Petroleum news

page 2 NWT, Mackenzie drilling nears meltdown; 13 wells in all

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White Rose blooms

COURTESY OF HUSKY ENERGY

Husky Energy is on track to launch the C$2 billion White Rose field, Newfoundland's third producing offshore project, within about two years. The latest success came April 6 with the arrival in Canadian waters of the massive SeaRose floating production, storage and offloading (FPSO) vessel after a 14,000-nautical mile, eight-week journey from South Korea via Cape of Good Hope and across the Atlantic. See story on page 14.

Kerr-McGee takes Westport Resources in $3.4 billion deal

Oklahoma's Kerr-McGee has agreed to take Denver's Westport Resources in a $3.4 billion stock merger that would boost Kerr-McGee's reserves by 30 percent and production by 34 percent, while expanding Kerr-McGee's exposure to North American natural gas.

For Westport, the merger would give its shareholders a chance to become part of "a larger, more diversified company" with "exciting upside potential," Don Wolf, Westport's chief executive officer, said April 7.

Westport, like Kerr-McGee an exploration and production

see **KERR-MCGEE** *page 10*

ANWR offshore stratigraphic test well permitting moves forward

On April 5, the Alaska Division of Oil and Gas awarded ASRC Energy Services E&P Technology Inc. a contract to initiate permitting for the proposed stratigraphic test well offshore the 1002 area of the Arctic National Wildlife Refuge. This will allow drilling during the upcoming winter drilling season, should a drilling consortium be formed, division geologist Jim Cowan told Petroleum News.

"Several permit approvals have to be in hand by the end of July or so in order to undertake several pre-mobilization and mobilization activities during the short open-water season in

see **PERMITTING** *page 23*

BREAKING NEWS

UNITED STATES

Independents sparkle

Nearly three-fold increase in earnings expected for U.S.-based companies

By RAY TYSON

Petroleum News Houston Correspondent

U.S.-based exploration and production independents on average are expected to report over the coming weeks a nearly three-fold increase in earnings for the first quarter of 2004 versus the previous quarter, according to a Petroleum News survey of leading E&P companies based on Thompson-First Call estimates. (See related story on page 7.)

However, the consensus among industry analysts used in the survey also projected that earnings during the 2004 first quarter fell about 9 percent on average compared to the same quarterly period in 2003.

Moreover, analysts forecast that earnings for the 2004 second quarter will drop nearly 20 percent on average from the 2004 first quarter, due in part to a winding down of winter demand for natural gas and heating oil.

> *… it appears the E&P sector had a healthy 2004 first quarter resulting from oil and gas prices that began to surge during the latter half of the 2003 fourth quarter.*

Nevertheless, it appears the E&P sector had a healthy 2004 first quarter resulting from oil and gas prices that began to surge during the latter half of the 2003 fourth quarter. In fact, all but one of the companies in the survey was expected to register an increase in profits during

see **SPARKLE** *page 22*

LIBYA

Mending a bad boy image

Delegation touts Libya's untapped oil and gas wealth; eyes $30B investment; Canadian companies encouraged to move early before U.S. lifts sanctions

By GARY PARK

Petroleum News Calgary Correspondent

Back on the global stage after being consigned to the pariah category, Libya is wasting no time spreading the message that its petroleum industry is open for business.

A delegation from the National Oil Corp. was in Calgary in late March and early April drumming up its potential, right on the heels of an announcement by Royal Dutch/Shell that it had signed a $200 million exploration deal with National Oil.

The Libyan officials said that was a mere kick-off to a possible multi-billion-dollar influx of for-

see **LIBYA** *page 23*

TOM KEARNEY

ALASKA

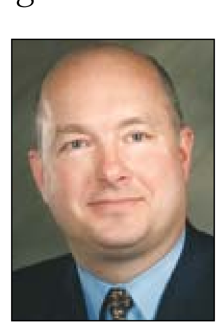
What went wrong?

The story behind failed gas line talks between MidAmerican, state of Alaska

By LARRY PERSILY

Petroleum News Government Affairs Editor

special **REPORT**



MidAmerican CEO David Sokol

Alaska Gov. Frank Murkowski

From the start of its talks with the state of Alaska, MidAmerican Energy Holdings Co. was looking for the state to put up something of value before the company would spend money on possibly building a North Slope natural gas project.

And, until the company broke off talks with the state in late March, MidAmerican believed it might be able to strike a deal with Alaska.

At first the Des Moines, Iowa-based pipeline operator wanted the state to cover half of the company's $100 million in estimated development costs for the multibillion-dollar pipeline project.

When the state said no to that, MidAmerican countered that the company would go ahead with development work only if the state granted it exclusive rights to the pipeline for at least three years —

see **FAILED** *page 19*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● NORTHWEST TERRITORIES

Drilling season nears meltdown

Busy winter as operators chase reserves to back nominations for space on Mackenzie Valley natural gas pipeline; Canadian government helps North realize potential

By GARY PARK
Petroleum News Calgary Correspondent

Northern Canada ended the first quarter with just three rigs at work and spring thaw fast approaching. But the winter season has been active, as E&P companies have tried to build natural gas reserves to nominate for the planned Mackenzie Valley pipeline.

Based on discussions and negotiations, Imperial Oil, operator of the Mackenzie Gas Project, has extended a March 15 deadline for potential shippers to nominate for precedent agreements that set the stage for firm shipping commitments.

In a separate development, the Canadian government's 2004-05 budget included C$90 million over five years to ensure that economic development opportunities are pursued in partnership with Northern Canadians and C$75 million over three years to ensure that the government and regional authorities respond in a "timely, responsible and effective" manner to pipeline and oil and gas development.

Indian Affairs and Northern Development Minister Andy Mitchell said the provisions follow earlier commitments to develop a northern strategy and "lay the groundwork for sustainable growth" in the region at a time when the North is preparing for investments of C$3.7 billion.


COURTESY OF ANADARKO CANADA
An Anadarko Canada rig in the Northwest Territories.

Work ongoing at seven wells

By late March, seven wells were being drilled in the onshore Mackenzie Delta region and the central and lower Northwest Territories, while operators had completed another six. Of the total, four were listed as completions.

On the Delta, a partnership of EnCana as operator, Anadarko Canada and ConocoPhillips Canada were hoping to complete the Umiak N-16 exploration well by the mid-April deadline.

The well on Richards Island, where EnCana shot seismic in 2003, is targeting a depth of just over 11,000 feet.

Chevron Canada Resources, with partners BP Canada Energy and Burlington Resources, are well past the halfway mark of a well expected to reach about 11,100 feet on Ellice Island, while Chevron is shooting about 96 square miles of seismic south of the island.

At Tweed Lake, Petro-Canada is completing a re-entry of a gas well that was first drilled in 1985.

In the Central Mackenzie, Apache Canada and Paramount Resources are drilling two exploration prospects south of the Colville Hills to the northeast of Norman Wells.

In addition, Apache is completing a Nogha M-17 re-entry, a wholly owned well that was completed as a successful gas well in 2003, but not perforated and flow tested due to spring break-up.

An C$18 million well in the Flintstone mountain range in the Central Mackenzie is under way with a partnership of Northrock Resources as operator, EOG Resources Canada, Husky Oil Operations, Pacific Rodera Ventures and International Frontier Ventures.

Meanwhile, International Frontier reported in late March that its Summit Creek B-44 exploratory wildcat was drilled to a depth of 9,950 feet, logged and drillstem tested.

Anadarko releases two rigs

Anadarko, setting a lively pace in the north, has rig released two wells at Arrowhead River — one a delineation well and one an exploration well, both of which were drilled last winter and have been re-entered for completions.

The company has also drilled an exploration well at Emile Lake A-77 north of the Arrowhead, with a targeted depth of about 7,500 feet.

In the producing Liard region, Chevron, with Purcell Energy as a 24 percent partner, is completing a re-entry development well to a depth of more than 12,100 feet and has approval for a second re-entry — both of them follow-ups to the 2K-29 development wells drilled last year. The original K-29 discovery well has produced at a peak of 75 million cubic feet per day.

Nearby, Paramount Resources has approval for a 6,650-foot re-entry that was drilled in 1998 with Berkley Petroleum.

Paramount and its partners have drilled five gas wells at Cameron, southeast of the Fort Liard well, followed up by two entries, and has licensed another three re-entries. ●

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UNITED STATES

Independents to increase exploration in the United States this year

Exploration spending on oil and gas exploration within the United States is expected to increase in 2004, as the demand for energy continues to grow.

According to a national survey of 60 mid-size independent U.S. oil and gas companies conducted by Grant Thornton LLP, a global accounting and consulting firm, 70 percent of respondents plan to increase their U.S. exploration spending in 2004, while only 21 percent plan to increase foreign exploration efforts. The survey was released April 6.

"Although a healthy majority of respondents expect domestic drilling activity to increase this year, only 30 percent and 44 percent expect prices for oil and gas, respectively, to be high enough to support an increase of more than 20 percent," said Ed Davis, partner-in-charge of Grant Thornton's Houston energy office.

Sixty percent of the companies surveyed plan to focus on natural gas over the next three years, primarily in the Rocky Mountains and Gulf of Mexico. Ten percent will focus on oil and 10 percent expect to pursue both.

Davis said natural gas prices are the most important factor affecting respondents' capital spending plans.The independents surveyed anticipate a rise in merger, acquisition and restructuring efforts in 2004, with 64 percent predicting an increase in such activity. Sixty-two percent of the respondents anticipate growth in industry employment in 2004, as compared to only 38 percent in 2003.

—PETROLEUM NEWS

WASHINGTON, D.C.

Another angle: Alaska gas line provisions added to tax measure in U.S. Senate

Backers of federal tax incentives for an Alaska natural gas line are trying another way to reach the Senate floor. Instead of pinning all their hopes on the stalled energy bill, they are trying to add the pipeline provisions to a corporate tax bill that may have a better chance of passage.

The gas line incentives in the revised tax bill include accelerated depreciation for the pipeline and tax credits for the gas treatment plant that would be constructed on the North Slope. The two provisions combined are worth about $500 million in tax breaks to a private developer of the line to carry Alaska gas to market.

"Whether or not that strategy is immediately successful, I think we'll now see a pattern of attaching various provisions of the energy bill to other legislation," said John Katz, director of the state of Alaska's office in Washington, D.C.

"The Senate leadership has released the hostages," Katz said, allowing members to look for other bills to possibly carry their favorite energy bill provisions to passage.

The revised tax bill also includes a third federal incentive for the Alaska gas line — tax credits to protect producers if the wellhead value of North Slope gas ever drops below $1.35 per thousand cubic feet. "We're told by friends and foes alike that the commodity-risk provision will not survive the legislative process," Katz said.

The Alaska natural gas project incentives, along with billions of dollars in tax breaks for renewable energy, coal and energy efficiency nationwide, were added to a bill needed to settle a trade dispute with the European Union. The legislation would repeal a tax break for U.S. exporters — which the World Trade Organization has declared illegal — and replace it with a tax cut for U.S.-based manufacturers.

But partisan battles over possible non-energy amendments to the bill could further delay action by the full Senate. The political battles include Democratic proposals to amend the bill to penalize U.S. companies that move jobs overseas, extend federal unemployment insurance benefits for an additional six months, and block the administration's plan to limit overtime for white-collar workers.

"The bad news is that the bill may or may not get out of the Senate," Katz said.

Senate Majority Leader Bill Frist, R-Tenn., announced the expanded 900-plus-page tax bill April 5, including the energy provisions.

Among the energy incentives added to the bill is a new personal income tax credit for wind-generated electricity and solar water heating systems — as long as none of the power is used for heating swimming pools or hot tubs.

The measure was scheduled for its first procedural vote April 7, though final passage could take a bit longer. The Senate will break for a week for Easter, with House members taking a two-week vacation. The Senate changes, if approved, would require

see ANGLE page 4

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Petroleum news

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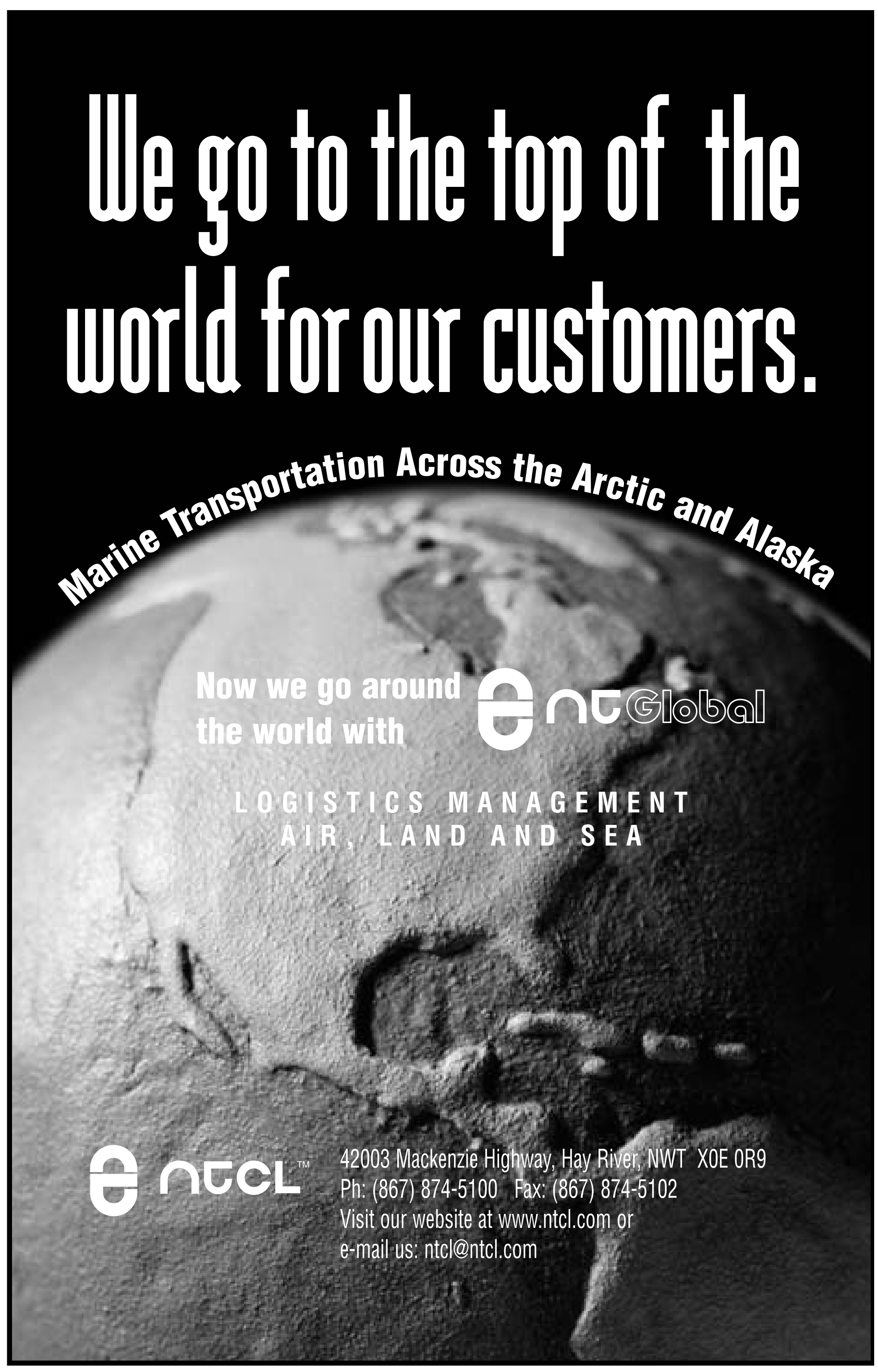

RUSSIA

Teton announces mystery acquisition

Teton Petroleum Co. says it has signed an agreement to acquire an interest in a producing field in Russia. Teton, which operates solely in Russia, didn't identify the field, the seller, or its partner in the venture. Teton did say it will have a majority interest and it will net about 3,400 barrels of oil daily from the deal. It also said it will own the field jointly with a "major western European partner."

According to Teton's April 5 announcement, the agreement was signed March 31 and Teton put up a deposit of $3 million. Closing date will be on or before July 1.

Denver-based Teton said it would provide additional information on the transaction over the next few weeks. Teton currently has interests in three fields in Russia under a single license. It has been producing oil in Russia since 1998.

—PETROLEUM NEWS

continued from page 3

ANGLE

the bill to go to a House-Senate conference committee to settle the differences, followed by another round of votes in each chamber.

Even if the tax bill stalls out, nothing is lost, said Chuck Kleeschulte, spokesman for Sen. Lisa Murkowski, R-Alaska. The energy bill is still alive and could come before the full Senate for a vote later this spring, though serious partisan battles within the Senate and disagreements with the House have held up the bill since late November.

"This is an attempt to speed the process along," Kleeschulte said. "Rather than wait for the energy bill, we'll do this in pieces."

A couple of key gas line incentives that are in the energy bill but not in the revised tax bill are an 80 percent federal loan guarantee for the project and streamlined permitting and judicial review provisions. Those could be added to a separate bill at a later date, Kleeschulte said.

— LARRY PERSILY, Petroleum News government affairs editor

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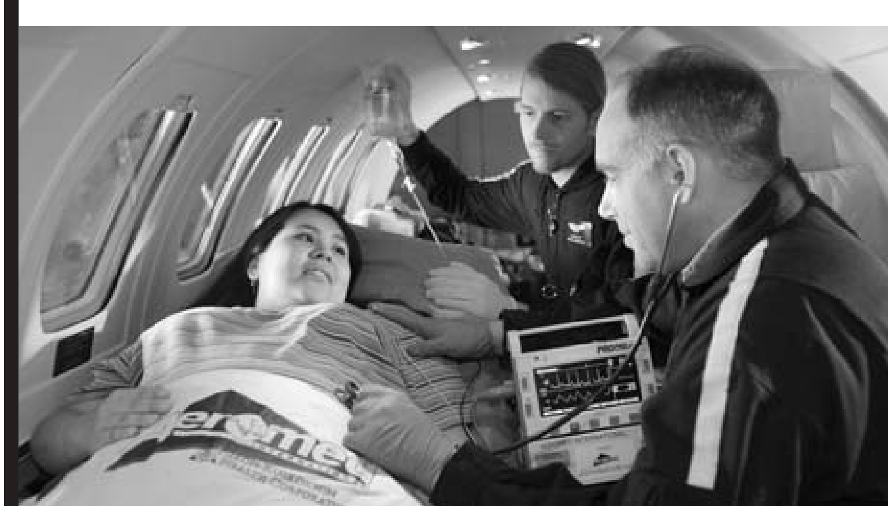

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● JUNEAU, ALASKA

Shallow gas bills moving slowly

House Resources has three bills to change Alaska's coalbed methane laws

By LARRY PERSILY
Petroleum News Government Affairs Editor

Legislative attempts to answer public complaints about Alaska's shallow gas leasing laws have moved to the House Resources Committee, which has three bills to consider — all of which were amended in the Oil and Gas Committee and likely will change again in Resources.

The measures, all of which still would need to move through the Finance Committee before getting to the full House for a vote, would end the state's over-the-counter shallow gas leasing program in urban regions of the state, take steps to protect water quality and possibly block renewals of existing leases unless work is under way to produce natural gas.

> *"I do think (exploration) licensing is a better deal."*
> —Mark Myers, director of the Alaska Oil and Gas Division

If any of the bills make it through the two House committees and are approved by the full chamber, they also would need to work their way through the Senate before the Legislature's adjournment deadline of May 12.

The three bills sat in the Oil and Gas Committee for a collective total of 27 weeks before moving on to Resources.

Critics of Alaska's shallow gas leasing program for coalbed methane have pushed hard since the session opened in January for changes in several laws, especially dealing with public notice of leases, protection for drinking water wells and property rights. About 300,000 acres are under lease in the Matanuska-Susitna Borough and near Homer on the Kenai Peninsula. Some exploration is under way but no gas is being produced.

Kohring supportive of industry

Countering public criticism of the program is industry and legislative support for developing Alaska's gas resources. Scrapping the entire shallow gas program would be "an overreaction," said House Oil and Gas Chair Vic Kohring. It's important that the industry look upon any legislation "as a reasonable law," the Wasilla Republican said at a committee meeting last month.

Changes were pushed through on two of the bills in House Oil and Gas on April 1, much to the displeasure of Rep. Paul Seaton, who represents the Homer area. The freshman Republican said the changes in House Bills 364 and 531 weakened the measures' protections for surface property owners, while confirming for him a committee chair's power to control legislation.

The two amended bills were not released to the public until at the hearing, and Kohring announced just an hour before the meeting that he would take up the bills that day.

Seaton, the prime sponsor of House Bill 364, said he would try in the Resources Committee to undo Kohring's changes to the bill.

House Bill 395, which was scheduled for a hearing in Resources on April 7, would not abolish the over-the-counter leasing program for shallow gas exploration and production but would impose stronger public notice requirements on future leases and block new leases if the gas would come from the same aquifer that supplies drinking or farm water.

One bill would protect Homer from any new leases

House Bill 364, which could come up in Resources on April 14, would block any further shallow gas leasing in the area around Homer, where many residents are strongly critical of state leasing of 22,000 acres two years ago.

The legislation also would set out requirements for the Division of Oil and Gas to follow before it could extend any of the existing three-year shallow gas leases statewide. Those conditions include judging the likelihood of eventual production from the leases.

Without an extension, the leases would revert back to the state.

House Bill 531 also could come up for its first hearing in Resources on April 14. The original version would have ended the state's over-the-counter shallow gas leasing program in favor of directing future activity into Alaska's exploration licensing program, which includes competitive bidding and best-interest findings for leases.

The House Oil and Gas Committee, however, narrowed the bill's effect. The non-competitive shallow gas leases would continue in all areas of the state except Anchorage, the Matanuska-Susitna Borough and Kenai Peninsula Borough.

Masek wants end to non-competitive gas leases

It's expected that the bill's main sponsor, Resources Chair Beverly Masek, R-Willow, will work in her own committee to change several of the Oil and Gas Committee's sections in the bill. She testified last month in Oil and Gas that the non-competitive shallow gas leasing program "has been used for large-scale commercial operations" in rural areas, contrary to the original intent of the legislation, and should be stopped.

The administration had testified in favor of Masek's original bill to end over-the-counter shallow gas leases in favor of the competitive exploration licensing program statewide.

It is a more effective way to get unique areas under lease, said Mark Myers, director of the state's Oil and Gas Division. Exploration licensing allows the division to eliminate "hot spots" from lease areas, he said, such as controversial and environmentally sensitive lands or areas with a low probability of gas.

"I do think licensing is a better deal," Myers said last month at the House Oil and Gas Committee. It's better for explorers because it allows the state to lease out larger areas with exclusive rights for longer terms, and without the 3,000-foot limit on well depth. ●

● JUNEAU, ALASKA

Alaska looks to acquire right of way in order to advance ANS gas commercialization

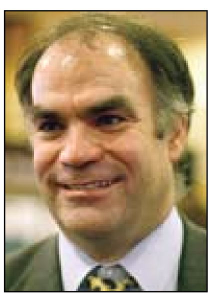
By LARRY PERSILY

Petroleum News Government Affairs Editor

The state believes it could reduce the financial risk and speed up development of an Alaska natural gas line if it goes ahead and obtains the needed pipeline right of way even before a developer steps forward to build the project.

"The state would actually permit its own right of way," Mark Myers, director of the Oil and Gas Division, told the Senate Finance Committee. "I know that may sound kind of strange."

But the state probably could do the job for itself faster and at a lower cost than a private applicant, Myers said. "We would accelerate the project significantly."



JUDY PATRICK

MARK MYERS

The Oil and Gas Division is asking legislators to appropriate $3.9 million in state funds to pay for the right-of-way work. The request is part of the governor's supplemental appropriations measure, Senate Bill 313, which received its first hearing April 2 in Senate Finance. The committee took no action on the bill, which includes almost $10 million total for several of the state's efforts to get a gas line built.

The newest idea is that the state would acquire the right of way for the pipeline's route through Alaska, then hold it and transfer it to whichever private venture decides to go ahead and build the line to move North Slope natural gas to Lower 48 markets.

"The process envisioned here is that a state corporation — undefined at this point — would actually be issued the rights of way," Myers told lawmakers in the first public announcement of the administration's latest plan.

The permits would apply only to state lands, though the effort would help coordinate later acquisition of federal and private rights of way, said Mike Menge, the governor's special assistant for oil and gas issues.

'Novel approach' to promote gas line

"At the appropriate time the state corporation would grant that right of way to whoever exactly is constructing that pipeline," Myers said. "It's a novel approach … but it is a way the state can significantly lower the cost of the project."

Though Myers did not name any specific state corporations to possibly hold the right-of-way permits, one Finance Committee member mentioned the Alaska Railroad Corp. as a possibility. Other state corporations with possible interest in the project would include the Alaska Natural Gas Development Authority and the Alaska Industrial Development and Export Authority.

Alaskans created the state gas authority by voter initiative in November 2002 to pursue a state-owned natural gas project, though nothing in state law would preclude it from holding right-of-way permits for eventual private ownership of a gas line.

"It's a novel approach … but it is a way the state can significantly lower the cost of the project."
—Director Mark Myers, Alaska Division of Oil and Gas

The $3.9 million appropriation, if approved by lawmakers, would be available immediately. The work schedule calls for the Department of Natural Resources to finish its work on the permits by June 2005.

In addition to the right-of-way funding, the administration's budget request for its gas line work also includes $1.58 million for a risk analysis study to determine if the state could help get the project built if it was willing to share in some of the financial risk.

Governor interested in risk sharing

Gov. Frank Murkowski said late last month the state may need to step in and share some of the risk of the estimated $20 billion project if it is to convince private companies and investors to go ahead with the 2,000-mile pipeline from the North Slope to the Midwest.

But the state needs to know a lot more before it can decide how it might share in the risk and whether it would help the project, the governor said, offering no speculation on how Alaska might take a share of financial risks for the pipeline that could boost domestic natural gas supplies by more than 6 percent in the next decade.

The $1.58 million would fund a four-month study including an analysis of possible proportionate risk sharing between the producers, pipeline owner(s), shippers, gas buyers and the state, said Steve Porter, deputy commissioner at the Department of Revenue.

"The analysis is to look at the project's risk, not just the state's risk," Porter said in an April 5 interview. "It provides you the perspective you have to have to make decisions." The study would look at construction, tariff and market price risks, ending in a recommendation by early fall for how the state could encourage development of the project.

"The goal is to understand the total risk so that by the time you are done you have apportioned that risk out to all the parties," Porter said. "If you don't take some of the risk, you don't play."

Risk taking could bring rewards

And it's more than just sharing in the downside. "If you take the risk, what's your expected reward out of it," Myers told the Senate Finance Committee.

The Department of Revenue would spend most of the money by hiring consultants for the risk analysis, Porter said.

"The process envisioned here is that a state corporation — undefined at this point — would actually be issued the rights of way," Myers told lawmakers in the first public announcement of the administration's latest plan.

A third piece of the $10 million funding request is $4.25 million in additional money for the state's continuing negotiations under the Stranded Gas Development Act.

About half of the money would go toward the state's anticipated expenses for negotiating gas line fiscal contracts for payments in lieu of state and municipal taxes with the three applicants under the Stranded Gas Act — the North Slope producers, Calgary-based pipeline company Enbridge Inc. and the municipally owned Alaska Gasline Port Authority.

The rest of the money would go toward studying in-state benefits and uses of North Slope gas, responding to project incentives in the stalled federal energy bill, and discussing rights of way and regulatory issues with the government of Alberta, Porter said.

Work list includes petrochemicals

The state also is close to issuing a contract for an analysis of a possible petrochemical industry in the state, he said.

"It is our hope that we could complete most if not all of this work" by June 2005, Porter said.

The state gas authority would receive $900,000 of the money for its benefits analysis, further work on financing options and a review of the federal law requiring U.S.-built tankers to move liquefied natural gas between domestic ports, he said.

The $4.25 million request is in addition to the $1.65 million in funding for the administration and state gas authority approved April 5 by the state Senate and sent to the governor for his signature into law. ●

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● NORTH AMERICA

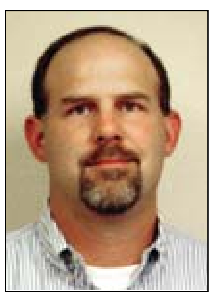
XTO plans only offshore Cook Inlet well this year

Permian, Cook Inlet basin oil stabilize XTO Energy's production decline curve; Fort Worth-based independent buys existing fields with complex geology, adds to production, balances quick declining gas wells with longer-lived oil wells

By KRISTEN NELSON
Petroleum News Editor-in-Chief

The Cook Inlet basin in Southcentral Alaska saw the state's first modern oil and gas production, with discoveries onshore in the late 1950s and offshore in the 1960s. Platforms were installed in the 1960s and production, supported by development drilling, has been continuous since that time.

While the Alaska Division of Oil and Gas forecasts oil production from offshore Cook Inlet fields could continue to as late as 2019, development drilling is clearly on the wane.



Kyle Hammond, XTO Energy

Kyle Hammond, XTO Energy's vice president of operations, told the Alaska House Special Committee on Oil and Gas April 1 that he has talked with other offshore operators, "and I believe this year … was planned to be the first year in the history of the Cook Inlet" without a well spud offshore.

Since XTO does plan to spud this year, "we'll continue that string" of continuous drilling, Hammond said.

"But if we drill a well, I think we're going to be the only operator that drills a well in the Cook Inlet offshore this year."

Hammond said XTO plans to drill one well, possibly two, from its offshore platforms at Middle Ground Shoal.

Unocal, the inlet's major operator, has no offshore wells planned this year, spokeswoman Roxanne Sinz confirmed April 6. Ditto for ConocoPhillips, which operates the Tyonek platform at the North Cook Inlet gas field. It completed some workovers at the field last year and early this year, but plans no wells this year, spokeswoman Dawn Patience told Petroleum News.

And Forest Oil, operator of the inlet's newest platform, Osprey, at the Redoubt Shoal field, said last year that results have been disappointing, substantially reduced its reserves estimates and replaced the drilling rig on the platform with a workover rig.

Cook Inlet, Permian balance decline curve

Cook Inlet production — onshore and offshore — has declined from a peak of 225,701 barrels per day in 1970 to 29,267 bpd in 2003, according to the 2003 annual report from the Alaska Division of Oil and Gas.

Lindsey Dingmore, Fort Worth, Texas-based XTO's manager of governmental and regulatory affairs, told the committee that decline curve management is important for XTO and that at its Middle Ground Shoal platforms, which it acquired from Shell in 1998, production is long-lived and, along with oil production from the Permian basin, helps the company balance its quickly declining East Texas gas wells.

XTO is "not really an exploration company," Dingmore said, but is "the kind of company that the majors look to when they are selling assets" that no longer fit their portfolios, but where a smaller company can come in and do "a lot of the work in terms of in-fill drilling and development."

JUDY PATRICK

XTO Energy's Platform A, the oldest platform in Cook Inlet

"A good acquisition company must be a great development company," Hammond said, and XTO tries to double reserves at the properties that it buys.

That is about what has happened at Middle Ground Shoal, he said, and as a result, production from the A and C platforms has remained about constant since the company acquired the platforms at Middle Ground Shoal from Shell in 1998. Shell installed the platforms in 1964 and 1967; Unocal installed the other two platforms at the field, Baker and Dillon, in 1965 and 1966.

About 90 percent of XTO's production is natural gas, Hammond said, and its oil properties in the Permian basin in Texas and in Alaska have flatter decline curves and help balance declines from other areas.

XTO doesn't buy companies, it buys oil and gas and it looks for "long-lived, high-margin-properties," he said. The high-margin part of the company's equation is important, so it can "continue to operate in a low-price environment," Hammond said.

Goal to keep production flat

XTO also looks for geologically complex reservoirs. If "it's very simple, anybody can find it," but "in geologically complex reservoirs, the probability that the previous operator missed something goes up dramatically," Hammond says.

Production from the A and C platforms at Middle Ground Shoal is about the same as it was six years ago, which is what XTO wants, he said: "We want to buy properties that as we continue to add capital into these properties, we can keep the decline essentially at zero."

The platforms, combined, average 3,900 barrels per day, Hammond said.

XTO has invested some $50 million to keep the decline curve flat, and plans to invest between $7 million and $8 million a year for the next several years at Middle Ground Shoal.

Shell had developed the east side of the reservoir at Middle Ground Shoal, he said, "on the east side the rock is significantly better rock, with more oil in place and more permeability — the ability of the oil to flow to the wells — and it's much easier to drill." On the east flank, where Shell worked, the structure is "relatively flat."

West flank tipped on end

The west flank, where XTO has worked, is on the other side of a major north-south trending fault, and tectonic activity has essentially turned the strata on the west side of the field "on end," he said, so when XTO drills on the west side, it drills directionally, penetrates the formation, then goes back and penetrates it again on the bottom side of the well.

"The wells are a lot more expensive to drill that way and technically more of a challenge," Hammond said, "but it's what makes drilling a well on the west flank economically viable."

Costs vary from $2-$3 million a well to as high as $7 million, he said. The company has drilled eight wells, including some drilled as injection wells, and has also con-

see XTO page 22

Want to know more?

If you'd like to read more about XTO Energy's activities in Alaska, go to Petroleum News' web site and search for these articles.

Web site: www.PetroleumNews.com

2004
- **Jan. 18** XTO Energy begins new year with a bang

2003
- **Oct. 26** XTO Energy gets new Alaska VP
- **The 2003 Independents** magazine, page 42, go to Products section on Petroleum News' web page

2002
- **Nov. 24** XTO Energy's 2003 Alaska budget up from 2002
- **The 2002 Independents** magazine, page 50, go to Products section on Petroleum News' web page
- **Nov. 3** Commission approves regulatory cost charges for fiscal year 2003
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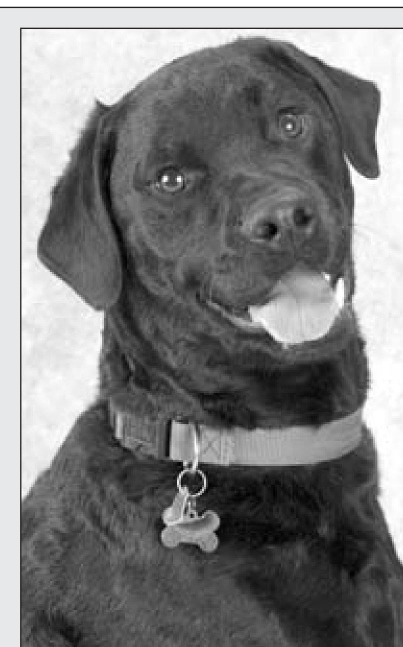
COURTESY ALASKA PETOGRAPHY

OSLO, NORWAY

Minister: Norway has no plans to follow OPEC's lead in cutting

Norway, the world's third largest oil exporter, has no plans to cut its oil production in the wake of OPEC's decision to cut its output by 4 percent, the minister of petroleum and energy said April 1.

"I take note of OPEC's production cut, but do not see that there is ground for cutting Norwegian production," the minister, Einar Steensnaes, was quoted as telling Norwegian news agency NTB.

The Organization of Petroleum Exporting Countries agreed March 31 to cut production to prevent a drop in prices this spring, when the global demand for oil usually slips to a seasonal low.

Norway, which trails only Saudi Arabia and Russia in oil exports, is not a member of the oil cartel, but has often cooperated with the bloc in efforts to manage the oil market.

Steensnaes spoke after meeting Oman's oil minister Mohammed bin Hamad al-Ramhi in the western Norway city of Stavanger, the center of Norway's oil industry some 200 miles west of Oslo.

Norway produces about 3 million barrels of oil a day, plus natural gas from the offshore fields along its coast.

—THE ASSOCIATED PRESS

CANADA

Petro-Canada to be protected from takeover by legislation

The Canadian government may be shedding its direct stake in Petro-Canada, but it is not ready to throw the doors open to a corporate takeover of the firm.

Legislation that prevents any other company or group of related investors from acquiring more than 20 percent of Petro-Canada's voting stock will remain in place once the government starts unloading its final 19 percent holding in the company, a spokeswoman for the Finance Department told the Edmonton Journal.

Finance Minister Ralph Goodale said the government is not opposed to selling its 8.5 percent stake in Canada Hibernia Holding.

She said Petro-Canada used taxpayers' money to grow in the first place, adding: "Canadian taxpayers took the risk. They should also have access to the rewards. They should keep the benefit."

But the ownership legislation sets no limits on foreign investment in Petro-Canada.

Meanwhile, Finance Minister Ralph Goodale told the House of Commons that some of the proceeds from the sale of 49.39 million government shares — currently worth about C$2.9 billion — will help finance new environmental technologies.

He said C$400 million from the divestiture will be contributed over two years to Sustainable Development Technology Canada as part of the government's contribution of C$1 billion over the next

see PETRO-CANADA page 8

● CANADA

Trusts in state of flux

Petrofund, Ultima deal could be start of merger wave, while offering possible answer to foreign ownership issue; Pengrowth introduces dual-class structure

By GARY PARK

Petroleum News Calgary Correspondent

Two Canadian energy trusts may have launched the sector on a new path towards consolidation after several years of rapid growth that has seen the creation of 28 trusts.

In the process, they will create a new entity that will comply with federal government rule changes setting a limit of 49.99 percent on foreign ownership.

When Petrofund Energy Trust announced plans to buy Ultima Energy Trust for C$450 million, moving it into the ranks of the top five trusts, industry analysts viewed the deal as the precursor of a merger wave that could see the big trusts swallowing their smaller peers which are having trouble building their production.

"It's going to be a trend in the future," Ultima President and Chief Executive Officer Brian Gieni told a conference call.

"As we have grown, so has the oil and gas trust sector — so much so that that the current Western Canada market is increasingly competitive, particularly for junior trusts," he said.

The challenge for smaller trusts, which rely on acquisition rather than the drill bit to grow production, is to find properties in a tightening market, while the larger trusts are bulging with cash and ready to pay a premium for assets.

New trust would have reserves of 112.54 million boe

Assuming approval by Petrofund and Ultima investors on May 26, the new trust will have proved reserves of 112.54 million barrels of oil equivalent, proved plus probable reserves of 143.47 million boe and production of 93.5 million cubic feet per day of gas and 21,550 barrels per day of oil and natural gas liquids. The stock market value would be about C$1.7 billion.

Because the two trusts opened discussions in January, Petrofund Chief Executive Officer Jeffrey Errico said it is a "little bit of serendipity on the side" that the transaction occurred just after the Canadian government decided to cap foreign ownership of trusts, which enjoy a tax-friendly status.

Under the rules, the trusts with more than 50 per-

see FLUX page 8

● UNITED STATES

Analysts predict drilling contractors to recover

Improved market conditions expected to result in 40% earnings jump

By RAY TYSON

Petroleum News Houston Correspondent

The major U.S.-based contract drillers can look forward to a pick up in rig activity during the 2004 second quarter following what is expected to be a relatively weak earnings performance in this year's first quarter.

First-quarter earnings among the leading drilling contractors could tumble roughly 25 percent on average from the previous quarter, according to a Petroleum News survey based on Thompson-First Call analysts' estimates. (See related story on page 1.)

However, because of improving market conditions worldwide, earnings per share are expected to jump more than 40 percent on average during the current second quarter ending June 30, the survey indicates. And 2004 first-quarter profits could be up substantially versus the same period last year.

A consensus estimate represents the average earnings of all analysts polled on a particular company. Individual estimates can be higher or lower than the consensus and tend to change as reporting season approaches. Earning estimates generally exclude special items and other charges taken by a company during a quarter.

For the major offshore drillers, the consensus among analysts is that Rowan and Diamond Offshore actually will be reporting losses for the recent quarter, as well as land contractors Parker Drilling and Grey Wolf.

see RECOVER page 8

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continued from page 7

RECOVER

Diamond Offshore could report 6 cent per share loss

Diamond Offshore could report a loss of 6 cents per share for the 2004 first quarter, compared to a loss of 17 cents per share in the year-ago period and a positive 1 cent per share in the 2003 fourth quarter. For the 2004 second quarter, the current consensus is that Diamond will earn about 6 cents per share.

Rowan could report a loss of 5 cents per share in this year's first quarter, compared to a gain of 5 cents per share in the prior quarter and a loss of 18 cents per share a year ago. Rowan could register a profit of around 5 cents per share in the current quarter, according to consensus estimates.

Grey Wolf is expected to lose 2 cents per share for the 2004 first quarter, while breaking even in the previous quarter and losing 5 cents per share for the same period a year earlier. The company is expected to break even in the 2004 second quarter.

Despite a resurgence in land drilling, particularly in the United States, Parker Drilling just can't seem to get on track. Parker is expected to post a loss of around 8 cents per share in the 2004 first quarter, preceded by a loss of 9 cents per share in the 2003 fourth quarter and a loss of 11 cents per share in last year's first quarter. Moreover, the company could lose 6 cents per share during the current quarter, according to consensus estimates.

Transocean expected to have earnings of 3 cents per share

Transocean is expected to check in with earnings of 3 cents per share in the 2004 first quarter, versus 7 cents per share in the previous quarter and 15 cents per share in last year's first quarter. The big offshore driller could see about 11 cents per share in the 2004 second quarter.

GlobalSantaFe, another large offshore driller, is expected to register net income of around 2 cents per share in the 2004 first quarter, according to consensus estimates. That compares to 10 cents per share each in the previous quarter and last year's first quarter. The company could see net income of about 8 cents per share in this year's second quarter.

Ensco International is expected to post net income of 14 cents per share in the 2004 first quarter, compared to 18 cents per share in the 2003 fourth quarter and 17 cents per share in the 2003 first quarter. The consensus has Ensco earning about 15 cents per share in the 2004 second quarter.

Nabors Industries is expected to earn about 47 cents per share in the 2004 first quarter, versus 42 cents per share in the previous quarter and 31 cents per share in the year-ago period. It's estimated the company will earn about 36 cents per share in the 2004 second quarter.

Noble Drilling should report 2004 first-quarter net income of about 20 cents per share, compared to 23 cents per share in the previous quarter and 30 cents per share in last year's first quarter. The company can expect to turn a profit of about 29 cents per share in this year's second quarter.

Patterson-UTI expected to earn 27 cents

Patterson-UTI Energy is the only drilling contractor in the survey expected to show improvement across the board. The land driller should see earnings of about 27 cents per share in the 2004 first quarter, compared to 25 cents per share in the previous quarter and 6 cents per share in the year-ago quarter. Moreover, the company's earnings are expected to increase to 33 cents per share in this year's second quarter.

Earnings among the leading oilfield service companies are expected to closely track those of the contract drillers, although none of the service companies is expected to report a net income loss for the 2004 first quarter.

Halliburton, plagued by controversy over its Iraqi fuel and military food contracts, is expected to post a first-quarter profit of 31 cents per share, compared to 34 cents per share in the prior quarter and 12 cents per share in last year's first quarter. The company should turn a profit of around 34 cents per share in this year's second quarter, according to consensus estimates.

Schlumberger's 2004 first-quarter profit should come in around 47 cents per share, versus 50 cents per share in the previous quarter and 26 cents per share in the year-ago quarter. For the 2004 second quarter, the company is expected to earn about 50 cents per share.

Baker Hughes is expected to register net income of about 25 cents per share in the 2004 first quarter, compared to 32 cents per share in the previous quarter and 14 cents per share for the same period last year. For the 2004 second quarter, Baker Hughes should earn around 30 cents per share.

Pride International, faced with its own contract problems, is expected to improve slightly sequentially with 2004 first-quarter earnings of about 4 cents per share, compared to 3 cents per share in the previous quarter and 3 cents per share in the year-ago period. Pride's 2004 second-quarter net income is expected to come in around 6 cents per share, according to consensus estimates.●

continued from page 7

FLUX

cent offshore ownership — Petrofund 60 percent, Enerplus Resources Fund 64 percent, Pengrowth Energy Trust 53 percent, Provident Energy Trust 70 percent and PrimeWest Energy Trust 54 percent — will have to comply with the new limits by Jan. 1, 2007.

The Petrofund takeover of Ultima will allow it to reduce its non-resident ownership to less than 50 percent from its current 66 percent.

Pengrowth asking approval of two classes of units

Pengrowth has taken a different route, asking unit holders to vote April 22 to create two classes of units — Class B restricted to Canadian residents and Class A to foreign residents — allowing it to retain its listing on the New York Stock Exchange, while maintaining majority Canadian ownership.

Currently, Pengrowth estimates that 53 percent of its units are held by non-residents.

Pengrowth President Jim Kinnear said the strategy has been developed over "several months" after the trust detected a substantial pick-up in foreign investor interest.

He said the dual-class structure would limit the "amount of foreign ownership without disenfranchising the unit holders because both classes of units will still have the same rights and distributions."

Kinnear said the "innovative solution" will enable Pengrowth to "maintain contact with both domestic and international markets" as it focuses on growth and expansion.

PrimeWest does not view the dual structure as a "silver bullet" to deal with the foreign ownership issue, but some analysts believe the approach will likely be studied by other trusts.

In other developments, the Alberta government intends to introduce legislation in the 2004-05 fiscal year to deal with trust liabilities, while the Saskatchewan government is pondering changes to its tax regime to put trusts and conventional oil and gas companies on the same level.

Alberta said it will adopt legislation confirming the limited liability provided to trust investors, putting trusts on the same footing as limited liability corporations and opening the way for pension funds to take a larger stake in the trusts.

Revenue Minister Greg Melchin said the action "is important to establish similar investor protection for (trust) unit holders as for shareholders."

The Ontario government has promised to introduce parallel legislation this spring, confirming that unit holders in publicly traded trusts are not liable.

A provincial budget released March 31 by Saskatchewan Finance Minister Harry Van Mulligen drew attention to the fact that trusts are "generally able to avoid Saskatchewan's corporation capital tax surcharge on their oil and gas production," while conventional producers are saddled with the tax.

Without disclosing its preferred option, the government said it will consult with the oil and gas industry to help determine a course of action to address this situation.

In addition, Saskatchewan also plans to review the implications of federal plans to reduce the tax rate on resource companies to 21 percent by 2007 from the current 28 percent. The province said it was committed to ensuring a "competitive and fair" tax environment. ●

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continued from page 7

PETRO-CANADA

seven years to promote new environmental technologies.

Canada Hibernia stake could also be sold

Goodale also said the government is not opposed to selling its 8.5 percent stake in Canada Hibernia Holding, which manages Newfoundland's offshore Hibernia oilfield.

With Hibernia now pumping more than 200,000 barrels per day, that interest is valued at C$500 million to C$700 million.

Goodale declined to offer a time line beyond saying it's "potentially something we could do in the future."

He said there is no compelling reason to remain a Hibernia partner, adding "it's a matter of making an appropriate commercial decision."

Newfoundland Premier Danny Williams has wasted no time laying claim to the Hibernia share, formally asking the Canadian government to "return" the ownership position to his province.

Failing that, he did not rule out a Newfoundland bid for the asset if it were placed on the open market.

Williams based his argument on a 1985 Atlantic Accord that recognized the right of Newfoundland to "be the principal beneficiary of oil and gas resources off its shores, consistent with the requirement for a strong and united Canada."

—GARY PARK, Petroleum News Calgary correspondent

● ALBERTA

Front end costs not the oil sands clincher

By GARY PARK

Petroleum News Calgary Correspondent

What's C$5 billion in return for oil reserve life indexes of 30 years?

Not enough to drive away those prepared to invest in Alberta's oil sands, according to Brian Prokop, an analyst with Calgary-based investment dealer Peters & Co.

Speaking to a Canadian Energy Research Institute conference, he said it's the operating costs, not the multi-billion-dollar capital costs that are the most "critical to overall sensitivities."

Canadian Energy Research Institute Research Director Bob Dunbar said that even the 20 percent gain in the value of the Canadian dollar against its U.S. counterpart in the past year is a lesser concern than surging natural gas prices at a time when the institute has forecast that the oil sands could consume 1.5 billion to 2.5 billion cubic feet per day by 2017.

A study institute analysts released last month found that both mining and thermal recovery of bitumen from the oil sands region need a West Texas Intermediate price of $25 a barrel to yield a net return on investment after inflation of about 10 percent, based on a NYMEX gas price of about $4.50 per million British thermal units.

Against a growing background of predictions that the Canadian currency will continue to strengthen, there is pressure on oil sands producers to "participate as much as possible in all areas of the value chain," said Brant Sangster, senior vice president of oil sands at Petro-Canada.

He told the institute conference that Petro-Canada has resumed work on expanding its Edmonton-area refinery to process its own oil sands volumes. By upgrading and refining into final products "we capture the entire value chain," Sangster said.

List of new oil sands players grows

Whatever the concerns about capital costs and budget overruns, the list of new oil sands players continues to grow.

Marathon Oil plans to decide before the end of 2004 whether to invest in the oil sands to feed its U.S. Midwest refineries.

Chief Executive Officer Clarence Cazalot said his company expects a growing share of Canadian crude exports to originate in the oil sands over the next seven to 10 years.

On a much smaller scale, Calgary-based Paramount Resources is exploring potential oil sands developments in northeastern Alberta.

It controls five separate possible developments on 120 sections after acquiring another section in the first quarter and has drilled 12 delineation wells this year on two leases.

President and Chief Operating Officer Jim Riddell said Paramount is weighing a number of technologies that could allow it to upgrade raw bitumen in the region and thus achieve a better price by not having to use diluent to ship the bitumen by pipeline to distant refineries.

He said the company is also delving into the use of coke from the upgrading process as a fuel rather than natural gas. ●

HOUSTON/CALGARY

GlobalSantaFe exits land drilling with $316M sale to Calgary-based Precision

Big U.S.-based contract driller GlobalSantaFe, wanting to concentrate on the offshore, has agreed to sell its worldwide land drilling business to Calgary-based Precision Drilling for $316 million, the companies said April 2.

The sale, which doubles the size of Precision's international fleet, includes 31 land rigs in the Middle East, North Africa and South America and an extensive fleet of specialized rig transport equipment that supports land rig operations in Kuwait and the Kuwaiti-Saudi Arabia Partitioned Neutral Zone. The transaction is expected to close during the 2004 second quarter.

"While we have been successful with the land rig business over the years, it has become an increasingly smaller part of our overall operations," said Jon Marshall, GlobalSantaFe's chief executive officer. "This transaction will permit us to focus our management efforts on growing the offshore market."

Hank Swartout, Precision's chief executive officer, said the transaction gives the company an opportunity to expand its growing international position.

"We recognize the excellent quality of both the rigs we are acquiring and the people associated with GlobalSantaFe's land drilling operations," Swartout said. "This combination with Precision's focus on international land drilling services will strengthen our product offerings …"

GlobalSantaFe's fleet of 59 offshore rigs includes premium and heavy-duty harsh environment jackups, semi-submersibles, and dynamically positioned ultra-deepwater drillships. Additionally, the company has three rigs under construction.

Precision, with headquarters in Houston, Texas, and Calgary, Alberta, is a global oilfield services company that provides a broad range of drilling, production and evaluation services. The company employs more than 10,000 people conducting operations in more than 30 countries.

—RAY TYSON, Petroleum News Houston correspondent

WESTERN U.S.

Galaxy boosts CBM position in Wyoming

Small exploration and production company Galaxy Energy, through its subsidiary Dolphin Energy, said April 5 that it acquired an additional 35 percent working interest in coalbed methane properties at the 3,200-acre Buffalo Run prospect near Sheridan, Wyo.

The acquisition provides Galaxy with a 100 percent working interest on its portion of the property, giving the company a 100 percent working interest in the 44 existing wells. Additionally, the company said it acquired another 26 percent working interest in about 323 acres of the Buffalo Run East lands.

The acquisition price for the additional working interests on both properties was $592,500, Galaxy said.

—RAY TYSON, Petroleum News Houston correspondent

ALBERTA

Alberta, Suncor in royalty arm-wrestle

The Alberta government and Suncor Energy are at odds over oil sands royalties that represent about C$875 million in potential revenues to the province.

Premier Ralph Klein and Energy Minister Murray Smith have indicated the government is adopting a firm stance over whether Suncor's Firebag project is new or just an extension of the company's existing oil sands operation.

A new project pays royalty rates of 25 percent from the outset; an expansion pays 1 percent until capital costs have been recovered.

Stage one of Firebag, which Suncor has repeatedly referred to as an expansion, is due to reach capacity of 35,000 barrels per day in mid-2005 and could grow in phases to 140,000 bpd by 2010-2012.

Because it is using steam-assisted gravity drainage technology to extract the raw bitumen, rather than Suncor's traditional mining methods, it is viewed as a new project, Smith said. He said the government is "standing very hard on its original agreement and is working to protect the resource interests of Albertans."

The final decision rests with the energy minister and "that is very clear," Smith said, although he said discussions continue with Suncor.

Suncor said it remains confident there will be "an agreement both sides see as beneficial."

—GARY PARK, Petroleum News Calgary correspondent

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D.O.D. APPROVED

continued from page 1

KERR-MCGEE

independent, has properties primarily in the Rocky Mountains, Permian Basin-Midcontinent, Gulf Coast and offshore Gulf of Mexico. Kerr-McGee entered Alaska in 2003 and announced a North Slope discovery there last month. (See cover of Petroleum News' March 28 edition.)

Kerr-McGee, with current assets of about $10 billion, is an energy and inorganic chemical holding company whose subsidiaries, joint venture partners and other affiliates have operations worldwide, including oil and natural gas onshore U.S. and in the Gulf of Mexico, the United Kingdom and Danish sectors of the North Sea, China, Australia, Benin, Brazil, Gabon, Morocco, Canada and Yemen.

Under the terms of the merger agreement, Westport shareholders would receive 0.71 shares of Kerr-McGee common stock for each common share of Westport. As a result, Kerr-McGee said it expects to issue about 49.4 million new shares to Westport's shareholders.

Of the $3.4 billion purchase price, about $2.1 billion would be allocated to the 297 million barrels of equivalent of proved reserves, equating to about $7.23 per barrel of equivalent. An additional $900 million is associated with 300 million barrels of probable and possible resources, or $3.10 per barrel of equivalent. The new company expects to convert these probable and possible resources into proved developed reserves at a cost of about $3.75 per barrel.

The transaction is expected to be nontaxable to the shareholders of both companies. Westport shareholders holding more than 42 percent of Westport's outstanding common stock already have agreed to support the merger, Westport said. The companies expect the deal to close in this year's third quarter.

Kerr-McGee said its executive management team, including Chief Executive Officer Luke Corbett, would keep their jobs after the transaction closes. However, one of the current board members of Westport would join Kerr-McGee's board of directors, increasing the size of the company's board to 10 members.

Proved reserves up by nearly 30 percent

The addition of Westport's reserves would increase Kerr-McGee's proved reserves by nearly 30 percent, mainly from North American natural gas, Kerr-McGee said. At year-end 2003, Westport had reserves of 1.8 trillion cubic feet of natural gas equivalent, consisting of 76 percent natural gas and primarily located in the Rocky Mountain and Texas Gulf Coast areas. Third-party reserve consultants determined 87 percent are proved reserves, Kerr-McGee said.

Westport also has reported probable and possible reserves of 1.8 trillion cubic feet of natural gas equivalent, about 50 percent of which are located in and around the Natural Buttes field, in the Uinta basin of northeast Utah. The Greater Natural Buttes area is similar to Kerr-McGee's tight-gas Wattenberg field.

Kerr-McGee's total daily production volume is expected to increase more than 34 percent, giving the new company daily production of about 1.2 billion cubic feet of natural gas and 160,000 barrels of oil. About 54 percent of total production would be natural gas.

Kerr-McGee said it has entered into hedges, primarily in the form of costless collars, that when combined with Westport's existing hedges, cover about 90 percent of Westport's anticipated proved production through 2006.

As a result of the transaction, Kerr-McGee's net debt as a percent of total capitalization is expected to decrease from 54 percent to about 42 percent by year-end. In addition, the companies said they expect to realize cost savings of about $40 million annually. The transaction would be accretive to both earnings and cash flow per share beginning in 2005, Kerr-McGee said.

The merger also would give the new Kerr-McGee an exploratory program based on more than 71 million gross undeveloped acres worldwide.

—RAY TYSON, Petroleum News Houston correspondent

● GULF OF MEXICO

Newfield still seeking Treasure Island partner

Forms separate alliance with BHP; looking for company to pick up drilling costs in exchange for interest in tracts

By RAY TYSON

Petroleum News Houston Correspondent

Exploration and production independent Newfield Exploration, faced with expiration of its Treasure Island leases, says it needs "a little more time" to secure a partner to drill into the "ultra-deep" prospect located below 25,000 feet on the Gulf of Mexico's continental shelf.

Newfield recently told Petroleum News the company also has formed a separate exploration alliance with Australia's BHP Billiton covering some 50 blocks just west of Treasure Island called Treasure Bay. Blocks that make up Treasure Bay were assembled by the two companies during the past three Central Gulf of Mexico oil and gas lease sales, Newfield said.

Geologists believe the same giant structures that produced large discoveries in deeper waters of the U.S. Gulf extend beneath the relatively shallow waters of the continental shelf.

In regard to Treasure Island, Newfield, a major natural gas producer on the continental shelf, said it continues to discuss a possible drilling venture with "a number of large companies" that sources believe may include ExxonMobil, ChevronTexaco and BP, as well as BHP Canada's Nexen.

Geologists believe the same giant structures that produced large discoveries in deeper waters of the U.S. Gulf extend beneath the relatively shallow waters of the continental shelf.

Only known effort a dry hole

Shell is believed to be the only explorer to have drilled below 25,000 on the continental shelf, an effort that resulted in a dry hole at the company's high-profile Shark prospect on South Timbalier Block 174. Shares of Newfield and 40 percent Shark owner Nexen were hammered when preliminary drilling results were disclosed in February.

Despite the dry hole and having its feathers ruffled by investors, Newfield said it has not altered its plan for Treasure Island, which is in close proximity to Shark and said to be a Shark "look alike" in terms of geologic structure.

"This hasn't discouraged industry," said Steve Campbell, Newfield's head of investor relations. "It proved a well could be drilled."

Analysts wrongly speculated that because of extreme heat and pressures below 25,000 feet, the Shark exploratory well might cost $60 million or more and take upward of a year to drill. Shell completed the well in just a few months and at a cost thought to be well below $60 million.

However, because the 20 government leases that make up Treasure Island begin to expire in March 2005, Newfield's immediate goal is to find a drilling partner and spud an exploratory well at Treasure Island before year-end 2004, Campbell said.

Newfield wanted BP to drill

Newfield wanted BP to drill the Treasure Island well because of the major's financial strength and "technical savvy," even after BP reneged on an earlier commitment to spud a well by year-end 2003. Under its agreement with Newfield, BP was to pick up 100 percent of the well's expense to maintain a 75 percent stake in Treasure Island. If BP missed the deadline, the leases would automatically revert to Newfield.

Campbell said Newfield has now received full title to Treasure Island leases, but both Newfield and BP declined to say whether the two companies are still negotiating. "We don't speculate on negotiations," BP spokesman Larry Thomas said.

Newfield said months ago that if a deal could not be worked out with BP, it would seek another partner with terms similar to what it had with BP, meaning the new partner would have to pay the entire cost of an exploratory well.

Newfield actually inherited its Treasure Island position from independent EEX in an acquisition. Under terms of the original agreement, BP acquired a 75 percent interest in the EEX blocks, promising to do additional leasing and geophysical activities. EEX's 25 percent interest was carried by BP, meaning BP would cover all initial exploration costs. ●

Want to know more?

If you'd like to read more about Treasure Island, go to Petroleum News' web site and search for these articles published in the last year.

Web site: www.PetroleumNews.com

2004
- **Feb. 22** Dry at 25,756 feet
- **Feb. 1** Newfield, Nexen shares climb on word of discovery

2003
- **Nov. 23** BP bails out of Treasure Island wildcat well
- **Oct. 12** Breaking the ultra-deep barrier
- **June 8** Target 25,000 feet: BP plans expensive Gulf well
- **March 16** U.S. natural gas demand expected to out-pace production 3-1

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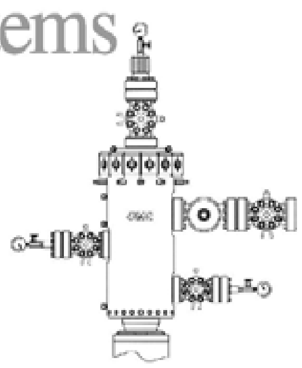

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ANS crude production back up above 1 million barrels per day

Alaska North Slope production was back above 1 million barrels of oil per day in March, averaging 1,006,790 bpd.

Although all North Slope fields had at least some production increase in March, the 5 percent increase over a February average of 959,250 bpd was primarily the result of a return to normal rates at BP Exploration (Alaska)'s Northstar field, which had no production for two weeks in February after a compressor motor failed.

Northstar averaged 72,597 bpd in March, an increase of 84.77 percent over a February average of only 39,291 bpd. The field did have some slow production days during the month, the Alaska Department of Revenue said, producing less than 60,000 bpd, March 13-14, because of a shipping pump repair. During the rest of the month Northstar production ranged from highs above 80,000 bpd at the beginning of the month to volumes in the high 60,000 bpd range at the end of the month, although Revenue said above zero temperatures and further repairs at Northstar caused a slope-wide output dip from March 20-23. Production at the BP-operated Prudhoe Bay field, which includes the Midnight Sun, Aurora, Polaris, Borealis and Orion satellites, averaged 488,020 bpd in March, up 0.87 percent from a February average of 483,820 bpd.

ConocoPhillips Alaska-operated Kuparuk River averaged 198,755 bpd, up 0.15 percent over February production of 198,455 bpd. Kuparuk production includes West Sak, Tabasco, Tarn, Meltwater and Palm. BP's Milne Point field, which includes production from Schrader Bluff, averaged 51,245 bpd, up 0.86 percent from a February average of 50,808 bpd. Endicott, also BP-operated, averaged 29,984 bpd, up 11.1 percent from a February average of 26,088 bpd. BP-operated Lisburne, which includes production from Point McIntyre and Niakuk, averaged 59,337 bpd in March, up 5.55 percent from a February average of 56,219 bpd.

ConocoPhillips-operated Alpine averaged 107,852 bpd, up 3.14 percent from a February average of 104,569 bpd.

The average temperature at Pump Station No. 1 on the North Slope was –13.9 degrees Fahrenheit, compared to a three-year average for March of –8.6 degrees.

Crude oil production in the Cook Inlet basin averaged 24,530 bpd in March, down 5.15 percent from a February average of 25,863 bpd.

—KRISTEN NELSON, Petroleum News editor-in-chief

● COPPER RIVER BASIN, ALASKA

Forest Oil looking to drill under-explored Alaska basin

Company's new farm-in partners, Rutter and Wilbanks, and Delphi, market Copper River acreage to potential investors at NAPE

By PAT HEALY

Petroleum News Contributing Writer

If all goes well, Forest Oil will be drilling the first well in Alaska's Copper River basin since Copper Valley Machine Works drilled the Alicia No. 1 well in 1983. Forest's heretofore unannounced exploration partners — Rutter and Wilbanks Corp. and Delphi International — were shopping for investors in the 398,445-acre Copper River block at the North American Prospects Exposition in Houston in February. The acreage, under an exploration license agreement with the state of Alaska since 2000, lies in the relatively unexplored Copper River basin of southern Alaska, west of the community of Glennallen.

Anschutz Exploration won the five-year Copper River basin exploration license back in August 2000. The license was issued in October of 2000. Kevin Corbett, new ventures manager for Anschutz, told Petroleum News that subsequent to winning the exploration license, Anschutz entered into an agreement with Forcenergy — now Forest Oil — to jointly explore the area. The 50-50 partners recently signed an exploration agreement covering the

> *"This is a risky deal, but we have a long history of taking risks. We have been wildcatters for three generations, and see no reason to stop now. We have a shot at some really big reserves on this deal."*
> **—Bill Rutter III, Rutter and Wilbanks Corp.**

see **FOREST** page 12

● BRITISH COLUMBIA

Marine parks touted for British Columbia offshore

Environment minister working on plan covering 6.8 million acres; three other protected areas under consideration; could scuttle exploration hopes

By GARY PARK

Petroleum News Calgary Correspondent

Dreams of turning the British Columbia offshore into an oil and natural gas producing region could be in danger of getting snuffed out.

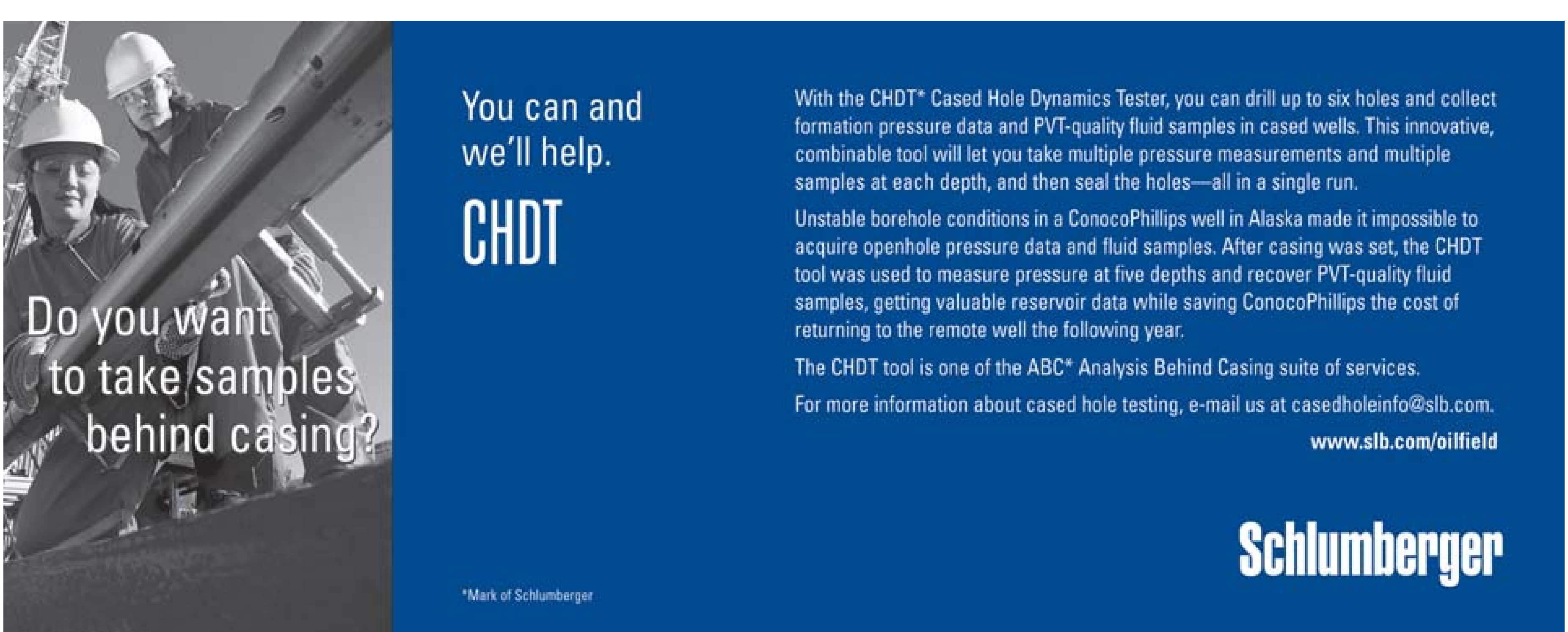
The Canadian government is reportedly on the verge of turning four large areas of the Queen Charlotte basin — by far the richest of British Columbia's petroleum basins — into marine parks.

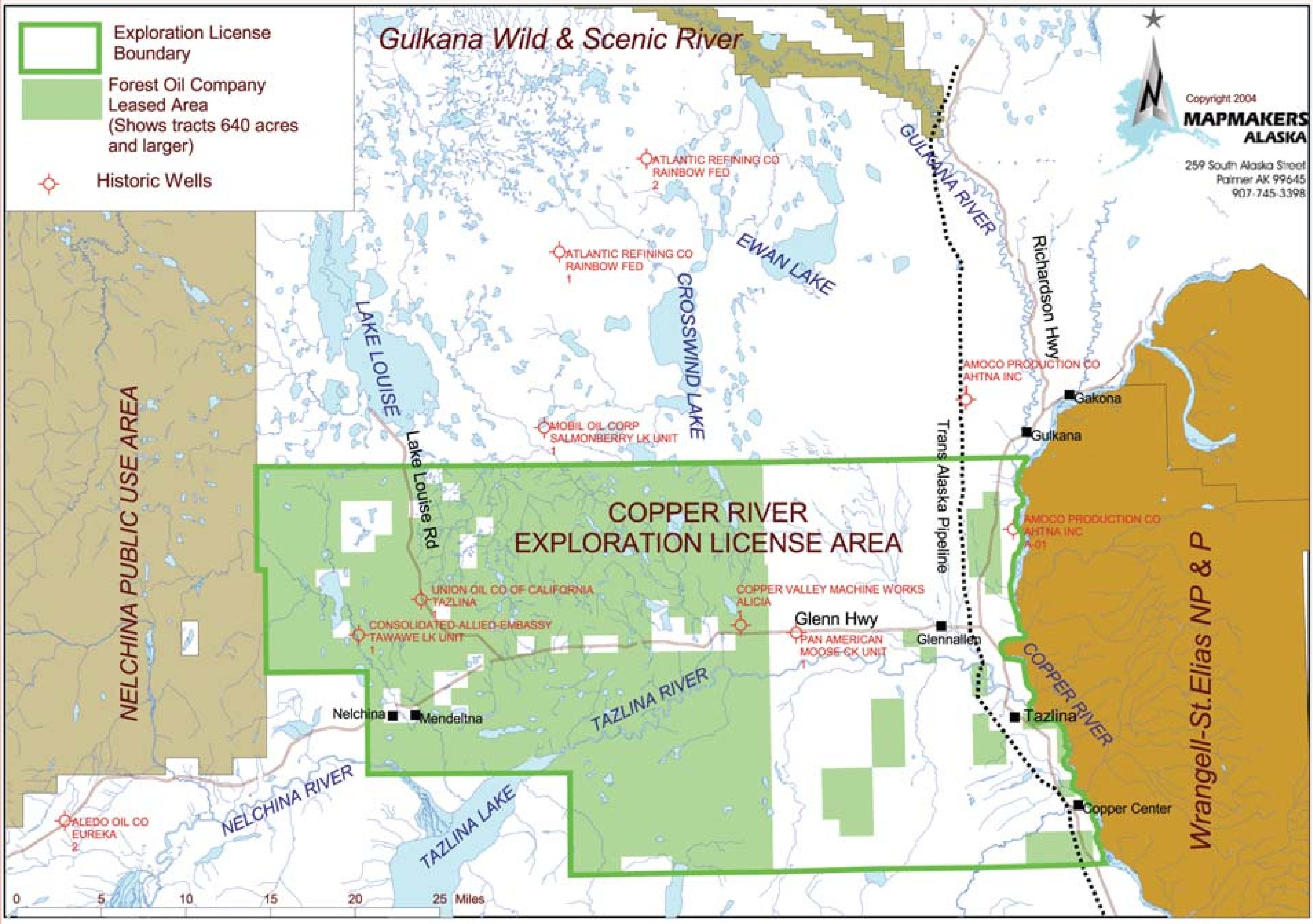
Federal Environment Minister David Anderson, who also represents a British Columbia constituency in Parliament, said he hopes to present a plan to the cabinet by this fall to create a marine wildlife area covering 6.8 million acres from the northern tip of Vancouver Island to the Queen Charlotte Islands.

The government is reported to be examining the possibility of establishing three other protected areas, stretching northward from Vancouver Island

> *Meanwhile, the U.S. government through the U.S. National Science Foundation is contributing C$3 million along with a research vessel to conduct a seismic study off the Queen Charlotte coast.*

see **PARKS** page 13





FOREST OIL COMPANY
STATE OF ALASKA EXPLORATION LICENSE
COPPER RIVER, ALASKA

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FOREST

398,445 acres with Rutter and Wilbanks and Delphi. Forest will be the operator. Delphi has had a long-term relationship with Anschutz and has been involved in this Alaska project for several years, but is a newcomer to Alaska. Now Rutter and Wilbanks and Delphi are hoping to find partners to share in the deal.

"We understand technology and we understand raising capital," Bill Rutter III told Petroleum News in March. "We are hoping to bring in some of our investors as partners to help with this deal, but we are contractually obligated to perform under agreement with Anschutz/Forest, with or without partners. This is a risky deal, but we have a long history of taking risks. We have been wildcatters for three generations, and see no reason to stop now. We have a shot at some really big reserves on this deal." Rutter praised the state of Alaska for their attitude and for the incentives the state provides to businesses. He said he was, "Looking forward to working in Alaska for that reason."

Three-phase project planned

According to their North American Prospects Exposition brochure, Rutter

see **FOREST** *page 13*

Wells drilled in the area

Operator	Well Name	Status Date	Location	TVD
Aledo Oil Co.	Eureka 1	Jun 1, 1957	Sec 9-T21N-R12E	4818
Unocal	Tazlina 1	Oct 29, 1962	Sec 10-T4N-R7W	8837
Aledo Oil Co.	Eureka 2	May 6, 1963	Sec 18-T2N-10W	8546
Pan American	Moose Ck 1	Jul 17, 1963	Sec 29-T2N-R10W	7869
Mobil Oil Corp.	Salmonberry Lk 1	Mar 18, 1964	Sec 24-T6N-R6W	7913
Atlantic Richfield	Rainbow Fed 1	Dec 21, 1965	Sec 31-T8N-R5W	3000
Atlantic Richfield	Rainbow Fed 2	Jan 26, 1966	Sec 1-T8N-R5W	2793
Consolidated Allied-Embassy	Tawawe Lk 1	Jan 17, 1970	Sec 24-T4N-R8W	6721
Copper Valley Machine Works	Alicia 1	Jan 15, 1983	Sec 23-T4N-R4W	1050
Amoco	AHTNA Inc 1	Apr 16, 1980	Sec 18-T6N-R1W	7917
Amoco	AHTNA Inc A-01	Aug 6, 1980	Sec 28-5N-r1W	5671

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FOREST

and Wilbanks and Delphi are seeking partners to participate in a three-phase gas project to explore the Copper River basin. Compliance with each phase earns investors the right to proceed to the next phase.

Phase I deals with investing in the 2004 seismic program. A 40 percent transferable and saleable state of Alaska tax severance credit is a major selling point for dollars invested in this seismic program.

A 2D seismic program is currently being permitted and PGS Onshore Inc. is scheduled to acquire the data this winter.

Phase II buys the investor an interest in the well. As stated earlier, Forest will be the operator. Investors will have the opportunity to buy a working interest with the obligation to participate in the first test well. Cost to drill to 7,000 feet is estimated to be $3 million to $4 million.

Phase III assumes commercial results from the test well and includes a 3D seismic program, additional drilling and laying pipelines. The brochure states, "Based on a discovered reserve of 100 BCF, the investors net share would have a finding cost of 7.4 cents/MCF."

Eleven wells drilled in basin

Eleven wells have been drilled in the Alaska Copper River basin.

"The Moose Creek No. 1 well had excellent gas shows in very high quality reservoir rock, with a gross sand package of 680 feet," the companies said in their brochure. Pan American Moose Creek No. 1 was plugged because there was no market for gas in 1963.

A map on the brochure shows a key seismic line running across the Copper Valley Alicia No. 1 and the Pan American Moose Creek No. 1 well locations. The exploration permit area includes the Unocal Tazlina No. 1, the Consolidated Tawawe Lake No. 1 and the Amoco Ahtna No. 1A well locations. The brochure also says that the Mesozoic geology is similar to Cook Inlet and that the structure is located across a major fault with existing seismic showing complex folding and faulting.

Anschutz bid a $1.42 million work commitment for the five-year exploration license it won in August 2000. The company paid 20 percent down on a one-time $1-an-acre rental fee for the 398,445-acre exploration license. Mon-Oil Inc. of Calgary also proposed a license for the area, but Anschutz won the final bid.

Anschutz proposed to spread work over four years. Partner and operator Forest has performed the work to date. In the first year the company proposed to conduct geological field work, mapping, sedimentology and stratigraphy, source rock sampling and geochemical modeling with a work value of $150,000.

Anschutz said it would license and reprocess existing seismic data for the area, also estimated at $150,000, for the second year.

The third year included collection processing and interpretation of gravity data, at a value of $120,000 done by PGS Onshore.

New seismic is current phase of project

In the fourth year, the company would spend $1 million for new seismic data acquisition, processing and interpretation. Phase I of Rutter and Wilbanks and Delphi's proposed deal begins at this point.

The Copper River basin oil and gas exploration license area runs west from Glennallen on either side of the Glenn Highway and includes most of the length of the Lake Louise Road to the north. In the east, the boundary is close to the Richardson Highway. The southern boundary is south of Copper Center. Exploration license areas are more likely to yield gas rather than oil, and reserves could provide a source for local energy consumption.

Rutter said, "What really interested us about this project was the potential to find and develop world-class reserves right here in the United States. The costs to operate in Alaska are higher, but we feel the upside in reserves justifies these added costs. And the State of Alaska has really been aggressive at creating incentives for investment in exploration and development of the oil and gas wealth of the state. It is really refreshing to not have the government fighting you every step of the way." ●

Rutter and Wilbanks

A new player in Alaska, Rutter and Wilbanks Corp. is a Midland, Texas-based independent oil and gas exploration company that has been involved in wildcat drilling all over the Lower 48 states.

The company began back in 1936 when A.W. Rutter Sr. hooked up with the Wilbanks brothers from Big Spring, Texas. Rutter had the capital and the Wilbanks had the drilling rigs. The partners put Permian basin deals together and commenced drilling.

In the 1950s Rutter and Wilbanks soundly profited from drilling the Sprayberry formation. Bill Rutter Jr. became a partner in the mid-1950s and has been running the company since the mid-1970s.

In the 1960s when oil was no longer a growth industry, Rutter and Wilbanks began investing in real estate and many other sectors.

During the 1970s and 1980s, the company was a large holder of federal leases across the western United States and active in a number of oil and gas plays, nationwide.

Today oil and gas represent about 60 percent of Rutter and Wilbanks' activity. Bill Rutter III manages the oil and gas and venture capital side of the business. Chris Rutter handles the real estate. For the past few years Rutter and Wilbanks has been actively involved in raising venture capital for various new technologies such as automotive transmissions, stabilized drill bits, landfill gas ventures and advanced geothermal technology. Green energy is especially interesting to Rutter and Wilbanks.

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PARKS

over several hundred miles along the coastline.

Plan would sharply reduce offshore available for exploration

Patrick O'Rourke, assistant deputy minister for the British Columbia Energy and Mines Ministry, said that if the federal government goes ahead with the plans, the amount of offshore available for exploration would be sharply reduced.

He told a conference in Vancouver that the proposal "adds to the challenges" faced by the provincial government, which has targeted a commercial industry by 2010.

Andy Burton, a Conservative Member of Parliament for northern British Columbia, said the talk of marine parks is "very frustrating" and could be a "backdoor maneuver to block off any offshore oil and gas activity."

Currently, a federal panel is reviewing that ban on exploration of a region Natural Resources Canada has estimated holds 43.4 trillion cubic feet of gas and 9.8 billion barrels of oil, of which the Queen Charlotte basin is estimated to contain 25.9 tcf of gas and all of the oil.

Under the federal Wildlife Act, Anderson could create a park without any support from the affected communities, although Tomas Tomascik, a senior advisor with Parks Canada, told the Vancouver conference he did not think that would happen.

Anderson is an avowed opponent of opening up the offshore to oil and gas drilling, having taken a role in developing the moratorium in 1972.

Federal panel reviewing ban on exploration

Currently, a federal panel is reviewing that ban on exploration of a region Natural Resources Canada has estimated holds 43.4 trillion cubic feet of gas and 9.8 billion barrels of oil, of which the Queen Charlotte basin is estimated to contain 25.9 tcf of gas and all of the oil.

The panel started public hearings April 5 and will visit 11 locations by May 15 before reporting to Natural Resources Minister John Efford this summer.

Officials expect a decision some time in 2005 on the moratorium.

Meanwhile, the U.S. government through the U.S. National Science Foundation is contributing C$3 million along with a research vessel to conduct a seismic study off the Queen Charlotte coast.

The study is scheduled for late 2005, regardless of whether or not the ban is lifted, said O'Rourke.

He told the Financial Post that the province thinks the seismic needs to be done because previous data was based on old and flawed techniques and is not affected by the moratorium.

Federal studies in the 1990s suggest the offshore has far more oil and gas than previously thought.

But a mountain of problems must be resolved before any of the leaseholders — notably Shell Canada, Chevron Canada Resources and Petro-Canada — are interested in developing exploration plans.

A regulatory regime, including how royalties will be shared by the B.C. and Canadian governments; aboriginal land claims; seabed ownership; and environmental issues are all on the agenda, prompting most experts to forecast that, if commercial discoveries are made, production is at least 10 to 12 years away. ●

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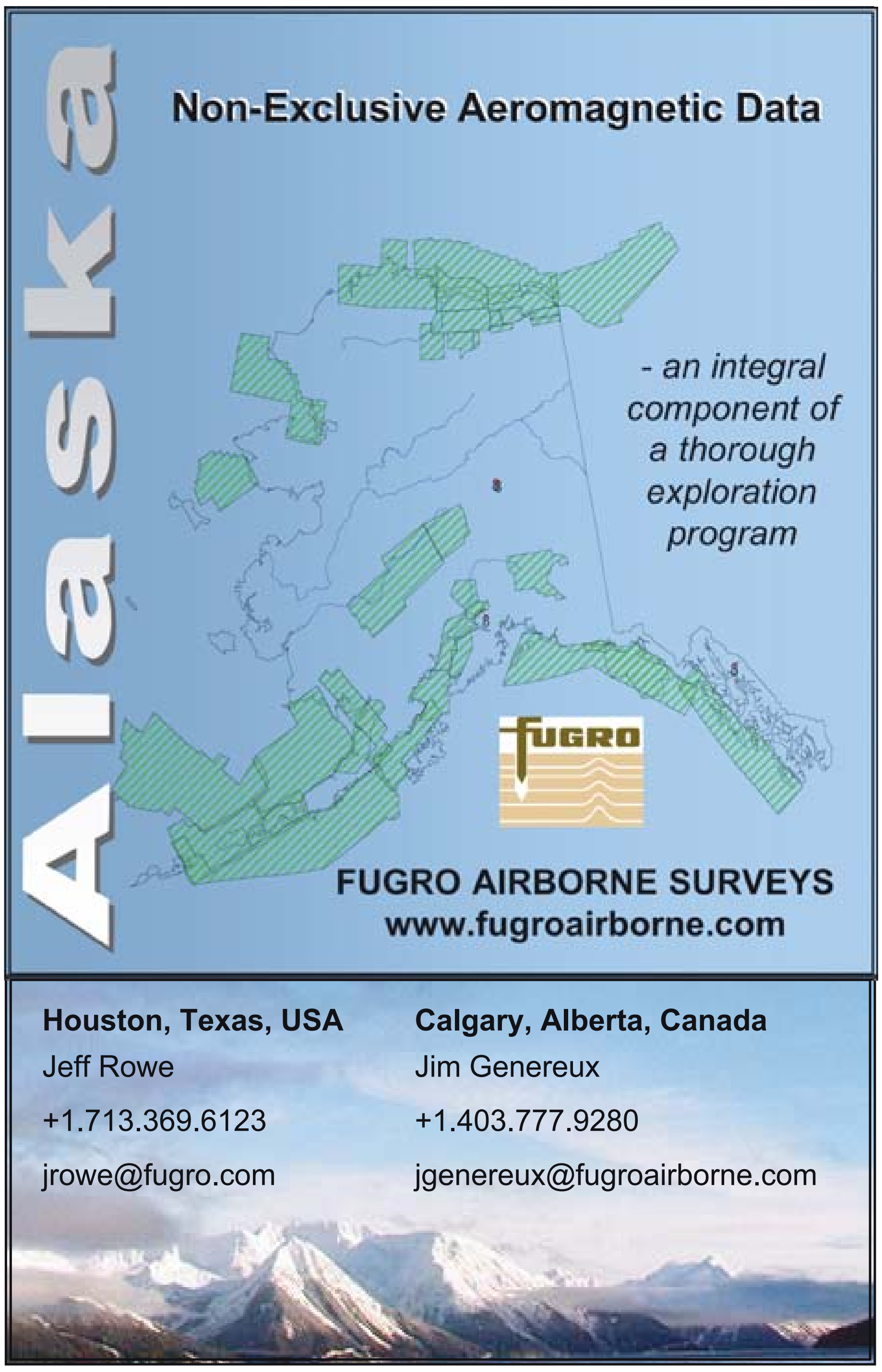


NEWFOUNDLAND

White Rose blooms: FPSO vessel arrives at Newfoundland after covering 14,000 nautical miles from South Korea

Husky Energy is on track to launch the C$2 billion White Rose field, Newfoundland's third producing offshore project, within about two years.

The latest success came April 6 with the arrival in Canadian waters of the massive SeaRose floating production, storage and offloading vessel after a 14,000-nautical mile, eight-week journey from South Korea via Cape of Good Hope and across the Atlantic.

Husky President and Chief Executive Officer John Lau said the delivery of the hull and turret are on schedule, setting the stage for the completion and installation of topsides facilities, which are more than 50 percent completed, over the next 18 months.

In the absence of any hiccups, White Rose should be pumping crude by late 2005 or early 2006, targeting peak output of 92,000 barrels per day.

Of Newfoundland's two existing projects, the seven-year-old Hibernia field is now producing more than 200,000 bpd, while Terra Nova averaged 134,000 bpd last year and is now in its third year of operation.

The White Rose owners are Husky at 72.5 percent and Petro-Canada at 27.5 percent.

The project is advancing on other fronts, spudding development wells last October as part of a 130-day drilling program that was 40 days ahead of program in early March.

Will Roach, Husky's East Coast manager, told the Newfoundland and Labrador Construction Safety Association that each day gained represents a saving of C$450,000 in drilling costs.

Husky also reported last October that after completion of two delineation wells, White Rose reserves had been boosted by 60-90 million barrels of oil from the earlier 200-250 million barrels and by 200-250 billion cubic feet of gas from the previous 1.85 trillion cubic feet, with about one-third of the oil deemed to be recoverable.

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

SNYDER, TEXAS

Bad weather causes Patterson-UTI Energy to lose 120 'drilling days' in March

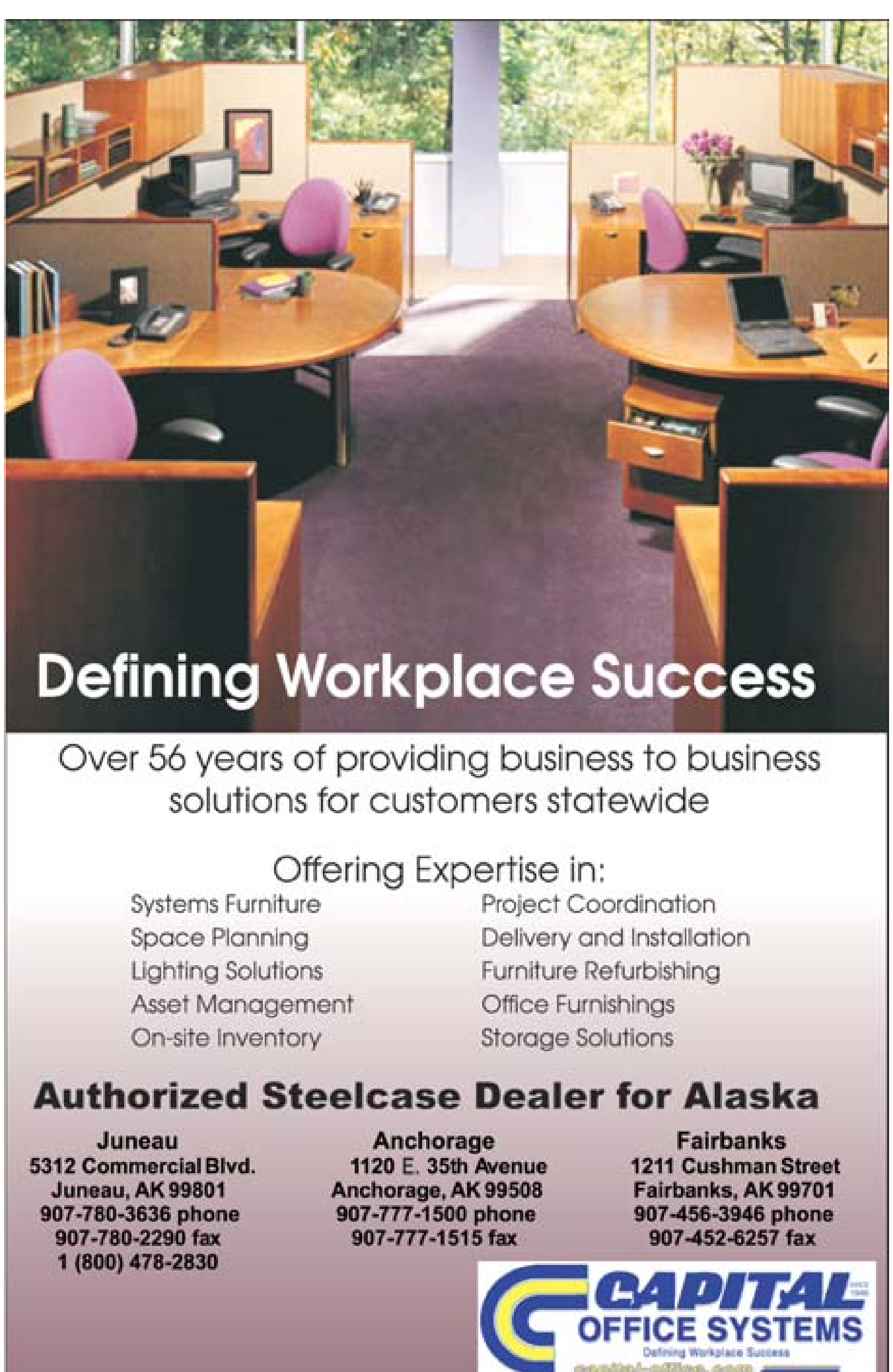
U.S. contract land driller Patterson-UTI Energy last month lost an estimated 120 drilling days, or an average of four rigs, because of weather related delays in moving rigs, the company said April 5.

Patterson's estimate does did not include drilling days lost due to weather conditions that caused customers to delay preparation of drilling locations, the company said.

Drilling days reported by Patterson represent the number of days in which a company rig was moving or operating under a drilling contract. The company owns 361 land-based drilling rigs that operate primarily in Texas, New Mexico, Oklahoma, Louisiana, Mississippi, Colorado, Utah, Wyoming and western Canada.

For the month of March 2004, the company said it had a total of 6,458 drilling days, or an average of 208 drilling rigs operating, including an average of 195 rigs in the United States and 13 rigs in Canada. For the three months ended March 2004, the company reported a total of 18,052 drilling days, or an average of 198 drilling rigs operating, including an average of 184 rigs in the United States and 14 rigs in Canada.

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



NORTH AMERICA

North American rig count plummets 116 to 1,354 on Canadian withdrawals

The North American rotary rig count, pushed lower by a slump in Canadian activity, dropped by a net 116 to 1,354 rigs during the week ending April 2, according to rig monitor Baker Hughes. Still, there were 161 more rigs working in North America in the recent week compared to the same period last year.

The number of rigs operating in Canada during the recent week fell by 126 to 194 from the previous week, down by 27 rigs compared to the same weekly period last year.

In the United States, the rig count rose by a net 10 to 1,160 during the recent week, up by 188 rigs versus the same period a year earlier. Land rigs alone jumped by nine to 1,055, while offshore rigs increased by one to 91 and inland water rigs were unchanged at 14.

Of the total number of rotary rigs operating in the United States, 1,000 were drilling for natural gas and 157 for oil, while three were being used for miscellaneous purposes, according to Baker Hughes. Of the total, 761 rigs were drilling vertical wells, 303 directional wells, and 96 horizontal wells.

Among the leading producing states in the United States, Oklahoma realized a gain of six rigs to total 158. Texas gained five rigs to total 502. Louisiana's rig count rose by two to 170. And California was up one rig to 23. New Mexico lost one rig for a total of 65, while Wyoming lost one rig for a total of 61. Alaska was unchanged at 12 rigs.

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

CALIFORNIA

Energy officials search for reasons for gasoline price spikes

California residents are being urged to drive their cars less to help stem the rapid increase in gas prices throughout the state.

"The bottom line is, for this summer we are going to have to do like we did during the energy crisis and make conservation and reducing demand something that we talk about everyday," John White, executive director for the Center for Energy Efficiency and Renewable Technologies, said April 1. "People need to get the link between the price and the demand."

Although he has investigated price fixing in the industry, Lockyer said he's never found evidence of unlawful conduct.

Many factors were blamed for California's gas prices, which are about 20 cents higher than the national average and often more than $2 a gallon. California Attorney General Bill Lockyer and energy officials told a California Assembly committee that lack of competition, a stagnant supply and too many cars on the road are contributing to the skyrocketing cost.

Highest prices in San Diego

San Diego has the highest gas prices in the country, at $2.12 for a gallon of regular unleaded.

"I frankly cannot pretend that we will have any magic bullets to make thing better. Clearly there are factors beyond our control," said Assembly Transportation Committee chairwoman Jenny Oropeza, D-Carson, citing the OPEC cutbacks announced March 31 and burgeoning demand for petroleum products in China and India.

A lack of competition between oil companies is contributing to the price spike, Lockyer said.

Although he has investigated price fixing in the industry, Lockyer said he's never found evidence of unlawful conduct.

Population growth stresses gasoline supply

As the population of the state grows, its gasoline supply has become stressed, said California Energy Commissioner James Boyd.

The state needs to look at alternative fuel, increase the use of hybrid vehicles and look for ways to increase the fuel efficiency of its cars, Boyd said.

Another factor contributing to costly gasoline is California's cleaner burning fuel requirements.

California should pursue a waiver of the federal government's requirement that gasoline contain an oxygenate like ethanol, a step that would reduce the cost of gasoline 3 cents a gallon, said Rob Oglesby, legislative director for the California Air Resources Board.

California officials have sought unsuccessfully for more than two years to get a waiver from the requirement, which is supposed to help reduce pollution. State officials argue that because of California's cleaner-burning fuel, the additives are unnecessary and costly.

—**ANNA OBERTHUR,** Associated Press writer

● KENAI PENINSULA, ALASKA

Commission conditionally OKs gas sales agreement

Regulatory Commission of Alaska calls for some changes in the natural gas sales agreement between Enstar and NorthStar Energy

By **KRISTEN NELSON**

Petroleum News Editor-in-Chief

The Regulatory Commission of Alaska has conditionally approved a gas sales agreement between Enstar Natural Gas Co. and NorthStar Energy Group Inc. that will bring natural gas to Homer at the southern end of the Kenai Peninsula in Southcentral Alaska.

The agreement provides for 20 years of natural gas delivery from NorthStar's North Fork field east of Anchor Point.

The commission, in a March 23 order, required some changes in the agreement.

In addition to amending the agreement, both companies have a lot of work to do before any pilot lights are lit on the lower end of the peninsula.

Dan Dieckgraeff, Enstar's manager of finance and rates, told Petroleum News in August when the companies announced the sales agreement that it would probably take a year and a half to two years to begin delivering gas. Approval of the contract and the proposed rate by the commission is the first step, he said.

The Alaska Attorney General opposed the pricing method for the gas, a 36-month trailing average of Henry Hub natural gas futures prices. The commission disagreed, finding the use of Henry Hub futures prices consistent with customary language and practice of commerce.

see **RCA** *page 16*

● HONOLULU, HAWAII

Court upholds ruling on gas station rent cap law

Federal appeals court agrees with lower court ruling that Hawaii's 1997 law to place rent caps on dealer-run gasoline stations is unconstitutional

By **BRUCE DUNFORD**

Associated Press Writer

A federal appeals court upheld a lower court ruling April 1 that Hawaii's 1997 law to place rent caps on dealer-run gasoline stations is unconstitutional.

Hawaii State Senate Minority Leader Fred Hemmings said the legal theory in the 9th U.S. Circuit Court of Appeals' ruling raises serious constitutional questions about a state law that will impose price caps on gasoline prices in Hawaii effective July 1.

The Legislature is considering delaying the price caps for one year to consider changes, including imposing them only at the wholesale level and pegging the caps on national instead of West Coast fluctuations.

U.S. District Judge Susan Mollway two years ago invalidated the 1997 rent caps law in a lawsuit filed by Chevron Corp., ruling it unfairly infringed on the company's ability to use its property. The appeals court agreed.

"Mollway's findings in the (rent cap) case, first and foremost, put out the biggest message regarding the foolhardiness of gas caps," Hemmings, R-Lanikai-Waimanalo, said. "In her findings, she found very clearly that gas is no more egregiously priced than most other consumer products."

Hemmings said the latest proposal to cap wholesale prices of gasoline can't guarantee lower retail

see **RULING** *page 16*

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RCA

There is a single well at the field, drilled in 1965. NorthStar has to drill at least one additional well before the gas sales agreement becomes effective, and must raise proved reserves at the field from 12 billion cubic feet to 14.5 bcf.

Then there are the pipelines: NorthStar will build the eight miles from North Fork to Anchor Point. Enstar will build the 11 miles from Anchor Point to Homer, and the local distribution lines.

NorthStar, for its part, hopes to do more than provide natural gas for Homer. Larry Snead, manager of land and contracts for NorthStar, said in August that building the pipeline from North Fork to Anchor Point is the most exciting part of the project for NorthStar, because that "allows us the opportunity to build a line north" later to hook up with the Kenai Kachemak Pipeline, allowing the company to move gas from the lower peninsula north.

Commission lowers floor price

Enstar and NorthStar proposed a floor price of $3 per thousand cubic feet for the gas but the commission found that floor to be too high, and is requiring the companies to reduce the floor to $2.75 per mcf, and also to modify the transportation rate to include a cap of 30 cents per mcf, and to limit arbitrage to not more than 15 percent of the total volume of gas sold under the agreement.

The commission approved a proposal to charge Homer customers a $1 per mcf surcharge to permit delayed recovery of the contribution customers must pay to Enstar to build its line extension to Homer, a charge which customers normally must pay up front before they receive service, the commission said. The surcharge would continue until actual capital costs of the pipeline from Anchor Point to Homer are recovered, estimated to be approximately 10 years.

Commissioner disagrees with RCA decision

Commissioner Kate Giard of the Regulatory Commission of Alaska disagrees with the decision of the majority of the commission's members to approve the gas sales agreement between Enstar and NorthStar Energy Group for natural gas from the North Fork field proposed for delivery to Homer.

That sales agreement is based on the Enstar-Unocal gas sales agreement, includes a floor price and indexes the price paid by Alaska consumers to a 36-month Henry Hub futures index price.

Giard said in a dissenting statement dated April 5 that Enstar "failed to meet its burden of proof that this (gas sales agreement) is in the public interest." Girard agreed with the Alaska Attorney General's argument that Henry Hub natural gas futures include Lower 48 transportation and tax costs, and said the Attorney General "provided evidence that the U.S. Average Wellhead Price Index is a more appropriate proxy, is nationally tracked and reported and linearly correlates to the prices of the Henry Hub Natural Gas Futures market."

The commissioner said the shift to a national pricing proxy "created a substantial increase in natural gas costs for Enstar's ratepayers," with natural gas price increases ranging from 12.44 percent to 13.93 percent between 2002 and 2003.

"To the extent these increases are necessary to assure future supply meets expected demand, they are a rational expression of economic policy," she said. "However, without adequate controls, this shift could create windfall profits and destabilize our economy."

In addition to using the U.S. Average Wellhead Price Index rather than Henry Hub, Giard also said the commission should establish a price cap, because as a consequence of the commission's approval of the Enstar-Unocal and Enstar-NorthStar sales agreements, "Alaska natural gas prices are utterly dependent on activities in the Lower 48.

"A series of events or a single dramatic event occurring in the Lower 48 could materially affect our economy."

If a terrorist attack in the Lower 48 put a gas pipeline out of commission for a period of time, or unusually cold weather occurred, the Henry Hub price would increase.

"The result is an increase in Alaskan prices completely unrelated to the supply or demand in Alaska," she said.

Giard said the commission should have required "a reasonable price cap" which would balance "the need to compete nationally for exploration and development dollars" with protection for Enstar's ratepayers.

Giard also said the commission should eliminate the floor price. Indexing Alaska's price to Henry Hub futures with no price cap "allows for unrestricted upward opportunity for price increases," she said, and coupled with an inflation-adjusted floor to secure against future decreases in the Henry Hub price, "is known in pejorative terms as having your cake and eating it too."

—PETROLEUM NEWS

Alaska Attorney General opposes pricing method

The Alaska Attorney General opposed the pricing method for the gas, a 36-month trailing average of Henry Hub natural gas futures prices. The commission disagreed, finding the use of Henry Hub futures prices consistent with customary language and practice of commerce, and noted that Enstar's current long-term gas supply agreements have typically included price adjustments based on various price indices, including the three-month average for light sweet crude futures and Henry Hub futures.

The Attorney General also said North Fork gas should be priced based on the Moquawkie contract, where a known field was developed for production through an existing well and where a second well was also drilled, with a flat $2.75 per mcf price, adjusted for inflation. That differs from the recent Unocal contract, which required Unocal to explore for gas in new areas, and which Enstar used as a model, proposing a $3 per mcf floor price and the use of Henry Hub pricing index, because NorthStar is required to drill a new well and create redundant gas supply.

The commission agreed with Enstar, noting that the Moquawkie contract did not require drilling a new well before deliveries could begin. It disagreed, however, on the floor price, saying the record did not support NorthStar's contention that the floor price should be 25 cents higher per mcf than the $2.75 Unocal floor, based on inflation, higher costs of capital and current elevated costs of gas.

Arbitrage, size of gas pipeline

The commission disagreed with Enstar on arbitrage, and inserted a 15 percent limit — the same as the Unocal contract — on the amount of gas volume sold under the agreement that may come from third party sources.

The Attorney General argued against the 20-year term of the agreement, saying Enstar should have an opportunity to get out of the contract if it finds it can get gas more cheaply elsewhere. The commission said NorthStar argued that without the long-term contract, it would have no assurance that its investment would make financial sense, and that investors and financiers must be assured NorthStar "would obtain sufficient revenues over a long enough period to justify investment."

The commission concluded that 20 years was a reasonable term, both for the companies and for Homer consumers, who have to retrofit their current heating systems to accept natural gas.

The commission added a transportation cap of 30 cents per mcf, noting the Unocal contract had a cap of $1 per mcf, based on a pipeline about three times as long and about three times the diameter.

The commission also said that when it comes to approving a tariff, it "will not approve transportation rates on NorthStar's pipeline that are in excess of the charges necessary to support a 4-inch pipeline from North Fork to Anchor Point." The commission said it understands that NorthStar hopes to find enough gas to eventually sell into the Southcentral market, and said it agreed with Enstar: "if NorthStar is successful '…the vast majority of the gas going through that line may be for other purposes and other people.'" On that basis, the commission said, it is placing "NorthStar on notice that we will only approve transportation charges that recover the costs of a pipeline four inches in diameter from its leases to Anchor Point."

And, because Enstar's affiliate, Alaska Pipeline Co., could be asked to build the NorthStar pipeline, the commission said it is requiring that NorthStar's "transportation tariff filing must demonstrate that a valid, reasonably advertised, competitive procurement process was undertaken for the construction of the NorthStar pipeline." ●

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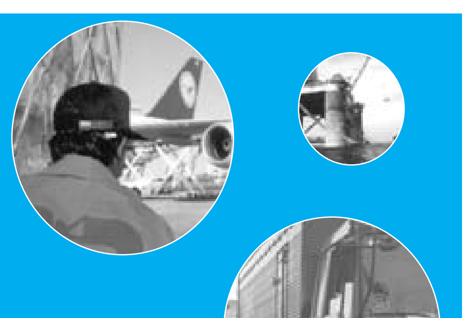

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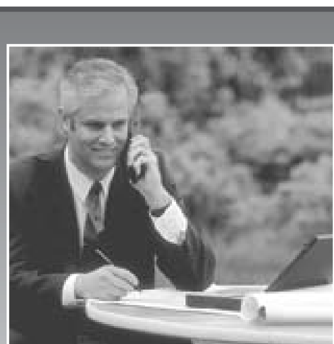

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RULING

prices, and doesn't meet the public interest requirement to override the constitutional prohibition against taking someone's property without just compensation.

Law first ruled unconstitutional in 1998

U.S. District Judge Alan Kay in 1998 held in a Chevron challenge that the law was unconstitutional, but the appeals court overturned his ruling in 2000, deciding it was premature since the factual dispute over whether the law would lower gasoline prices — the legislative intent — hadn't been argued in court.

Mollway in 2002 ruled the law, which was never enforced because of the legal challenge, would have had the opposite effect, because oil companies would have raised wholesale gasoline prices to make up for reduced rental income.

Lawmakers passed the 1997 law after concerns were raised that island motorists were paying too much for gasoline. The law restricted what lease rents oil companies could charge for their dealer-owned stations and prohibited the companies from taking over those stations.

In its ruling April 1, the appeals court rejected the state's arguments that Chevron's claim was an issue of due process and not one of wrongful taking of property, that the state law advanced a legitimate state interest and that Mollway erred in finding the law wouldn't reduce retail gasoline prices. ●

● MOBILE, ALABAMA

ConocoPhillips plans offshore LNG terminal

Construction could start next year on Compass Port Terminal, with first liquefied natural gas to terminal by early 2009

THE ASSOCIATED PRESS

Houston-based ConocoPhillips plans an offshore liquefied natural gas terminal in federal waters about 11 miles south of Dauphin Island offshore Alabama in the Gulf of Mexico.

The company announced April 2 that its Compass Port Terminal would handle LNG arriving on ships for delivery by pipelines to its gas customers.

Depending on federal permitting, construction could start next year. The first LNG shipment could be delivered to the terminal by early 2009.

ConocoPhillips applied in early April with the U.S. Coast Guard for the terminal. The Coast Guard has almost a year to rule on the permit request.

Mobile has pipeline connections

Mobile is attractive to energy firms because of its existing pipelines, deepwater ports and proximity to Middle Eastern markets, rich with natural gas, said Bob Davis, spokesman for Exxon Mobil Corp., which is considering constructing an LNG terminal on western Mobile Bay.

Exxon Mobil's proposal ran into opposition from environmentalists and property owners near the land-based site. It's now "on hold" in favor of its possible sites on shore in Texas and offshore near Louisiana, Davis said.

Cheniere Energy Inc., another Texas firm, also has an LNG land-based terminal proposed for Mobile Bay.

Mobile Mayor Michael C. Dow said April 2 that he favors an offshore terminal over an onshore one because "that certainly will take some of the anxiety out of our community's response to LNG."

ConocoPhillips has paid for a site-specific independent safety study by San Antonio-based Baker Engineering and Risk Consultants. The report indicates the effects of an accidental release of LNG would be contained within a one-mile area.

The ConocoPhillips proposal is "good news for Mobile," said James Fay, a professor emeritus at Massachusetts Institute of Technology who has been a leading critic of plans to build LNG facilities onshore.

"There will be no big supply of liquid gas that would be close enough to land to do any harm if it got attacked out there," Fay told the Mobile Register for a story April 3.

The gas pumped to shore, Fay noted, would already be in its familiar, and much less concentrated, gaseous form.

Players see too much opposition onshore

Fay said that the ConocoPhillips announcement was a "sign that the major players have convinced themselves it wasn't worth tackling the opposition to siting these terminals onshore."

A proposal by ConocoPhillips to build an onshore terminal in Maine was recently rejected in a vote in that community.

As for damage to marine life from an offshore terminal, ConocoPhillips officials said that they have hired scientists with the Dauphin Island Sea Lab to do sampling in an attempt to better address that question.

Sea Lab Director George Crozier said that there simply is a lot no one knows about the use of this water from the Gulf.

For example, Crozier said that there are no good studies that show how many fish or shrimp fry or plankton might get sucked up into the water intakes because there's so little data on how many creatures are floating in a typical gallon of Gulf water.

ConocoPhillips spokeswoman Linsi Crain said the company would not finalize its plans for the project until there was sufficient research to proceed.

Crain also said the company "would be up to considering anything" suggested by the research, including the possibility of using natural gas rather than sea water for the regasification process.

"It would not be the first time we re-engineered something," Crain said. ●

NEW BRUNSWICK

Canada's first LNG terminal in regulatory stream, aims to be online in 2006

Irving Oil, part of the giant privately held Irving conglomerate, has put itself in the forefront of the race to establish Canada's first liquefied natural gas terminal.

The New Brunswick company reported a "significant milestone" in filing its environmental impact statements with the New Brunswick government that it hopes will allow construction to start later this year on the $375 million plant at Saint John.

It is aiming to come on line in 2006 at 500 million cubic feet per day and eventually double those volumes, making the Canaport project the third largest LNG terminal in North America. There are two rival projects for Canada — the Bear Head project by Access Northeast Energy, which is targeting a late 2007 start-up at Port Hawkesbury, Nova Scotia, of a $350 million terminal and a joint venture by TransCanada and Quebec utility Gaz Metropolitain to build a terminal on the St. Lawrence River.

ChevronTexaco had initially planned to ship gas to New England through the Irving facility, but has since decided to pursue other opportunities.

An Irving spokesman doubted Canaport would face the community and environmental opposition that forced TransCanada and ConocoPhillips to scrap plans for a terminal at Harpswell, Maine. He said New Brunswickers are well accustomed to the crude oil tankers arriving at Saint John, where Irving has Canada's largest refinery.

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

CANADA

Gas exports end 17-year growth streak

Canadian natural gas shipments to the United States fell by 7.9 percent last year, the first year-over-year decline since 1986, but not something that would cause lost sleep among producers.

While exports shrank to 3.48 trillion cubic feet from 3.78 tcf in 2002, revenues made a staggering surge to C$25.3 billion (US$19. billion) from C$18.3 billion (US$13.7 billion) as the average price rose to C$6.72 per gigajoule from C$4.47 and beating the previous record of C$6.15 in 2001. The National Energy Board, in releasing the numbers, said the drop in exports stemmed partly from lower Canadian production, higher Canadian end-use demand, storage build-up in 2003, lower demand in some export markets, and higher imports of liquefied natural gas to the United States.

Natural Resources Canada has forecast a slight rebound this year to 3.53 tcf and 3.54 tcf in 2005, peaking at 3.7 tcf in 2010, then falling again to 3.56 tcf in 2015.

But export revenues are expected to remain strong at C$17.8 billion (US$13.3 billion) in 2005, C$20.3 billion (US$15.2 billion) in 2010 and C$21.8 billion (US$16.4 billion) in 2015. The U.S. Energy Information Administration has projected Canadian imports will remain at about 3.6 tcf through 2010, then start sliding to 2.6 tcf in 2025, based on data and projections from various sources.

The Alberta government has echoed those trends, forecasting a 17 percent decline in the province over the next three years to 4.6 tcf in 2006-07.

The bulk of last year's volume declines occurred in the California market, which was off 21 percent to 433 billion cubic feet and the Pacific Northwest, which dropped 17 percent to 401 bcf. The U.S. Midwest slipped by 1 percent to 1.59 tcf and the Northeast was down by 6 percent at 1.08 tcf. California sales fetched C$6.48 per gigajoule, up 64 percent from 2002; the Midwest rose 52 percent to C$6.70; the Pacific Northwest grew by 47 percent to C$5.92; and the Northeast was up 42 percent at C$7.09.

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

Editor's note: a gigajoule is a Canadian unit of heating value equal to approximately 95 percent of a million British thermal units.

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● JUNEAU, ALASKA

State funding on its way to ANGDA

Alaska legislators approve immediate $1.65 million for gas line efforts

By LARRY PERSILY

Petroleum News Government Affairs Editor

It took almost three months for the Alaska Legislature to agree on supplemental funding for the state-owned natural gas pipeline effort, but the measure is now on its way to the governor for his signature and the money could be available within a few days.

The Senate on April 5 concurred with House changes to the legislation, appropriating $1.65 million to be shared by the Alaska Natural Gas Development Authority and the Department Revenue. The department will share its money with the departments of Law and Natural Resources to cover the state's cost of negotiating long-term fiscal contracts with private companies also looking to build a North Slope natural gas project.

> ***The lone senator to vote against the spending was Anchorage Republican Con Bunde. "I guess I've got a three-word answer" for the vote, the senator said, listing the Matanuska Dairy, Alaska Seafood International plant and Delta barley project as past unsuccessful attempts by the state to get into business ventures.***

The $1.65 million is to cover the state's immediate needs for consultant contracts and staff expenses, and is separate from the governor's almost $10 million request to lawmakers April 2 to continue and expand Alaska's gas line efforts through at least June 2005.

Alaska's push to determine the feasibility of a state-owned pipeline is running concurrently with its negotiations with the North Slope producers and others interested in building a privately owned line to move Alaska gas to market.

The state gas authority said at the start of the legislative session it needed $2.15 million for its proposed liquefied natural gas project. The administration later expanded the funding request to also include its negotiating costs with potential private developers.

Senate accepts House funding level

The Senate last month approved a combined $1 million supplemental budget for the state's coordinated work effort. The House then battled over amendments to increase the amount and, after a 20-20 tie on one proposal, settled on $1.65 million, which the Senate accepted April 5 on a 19-1 vote.

The appropriation measure, Senate Bill 241, includes a statement of legislative intent that at least $650,000 of the money go toward the state gas authority.

The lone senator to vote against the spending was Anchorage Republican Con Bunde. "I guess I've got a three-word answer" for the vote, the senator said, listing the Matanuska Dairy, Alaska Seafood International plant and Delta barley project as past unsuccessful attempts by the state to get into business ventures.

With the arrival of more funding, the Alaska Natural Gas Development Authority will move quickly to contract for a study of its financing options. A consultant will look at debt and equity ratios, interest rates and how the authority's possible tax structure could affect financing, said Harold Heinze, chief executive officer.

"Which combination of those things gets you to the lowest cost of business," Heinze said.

Second on the work list is a contract to prepare a cost estimate for spur line to deliver North Slope gas to Cook Inlet, which is running low on its own supplies, Heinze said.

Next on the authority's list would be a study to determine the potential value of possibly buying Yukon Pacific Corp.'s permits from its 20-year failed attempt to build an Alaska gas project, followed by a cost estimate for a liquefied natural gas shipping terminal at Valdez. ●

Want to know more?

If you'd like to read more about the Alaska Natural Gas Development Authority, go to Petroleum News' web site and search for these articles published in the last few months. There are many more articles not listed that mention the gas authority or deal with LNG terminals in the continental United States and Mexico.

Web site: www.PetroleumNews.com

2004
- **March 7** Politics snag natural gas line funding
- **Feb. 15** Alaska gas authority work could shift
- **Feb. 8** Senate committee recommends state gas authority funding
- **Feb. 1** Alaska's other gasline group may have buyer for LNG
- **Feb. 1** Bill expands Alaska gas authority's options
- **Feb. 1** Natural gas pipeline plans not the same
- **Jan. 25** LNG bills get first hearing
- **Jan. 18** Natural gas authority counts LNG votes
- **Jan. 18** Gas authority drops lobbyist idea
- **Jan. 18** State of Alaska investment in gas pipeline under discussion
- **Jan. 18** State gas authority sees competition
- **Jan. 18** Too much LNG a possibility
- **Jan. 11** Bills address state natural gas authority

2003
- **Dec. 28** Alaska natural gas board sees problems
- **Dec. 28** Sempra Energy taps Indonesia LNG for U.S.
- **Dec. 21** State natural gas authority thinks bigger
- **Dec. 21** State gas authority wants lobbyist
- **Dec. 14** Alaska gas authority delays funding request
- **Dec. 7** Federal loan guarantee extended to LNG
- Nov. 30 Gas authority wants more money

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FAILED

which later became a five-year demand.

The state said no to that, too, and the highly publicized, highly promoted effort to build Alaska's long-awaited gas line broke down.

The two sides then took their case to dueling press conferences.

"MidAmerican has so far offered very little" to get the project built, Alaska Gov. Frank Murkowski said at a March 26 press conference, a day after the pipeline company ended talks with the state and withdrew its application under Alaska's Stranded Gas Development Act.

"For me to arbitrarily go out and negotiate a binding contract for five years … is something that I would be derelict in proposing," the governor said. "In five years we could very well get the project back."

MidAmerican wanted to protect its investment

The company sees it differently, asserting it was willing to spend a lot of time and money trying to put together the project and was merely looking for reasonable assurances that it would not be pushed aside for another project developer.

"It was enormously distortive of reality," MidAmerican CEO David Sokol said of Murkowski's press conference.

The governor knew about the company's insistence on exclusivity, or sole developer status, before MidAmerican ever submitted its application under the Stranded Gas Act in January, Sokol said at his own press conference a few hours after the governor's March 26 event.

"The governor is trying to make it sound sinister," Sokol told reporters.

If MidAmerican had known in January that the state would never agree to its request for sole developer status, Sokol said, the company would not have submitted a Stranded Gas Act application.

Although correspondence between the state and MidAmerican confirms the company told state officials of its insistence on exclusive rights to the project as far back as early January, neither the company nor the state ever told the public about the issue until late March.

Stranded Gas Act negotiations are confidential, but with the breakdown in negotiations both sides are talking.

Sole developer status an issue since at least January

"It (sole developer status) has been on the table since the very beginning," said Mike Menge, the governor's special assistant on oil and gas issues. "They claimed they needed some level of protection for their investment."

Menge said the issue of exclusive rights clearly was "a line in the sand" for the company, a line the governor was not willing to cross on the company's terms.

MidAmerican, however, never mentioned sole developer status or exclusive rights to the project anywhere in its Jan. 22 Stranded Gas Act application to the state. Nor did Sokol say anything about the company's demand when he briefed Alaska legislators in Juneau on Feb. 25, when he said he wanted to have a draft fiscal contract with the state ready for public review by March 12 to start field work this summer and to have gas flowing by the end of 2010.

And, looking back, no one said anything about any sort of exclusive rights at the cheering press conference in Fairbanks the day MidAmerican turned in its application to the state.

"Today, I am happy to announce that a very big step is being taken toward making this dream a reality," Murkowski said in Fairbanks. "The application we have received today is from a group of prominent industry partners, including MidAmerican Energy Holdings Co. … These companies have a level of financial vitality, pipeline expertise, consumer market base, and Alaska business association that is far beyond anything we have seen to date."

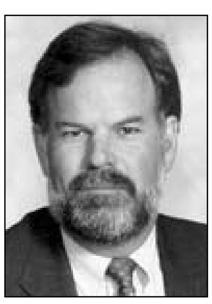
The fact that MidAmerican is controlled by Berkshire Hathaway Inc., which is controlled by billionaire Warren Buffet, added to the excitement.

But the enthusiasm of January is long forgotten between the two parties. "We would have no interest in re-entering the project," Sokol said March 26. It's hard to do business with the state "when people don't tell the truth," he added.

Company claims it was surprised

The governor's refusal at a March 22 meeting in Anchorage to accept the company's request for sole developer status surprised MidAmerican, Sokol said. Especially since the state did not appear to have a problem with it until a few weeks ago, he claimed.

However, correspondence between MidAmerican and the state in the month before the March 22 meeting appears to contradict Sokol's claim and support the administration's contention that it had been consistent in its opposition to granting fully exclusive rights to MidAmerican.



President of MidAmerican's Alaska Gas Transmission Co. Robert Sluder

The letters also indicate the state was looking to find some compromise to keep the talks alive, and MidAmerican's correspondence indicates the company was pushing the issue with the state — perhaps believing it could win its point in the end.

The company, in a Feb. 20 letter to the state, criticized Alaska's refusal to accept any form of exclusive rights for MidAmerican. "I cannot overemphasize our concern regarding the (state negotiating) committee's reluctance to agree even in concept with the limited provisions for three years of exclusivity for the project that we have proposed to include in our agreement," said Kirk Morgan, project manager of MidAmerican's Alaska gas line effort.

"MidAmerican has been clear from the outset that exclusivity is crucial to our ability to proceed on a timely basis with the state," Morgan said.

The company pushed the issue 10 days later, in a letter from Sokol to the governor. "Successfully concluding our negotiations, including exclusive development rights, is critical," the CEO said in his nine-page, March 1 letter.

The company restated its demand in a March 9 letter to the state by Robert Sluder, president of MidAmerican's Alaska Gas Transmission Co., a new company established for the Alaska project.

Company says it thought it had a deal

"Governor Murkowski has just informed me that Alaska is unwilling to meet one of MidAmerican's primary elements, which was a period of exclusivity granted by the state," Sluder said in his letter to Alaska Department of Natural Resources Commissioner Tom Irwin. "We are, frankly, disappointed that a concept we advanced in early January has been rejected."

Instead of accepting the company's original proposal of last November to share in the estimated $100 million development costs 50-50, Sluder wrote, the governor had suggested the company apply under the Stranded Gas Act to negotiate a long-term state fiscal contract for the gas line.

"It was understood that such an application would permit the state to negotiate terms needed to pursue this project, including exclusivity, and thus would allow us to proceed arm in arm with the state in the manner we sought from the outset.

"Unfortunately, it appears the benefits we bring to the table are outweighed by the state's concern with preserving the option of having other developers pursue the project," Sluder said in his March 9 letter.

The company a week later restated its assertion that the governor had encouraged MidAmerican to proceed with its Stranded Gas Act application in January, with the expectation of receiving sole developer status after Murkowski had rejected the company's original proposal of sharing development costs 50-50.

"In early January 2004, we met with you and your team and were encouraged to submit an application … with the understanding that we would agree to develop a financeable project … in exchange for an agreement under the act that designates us to be the builder, owner and operator of the Alaska portion of the pipeline," Sokol said in a March 16 letter to Murkowski.

"Unfortunately, since we have been unable to reach even a framework of agreement with the state of Alaska to be its project developer, notwithstanding over four months of effort, our participation in such a meeting does not seem appropriate or useful," Sokol said, rejecting Murkowski's invitation to attend a March 22 meeting with state officials, the producers and pipeline company TransCanada Corp.

Governor denies state ever promised exclusivity

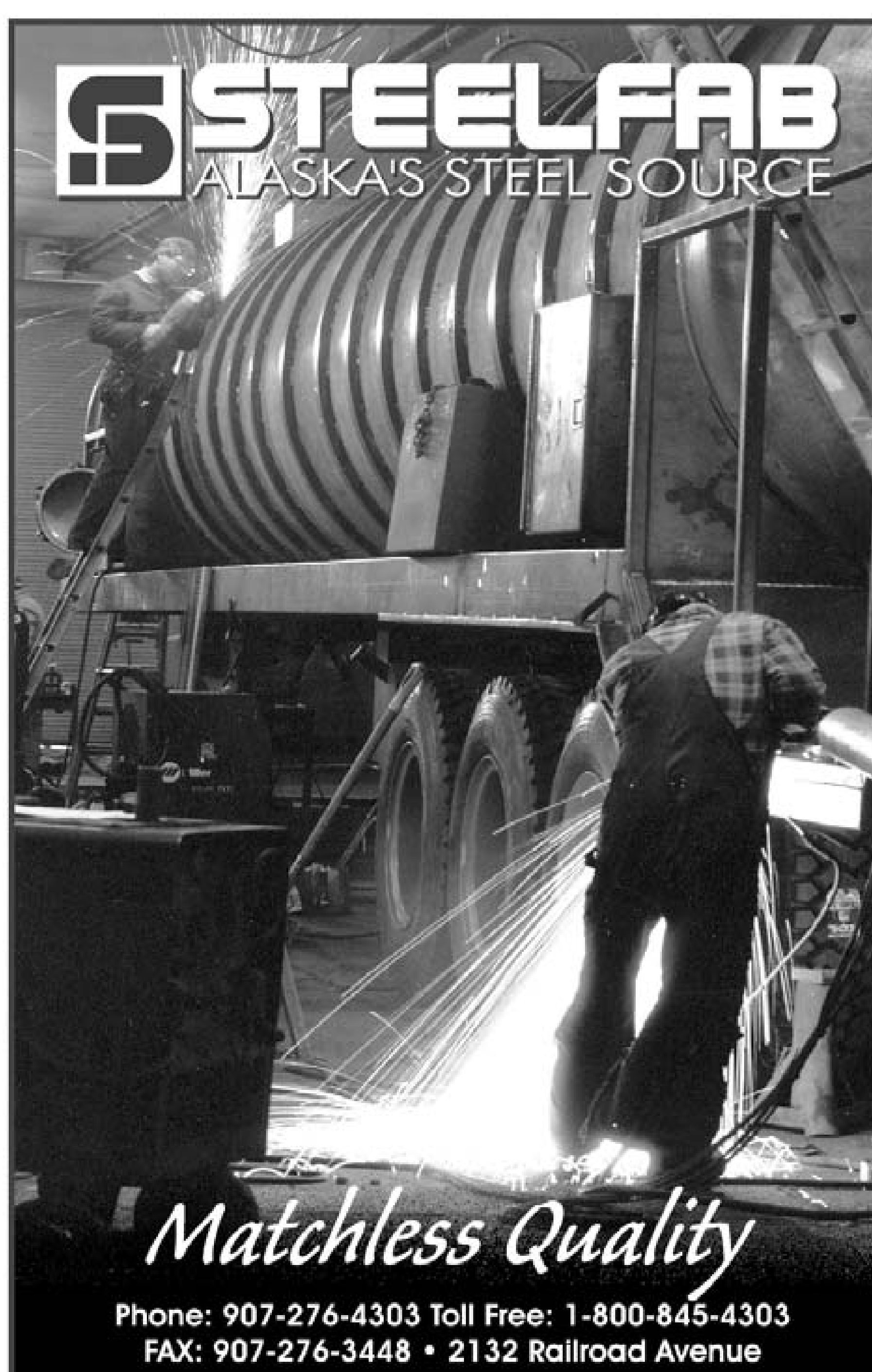
The governor replied that same day. He denied there had ever been any inconsistency in the state's position regarding sole developer status. "We made no commitment to enter into a contract under the Alaska Stranded Gas Development Act to provide you with an exclusive right to build, own and operate the Alaska portion of the pipeline," Murkowski wrote to Sokol.

Sokol later decided to attend the March 22 meeting in the governor's office in Anchorage, where the state offered MidAmerican a five-year exclusive deal that applied only to processing the company's applications for state rights of way along the pipeline corridor. It would not have stopped the state from negotiating a Stranded Gas Act contract with other potential pipeline developers.

The state's five-year offer of exclusive rights of way also included the condition that MidAmerican strike a deal with TransCanada, which holds U.S. and Canadian certificates for the project from the late 1970s and has expressed an interest in taking a major role in the gas line.

The state also offered other assurances and commitments to MidAmerican, along with the pledge not to process any other applicant's right-of-way permits, but the company rejected the deal as insufficient and broke off further discussions with the state, accusing the administration of misleading the company about the possibility

see **FAILED** *page 20*



● NORTHWEST TERRITORIES

Conflict allegations dismissed against Bernier

Independent investigator finds government official was in no 'real or potential' conflict over mineral claims staked by his wife

By GARY PARK

Petroleum News Calgary Correspondent

Allegations of guilt-by-association leveled against a Canadian government official involved in the Mackenzie Gas Project have been dismissed by an independent investigator.

The issue was raised last summer when the Deh Cho First Nations, whose land covers 40 percent of the proposed 800-mile Mackenzie Valley pipeline route, said the wife of a federal environmental official had staked mineral claims along the proposed pipeline right of way.

Quebec attorney Vincent O'Donnell, who was appointed last October to probe the claims, reported to the federal government's Canadian Environmental Assessment Agency that agency Vice President Paul Bernier was "not in a real or potential conflict of interest in relation to the mineral claims," registered in the name of his wife Maureen.

"Neither the (agency) nor Paul Bernier had any influence on the route of the proposed pipeline," O'Donnell said.

He concluded that Maureen Bernier had been acting for her sister when she staked 12 mineral claims in 1998 between Fort Simpson and Jean Marie River.

O'Donnell said he had no reason to believe that Paul Bernier had deliberately excluded the Deh Cho from the regulatory process.

Claims in area ranked low to moderate for mineral deposits

There was no immediate response from the Deh Cho, although Grand Chief Herb Norwegian had earlier said Maureen Bernier has also spent C$100,000 to keep the claims current on land he said has "no diamonds, no gold, not much of anything," adding the claims were registered several years before the pipeline alignment became public.

The claims are in an area ranked low to moderate in all mineral deposits, but the Deh Cho argued that under the Territorial Lands Act it is illegal for a federal employee to have a direct or indirect interest in land in the Northwest Territories.

Because Paul Bernier was personally involved in negotiating the pipeline project cooperation plan to streamline the approval process, the Deh Cho asked the Royal Canadian Mounted Police to investigate because they believed Bernier had advance knowledge of the likely pipeline route.

The environmental agency, describing the allegations as "very serious," ordered its probe, hiring O'Donnell for the job.

Paul Bernier was suspended on full pay for the course of the investigation and returns to work on the week of April 12 as vice president of program delivery, although he will not be assigned to the Mackenzie Gas Project.

The Deh Cho, insisting they have not surrendered any rights to their traditional lands, have refused to join other aboriginal communities in supporting a pipeline through their territory while they seek to negotiate a land claim and regional self-government.

They have already served notice on the Canadian government that unless a "flawed" regulatory process is halted and changed they will exercise their "legal right to veto the project."

Norwegian said the Deh Cho are ready to move forward as long as the 13 Dene and Metis communities comprising the First Nations get "meaningful involvement in the review." ●

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FAILED

of reaching a deal for sole developer status.

Exclusive rights of way would not have protected the company's investment, Sokol said at the March 26 press conference. A competing applicant could have applied to the Federal Energy Regulatory Commission and obtained a federal certificate for building the project, regardless of any state rights of way held by MidAmerican, the CEO said.

MidAmerican and state officials disagree

Sokol placed much of the blame on Jim Clark, chief of staff to the governor, and Gregg Renkes, attorney general. He said Clark and Renkes had "pleaded" with MidAmerican officials in a March 19 phone call to attend the March 22 meeting with the governor, and that Clark and Renkes had said they would back the company in its request for sole developer status.

Alaska Attorney General Gregg Renkes

The CEO said he later concluded the governor's staff only wanted the company at the meeting so they could "bludgeon" MidAmerican into accepting something less than what it wanted in the deal.

Clark, in an interview April 3, denied Sokol's accusations. The governor had repeatedly told the company the state would not consent to exclusive development rights, and neither the chief of staff nor attorney general had the authority to tell Sokol anything different, Clark said.

"We did not contradict what the governor had said in his letter to Sokol of the 16th," Clark said. "We wanted to have other applicants," he said. "What if it didn't work (with MidAmerican)?"

Clark also denied MidAmerican's allegations that the administration had ever misled the company.

MidAmerican officials April 5 declined any further comment on the failed Alaska negotiations.

It's not which company or companies build the gas line, but which can do it at the lowest possible pipeline tariff, Clark said, adding it wouldn't make sense for the state to commit to a project developer without knowing the costs.

Lowest possible tariff key for state

Although the state is eager to find someone to risk perhaps $20 billion on building a project to move North Slope gas to Lower 48 markets, the state's financial interests would be best served by the lowest possible pipeline tariff. The lower the tariff, the higher the wellhead for the gas, and the higher the state's production tax and royalty revenues.

"It is in the best interest of the state for the pipeline to be owned and operated by an unaffiliated pipeline company, assuming that such a company is able to provide the lowest possible tariff," Murkowski said in a March 25 letter to Sokol, in an unsuccessful attempt to get the company back to the negotiating table.

Promising any one developer exclusive rights also doesn't make sense to BP Exploration (Alaska) Inc., said company gas line spokesman Dave MacDowell. "We are surprised any party would assert that exclusivity or mandated ownership is in the best interests of the state.

"We can't imagine how anyone could contemplate authorizing an exclusive arrangement before knowing whether that project had the lowest transportation costs," MacDowell said. "That would be like betting on a horse without knowing it could run, let alone run well."

Producers spent $125 million without any guarantees

BP, along with its North Slope producing partners ConocoPhillips and ExxonMobil, spent $125 million in 2001-2002 to study environmental and regulatory issues, construction costs and conceptual engineering, MacDowell said, all without any guarantees that the producers would be the ones to build the line.

BP Exploration (Alaska)'s gas line spokesman Dave MacDowell

The work showed the project's economic risks still didn't pass the test. The companies applied to the state under the Stranded Gas Act about the same time as MidAmerican, and are continuing to negotiate for a fiscal contract for payments in lieu of state and municipal taxes should they build the pipeline. The producers also continue working to reduce the project's costs, while waiting for Congress to take action on the federal energy bill and its gas line incentives.

The producers want whatever contract terms they might negotiate with the state to also be available to any other potential project developer, and the same rules to apply to any terms reached by other applicants. "We've specifically requested that any pipeline terms negotiated under the Stranded Gas Act be fully assignable to any party," MacDowell said.

Sokol denied MidAmerican ever asked the state to stop negotiating with other Stranded Gas Act applicants, though he later explained a key distinction during his March 26 press conference. While the company's exclusive rights would not block the state from negotiating a contract with the producers for the North Slope gas treatment plant or taxes on the producer-owned gas, MidAmerican's request for sole developer status would have prevented the state from talking with the producers — or anyone else — about building the pipeline itself.

Such an exclusion would have forced the producers to negotiate with MidAmerican for moving their gas to market through the company's project.

MidAmerican wasn't interested in negotiating a contract covering taxes on the gas treatment plant because it did not want to build the plant, estimated at around $2 billion to $3 billion, and had said in its application that it would prefer the producers take on that project.

MidAmerican will not pay state negotiating expenses

In addition to leaving the state unhappy at how they were treated, MidAmerican is leaving behind about $200,000 in costs the state ran up in its two months of negotiating with the company. The Stranded Gas Act allows the state to recover its negotiating costs — mainly consultants hired to advise the state and tax, tariff and fiscal issues — from contract applicants.

Alaska Revenue Commissioner Bill Corbus

Although the producers signed their reimbursement agreement with the state early in their talks, MidAmerican declined to commit to covering any of the state's costs.

"Please understand that, because of the critical nature of the exclusivity question, until that matter is resolved, we cannot commit to a reimbursement agreement with the state," MidAmerican's Morgan said in a Feb. 20 letter to Alaska Revenue Commissioner Bill Corbus. ●

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

Judy E. Phillips, HR/Medicine Department assistant

Agrium Kenai Nitrogen Operations

Cominco Fertilizers Ltd. came into being in 1931 and became known as Agrium Inc. in 1995. The Kenai plant was purchased from Unocal, which had operated it since the early 1970s, in October 2000. Now the Kenai Peninsula's third largest employer, company officials say production will likely cease in 2006 without stable, low-cost gas supplies.

Judy Phillips worked for Unocal Outside in several positions before joining its Alaska operation in 1991. She now works in the medical department and assumed various HR duties after the company's 2003 reorganization. Altogether she has 22 years with Unocal and Agrium. She's married to David and has a son, three daughters and two grandchildren. Big family get-togethers are a must since most of the family lives in Colorado.

FORREST CRANE

Dale Shirley, sales manager

Engineered Fire & Safety

Engineered Fire & Safety provides fire alarm, gas detection, fire suppression and intercom/paging systems for petroleum, power generation and other industries. The company now operates under Kidde NDO (national distributor organization) to capitalize on its design and contracting infrastructure, plus its access to product lines such as Notifier. Let our experts handle your protection systems so you can concentrate on business, the company says.

Dale Shirley has worked in the fire protection industry for more than 20 years. Four years ago he returned to Alaska as general manager for Western States Fire; in 2003 he rejoined EFS as sales manager. He and wife Robin have a son, Curtis, who just signed on to play football for Western Oregon University. Dale's best times are spent fly fishing and fly tying.

continued from page 6

XTO

verted wells to injection to "artificially pressure the reservoir and move the oil to our producing wells."

That's another thing the company liked about Middle Ground Shoal: "This is essentially a water flood that's out under the water. It's a very similar water flood to what we do in the Permian basin of West Texas," Hammond said, "it just happens to be in a little bit more challenging environment, but the basic reservoir rocks and the basic water flood is something that this company's done for years …," and the field fits well with XTO's portfolio.

"But if we drill a well, I think we're going to be the only operator that drills a well in the Cook Inlet offshore this year."
—Kyle Hammond, XTO Energy

Although, he said, it's a bit of a challenge to water floor in a vertical environment.

Costs going up

The Alaska Legislature passed a royalty reduction bill for Cook Inlet properties last year, and Dingmore said XTO's properties ended up in a category where royalty relief would be applied at 975 barrels.

He said XTO anticipates that it is a few years away from that production level, but said costs are a concern.

Since Unocal has shut-in its Baker and Dillon platforms at Middle Ground Shoal, "that's caused us to take control of some onshore properties, some pipelines that we were sharing with them," and thus taking on additional cost.

Average production from its new wells has been 400 barrels per day, but that ranges from zero (one well was a dry hole) to 1,200 bpd, with average reserves per well drilled of 750,000 barrels, ranging from zero to some that are "much greater," Hammond said.

We like being here, he told the committee, but "one of the things that I try to explain to people is, this reservoir has an inherent risk that does make it very challenging for us to present projects to our management."

The one, perhaps two, wells the company plans to spud this year will be in the third or fourth quarters. ●

continued from page 1

SPARKLE

the recent quarter.

A consensus estimate represents the average earnings of all analysts polled on a particular company. Individual estimates can be higher or lower than the consensus and tend to change as reporting season approaches. Earnings estimates generally exclude special items and other charges taken by a company during a quarter.

Kerr-McGee expected to be up 53 percent

Among the large independents, Kerr-McGee is expected to report 2004 first-quarter net income of $1.32 per share, up 53 percent from 86 cents per share earned in the prior quarter and up 10 percent from $1.20 per share in last year's first quarter.

Big natural gas producer Burlington Resources also is expected to report strong first-quarter earnings of around $1.57 per share, up about 35 percent versus $1.16 per share in the previous quarter but down slightly compared to the same period last year, according to analysts' consensus estimates.

Anadarko Petroleum, compared to $1.17 per share in the 2003 fourth quarter, could see a 16 percent jump in 2004 first-quarter earnings to about $1.36 per share. But earnings could be about 6 percent below the $1.45 per share the company earned for the same period last year.

Apache also is expected to see its 2004 first-quarter profit increase roughly 16 percent to $1.01 per share from 87 cents per share in the previous quarter. That would put Apache's net 4 cents above the 97 cents per share earned in the year-ago period.

Devon could be up 7 percent, down nearly 30 percent from last year

Devon Energy, the largest independent producer in the United States, could see 2004 first-quarter earnings of $1.74 per share, a 7 percent increase from reported 2003 fourth-quarter earnings of $1.62 per share. However, based on consensus estimates, Devon's 2004 first-quarter profit would be down nearly 30 percent compared to the same period last year.

Unocal's profit for the 2004 first quarter is expected to come in around 77 cents per share, up about 22 percent from the previous quarter's 63 cents per share, but down 11 percent from 87 cents per share in the year-ago quarter.

Noble Energy should turn in a strong performance across the board. The company could see its 2004 first-quarter profit rocket 48 percent to 92 cents per share from 62 cents per share in the previous quarter, and increase 29 percent per share from 71 cents in last year's first quarter, according to analysts' estimates.

EOG Resources, another big natural gas producer, is expected to weigh in with 2004 first-quarter earnings of about 88 cents per share, up 20 percent from 73 cents per share in the prior quarter, but about 30 percent below year-ago earnings of $1.25 per share.

Pioneer Natural Resources should post a modest 4 percent increase in earnings to around 50 cents per share in the 2004 first quarter, compared to 48 cents per share in the previous quarter. But compared to the year-ago quarter's 58 cents per share, the company's net income would be down about 14 percent.

XTO Energy, largely on production increases from acquisitions, also is among the few larger independents expected to post gains in the 2004 first quarter versus the previous quarter and the year-ago quarter. Analysts project the company will report about 51 cents per share in the first quarter, compared to 39 cents per share in the prior quarter and 31 cents per share a year ago.

Chesapeake Energy's 2004 first-quarter net income is expected to increase slightly to 38 cents per share from 37 cents per share in the previous quarter. However, the company's profit could be up about 65 percent versus 23 cents per share in the year-ago period.

Newfield could jump 70 percent from last quarter

By far, Newfield Exploration is expected to turn in the best performance among the middle-sized independents surveyed by Petroleum News. Newfield's 2004 first-quarter net income could jump 70 percent to $1.34 per share, compared to 79 cents in the previous quarter, and increase 12 percent from $1.20 per share in the year-ago quarter.

Forest Oil's net income in the 2004 first quarter is expected to rise 35 percent to 42 cents per share from 31 cents per share in the 2003 fourth quarter, but to decrease 42 percent compared to 73 cents per share in last year's first quarter.

Tom Brown's 2004 first-quarter profit could increase 40 percent to 76 cents per share from 54 cents per share in the previous quarter and increase 49 percent when compared to 51 cents per share in the year-ago quarter.

Coalbed methane producer Evergreen Resources is expected to check in with earnings of 43 cents per share for the 2004 first quarter, down slightly from 45 cents per share in the previous quarter and 45 cents per share compared to the same period last year.

Spinnaker Exploration's 2004 first-quarter earnings are expected to come in around 40 cents per share, versus 19 cents per share in the previous quarter and 56 cents per share in the year-ago quarter.

Pogo Producing should post earnings of about 98 cents per share in the 2004 first quarter, compared to 86 cents per share in the previous quarter and $1.44 per share a year earlier.

Cabot Oil & Gas' net income for the 2004 fourth quarter is expected to be around 50 cents per share, compared to 60 cents per share in the previous quarter and 69 cents per share in last year's first quarter, according to consensus estimates. ●

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TOM KEARNEY

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LIBYA

eign investment to raise production to 2 million barrels per day.

Tarek Hassan-Beck, the planning director at National Oil, said that after 10 difficult years as an international outcast, Libya is "preparing for a prosperous 10 years."

He estimated that an extra $2 billion a year might be needed to achieve the "projects we foresee in the upstream and midstream" and possibly as much as $30 billion in foreign investment through 2010.

Only one quarter of country has been explored

The prizes are proven reserves of 36 billion barrels of oil and 54 trillion cubic feet of gas, based on exploration covering only one-quarter of the country.

Hassan-Beck told reporters that production costs average $3 per barrel, with some companies operating at $1.50 per barrel, to generate 1.5 million bpd of oil and 1 billion cubic feet per day of natural gas.

Because many of the "elephant" finds were made in the 1960s, National Oil believes recoveries and reserves could easily be doubled, given advances in technology, he said.

In addition, Libya has dreams of growing its natural gas output to become a leading producer in North Africa.

Hassan-Beck said that once the U.S. administration removes sanctions, companies such as Occidental Petroleum, Amerada Hess, Marathon Oil and ConocoPhillips are eager to return to fields they once operated.

Occidental had assets yielding 170,000 bpd frozen when sanctions were imposed in 1986, while the Oasis Group, comprising the other three companies, was pumping 850,000 bpd in 1986.

In addition, President Moammar Gadhafi last year proposed privatization of the industry as part of measures he is taking to open Libya to foreign investment.

Canadian companies see window of opportunity

The visit by the Libyan delegation was hosted by the Exporters & Importers Association of Alberta, which believes there is an early opportunity for Canadian companies to seize what may be a narrow window of opportunity before the U.S. majors swarm back.

Other sponsors included Petro-Canada, Talisman Energy and Nexen — Calgary-based producers with extensive international experience, much of it in global hot spots — along with oilfield services contractor Precision Drilling.

Petro-Canada, following its 2002 takeover of Germany's Veba Oil & Gas, has reserves in North Africa and the Near East of 133 million barrels of oil equivalent, which averaged 145,900 boe/d in the final quarter of 2003. Libya contributed 50,800 bpd and Syria contributed 91,700 bpd. The target for 2004 from the region is 133,000 boe/d.

With one eye on Libya, Petro-Canada is moving ahead with expansion of its Syrian interests, undeterred by threats of U.S. sanctions against a country labeled as a "state sponsor of terrorism."

The Canadian integrated oil company announced on April 1 that along with Occidental and United Kingdom-based Petrofac it is negotiating the possible development of a natural gas project in Syria.

An Occidental spokesman, referring to the threatened sanctions, said that because no money is committed at this stage, nothing is being risked.

The U.S. Energy Information Administration has estimated Syria's proven gas reserves at 8.5 trillion cubic feet, of which 3.6 tcf is in the Palmyra area, which has 15 discoveries and is the object of the negotiations. ●

continued from page 1

PERMITTING

the area," Cowan said. "Hopefully, knowledge that these permit applications are being initiated will encourage participation in the project. As per last week's amendment to the original award, interested parties now have until May 31 to join the program as original participants." (See related article in the April 4 issue of Petroleum News.)

Alaska Gov. Frank Murkowski has said he would like the test well drilled this coming winter.

The initial permitting work will not be site-specific in nature, Cowan said.

—**KAY CASHMAN,** Petroleum News publisher & managing editor

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The ABB Passion For Safety

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A significant portion of ABB's history demonstrating its leadership position as an automaton supplier to the energy industries is a direct result of harsh Oil industry's lessons learned following the tragedy of Piper Alpha. This article will attempt to put into perspective the reason for ABB's Passion for Safety, and why it is proud of its heritage as the first to respond when the safety community needs a reliable partner in total safety solutions.

Piper Alpha disaster in the North Sea in 1988

A total of 167 oil workers died when the Piper Alpha production platform in the North Sea caught fire with horrific consequences almost 16 years ago. In response to this overwhelming loss of life, the accident prevention industries and the UK HSE banded together to analyze the root cause of the accident. These findings, as published in The Cullen Report, were the catalyst in revolutionizing the safety industry and fueling an ongoing passion to make sure that this would never happen again.

Today owners, engineers and operators around the world are all united in a no cost is too high mandate not to compromise the safety integrity of a facility, as you cannot place a price on human life. This unity has made the Oil and Gas industry a safer place.

When the next offshore platform was built to the new standards, it was ABB's August Systems group that was awarded the contract for the safety systems based an advanced ultra high availability technology known as TMR or Triple Modular Redundancy. Today, members of the replacement platform project's design and commissioning team are among the staff of ABB's TMR Safety Systems Center of Excellence – COE. Located in ABB's offices in Houston, Texas, they are helping spread their knowledge to the industry by sharing their passion to get it right and show how disasters can be prevented.

ABB's high integrity safety technology has been used for the last 25+ years by those customers who are committed to combining the best available technology with comprehensive engineering studies to assure that the protection of life, the environment and their company's assets are managed to achieve the lowest possible risk profile.

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- Training and Certification
- Maintenance and Service of Fire & Gas Detection and Safety Instrumented Systems
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- Asset Management Software
- On-Line / Off-Line Testing Optimization

While each of these ABB products has their own differentiating merits, the most important message of the day is:

ABB Triguard SC300E SIL-3 TMR Safety System has now been qualified as a Fire & Gas Alarming and Protection system conforming to the UL-864 Fire Protection and Alarming Standard, at the Underwriters Laboratory's Northbrook Laboratory outside Chicago, IL.

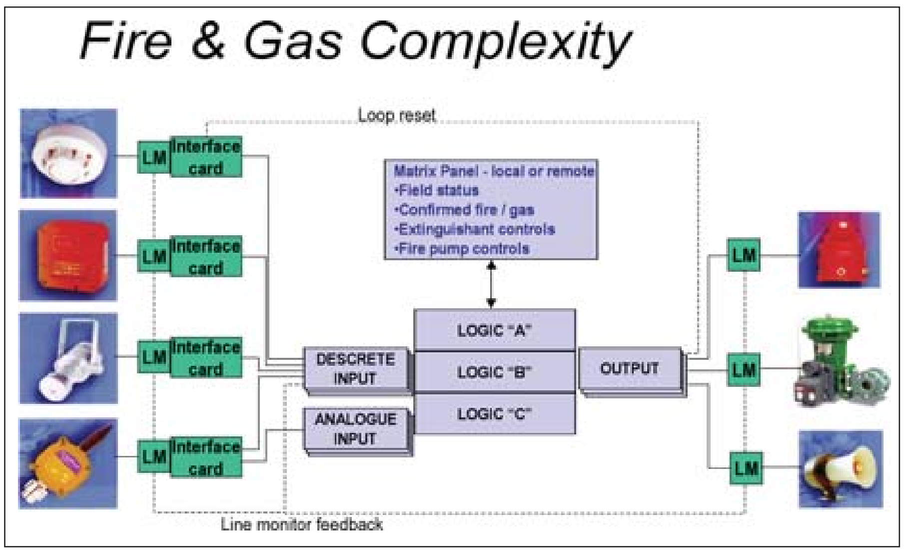

ABB is pleased to be able to demonstrate its commitment to becoming the first and only safety system supplier to achieve the goal of bringing a combined TUV SIL3 approved Fire and Gas Detection and Safety Instrumented System to comply with ISA S84 / IEC 61508 standards for SIS and the NRTL requirements of the Alaskan Fire Codes. This affords Alaskan owners and operators the ability to now move Safety to the same high integrity levels to met the harsh environmental standards of Alaska.

The open architecture approach that the ABB Triguard System affords its users is the diversity to match appropriate filed devices to solve the challenges that site wide Safety combined with Fire and Gas Detection bring to industry.

The integration of advanced systems requires a full understanding of the impact of overall compliance to industry standards. ABB designs its solutions to meet or exceed the requirements of the industry as set out by well recognized agencies.

Left: The open architecture approach that the ABB Triguard System affords it's users is the diversity to match appropriate filed devices to solve the challenges that site wide Safety combined with Fire and Gas Detection bring to industry.

Bottom: ABB Triguard SC300E, "World's First TUV Certified SIL 3 Triple Modular Redundant Fire Detection and Protection System" certified by Underwriters Laboratory to UL-864 Standard.

ABB is proud to have strategic alliances in place with equally committed technology partners to provide the flexibility it takes to offer a complete solution. This gives the owner the best of the best working in concert to fill their needs.

ABB offers total solutions for transportation and distribution to manage the movement of hydrocarbons through pipelines, tankers and terminals; eliminate losses; and meet strict government regulations, for example environmental protection. From the well head to the SCADA control room, and on to the boardroom, ABB's solutions provide your pipeline business a new competitive edge, with unsurpassed enterprise connectivity and information access.

Caspian Sea pipeline project.

ABB is presently executing a significant supply of services and equipment to BP in the Caspian region for the ACG Oil, Shah Deniz Gas and AGT Oil & Gas Export Pipelines Development. This project covers many EPC contractors across several distanced Countries. It also involves up to seven separate project organizations working at different project schedules and sanction dates. This spread of project requirements, time-scales and varying definition states presents both a challenge in control and confidence in ABB for openness and commercial integrity. ◆

ABB is proud to have strategic alliances in place with equally committed technology partners to provide the flexibility it takes to offer a complete solution.

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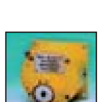

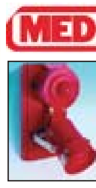

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UL Northbrook, Ill. test facility upon completion of **UL864** testing:
(Left) Derek Matthews - UL Project Engineer
(Right) Gerald Farnaby - ABB Safety COE Business Development Manager

According to the ARC Advisory Committee:

Fire and Gas monitoring is a significant segment of the safety shutdown system market. "With the approval of Triguard SC300E system by UL, users will be able to use ABB's certified system with greater confidence for fire and gas protection applications" says Asish Ghosh Vice President of ARC Advisory Group.

For more information on the ABB Triguard SC300E ESD and Fire and Gas Detection and Protection System please contact:

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