronTexaco's upstream growth strategy. It will also add considerably to our Gulf of Mexico deepwater portfolio."

The Tahiti field will be developed from two subsea drill centers near the two Tahiti appraisal wells in Green Canyon blocks 596 and 640, completed in early 2003. One of the wells encountered more than 1,000 feet of net pay.

Next steps for the project include front-end engineering and additional technical and commercial assessments, ChevronTexaco said A production test of the discovery well and front-end engineering are scheduled to begin the second quarter of 2004, the company said.

ChevronTexaco is the operator of the Tahiti project with a 58 percent working interest. EnCana holds a 25 percent stake in the project, followed by Shell Exploration & Production with a 17 percent interest.

—**RAY TYSON,** Petroleum News Houston correspondent

● MONTERREY, MEXICO

Mexico: energy opportunity or production demise?

By DEBRA BEACHY
Petroleum News Contributing Writer

Mexico needs to pump vast amounts of new investment into energy exploration or face an energy deficit in the next 10 to 20 years that could affect North America's security, said officials at a two-day energy conference April 1 and 2 in Monterrey, Mexico.

But getting that new investment poses a challenge.

Strict laws prohibit foreign investment in Mexico's state-owned oil monopoly, Pemex. So Mexican legislators are pushing a bill to lower the amount — 60 percent of its revenues — that Pemex pays the government each year, so that more can be spent on exploration.

"The goal of Pemex (Mexico's state-owned oil monopoly) is to increase production. If there is not new investment, production can't increase, because Mexico is dealing with maturing fields that may last only another 10 or 20 years," said Mexican Congressman Francisco Salazar, president of the House of Deputies' Energy Commission.

Salazar, a conservative National Action Party deputy from the central state of San Luis Potosi, said all the political parties were behind the bill. "Everyone agrees on this," he added.

Fox has not been able to push reform

Despite the urgency cited for more investment for crude production as well as oil and gas production, Mexican President Vicente Fox has not been able to push through energy reform that would permit more foreign investment, said Michelle Foss, executive director of the University of Houston's Institute for Energy, Law and Enterprise, and a conference participant.

"Right now there are eight energy initiatives in Mexico's Congress," she said. "But it seems doubtful that they can get passed at this point."

Even multiple service contracts that would pay fees to foreign oil companies to drill for gas in Mexico's Burgos basin have been attacked as unconstitutional.

According to Congressman Salazar, there are seven bills dealing with electricity in Congress, and another that would allow more foreign investment in gas wells through Mexican majority-owned joint ventures.

Attempts to pry open Mexico's energy sector to foreign oil companies have sparked bitter controversy and protest in Mexico, where the oil industry was nationalized in 1938 by President Lazaro Cardenas. Mexico has kept its oil industry closed to foreign oil companies, which aren't allowed to have any share in production of crude oil or natural gas.

The Canada-based North American Forum on Integration organized the conference entitled: "Forging North American Energy Security," which focused on Mexico as well as the increasingly interwoven energy networks of the United States, Mexico and Canada.

Ever since Sept. 11, energy security has been an even greater concern of the United States. Many analysts argue that the United States relies too much on unstable Middle Eastern energy sources. So now, even closer scrutiny is being given to Mexico and Canada, which plans to develop $30 billion worth of petroleum projects in Alberta, Newfoundland and natural gas off the Atlantic Coast, according to Shawn Smallman, director of Portland State University's International Studies Program. The question is whether North American partners of NAFTA can agree on a shared vision of energy security, the forum's organizers said.

Enormous opportunity in Mexico

"Mexico represents an enormous opportunity for new energy investment and production, but as we engage in more and more cross-border commerce and dialogue, it is important to look at Mexico in the North American context," said Ed Kelly, vice president of Wood Mackenzie's North American gas and power team.

Andres Rosental, a Forum board member and president of the Mexican Council on Foreign Relations, said the attention to energy, something that wasn't included in the North American Free Trade Agreement, needs to be addressed.

"As a region, North America has among the richest and most diversified energy resources in the world, which favors a trilateral policy that … benefits the three nations," he said.

Despite the absence of formal energy integration initiatives the three countries are becoming increasingly integrated when it comes to energy.

Mexico, the world's fourth largest crude producer, has steadily increased its oil exports to the United States, making it a major supplier of crude.

U.S. companies already are building power plants in Mexico and are vying to build regasification terminals in Baja California to supply energy to California.

More than a dozen gas pipelines stretch across the U.S.-Mexico border. In early April a subsidiary of Houston-based Global Industries Ltd. announced it had won a $100 million pipeline installation project from Pemex to install pipelines in the offshore Cantarell field.

The cross-border energy needs also were underscored by an early April report on a major power outage that caused a blackout on Aug. 14, darkening all or parts of eight states from Michigan to New York, and areas of Canada. The U.S.-Canada Power System Outage Task Force report found the power industry's disregard of its rules intended to ensure the reliable flow of electricity contributed significantly to last summer's blackout, the Associated Press reported.

Challenge to coordinate policy enormous

Rosental said the challenge to coordinate a cohesive energy policy is enormous but crucial.

"Mexico, a country that is fortunate to have energy wealth — is facing a serious deficit in gas and electricity that is inhibiting our growth. If we don't find a solution that allows us to attract financial and technical resources needed to exploit the huge fields of natural gas in the country's northeast, then inevitably we will … continue to pay high prices for gas that we will be obliged to import."

Mexico needs to develop all of its energy resources, along with the United States and Canada, he said, because each country "has its own interpretation" of how to best meet the goal of an integrated energy policy. It's important to take steps toward meeting that goal, he said. ●

GULF OF MEXICO

Newfield takes on partners to drill 'ultra-deep' Treasure Island prospect

Newfield Exploration, following a lengthy search for a partner to pick up the costs of an "ultra-deep" exploration well on its Treasure Island play in the shallow waters of the Gulf of Mexico's continental shelf, has signed on ExxonMobil, BP, and a third party which Newfield would not disclose.

"We are extremely happy," Newfield spokesman Steve Campbell told Petroleum News April 22. That's because Treasure Island leases are set to expire in March 2005. Under the terms of the agreement, the Treasure Island well must be spud no later than Jan. 31, 2005.

ExxonMobil will serve as operator, targeting the Blackbeard West Prospect that covers multiple blocks in the South Timbalier and Ship Shoal regions offshore Louisiana, Newfield said.

The well is being designed to test prospective objectives that range from 27,000 feet to more than 30,000 feet, which likely would make it the deepest well yet drilled on the Gulf's continental shelf. Shell was the first explorer to break the 25,000-foot ultra-deep barrier on its Shark prospect at South Timbalier. It was a dry hole.

Analysts speculated that an ultra-deep well on the shelf could cost upward of $50 million or more, although it's believed Shell paid far less for Shark.

Newfield, an exploration and production independent based in Houston, Texas, said the undisclosed third party's participation is still subject to approval by its board of directors. Newfield will be carried for a 23 percent working interest in Blackbeard. Just how the remaining interest would be split among Newfield's partners also was not disclosed.

The Blackbeard West Prospect is subject to a 1.25 percent overriding royalty interest held by the Treasure Island Royalty Trust, which was established in connection with Newfield's November 2002 acquisition of independent EEX. The sole purpose of the trust is to hold non-expense bearing overriding royalty interests in future production from the ultra-deep zones of the Treasure Island area, Newfield said.

—**RAY TYSON,** Petroleum News Houston correspondent

NORTH SLOPE, ALASKA

Nikaitchuq tests at 960 bpd

Kerr-McGee Corp.'s Nikaitchuq No. 1 exploration well at the Northwest Milne prospect tested 960 barrels per day of 38 degrees American Petroleum Institute crude oil.

The company said in March that it encountered "high-quality hydrocarbons" at the Nikaitchuq No. 1, and was drilling the No. 2, expected to test the down-dip limit of the reservoir.

Oklahoma City, Okla.-based Kerr-McGee said April 19 that the Nikaitchuq No. 1 vertical well "production tested more than 960 barrels per day of 38 degree API crude" from the Sag River formation. It also said that if the prospect is developed "horizontal wells would most likely be utilized, which would be expected to produce at higher flow rates than the vertical well."

The company said the Nikaitchuq No. 2 was drilled 9,000 feet southwest of the No. 1 well, "and successfully extended the accumulation down dip." Kerr-McGee spokeswoman Debbie Schramm told Petroleum News April 19 that the rig is off the ice at the Northwest Milne prospect. She also said that the company did not test the No. 2 well.

The company said it is evaluating the data collected and re-calibrating 3-D seismic of the area "to define appraisal drilling plans for the upcoming winter drilling season."

The Northwest Milne Point prospect is operated by Kerr-McGee, which holds a 70 percent interest in 12,000 acres, with an option to acquire an additional 54,000 acres.

Denver, Colo.-based Armstrong Alaska, which holds the remaining 30 percent interest, assembled the Northwest Milne prospect and brought in Kerr-McGee as operator and majority partner.

The wells are in the Spy Island area in shallow waters of the Beaufort Sea off Alaska's North Slope, and were drilled from ice with a land drilling rig, requiring about four miles of ice road from the existing North Slope road system at Oliktok Point.

—**KRISTEN NELSON,** Petroleum News editor-in-chief

NORTH AMERICA

U.S. gains 12 rigs, Canada loses 11

The number of rotary drilling rigs operating in North America during the week ending April 16 increased by one to 1,287 rigs, and was up by 184 rigs compared to the same period last year, according to rig monitor Baker Hughes.

The total number of rigs operating in the United States increased by 12 from the previous week to 1,150, up by 156 rigs compared to the same period last year.

The Canadian rig count, due in part to a winding down of the winter drilling season, continued its decline during the recent week, falling by 11 to 137, but was up by 28 rigs versus the year-ago period.

The total number of rigs operating in the United States increased

see **RIGS** page 13

● GULF OF MEXICO

Neptune coughs up more pay, unit partners consider their options

By RAY TYSON

Petroleum News Houston Correspondent

Results from the latest appraisal well at the Neptune prospect confirms what is looking more and more like another commercial oil discovery in the Gulf of Mexico's prolific Atwater Foldbelt region.

The Neptune-7 well, drilled on Atwater Valley block 618 to a total depth exceeding 18,700 feet, encountered a hydrocarbon column with about 114 feet of net oil pay, operator BHP Billiton said April 20.

More important than its modest pay thickness, Neptune-7 is situated between Neptune-5, which was drilled in 2003 on Atwater Valley block 574 and encountered an impressive 500 feet of net oil pay, and Neptune-3, which was drilled in 2002 on Atwater Valley block 617 and logged 130 feet of net pay.

"The Neptune-7 well confirms information found from previous drilling in the field," BHP spokesman Patrick Cassidy said. "It's an encouraging result."

Partners not ready to sanction development

Even with the mounting evidence, BHP and its partners are not quite ready to sanction Neptune for commercial development.

"Pre-feasibility studies into the development of the Neptune resources are progressing and expected to be complete by the end of 2004," BHP said. "Information collected from the (Neptune-7) well will be used to help determine the size of the resource and options for its development." Neptune-7, 135 miles from the Louisiana Coast,

see **NEPTUNE** page 12

● NEWFOUNDLAND

Dreaming of a breakthrough

Province's west coast has history of unfounded rumors, financial troubles; consortium of junior explorers adds to list of setbacks, but ready to try again

By GARY PARK

Petroleum News Calgary Correspondent

For decades there have been dreams of a big pay-off, but instead the history of western Newfoundland has been one of hopes raised, hopes dashed.

Not unlike the often frustrating search for oil in the Grand Banks region off Newfoundland's east coast, which is now producing more than 300,000 barrels per day, the west coast has been a litany of failures and dampened expectations.

The latest stumble occurred earlier this month when a consortium of junior E&P companies led by Contact Exploration stopped drilling an onshore well at Parson's Pond 460 feet short of the planned total depth of almost 4,000 feet.

Oil seepages from Parson's Pond were first noticed almost 200 years ago and were used as a cure for rheumatism. An exploratory well was drilled in 1867.

But the latest serious attempt to commercialize the region has hit a wall with the decision to cement Contact's C$1 million well and return the drill rig to its owners after the drill bit was unable to penetrate a fault zone and reach the main target.

Pat Laracy, president of Vulcan Minerals, one of the partners, said the feeling was more one of frustration than disappointment, given that the well is not yet a dry hole.

He said the only answer now is to return with a dif-

see **DREAMING** page 12

● GULF OF MEXICO

Kerr-McGee hits at Ticonderoga prospect

Gulf of Mexico discovery well penetrates 250 feet of 'high-quality' pay; holds up to 50 million barrels of primarily oil

By RAY TYSON

Petroleum News Houston Correspondent

Oklahoma's Kerr-McGee has kicked off its 2004 drilling season in the deepwater Gulf of Mexico with an oil discovery at the Ticonderoga prospect on Green Canyon Block 768.

If deemed commercial, Ticonderoga could be tied back as a satellite to Kerr-McGee's Constitution development, the company said April 19. The prospect is in roughly 5,250 feet of water and about five miles south of Constitution.

The Ticonderoga exploratory well and an initial sidetrack encountered 250 feet of net "high-quality" hydrocarbon pay, mainly oil, in three separate zones, Kerr-McGee said. The field "offers potential resources" of 30 million to 50 million barrels of oil equivalent, the company said.

The company said it is currently performing reservoir modeling, with plans for additional appraisal work this year. The Ticonderoga well was spud on March 21 and drilled to a total measured depth of 13,556 feet using the offshore Amos Runner drilling rig. A sidetrack confirmed the down-dip limit of this reservoir, the company said.

The discovery well was operated by Kerr-McGee with a 50 percent interest in the discovery. Fellow exploration and production independent Noble Energy holds the remaining 50 percent interest.

see **TICONDEROGA** *page 13*

continued from page 11

DREAMING

ferent drilling technique to break through the fault zone, once the results so far have been analyzed. Contact has estimated that the structure could hold 100 million barrels of recoverable oil.

Vulcan moving ahead

Undeterred, Vulcan is moving ahead with its own drilling application for southwest Newfoundland, with hopes of spudding a well this spring. But an earlier well in that region was abandoned three years ago by American Eagle Reserve Canada when it encountered drilling problems.

In 1995, there was a frenzy of speculation involving a secretive well by Hunt Oil and PanCanadian (which has since merged with Alberta Energy Co. to form EnCana). The well lit up the night sky with a flare after being drilled at a cost of C$10 million-$15 million to a depth of almost 15,000 feet, triggering talk of a 100 million barrel find. But by mid-1996 the two companies plugged and abandoned the well.

In 1999, Canadian Imperial Venture said it was poised to become the first company to produce oil in Newfoundland from a land-based well, after farming into the Hunt-PanCanadian acreage, then eventually taking over as operator after the other two exited the play. The junior said it was counting on 3,270 bpd of oil and 48 million cubic feet of gas, starting in 2000.

Canadian Imperial then announced in 2001 that it planned to spud the first of three onshore evaluation wells to support a project that could yield as much as 10,000 bpd of light crude and "significant volumes" of associated gas.

In May 2002, creditors of Canadian Imperial who were owed C$11.1 million gave the company a second chance to prove that its onshore properties held commercial oil reserves. That came just four months after Canadian Imperial admitted it was suffering from a "significant cash-flow deficiency" because of cost overruns at the venture on the Port au Port Peninsula.

But by late 2003, Canadian Imperial had filed for insolvency reorganization after failing to produce at least 10,000 barrels in any two consecutive months. ●

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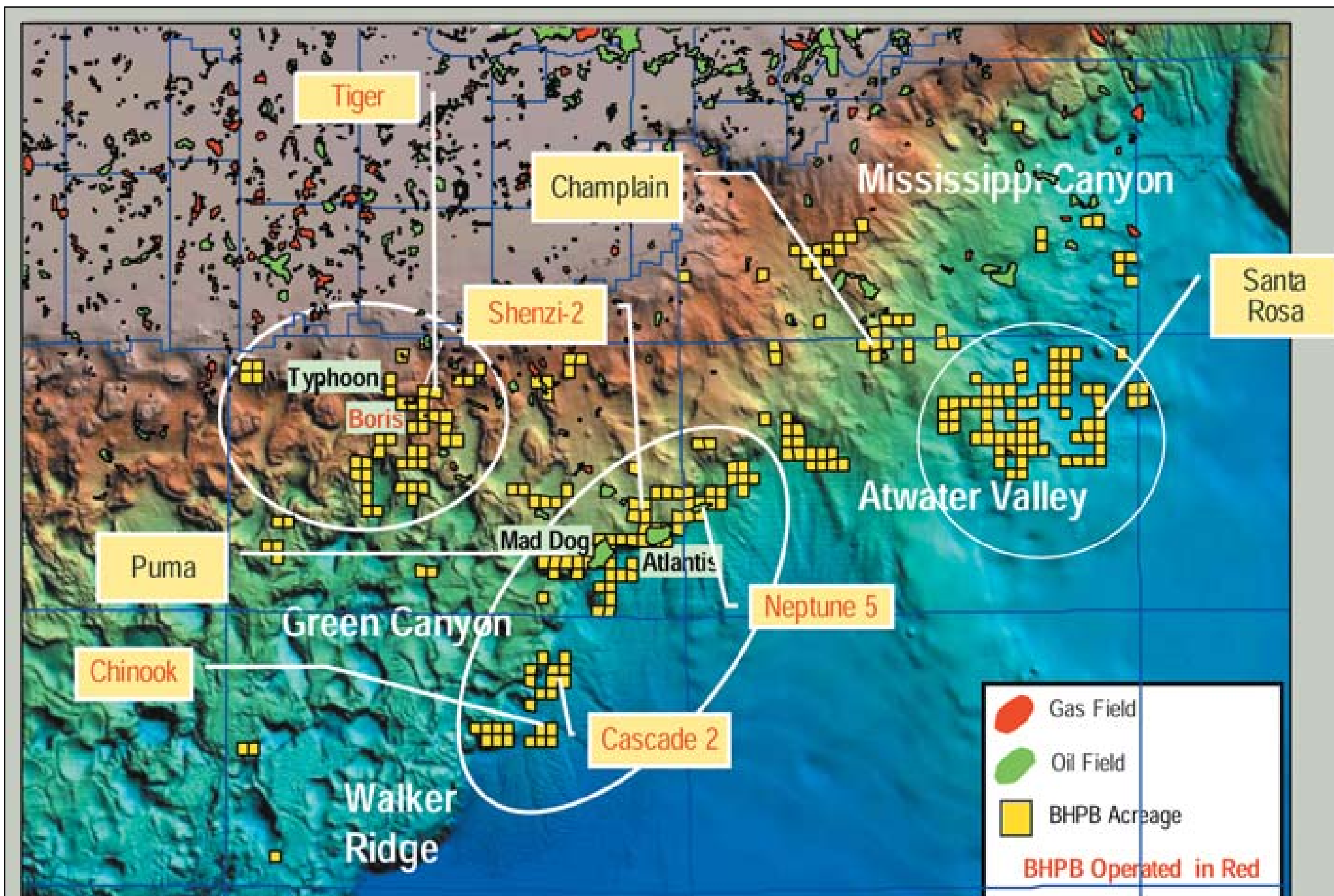
NEPTUNE

was drilled in nearly 6,260 feet of water using the GlobalSanteFe-operated drillship Explorer.

A key turning point in Neptune came last September when announced results from a pair of sidetracks not only confirmed the 500 feet of net oil pay encountered by Neptune-5 but extended its reach. One of the sidetracks extended by 100 feet the gross 1,200-foot hydrocarbon column down dip of the original well, and the other encountered another 120 feet of net oil column up structure.

The Neptune prospect is in the Atwater Foldbelt region of the Central Gulf of Mexico, the same area that has produced such discoveries as BP's Mad Dog and Atlantis fields, which are currently in development, and the BHP-operated Shenzi discovery, where appraisal activities are currently under way.

BHP holds a 35 percent working interest in the Neptune Unit. Marathon Oil holds a 30 percent interest, Woodside Energy (USA) a 20 percent interest, and Maxus (US) Exploration Co., a subsidiary of Repsol YPF, a 15 percent interest. ●



COURTESY OF BHP BILLITON

The Neptune prospect is in the Atwater Foldbelt region of the Central Gulf of Mexico, the same area that has produced such discoveries as BP's Mad Dog and Atlantis fields, which are currently in development, and the BHP-operated Shenzi discovery, where appraisal activities are currently under way.

COURTESY OF KERR-MCGEE

Amos Runner drilling rig

continued from page 12

TICONDEROGA

Constitution would be hub

"Consistent with our strategy of creating hubs in core areas, our nearby Constitution facility would allow for the successful development of Ticonderoga, which would further enhance the original economics of the Constitution project," said Dave Hager, Kerr-McGee senior vice president responsible for oil and gas exploration and production.

Earlier this year Kerr-McGee approved development of its 100 percent owned Constitution field on Green Canyon blocks 679 and 680, creating the company's sixth deepwater hub in the Gulf of Mexico.

Dave Hager, Kerr-McGee senior vice president

Constitution has estimated proven and probable resources of roughly 110 million barrels of oil equivalent. The total project costs, including $125 million spent on leases and drilling, would be about $600 million.

Constitution would be developed with a truss spar similar in design to Kerr-McGee's previous three truss spars. Like the Nansen, Boomvang and Gunnison spars, the Constitution spar will have capacity to process 40,000 barrels of oil per day and 200 million cubic feet of gas per day. The hull will be 98 feet in diameter and about 550 feet long. It will be built by Technip at its Pori, Finland yard, where the hulls for Kerr-McGee's Neptune, Nansen, Boomvang and Gunnison spars were fabricated.

"Constitution is the next milestone in our successful deepwater exploration and development program," said Luke R. Corbett, Kerr-McGee's chief executive officer.

In a similar-type hub project, the company said drilling activities have ended at the Dawson Deep prospect and it is being evaluated as a possible sub-sea tieback to Kerr-McGee's producing Gunnison facility. Dawson Deep is located about three miles from Gunnison on Garden Banks 625.

Ticonderoga was the first of about 10 exploration wells Kerr-McGee plans to spud over the next few months in deepwater Gulf of Mexico. They include Tin Cup near the Gunnison field on Green Canyon Block 582, a potential 40 million barrel satellite, and the Chilkoot wildcat on Green Canyon Block 320. ●

> *"Consistent with our strategy of creating hubs in core areas, our nearby Constitution facility would allow for the successful development of Ticonderoga, which would further enhance the original economics of the Constitution project."*
> **—Dave Hager, Kerr-McGee**

continued from page 11

RIGS

by 12 from the previous week to 1,150, up by 156 rigs compared to the same period last year. Land rigs accounted for the entire gain. Offshore rigs were unchanged at 91, as well as inland water rigs at 16.

Of the total number of rigs operating in the United States during the recent week, 992 were drilling for natural gas and 156 for oil, while two were being used for miscellaneous purposes, according to Baker Hughes. Of the total, 755 were drilling vertical wells, 289 directional wells, and 106 horizontal well.

Among the leading producing states in the United States, Oklahoma gained four rigs for a total of 162, while California's rig count rose by one to 24. New Mexico's rig count fell by four to 61. Texas was down by three rigs to 499. Wyoming was down by four rigs to 57. Louisiana was down by three rigs to 167. And Alaska was down by two rigs to 10.

—RAY TYSON, Petroleum News Houston correspondent

natural gas

ALBERTA

Ban sought on use of groundwater pending new coalbed methane rules

An Alberta farm group wants the provincial government to ban the use of groundwater in the coalbed methane process until new regulations take shape.

The lobby group has sent letters to Premier Ralph Klein and three cabinet ministers calling for a moratorium until a multi-stakeholder advisory committee makes recommendations to the government and the Alberta Energy and Utilities Board in November.

Energy Minister Murray Smith, while viewing coalbed methane as a major potential source of supply, revenue and jobs, said it is "imperative government and industry get it right."

A spokesman for the farmers said one coalbed methane project is using water in southern Alberta and four more are in the regulatory stream.

He said rural residents fear Alberta's fresh water supplies could be drastically affected, given the "enormous" impact of coalbed methane activities in Wyoming, Colorado and other U.S. states, where water wells have been severely depleted.

Up to this point, coalbed methane drilling in Alberta has been concentrated mainly on thinner coal seams and has tended to produce little or no water, unlike the significant water volumes in the United States that have set environmentalists, landowners and

see **BAN** page 15

MAT-SU BOROUGH, ALASKA

Alaska proposes CBM development guidelines

The Alaska Department of Natural Resources Division of Oil and Gas issued a "public review draft" April 19 of proposed standards for coalbed methane development of state-owned resources in the Matanuska-Susitna Borough.

The agency said it will accept comments through the end of business May 21, and will also hold public meetings in early May to take comments.

It said it would use the enforceable standards "when making decisions related to coalbed methane development in the Mat-Su Borough," including decisions on leasing and licensing, plans of operations and unit decisions and will also recommend that the Matanuska-Susitna Borough and the Alaska Oil and Gas Conservation Commission adopt similar standards.

Following public debate last summer, Commissioner of Natural Resources Tom Irwin announced in October that the department

see **GUIDELINES** page 15

● MAT-SU BOROUGH, ALASKA

Evergreen Resources uses Raton model for Alaska

Company dewatering pilot holes in Matanuska-Susitna Borough north of Anchorage, completing core drilling; 7,000 feet already acquired

By **KRISTEN NELSON**

Petroleum News Editor-in-Chief

Evergreen Resources (Alaska) is dewatering pilot coalbed methane wells and completing a core drilling program in the Matanuska-Susitna Borough area north of Anchorage.

What the company would like to find in the area is a coalbed methane resource comparable to what it is developing in the Raton basin in Colorado, where it is drilling on more than 300,000 acres and expects to drill some 1,500 wells.

Corri Feige, the company's manager of government affairs and public relations, told the Society of Petroleum Engineers in Anchorage April 12 that the company has drilled four of five core holes planned for this winter in the Mat-Su area and was getting ready to complete the fifth.

Denver, Colo.-based Evergreen Resources acquired the Pioneer unit, almost 74,000 acres in the Palmer-Wasilla area north of Anchorage, from Ocean Energy and Unocal in 2001, and in 2002 and 2003 the company drilled two four-hole coalbed methane pilots, Feige said. Only one of the wells pilot No. 2, the Cook No. 1 on Church Road, was completed, and that well was "shut in and put into production shutdown the first of October 2003." She said there were porosity and permeability issues and calcium carbonate cement at the 3,300-foot depth the company was testing.

But, she said, there are shallower horizons in the pilot No. 2 wells, as well as in pilot No. 1, which is in production testing, and Evergreen may test those shallower horizons at a later date.

Pilot No. 1, along the Parks Highway between Wasilla and Houston, "will remain in production testing throughout 2004," Feige said. Then Evergreen will "compile all of the new geophysical data and the new geologic core data coming out of the core program, then we'll determine if we want to step up and test those shallower coal horizons."

New look at the Susitna basin

Core from the five holes is estimated at 10,000 feet, she said, and the company has acquired a little more than 7,000 feet from the first four cores.

JUDY PATRICK

Corri Feige, Evergreen Resources

Feige said the first four holes have given Evergreen "a much better understanding — and a new look at the Susitna basin." There is "a great deal more complexity to the basement structure and the basement fabric in the Susitna" than publicly available data indicated, she said.

The company's "highest priority" will be "to advance our in-the-ground program," Feige said. That includes analyzing data from the core program, combining it with "some new geophysics" and updating the company's "geologic assumptions for the Susitna basin."

Then the company will target and drill its next pilot or pilots, she said, and "also advance our drill testing within the Pioneer unit with at least one core hole and possibly another pilot within the Pioneer unit…"

Raton the working model

In Evergreen's major producing area, the Raton basin in Colorado, the company produces about 170 million cubic feet per day out of some 1,100 wells, with well costs in the range of $300,000 to $500,000 per well, and a 2004 budget of $82 million. Feige said the company anticipates another seven years of "full-blown, full-scale development" in the Raton, or five years if the development program is really accelerated.

Shane Gagliardi, the company's Alaska petroleum engineer, said full development in the Raton is expected to be some 1,500 wells.

see **EVERGREEN** page 15

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EVERGREEN

The coals in Alaska appear to be younger than those in the Raton basin, Gagliardi, said, so the gas content in Alaska might not be as high — but the coal in Alaska is thicker, he said, so it's possible that "what we lose in gas content we can make up for in thickness."

He said that with "virgin coals where no dewatering has happened, you wouldn't expect to have much gas for the first year or first 18 months" until enough water has been produced to reduce bottom hole pressure. The pilot holes are making some 3,000 cubic feet per day of natural gas, with about 300 barrels a day of water from one well and roughly 20 barrels per day from the others. All of the water in Alaska is re-injected, and Gagliardi said tests on the produced water show it's similar to Raton basin coalbed methane produced water used to water cattle.

Production in Alaska is with progressive cavity pumps, he said, compared to the Raton basin, where about 70 percent of the company's wells are on progressive cavity pumps and about 30 percent on rod lift pumps.

Educational program also continuing

Evergreen's work in Alaska has created a need to educate the public and public officials about coalbed methane development, Feige said, and she noted that the company is finding many of the same public relations issues in the Matanuska-Susitna basin that it dealt with when it began work in the Raton basin in 1993-94.

Property values are one concern and Evergreen did a survey of property resale values in the Raton from 1997 through 2001.

"Property values, resale values, in the gas development area, increased by 17 percent," she said, compared to an increase of only 8 percent outside the development area.

One study by the Southern Colorado Economic Council showed a 22 percent decline in certain property values, Feige said, but "in fact, it was not a decline, there was property removed — actual acreage taken out of the equation, with those properties, which amounted to the decline of 22 percent."

She said Evergreen attributes increased property values in its development areas to "improved quality of life and the higher tax base." Evergreen's Raton basin development is in Las Animas county, and in addition to a total investment of more than $500 million west of Trinidad, 220 full-time employees in Trinidad and a 2003 payroll of about $10.7 million, Evergreen is the county's largest tax payer, paying $2.9 million last year.

On the development side, the two main issues in both Alaska and Colorado "are environmentally sensitive development and protection of the view shed," she said, and in both areas Evergreen "has used the natural typography and used the vegetation to shroud the facilities."

Split estate, other basins, issues in Alaska

Feige said split estate — separate surface and subsurface ownership — is a big issue in Alaska, and an issue where a lot of education is needed.

"Most people do not realize that there is over a hundred years of history in the United States with split estate," she said, noting that most states west of the Mississippi have split estate, so oil and gas ownership can be different than surface ownership.

Surface-owner protections are mandated in Alaska's regulations, she said, and Evergreen's role has been to support the state in its effort to educate the public, since split estate "really is a state agency issue."

An educational issue Evergreen faces is explaining what coalbed methane development looks like.

Alaskans, she said, have been told that Powder River and San Juan basin coalbed methane developments are typical, not what Evergreen has done in the Raton basin.

> *Pilot No. 1, along the Parks Highway between Wasilla and Houston, "will remain in production testing throughout 2004." Then Evergreen will "compile all of the new geophysical data and the new geologic core data coming out of the core program, then we'll determine if we want to step up and test those shallower coal horizons."*
>
> **—Corri Feige, Evergreen Resources (Alaska)**

Feige said there are big differences.

The Powder River basin, she said, is "absolutely anomalous in terms of coalbed methane development basins" because the coal is very shallow with thick, highly fractured, highly permeable coals. Powder River coalbed methane also produces twice as much produced water as gas, "and that's absolutely backwards, when you compare it to all of the other producing basins in the nation."

And the Powder River basin is "flat, there's no typography, there's no vegetation," so everything is visible.

The San Juan basin is also somewhat flat, she said, but the worst problem there is that coalbed methane development has sometimes been done from conventional oil and gas pads "in an effort to limit additional impacts within the basin." Because the conventional pads are so much larger than modern coalbed methane pads, "there's been a lot of bad press and spin," Feige said. ●

Evergreen applies to drill additional core hole in Pioneer unit instead of Willow-Fishhook

Evergreen Resources (Alaska) has applied to the Alaska Department of Natural Resources, Division of Oil and Gas, to amend the plan of operations approval for its mineral core drilling program to add an additional core hole, the Slats No. 1.

Both surface and subsurface are privately held, the core hole is being drilled for geological information only and does not involve dewatering coal seams or gas production, the state said in a request for comments. The site, accessed from existing roads, is in section 17, township 17 north, range 2 west, Seward Meridian, south of the Parks Highway and east of Ridgecrest Road.

A drill pad approximately 45 feet by 60 feet will be in an existing clearing; drilling will begin in April and take about a month.

In a letter to the division, Corri Feige, manager of governmental affairs and public relations for Evergreen Resources (Alaska), said the company would like to defer drilling the previously permitted Willow-Fishhook No. 1 core hole and instead drill this core hole within the Pioneer unit, with privately held subsurface mineral rights currently under lease to Evergreen.

Initial results of the coring program, Feige said, "indicate that the geologic nature of the Susitna basin in the vicinity of the Willow-Fishhook #1 is more complex than originally thought," and the company "would like the opportunity to analyze the recently acquired core data and work it into our geologic interpretation of the region, in order to determine if the Willow-Fishhook #1 is still a reasonable location for an effective geologic exploration core hole."

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BAN

agricultural producers at odds with the industry.

Under current Alberta regulations, produced water must be collected and re-injected into a similar underground water source.

The current review is designed to ensure regulations covering coalbed methane development achieve balanced economic benefits for Albertans while protecting land, water and water resources.

Energy Minister Murray Smith, while viewing coalbed methane as a major potential source of supply, revenue and jobs, said it is "imperative government and industry get it right.

"We want to learn from the experiences of other regions and from the wells that have been drilled so far in Alberta in order to promote responsible, sustainable development," he said.

—GARY PARK, Petroleum News Calgary correspondent

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GUIDELINES

would begin a public process to establish enforceable standards for Mat-Su Borough coalbed methane development. A number of public meetings were held and the department said those meetings were the basis for the proposed standards, which will apply to coalbed methane decisions the department makes in the Mat-Su Borough on "lands subject to a state oil and gas lease or contained within an oil and gas unit." Mitigation measures will be imposed on leases and licenses and conditions will be imposed on plan of operation approvals.

Public notice provisions

In addition to existing requirements for public notice, the department will provide public notice and a 90-day comment period for shallow gas lease applications or best interest findings for oil and gas licenses or lease sales through a variety of methods including display ads and public service announcements on radio stations.

The agency will also provide a 30-day public notice and review/comment period for each phase of coalbed methane development requiring a plan of operation — exploration, development and transportation. The applicant will be required to notify owners of surface land within a half-mile by certified mail, and there will also be published notices.

The standards include requirements for disclosure of fracturing materials in plans of operations, posting hazardous materials lists at each drill site, a written emergency preparedness and response plan and as-built surveys for permanent coalbed methane facilities.

There are setbacks for drill pads and compressor stations, and a prohibition against construction of either in subdivisions "containing lots predominantly sized at five acres or less." Both noise and visual mitigation are required, as is light shielding.

Split estate brochure

The standards require "good-faith efforts to negotiate a surface use agreement" and mandate the department to develop an informational brochure on split estate issues.

Recommendations to other agencies include that the Mat-Su Borough establish standards similar to the state's "to be applied by the borough on non-state managed lands."

The department recommends that the Alaska Oil and Gas Conservation Commission adopt regulations to prevent production of coalbed methane from coal seams that serve as a current source of drinking water, continue its efforts to develop a public notice procedure for permits to drill coalbed methane wells and continue its efforts to develop requirements for proposed coalbed methane wells of baseline testing and on-going monitoring for water quality of any existing drinking water that may be negatively affected by the coalbed methane production.

—PETROLEUM NEWS

WYOMING/MONTANA

Galaxy boosts ownership in CBM

Denver's Galaxy Energy, through its Dolphin Energy subsidiary, said it has increased its working interest by an average 50 percent in about 8,950 gross acres on the Pipeline Ridge, Buffalo Run East and West, Horse Hill, and Dutch Creek coalbed methane properties near Sheridan, Wyo.

The independent said April 19 that the acquisition boosted its working interest to near 100 percent in about 12,000 gross acres and includes 63 wells that are in various stages of drilling, completion, and connection to infrastructure facilities. The acquisition price for the additional working interest was $300,000 cash and 360,000 shares of restricted stock, Galaxy said.

Elsewhere in the Powder River basin, Dolphin has tendered payments of $1.69 million and $47,500, respectively, to earn an assignment of its 12.5 percent working interest in about 206,000 gross acres, and its 25 percent working interest in roughly 26,600 additional acres in Montana.

—RAY TYSON, Petroleum News Houston correspondent

WYOMING

Wyoming jobs soar on mining, gas

In the 1970s, it was coal mining. Then a boom in oil drilling.

Now, Wyoming's deep and abundant natural gas fields are buoying the state's economy, keeping unemployment low as people in other states struggle to find work and creating jobs at one of the fastest paces in the nation.

In the past year, Wyoming added 5,300 jobs to its economy, with many of those sprouted from its mining industry and drilling for natural gas, oil and coalbed methane, state economist Wenlin Liu said. Wyoming's 2.2 percent annual job growth is one of the highest in the nation, with a 10 percent jump in mining jobs being the main contributor, Liu said. Job growth nationwide, meanwhile, remains stagnant and has dropped off sharply in some areas, according to the Wyoming Department of Employment's Research & Planning Section. Wages are also suffering.

In Wyoming, miners and gas drillers are breathing easy.

Like their counterparts in the oil and gas industry, miners make more than double the average resident at $56,000 a year and nearly four times the pay of some industries, such as retail, which averages a $17,000 salary, Liu said.

According to the Wyoming Oil and Gas Conservation Commission, the largest potential for natural gas drilling lies in Carbon, Sublette and Sweetwater counties, which have reported the highest rig utilization rates in Wyoming the past two years.

—THE ASSOCIATED PRESS

● CANADA

Report: Canada has enough gas for 80 years

National Energy Board report estimates 501 tcf of ultimate potential, but warns against any slackening of drilling effort

By GARY PARK

Petroleum News Calgary Correspondent

Canada has 501 trillion cubic feet of ultimate natural gas potential, more than 80 years of supplies at current rates of production, the National Energy Board has reported.

But turning the 286 trillion cubic feet rated as undiscovered into the discovered category will need an all-out drilling effort.

For Alberta alone, the challenge is to continue the frenzied pace of drilling that saw 80,000 gas wells completed in the 1990s.

"There will continue to be a need for the very high drilling levels experienced over the past few years in order to maintain current production levels," the federal regulator said in its updated status report, noting that the bulk of undiscovered resources will be found in high-decline shallow pools.

Spokesmen for the Canadian Association of Petroleum Producers and the Canadian Association of Oilwell Drilling Contractors were encouraged by the findings, suggesting the trends provide a counter-weight to those who believe the Western Canada sedimentary basin in particular is on an irreversible slide.

Of Alberta's preliminary ultimate gas resource of 207 tcf, the board estimates that 156 tcf is discovered, or confirmed by drilling, and 61 tcf remains undiscovered.

Its projected resource for Alberta is marginally higher than the 200 tcf estimate by the province's Energy and Utilities Board in 1992 and the Canadian Gas Potential Committee's 203 tcf in 2001.

More complete Alberta estimate under way

A more complete estimate for Alberta is expected by late 2004 or early 2005 when the federal and Alberta regulators complete a joint assessment.

Despite the 80,000 wells last decade, the federal board said there was no significant gain in gas resources. The major change came from switching resources from the undiscovered category to discovered.

For all of Canada, the report said one third of the estimated 286 tcf of undiscovered resources will be found in the Western Canada sedimentary Basin, which sprawls over most of the Northwest Territories and Alberta and stretches from the northeastern corner of British Columbia into Saskatchewan and Manitoba.

The Western Canada sedimentary basin contributes more than 90 percent of Canada's gas volumes and meets 23 percent of North America's needs.

The NEB estimates the basin has 178 tcf of discovered gas and 96 tcf undiscovered.

The board believes that only 2.5 tcf, or 4 percent of the total undiscovered resources are inaccessible, although another 1.5 tcf call fall into that category if undiscovered sweet gas in the path of expanding cities is not quickly developed.

Of the regional breakdown, the report said:

• The Mackenzie Delta/Beaufort Sea region has 9 tcf of discovered and 52 tcf of undiscovered gas, while the more remote Arctic Islands has 12 tcf discovered and 28 tcf undiscovered.

• For British Columbia, 15 tcf of gas had been produced by the end of 2002 and 35 tcf was undiscovered, but a more complete assessment is scheduled for 2005 if the board and the B.C. Ministry of Energy and Mines conduct a joint study.

• Estimates for the East Coast offshore put discovered resources at 14 tcf and undiscovered at 77 tcf, including 5 tcf and 23 tcf, respectively, for the Labrador Shelf, 4 tcf and 13 tcf for the Grand Banks and 5 tcf and 18 tcf for Nova Scotia.

The East Newfoundland/Orphan basin between the Grand Banks and Labrador has only 12 tcf of undiscovered potential, but that could change following a 2003 land sale when Chevron Canada Resources, ExxonMobil and Imperial Oil made combined work commitments of C$673 million for eight properties in the Orphan basin. ●

● SOUTHCENTRAL ALASKA

Piping North Slope gas to Southcentral Alaska might be cheaper

New study suggests a spur line from the north might be more economic than developing new Cook Inlet gas sources


JUDY PATRICK

Unocal's King Salmon platform in Cook Inlet

By KRISTEN NELSON

Petroleum News Editor-in-Chief

The cliff is getting to be a well-known graphic: It shows Cook Inlet natural gas production falling off steeply in this decade, first curtailing industrial uses and then utility and home heating.

Known reserves can be developed and more gas can probably be found at existing fields, but beyond that, into the realm of exploration, the costs rise. North Slope gas may be an attractive alternative, if the local market is large enough for gas — not at historically low Cook Inlet stranded gas rates — but still perhaps at a favorable price differential to Lower 48 Henry Hub prices.

The U.S. Department of Energy's Arctic Energy Office funded a study to look at future demand and supply of natural gas in Southcentral Alaska and evaluate options to meet the demand.

The study is still in draft, but Charles Thomas of Science Applications International Corp., one of the study's authors, said April 12 that a spur line to Southcentral from a North Slope gas pipeline may be an attractive option compared to exploring for and developing more gas in the Cook Inlet basin, if there is enough of a market for the North Slope gas in Southcentral Alaska.

Thomas reviewed study results to date for the International Association for Energy Economics in Anchorage April 20. A draft of the report is being circulated for comments, and Thomas said he expects that the final report will be released in early May.

Options considered include conventional natural gas resources, a spur line from a North Slope gas pipeline and limiting industrial usage.

More local gas

Increased natural gas resources in the Cook Inlet area could come from reserve additions in existing fields, exploration and discovery of additional conventional gas fields or unconventional gas.

The study looked at how much gas there might be in the Cook Inlet basin — the total endowment. Thomas said the study used "the accepted geologic theory that fields should be log normally distributed," and then tried to come up with a good fit for the basin total by filling in "missing" fields expected on a log-normal distribution, and concluded that a total of 25 to 30 trillion cubic feet additional gas in place was a good fit with both number of fields and resource distribution.

"Now, I emphasize an analysis like this, number one, doesn't prove it's there, and it certainly doesn't tell you where to go look," Thomas said.

Prime exploration areas could be restricted or off limits

The study looked at land classifications, and the authors concluded that because a major portion of the Cook Inlet land area is in federal and state wildlife refuges, parks and restricted areas, and because of historical production in some areas, that up to 30 percent to 50 percent of the prime exploration areas could have restricted access or be off limits.

> *… people advising on the study emphasized the cost, telling study authors, "Yes, we would say there's a lot of gas to be found in the Cook Inlet, it's pretty under explored, but it's not going to be free."*
> **—Charles Thomas, Science Applications International Corp.**

Thomas noted that historically exploration has been for oil, with gas discoveries prior to 1970 accidental. All exploration has been for structural plays, "and we would expect that there would be a lot of gas to be found in stratigraphic plays, and no one has even looked for that gas."

Of the estimated endowment of 25-30 tcf, about 20-25 tcf should be technically recoverable, with 13-17 tcf of that in upper Cook Inlet, including 2.5-3 tcf reserves additions to existing fields and 10-14 tcf possible in undiscovered resources.

But land access is required, application of 3-D seismic and long-reach drilling, "and major investments — this is not going to be free gas," Thomas warned. He said people advising on the study emphasized the cost, telling study authors, "Yes, we would say there's a lot of gas to be found in the Cook Inlet, it's pretty under explored, but it's not going to be free." Money will have to be spent to find the gas.

Cost of spur line gas

The option to bring North Slope gas to Anchorage included Alaska-only capital costs and throughputs based on the MidAmerican proposal for the line from Prudhoe Bay — now defunct, Thomas noted — and used estimates from Enstar for a spur pipeline. The result was an estimated tariff of $1.40 per thousand cubic feet to bring gas from the North Slope to Anchorage, not including the price of the gas. "This is what I'd call definitely our first-cut analysis," he said, but it does suggest that gas to Anchorage would have about a $1 per mcf cost advantage over gas to Chicago, creating "some opportunities for value-added products in Alaska — it might give us some competitive industrial businesses located in this region compared to people who are operating on gas at Lower 48 prices."

None of the options are cheap

Compare that to costs to find and develop gas.

None of this gas is cheap, Thomas said. Even proven reserves will require $77 million to develop.

"We hear discussions of 3-D seismic they want at Beluga and I think maybe at North Cook Inlet and any number of other places. Marathon has gotten approval for a new zone in the Kenai field," so an estimated 1.4 tcf of reserves growth is estimated to cost $465 million.

If 50 percent of the estimated undiscovered 13-17 tcf of gas had a finding and development cost of 75 cents per mcf that would be a total of $5.6 billion of investment for onshore discoveries, with offshore costs higher.

That kind of investment may be hard for Alaska operations to get, based on international competition for investment, Thomas said.

At $500 million for a spur pipeline, that "certainly may be an attractive option, but you do have to have a market for the gas." And the price for gas in Anchorage could be less than in the Lower 48.

Conventional gas coverage until 2012

Because of statements made by Agrium about the uncertainty of plant operation after 2005, Thomas said the study assumed that Agrium operations stop in 2005 and that the LNG plant stops operations at the end of its current export license, which runs through the first quarter of 2009.

If gas stops going to the Agrium fertilizer plant after 2005, and to the LNG facility after the first quarter of 2009, there is gas to meet commercial and residential consumer demand until 2012 with the existing reserves base, but the critical date is 2009 with existing reserves, if gas continues to be dedicated to industrial use.

Successful exploration and production effort will be needed to maintain current levels, and the economics look favorable for 30-100 bcf fields onshore and 120-220 bcf fields offshore, depending on the price of gas.

Thomas said exploration or reserves growth — or some combination — can provide additional supply and with an assumed growth in reserves of 1.4 tcf, there would be sufficient gas through 2025 for commercial and residential consumers and perhaps one industrial user.

Another option, Thomas said, is to import liquefied natural gas into Southcentral — a reverse of the current pattern, which sees LNG shipped from Southcentral Alaska to Asia.

The study did not analyze incremental contributing factors such as gas storage, conservation and increased efficiency and power generation alternatives such as wind, coal and hydropower. Thomas said the study did not estimate the economic potential of coalbed methane since there is such limited information available on its economic potential in Southcentral. ●

SOUTHWEST WYOMING

BLM proposes drilling halt in southwest Wyoming to protect miners

Oil and gas drilling must be stopped on 312,000 acres in southwest Wyoming to protect underground soda ash miners from flooding, cave-ins and other disasters, the government says. After 11 years of work, the Bureau of Land Management has unveiled a proposal designed to resolve conflicts between the two industries by halting area oil and gas development until trona mining is complete.

A public comment proposal is expected in the coming months.

In a meeting April 15, BLM officials told representatives from both industries that, while technically feasible, trona mining and oil and gas drilling are "incompatible" in the Green River Basin.

"It places unacceptable burdens on both industries," said Ted Murphy, assistant manager of the BLM's Rock Springs, Wyo., field office.

Southwest Wyoming holds almost all of the nation's mineable trona reserves. Trona ore is used to produce soda ash, which in turn is used in the production of glass, detergents and baking sodas.

But there is also about 2.7 trillion cubic feet of natural gas within the basin, according to BLM estimates. Most of that lies 8,000 feet or deeper underground.

Federal regulators fear miners could encounter those abandoned oil and gas stems underground with disastrous effects.

Under the BLM's proposal, 66 of the area's federal oil and gas leases would be suspended until all trona reserves have been mined and all miners cleared from working underground, Murphy said.

The plan is supported by Wyoming Gov. Dave Freudenthal, he said.

"(Freudenthal) said something to the effect ... that if something happened within the basin, it could affect the world's economic viability in terms of the soda ash industry," Murphy said.

—THE ASSOCIATED PRESS

ALBERTA

Coal project spurred by world demand

Elk Valley Coal Partnership is ready to invest C$120 million in a west-central Alberta mine, confident in the outlook for export markets.

The partnership, owned 65 percent by Fording Canadian Coal Trust and 35 percent by Teck Cominco, is aiming for production of 1.4 million tonnes in the fourth quarter and, depending on market demand, 2.8 million tonnes in 2005.

El Valley Coal President and Chief Executive Officer Jim Popowich said in a statement March 16 the prospects for coking coal sales are "very positive."

He said the 62 million tonnes of coal reserves in the permit area at the Cardinal River operation should provide jobs and economic benefits for 20 years.

Elk Valley Coal said mining activities will start once a mine license is obtained from the Alberta Energy and Utilities Board.

The partnership has budgeted C$50 million for the initial phase and another C$70 million if it decides to double production.

Fording is Canada's largest coal producer, while Elk Valley Coal is the world's second largest exporter of metallurgical coal, capable of supplying 25 million tonnes to the international steel industry.

—GARY PARK, Petroleum News Calgary correspondent

● DELTA JUNCTION, ALASKA

Environmental appeal halts Pogo gold mine

Northern Alaska Environmental Center appeals EPA water discharge permit, construction workers sent home

By PATRICIA LILES
Mining News Editor

An administrative permit appeal filed on April 13 by a Fairbanks-based environmental group has invalidated the federally issued water discharge permit for the Pogo gold mine being developed about 40 miles northeast of Delta Junction, Alaska.

Lawyers working for the Environmental Protection Agency's Region 10 based in Seattle will prepare a response within six weeks defending EPA's issuance of the project's water discharge permit under the National Pollutant Discharge Elimination System.

> *"It's not appropriate to bring in front of the EAB arguments that have not been responded to previously." The appeal filed by the Northern Alaska Environmental Center could be rejected on that basis. "It's a subject being discussed."*
> **—Keith Cohon, EPA assistant region council**

EPA's Environmental Appeals Board in Washington, D.C., a quasi-judicial review group, will rule on the appeal, taking anywhere from four to 12 months to decide, said Keith Cohon, EPA's assistant region council and the agency's lawyer handling the permit appeal.

"In the short term, it stays the affect of the permit … until the appeal is resolved," Cohon told Petroleum News on April 20.

The Environmental Appeals Board's decision can then be appealed to the Circuit Court of Appeals, and then on to the U.S. Supreme Court. An appeal in those judicial arenas has more stringent criteria defining impacted groups who can file such a claim, Cohon said.

To launch a valid appeal to the Environmental Appeals Board, an individual or group must have raised the same arguments or claims during the public comment period of the environmental review, he said. "It's not appropriate to bring in front of the EAB arguments that have not been responded to previously," he said.

The appeal filed by the Northern Alaska Environmental Center could be rejected on that basis. "It's a subject being discussed," Cohon said.

Ed Fogels, permit project manager for the Alaska Department of Natural Resources, said the appeal's issues were "kind of a shocker to us. We saw none of these issues ever raised during the process."

EPA issued its NPDES on March 15, the final regulatory permit needed for construction by Teck Pogo Inc., a joint venture formed in 1997 by Teck Cominco and Sumitomo Metal Mining to develop and mine the 5.5 million ounce underground gold deposit in the upper Goodpaster River valley.

Teck Pogo submitted its original plan of operations for Pogo in August 2000. A final environmental impact statement was released by agencies in September 2003.

No valid claims

The environmental group's claims of inappropriate discharges and seepage have "no validity," Fogels said.

One claim is that rain water running off of the dry stack tailings facility will go untreated into a 400-foot section of Liese Creek, upstream or before the stream's water is collected in a runoff pond, then treated and discharged.

"They're saying the water out of the dry stack needs to be regulated before it gets to the treatment plant," Fogels said.

The other claim involves classification of the recycle tailings pond as waters of the United States and says its contents should meet Clean Water Standards. "That's never going to happen because it's rock and dirt," Fogels said. "You don't regulate water that is going into a pond to be recycled into the mill for makeup or to be treated."

Water permit needed for construction

The water discharge permit is needed during the two-year construction of the underground hard rock mine and mill, where the number of builders may peak at 500. Water and sewage treatment facilities to accommodate those construction workers are covered by the NPDES.

More than 300 workers have started work at Pogo, beginning this winter with construction and operation of an ice road, cutting out a planned 50-mile route for construction of an all-season road and preparing temporary camp facilities for this summer.

> *Ed Fogels, permit project manager for the Alaska Department of Natural Resources, said the appeal's issues were "kind of a shocker to us. We saw none of these issues ever raised during the process."*

The lack of immediate water discharge caused Teck-Pogo to halt construction work, said Karl Hanneman, manager of public and environmental affairs and special projects.

"We don't have a permit to discharge, so we have to stop," he said on April 20. "We looked for ways we could continue, but EPA didn't find any legal method they could offer us to proceed."

Rather than treating the sewage and extracting water, raw sludge would have to be removed from Pogo. With no ice road remaining and construction of the all-season road only beginning, that would entail flying out sewage material.

Cohon said EPA offered a solution that would allow Teck-Pogo to continue construction during the appeal process. "They stopped construction because of the uncertainty of the ultimate outcome of the appeal," he said.

Construction of Pogo was originally estimated at $250 million. Prior to this year's work, Teck-Pogo spent almost $80 million on exploration, permitting, engineering and other pre-construction work. ●

● WASHINGTON, D.C.

Federal energy bill items next in line

Senate could vote this week on Alaska gas incentives added to tax bill

By LARRY PERSILY

Petroleum News Government Affairs Editor

This could be the week the U.S. Senate takes up tax incentives for an Alaska natural gas pipeline project.

Or maybe not.

After coming back to work from its Easter break, the Senate took up asbestos trust fund legislation and was scheduled to consider a victims' rights bill before moving to the next item on its agenda — a major international tax bill amended to carry at least $13 billion in domestic energy tax incentives.

Senators could vote on the bill this week or, if not, anytime before they leave for their Memorial Day holiday, said Chuck Kleeschulte, spokesman for Sen. Lisa Murkowski, R-Alaska. The schedule could depend on how Senate leaders decide to deal with 80-plus amendments proposed for the bill, he said.

"They're in the process of trying to winnow down the number of amendments," said John Katz, head of the state of Alaska's office in Washington, D.C. "Nobody wants to sit around while all that occurs," he said of the floor time that 80 amendments — and their debate — would consume.

After Memorial Day, time will be short in Congress.

Lawmakers will be back for parts of June and July, then break again for political party conventions before returning to finish up work before shutting down for the November elections. And if the tax bill passes the Senate, it would still need to make it through the House and then a House-Senate conference committee to resolve differences between the two chambers.

According to the congressional calendar, lawmakers had just 44 work days left in the session as of April 20, Katz said.

Key gas line provisions salvaged

Among the oil and gas incentives salvaged from the stalled comprehensive federal energy bill and added to the tax legislation are two key provisions intended to encourage construction of a pipeline to move Alaska North Slope gas to market.

"(Congressional) leadership clearly contemplates segmenting the energy bill," and tacking key provisions to other bills with better odds of passage, Katz said.

The energy bill has been stalled in the Senate since late November over several disputes, including its bulging multibillion-dollar cost and a controversial product liability waiver for manufacturers of a gasoline additive.

In picking up the energy bill's tax provisions and moving them into the corporate tax bill, Senate Republican leaders have given hope to incentives for an Alaska North Slope natural gas pipeline: tax incentives for construction of the North Slope gas treatment plant, and accelerated depreciation for the pipeline. A third provision added to the tax bill — a price floor for North Slope gas — is not expected to survive in the final legislation.

That still leaves two other gas line provisions from the energy bill that will need a new legislative home, Katz said. Those are the federal loan guarantee for the project and enabling legislation for fast-track permitting and judicial review. ●

● ALBUQUERQUE, N.M.

Energy summit: old and new energy sources both needed

By SUE MAJOR HOLMES

Associated Press Writer

A three-day North American Energy Summit held in Albuquerque, N.M., concluded that renewable sources will provide more energy in the future, but the old standards of oil, gas and coal will be the backbone of energy for years to come.

The summit, sponsored by the Western Governors Conference, brought together some 700 people from state, tribal, provincial and national governments in the United States, Mexico and Canada as well as representatives of industry, consumers and environmental advocates. It ended April 16.

Those attending also concluded that fuel efficiency in cars, buildings and utilities is the wave of the future, and that consumers need to be educated about the benefits of conservation and efficiency.

The summit shows that a united West, at least as far as energy issues, may not be all that hard to achieve, New Mexico Gov. Bill Richardson, chairman of the western governors, said in a closing news conference.

"We can, in fact, unite around the goal of creating a diversified energy supply," he said.

U.S., Canada, Mexico represented

The summit also points the way for the United States, Canada and Mexico to discuss how they can have a more integrated energy policy, said Richardson, who would like to see the 1994 North American Free Trade Agreement between the three nations include free trade in energy.

The gathering came up with numerous recommendations, which Richardson labeled "roadmaps, frameworks, for achievable results."

The Western Governors Association will consider the recommendations in trying to develop an energy plan at its annual meeting June 20-22 in Santa Fe. However, Richardson also noted energy will be only a part of that meeting, along with other common interests such as water and forest issues.

Manitoba, Canada, Premier Gary Doer said the challenge will be "to go beyond the talk, talk, talk to action, action, action."

The implications for the long term are to conserve and use efficient renewable energy as well as cleaner fossil fuels, Doer said.

"The old debates are over," he said.

Achievements from the summit are hard to measure in the short term, said Colorado Gov. Bill Owens, vice chairman of the association. Owens, who headed back to Denver before the closing session, said he believed "thousands of discreet conversations" among various participants could push ideas forward.

"What we achieved was a hell of a debate," Owens said.

Owens, a Republican who will take over from the Democrat Richardson as head of the association later this year, said he has not developed themes or plans for his upcoming tenure, but doesn't see significant changes from the leadership of Bill Richardson to that of Bill Owens.

"We try to make progress incrementally instead of throwing bombs," he said.

The summit's final session was a rundown of more than a hundred separate recommendations from 18 workshops that ran the gamut from the role of nuclear energy and how to use hydrogen in transportation and electrical generation to developing coal for the 21st century and sustainable energy.

Several speakers for the workshops said they were surprised at how much agreement they developed considering the various, often competing, interests involved. Others acknowledged their panels did not come to complete agreement — including a panel on the future of natural gas which presented five recommendations but also showed a blank page labeled "areas of consensus." ●

ALASKA

Potential Alaska, federal oil gas lease sales

Agency	Sale and Area	Proposed Date
DNR	Cook Inlet Areawide	May 19, 2004
DNR	Foothills Areawide	May 19, 2004
MMS	Sale 191 Cook Inlet	May 19, 2004
BLM	NE NPR-A	June 2, 2004*
BLM	NW NPR-A	June 2, 2004*
DNR	North Slope Areawide	October 2004
DNR	Beaufort Sea Areawide	October 2004
MMS	Sale 195 Beaufort Sea	March 2005
DNR	Cook Inlet Areawide	May 2005
DNR	Foothills Areawide	May 2005
BLM	NE NPR-A	June 2005
DNR	North Slope Areawide	October 2005
DNR	Beaufort Sea Areawide	October 2005
DNR	Alaska Peninsula Areawide	October 2005
MMS	Sale 199 Cook Inlet	2006
MMS	Sale 202 Beaufort Sea	2007
MMS	Chukchi Sea/Hope Basin	interest based
MMS	Norton Basin	interest based

** Selected tracts in northwest NPR-A, including some northeast area tracts along border of northeast and northwest areas.*

Agency key: BLM, U.S. Department of the Interior's Bureau of Land Management, manages leasing in the National Petroleum Reserve-Alaska; DNR, Alaska Department of Natural Resources, Division of Oil and Gas, manages state oil and gas lease sales onshore and in state waters; MHT, Alaska Mental Health Trust Land Office, manages sales on trust lands; MMS, U.S. Department of the Interior's Minerals Management Service, Alaska region outer continental shelf office, manages sales in federal waters offshore Alaska.

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PROSPECT

Canyon Block 734, according to the U.S. Minerals Management Service. The exploratory well, situated in 5,724 feet of water, is being drilled from Transocean's Cajun Express.

Thunder Hawk is believed to overlap Thunder Horse's official borders, and is said to have a resource potential of 300 million to 400 million barrels of oil equivalent. It specifically adjoins Mississippi Canyon Block 778 on the northeast side of the eight-block Thunder Horse complex, due to launch first production next year.

Most of area leased

Most of the leases within a 15-mile radius of Thunder Horse have been scooped up by various companies over the last four years, demonstrating the area's strong attraction to explorers. Other players in the region include Shell, ChevronTexaco, ConocoPhillips, Marathon Oil and big exploration and production independent Anadarko Petroleum.

WesternGeco, the world's largest seismic company, is currently shopping on its website non-proprietary charts of the Thunder Horse region, covering an expansive area ranging in size up to 48 blocks, to give prospective clients "a chance to see the real shape of the biggest field in the Gulf of Mexico."

However, because of the region's complex geology and reservoir imaging challenges, no one is certain of Thunder Horse's true potential. Some analysts believe the play could hold upward of 7 billion barrels of recoverable reserves, although 3 billion barrels is often cited as the likely mean.

The Boarshead basin, in the south-central part of Mississippi Canyon, houses three large geologic structures, including the one that spawned the primary Thunder Horse accumulation, the estimated 1 billion barrel Thunder Horse South field. Thunder Horse North, a separate BP discovery and part of the complex, holds additional estimated reserves of around 400 million barrels.

Seismic imaging difficult in area

Geologists say the problem with Boarshead is that all three structures within the basin, including Thunder Horse's, are overlain by so-called "allocthonous" salt bodies, which tend to distort seismic readings and make imaging difficult.

"Resolving structural complexity and stratigraphic details through adequate seismic imaging key to the success of future development of this field," according to one BP official.

Still, daily production at Thunder Horse is scheduled to begin next year with output of 250,000 barrels of oil and 200 million cubic feet of natural gas.

Thunder Hawk partners Dominion, Spinnaker and Murphy acquired Mississippi Canyon Block 734 in the 2000 Central Gulf of Mexico Lease Sale 175 on an uncontested bid of $2.1 million. Thunder Horse partners BP and ExxonMobil passed on the block.

Proteus Oil Pipeline and Endymion Pipeline will carry Thunder Horse oil and natural gas about 150 miles from Thunder Horse to storage facilities near New Orleans, La.

—RAY TYSON, Petroleum News Houston correspondent

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IMPERIAL

look at all kinds of ways to make recommendations to streamline the process, to make sure there's not waste in it," Hearn said.

"We shouldn't let this (project) slide around and lose it because of our own inability to stay focused."

The sense of urgency among partners in the Mackenzie Gas Project, headed by Imperial, has quickened with word April 20 that Calgary-based TransCanada will file an application for a trans-Alaska pipeline to the Canadian border.

Hart Searle, a spokesman for the Mackenzie partnership, told Petroleum News that what happens in Alaska is "something we have had in front of us for quite a while. We want to ensure that this tremendous opportunity (for producers, aboriginals, the North and Canadians) doesn't become a missed opportunity and we fall behind."

Alaska a threat

From a project standpoint, he said the Mackenzie partners must stay abreast of developments in Alaska, because any commitment to develop Alaska gas could pose a threat to the commercial viability of the Mackenzie project, as well as have an impact on the North American gas market and the availability of materials, supplies and contractors.

Searle said there is no specific date for regulatory filings, but he noted that regulators have indicated the pieces for the environmental assessment and other regulatory aspects could be in place by early July.

He said it's important for the Mackenzie partners to "ensure our work is in alignment and consistent with" the regulatory terms of reference and that they not act in any presumptuous manner.

Two months ago, Hearn said foot dragging by Canadian government officials involved in the environmental impact process could delay construction of the Mackenzie pipeline by six months.

On other issues, Hearn said Imperial, although "most concerned" about a projected C$2.1 billion cost overrun and one-year delay in an expansion of the Syncrude Canada oil sands complex, is still committed to successfully completing the project.

He said at the time he was concerned that the slow pace could result in fierce competition for labor and materials, given that Canadian pipeline companies Enbridge and Terasen are moving ahead with plans to build multi-billion-dollar pipelines from the Alberta oil sands.

Renewed focus from officials

Hearn said April 21 that those worries have been eased as officials have demonstrated a "renewed focus" on the project.

"I think we're doing better today, but ask me tomorrow and see how I feel," he said.

On other issues, Hearn said Imperial, although "most concerned" about a projected C$2.1 billion cost overrun and one-year delay in an expansion of the Syncrude Canada oil sands complex, is still committed to successfully completing the project.

With a 25 percent stake in Syncrude, Imperial is making "experienced personnel" available to "strengthen the project management team" and get the job completed by mid-2006.

Imperial also announced that it hopes to enter the regulatory phase next year with its Kearl Lake oil sands project in conjunction with sister company ExxonMobil Canada.

That development, which could cost C$5 billion to C$8 billion over the long-term, is targeted for a 100,000 barrel per day start up.

Hearn said drill tests at the Kearl leases have been "encouraging."

—GARY PARK, Petroleum News Calgary correspondent

Companies involved in North America's oil and gas industry

All of the companies listed above advertise on a regular basis with Petroleum News

Petroleum news

Business Spotlight

By PAULA EASLEY

FORREST CRANE

David K. Johnston, P.E., senior vice president

ASRC Energy Services

ASRC Energy Service's engineering and technology business unit provides: environmental and regulatory planning and permitting, geological/geophysical services, drilling and completion engineering, exploration and production services, well stimulation, on/offshore facility design, engineering, fabrication, construction and management. The firm's Alaska headquarters are in Anchorage.

Petroleum engineer David Johnston has 20-plus years' experience in E&P operations. Being able to take ideas from concept to something tangible is a great job reward, he says. After moving to Alaska in 1996, David and wife Carolyn were thrilled to watch children Kyle and Katelyn reel in their first king salmon: the fish were larger than they were. David's a golfer and weekend woodworker who believes "Minds are like parachutes; they only function when open."

FORREST CRANE

Amber Babcock, fixed wing marketing manager

Era Aviation

Era Aviation's capabilities have been demonstrated on five continents, during on- and offshore missions, on jobs ranging from crew changes to peacekeeping missions to firefighting and to environmental cleanups. It also provides scheduled flights and remote location support using aircraft and equipment options designed to accommodate client needs. See the website at www.eraaviation.com.

During her 12-year tenure with Era, Amber Babcock has held positions in customer service, sales, marketing and revenue management. She has administered contracts for aerial surveys, whale studies, athletic team movement and typical oil and mining activities. She also manages Era's security compliance program. This lifelong Alaskan loves her great guy, her great dog, globetrotting, scuba diving, flying, fishing and riding motorcycles, but the order sometimes varies.

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COSTLY

seriously underestimating debt and transportation costs and overestimating any tax benefits of public ownership. The memo also questions several of the non-tariff assumptions such as gas supply costs and reserves, market demand and prices.

"There may ultimately be a role for LNG or public ownership in commercializing North Slope gas," the memo said. "However, such a project should be based on solid commercial principles." Tax Division petroleum economist Roger Marks prepared the nine-page analysis from research with financial consultants and using a tax and tariff model he developed. (See sidebar on the memo with this story.)

LNG advocate says memo 'flawed'

"I think there are many points that are flawed," said Fairbanks North Star Borough Mayor Jim Whitaker, a board member of the Alaska Gasline Port Authority. The authority wants to build and operate a municipally owned pipeline and LNG project for commercializing the more than 35 trillion cubic feet of stranded North Slope natural gas.

The purpose of the late-March report is not to pronounce judgment on either project — the Alaska Gasline Port Authority or the state-owned Alaska Natural Gas Development Authority — said Steve Porter, deputy commissioner at the Department of Revenue, who reviewed the memo.

"The focus of that memo is to identify those areas that need further research," he said in an April 8 interview. "We've got to make sure we fine tune all these feasibility issues."

Porter told the state gas authority board of directors last fall that the department would review the economic assumptions behind the authority's business plan. The state authority, created by Alaska voters in 2002, has based its plan on financial models promoted by the municipal port authority and Yukon Pacific Corp., which in 2001 shut down its 20-year effort to develop a privately owned Alaska LNG project.

"These models conclude that the project is economic," Revenue's memo said of the Yukon Pacific and port authority assumptions embraced by the state gas authority. But, the memo advised, "Many critical assumptions in the model are uncertain and should be researched."

Memo lists items that need more study

"The memo provides information … justification for items we ought to study," said Harold Heinze, chief executive officer of the state gas authority. The Legislature has appropriated a total of $1 million for the authority to hire consultants to help answer questions as the board puts together its development plan for a state-owned pipeline and LNG project.

Rather than rely on North Slope producers to develop the companies' preferred gas pipeline through Canada to serve North American markets, supporters of public ownership say the state or municipalities should take on the job.

The major North Slope producers have done their own financial analysis of exporting Alaska LNG to U.S. West Coast or overseas markets and determined the project is not commercially feasible. But proponents of a publicly owned project say tax and financing savings could give their proposal a competitive advantage in the marketplace.

However, the Department of Revenue memo said possibly faulty tax and financing assumptions in the LNG supporters' models could mean they are underestimating the pipeline tariff by up to $1.34 per mcf. Plus the memo also questions the assumptions on tanker charges, saying the additional cost of U.S.-built and U.S.-crewed tankers, as required by the federal Jones Act, could add at least another 55 cents to the tariff for serving the California market.

Higher tariffs could be a problem

Those numbers, if the Revenue memo is correct, could result in tariffs to move Alaska LNG to California at almost double the amount estimated by the municipal port authority or state gas authority.

Finding a market for at least 2 billion cubic feet of Alaska LNG also could be a faulty assumption, the memo said. The U.S. West Coast doesn't need that much gas, and it would be difficult for Alaska to compete with less expensive LNG supplies closer to Far East markets. The cost of an arctic pipeline also puts Alaska LNG at a disadvantage, the memo said.

Those statements prompted a strong reaction from Whitaker. "It is near ludicrous to suggest a market does not exist," the mayor said.

But the memo's statements make sense to Larry Houle, general manager of the Alaska Support Industry Alliance, who sent copies of the memo to all of his directors. "It just sort of validates what I put together in the past," said Houle, who opposed the 2002 voter initiative that created the state gas authority.

Regardless of the serious questions raised by the memo, Houle doesn't expect it will change many minds among supporters of a publicly owned LNG project. "The true believers are so committed out there," he said.

Port authority moving ahead with project

On the other side is Mayor Whitaker, who said the memo's statements questioning the port authority's tax status and benefits are "ill-informed and incorrect." The authority, created in 1999, is comprised of the Fairbanks borough and the city of Valdez.

"We are well beyond memos in moving our project forward," the mayor said. The authority is talking with potential buyers for its gas, while it investigates financing options and looks for ways to buy gas from North Slope producers.

A key part of both the port authority's plan and the state gas authority's model is borrowing all of the billions of dollars needed to build the pipe, liquefaction plant and terminal at Valdez and, for the state authority, even the LNG tankers.

But that likely will be a problem, the memo said.

"It is difficult to find any similar, single-purpose commercial endeavor that has been financed at 100 percent debt," the memo said. "The reasons are clear. … Equity is the shock absorber for financial distress. Otherwise, if something goes wrong, the debt is at risk. In addition, equity contributions make creditors comfortable that project sponsors are serious.

"The more risky the project, the more debt holders want additional equity in the project. Typically, LNG projects have 70 percent debt," the report said.

"This report highlights that projects like this are not 100 percent financeable," Houle said. ●

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MEMO

The memo raised several issues, not all of which would apply to every proposed project development plan:

Market size and timing issues

With Shell, BP and Sempra Energy already committed to supplying the U.S. West Coast with 1 billion cubic feet per day of Indonesian, Australian and/or Russian LNG, the market has room for no more than an additional 1 bcf/d, the memo said. For Alaska LNG to capture all of that remaining market "would be challenging," considering that supply competitors do not need to build an 800-mile arctic pipeline to tidewater.

"Moreover, this market will grow incrementally, not all at once. Getting the entire 1 bcf/d into the market at once will be particularly difficult."

Taking Alaska LNG to Far East buyers also could be a problem, the memo said, considering the distance and the reality of lower-cost, nearby producers chasing the same customers.

The memo estimates the additional cost of phasing Alaska LNG into the markets with a longer ramp-up period — six years instead of two years — could add 48 cents per thousand cubic feet to the cost of service, as the project developer would need a higher tariff to make up for smaller returns in the early, low-volume years.

Supporters see the market differently, and believe they could sell enough LNG without undue delays.

LNG market prices

LNG project supporters point to high prices the past couple of years as a good indicator of where the market is headed. But, the memo said, "if prices are high, they are high for everyone — they do nothing for making the project more competitive, and in fact bring forth more competition."

Price volatility is a constant worry, the memo said, especially for Alaska projects that must compete with low-cost suppliers. "The excess supply of potential LNG for Asia is already pushing prices down to the cost of marginal supply. Indonesia recently made a 15-year deal with China to supply LNG at $2.90."

Federal Jones Act a problem

The Jones Act requires the use of U.S.-built and U.S.-crewed ships for moving goods between domestic ports. The memo, which recommended further research into how the law applies to Alaska LNG shipments to U.S. West Coast ports, said using U.S. ships instead of foreign tankers to carry the gas from Valdez could add at least 55 cents per mcf to the cost of delivering 2.2 bcf/d to California.

Project supporters have said perhaps Alaska could obtain a congressional waiver from the Jones Act.

Memo questions 100% debt financing

Though advisers to the municipally owned Alaska Gasline Port Authority and state gas authority have indicated either could obtain 100 percent debt financing for a gas line project, the memo challenges that assumption. "It is difficult to find any similar, single-purpose commercial endeavor that has been financed at 100 percent debt."

Building the project with 30 percent equity and 70 percent debt is a more likely assumption, the memo said.

And since equity investors demand a higher return than lenders — since lenders get paid first and therefore equity investors take more risk of not getting paid — the return on equity investment would add an estimated 69 cents per mcf to the tariff, the memo said.

Cost of borrowing

The port authority and state gas authority have underestimated by 2 full percentage points the interest rate they would need to pay for borrowed money to build the project, the memo said. "With no assets, no collateral, borrowing by a public entity (not backed by the full faith and credit of the state) of any amount will be difficult, especially for the commercialization of an asset with so much price volatility."

The higher-cost debt could add 29 cents per mcf to the tariff, the memo estimated.

Tax-free debt

The state has been looking the past couple of years at perhaps issuing tax-exempt bonds for a natural gas project through the Alaska Railroad Corp., pointing to a provision in the federal law that transferred the railroad to the state that allows for tax-exempt financing. However, the provision does not explicitly allow for financing of non-railroad projects, and the memo recommends that advocates of a publicly owned LNG project research the issue further before counting on the savings.

Tax-exempt bonds generally carry a lower interest rate than taxable bonds. The higher cost of taxable bonds could add 21 cents per mcf to the cost of an Alaska LNG project, the memo estimated.

Federal income tax status

Project supporters have relied on a 2000 letter from the Internal Revenue Service, stating that the Alaska Gasline Port Authority would be exempt from federal corporate income tax on its profits, but the Department of Revenue memo questions that assumption.

The IRS based its ruling on statements that most of the gas would be used in-state.

"However, it appears that given the rather limited opportunities for in-state use of gas, most of the port authority's revenues would be derived from the commercial sales of gas to either East Asia or the West Coast," the memo said.

"This distinction may be very significant for the (IRS) ruling," and could jeopardize the port authority's reported tax-exempt status, the memo said, estimating that federal taxes on equity investment in an LNG project could add 15 cents per mcf to the tariff (assuming the project is financed 30 percent with equity and 70 percent debt).

—**LARRY PERSILY,** Petroleum News government affairs editor

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MODEL

these huge very obvious structures that you could see on seismic," said Boyd, who came to Alaska with Marathon in 1978 and later spent 10 years at the Alaska Division of Oil and Gas, as deputy director and then as director, and who is now a consultant for EnCana, which is prospecting North Slope and Foothills acreage.

Different geology

In the 1970s, Boyd said, companies "were probably using an upper Cook Inlet model for a lower Cook Inlet sale." Other than a stratigraphic well drilled by ARCO, "there were no wells down there … and nobody really knew very much, and so they used the same model."

In upper Cook Inlet, Boyd said, "if you have the Jurassic rocks and you have Tertiary rocks sitting on top of them, you've probably got an oil field."

It may not be commercial, but it probably is an oil field, because the Jurassic Tuxedni formation is the source rock for the oil and the Tertiary Hemlock and Tyonek form the reservoirs that hold the oil.

"And if the Cretaceous gets in there" in the middle in the upper inlet, "then you probably don't have an oil field," because the Cretaceous prevents oil from getting into the reservoir rocks.

"But in the lower Cook Inlet … the Cretaceous seems like it might be the reservoir," Boyd said.

The Tertiary thins out as you move south, he said, and there is almost none in the body of the MMS sale area, so what is the source rock in the upper inlet, doesn't continue into the lower inlet.

New view needed for lower inlet

Boyd said he thinks anybody going to this year's sale is going to have to rethink the way they explore.

They're going to have to "forget about the upper Cook Inlet model, except in a few places."

And, "you can mainly forget about these big structural plays. Maybe not forget about them, but maybe they're not as important."

Instead, he said, companies should do what has been done on the North Slope, "look for these stratigraphic plays."

Prudhoe Bay and Kuparuk, Northstar and Milne Point and Endicott, "the great old fields of the North Slope," were all discovered relatively early, he said, and then there was "this sort of dead period … when people couldn't find anything." And then, with the advent of 3-D seismic, companies started to have exploration success on the slope again, but with stratigraphic plays, finding Badami on the east, Tarn and Meltwater south of Kuparuk, and Alpine to the west.

No good seismic for area

Can you pull the same rabbit out of the hat in lower Cook Inlet? Boyd asked.

"Is the same rabbit available to be pulled out of the hat in lower Cook?"

It's hard to know because there is very little 3-D seismic in lower Cook Inlet.

"Most of the seismic is very old and it's very, very lousy," he said. "So the database is pretty weak" going into the sale.

There are records from the wells, and MMS said in its draft environmental impact statement for the Cook Inlet planning area that three of the wells found oil in the Cretaceous. Two had significant shows in the late Cretaceous, but tested non-commercial flow rates; the third well had shows but was not tested. All of the wells at the 10 prospects tested (13 wells including three redrills) were plugged and abandoned. No leases from the 1977 lease sale remain, nor do any from a second sale, in 1981, which brought in $4.4 million from two bidders for 13 leases of 153 offered. Ten wells were drilled on leases from the first sale, three on leases from the second. A third sale of a portion of lower Cook Inlet, in 1997, offered 101 blocks but only two, now part of the Cosmopolitan unit off Anchor Point, were taken in that sale.

Reservoir quality an issue

In addition to demonstrating that oil didn't exist where companies expected to find it, Boyd said the drilling turned up a "huge problem, geologically, in lower Cook Inlet … There are zeolites, in particular one called laumontite."

Laumontite is a mineral that "deposits in the pore spaces," destroying the porosity of what might have been good quality reservoir rock.

This is different than permeability, the ease with which oil moves between pore spaces, Boyd said: laumontite cement plugs the pores in the rock, so you don't have a reservoir to hold the oil.

If the oil didn't go into potential reservoir rock cemented with laumontite, did it go somewhere else? These, he said, are "the usual kind of questions you have to go through" when you try to figure out whether an area might produce hydrocarbons, and, he said, the laumontite question is probably not something you could figure out from seismic — if you had seismic.

Different players than upper Cook Inlet

Not only are lower Cook Inlet rocks different than upper Cook Inlet rocks, but Boyd said he expects the players would be different, too. Upper Cook Inlet is attracting mature basin players, he said, smaller companies which are developing smaller fields and producing reserves around older fields.

But there is no infrastructure in lower Cook Inlet, and the costs to work there will be high.

Drilling from onshore won't really be an option, he said, and costs of $15 million to $18 million have been discussed just to bring in a drillship or semi-submersible to work in water depths ranging up to 600 feet.

MMS estimates a mean of 600 million barrels of economically recoverable oil at $30 oil prices. If that was one field, he noted, it would be in the range of Alpine, but perhaps in 200 feet of water some 25 miles from shore.

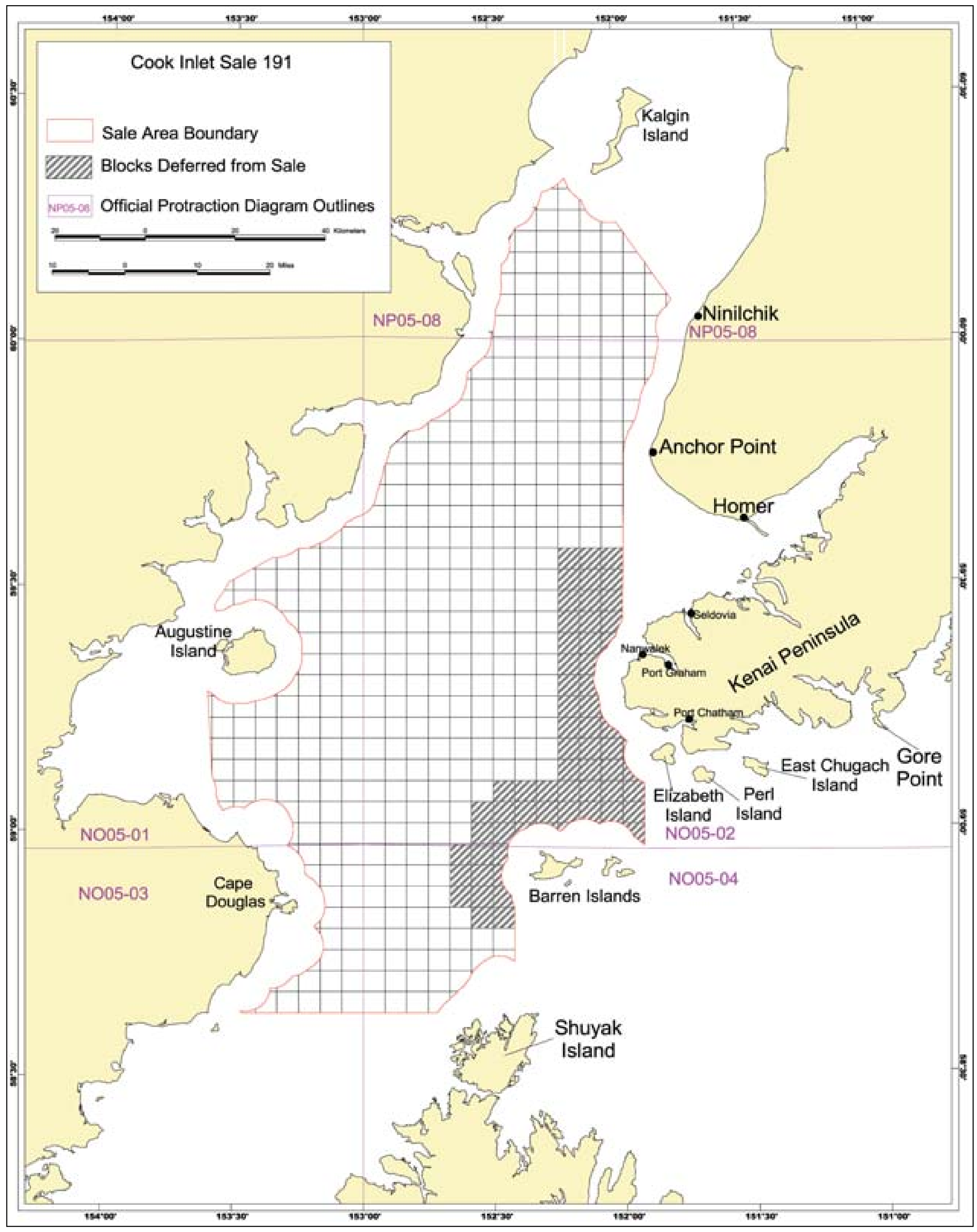
A small company, he said, probably couldn't handle the "huge risks, the huge up-front costs," and then the challenge of getting oil or gas to shore.

And with only poor data available, "it's going to be a tough first go," he said.

Good seismic is a necessity if you're looking at stratigraphic plays, he said, and 3-D seismic is very expensive.

He said he hopes "somebody has the wherewithal to go out there and give it a shot, and at a minimum get some decent (seismic) data shot out there," and either figure out that "this won't work, will never work, or … maybe if we looked over here, maybe if we look at this kind of thing."

Boyd also said he wonders if the players who come to the lower Cook Inlet sale could be a clue to the kind of companies that might be interested in the state's Bristol Bay sale. Bristol Bay is onshore, and the basins are very different, he said, but there also hasn't been much success with the rocks there and it's pretty far away from infrastructure. ●



MMS finalizes May 19 Cook Inlet oil and gas lease sale

The Minerals Management Service said April 15 that it has finalized plans for its Cook Inlet oil and gas lease sale, which will be held May 19 in Anchorage, Alaska, in conjunction with two state of Alaska areawide sales.

MMS said Cook Inlet sale 191 covers some 2 million acres from just south of Kalgin Island to just northwest of Shuyak Island, in water depths ranging from about 30 to 650 feet. The agency said it removed from the sale a band of blocks offshore the lower Kenai Peninsula and the Barren Islands, "which include critical habitat for the endangered Stellar sea lion" and areas identified as special by the Kenai Peninsula Borough, areas also used for subsistence.

For the first time MMS is offering economic incentives in Cook Inlet: a longer primary term of eight years; lower minimum bids of $25 per hectare ($10 per acre); annual rental rates of $5 per hectare ($2 per acre); and royalty suspension volumes which would relieve royalty payments on a producing lease up to the first 30 million barrels of oil equivalent, applying to both oil and gas. The suspension includes price floor and ceiling thresholds for oil, but MMS said there is no ceiling or floor for gas at this time.

MMS said it estimates that the potential in federal waters could exceed 1 trillion cubic feet of conventionally recoverable natural gas, and said the reserves can contribute to long-term gas supply for Southcentral Alaska.

Public opening of bids will begin at approximately 10 a.m., May 19, in the Wilda Marston Theater, Z.J. Loussac Public Library, Anchorage, immediately following the planned state of Alaska Cook Inlet and North Slope Foothills areawide sales.

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HOPES

Lake project.

UTS Energy, frustrated with "indefinite deferral," announced an offer of C$178 million to buy out its 78 percent majority partner, TrueNorth Energy, in the Fort Hills project.

OPTI raises more than C$1 billion

OPTI President and Chief Executive Officer Sid Dykstra said in an April 15 statement that OPTI in the past month has raised more than C$1 billion in new equity and sold C$800 million in debt to meet its financing obligations for the fourth oil sands project in Alberta.

Dykstra said OPTI now has shareholders in Canada, the United States, Europe and Australia and "most importantly, is fully funded for its share of the Long Lake project."

As OPTI entered its financing phase there was a spreading cloud over the oil sands sector, stemming from the announcement by Syncrude Canada that an expansion of its oil sands plant had soared by C$2.1 billion to C$7.8 billion and completion had fallen a year behind schedule.

But OPTI showed no hesitation, plunging ahead with raising C$750 million from a private placement of equity, surpassing the upper limit of C$700 million it had been targeting, and selling debt.

Then, for its initial public offering, OPTI issued 13.7 million shares at C$22 per share, compared with the share price of C$18.75 for the private placement that closed March 15.

The lead underwriters for the IPO were TD Securities, Scotia Capital and RBC Capital Markets on behalf of a syndicate of 10 underwriters.

But the last week has seen two junior companies, who are hoping to make their debut in the oil sands, raise the spirits of those who feared potential investors in a 300 billion-barrel resource might be getting cold feet because of the sector's shaky trends.

First phase of Long Lake 72,000 bpd

The first phase of Long Lake consists of 72,000 barrels per day of production, integrating steam assisted gravity drainage, integrated with an upgrading facility that will apply OPTI's proprietary process and commercially available technology.

The configuration is designed to significantly reduce the exposure to and the need to purchase natural gas and is expected to produce 58,500 bpd of products, primarily 39 degree API premium sweet crude, with a very low sulfur content, making it a desirable refinery feed stock.

Construction is set to start in mid 2004, with steam assisted gravity drainage bitumen production in 2006 and the upgrader coming on stream in 2007. If all goes well, Long Lake will double its volumes by 2011.

Dykstra has predicted that the new processing system should see Long Lake's operating costs undercut existing integrated projects by C$5-$10 a barrel. The 50,000-acre lease has an estimated 1.5 billion barrels of recoverable bitumen.

Fort Hills to be rescoped

UTS Energy cooled its heels for 15 months after TrueNorth, an affiliate of Koch Industries, stopped work on the planned C$3.5 billion Fort Hills project, blaming market uncertainties and a risk analysis.

But UTS was not prepared to walk away, after participating in C$178 million worth of exploratory drilling that boosted recoverable reserves by 400 million barrels to 2.8 billion barrels, project engineering and obtaining regulatory approval from the Alberta Energy and Utilities Board in October 2002.

Dennis Sharp, UTS chairman and chief executive officer, said last summer he was confident Fort Hills could be rescoped to improve its economics. On April 19, he said UTS is determined to be the catalyst for development of Fort Hills "utilizing innovative concepts for evolving Canada's oil sands in the next generation of projects."

If financing can be arranged by July 5, UTS will pay C$125 million cash for TrueNorth's stake, plus 7 million warrants, each convertible into one UTS common share at a price of 75 cents for a period of five years. UTS, which hopes to raise C$50 million through a private placement of shares to provide working capital, said it has filed a revised plan and timetable to the Alberta government and is encouraged by progress in those negotiations. It is also looking for prospective partners and is working on technologies to upgrade the raw bitumen on site.

Fort Hills was originally scheduled to come on stream in 2005 at 95,000 barrels per day and double in size by 2008. But UTS said it is now weighing an initial production phase of 50,000 bpd in 2009, growing to 200,000 bpd through further expansions. ●