**Vol. 9, No. 15 • www.PetroleumNews.com**

**White Rose blooms**

[Image: 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 company would spend money for the state to put up something of value before the company would spend money on possibly building a North Slope natural gas project.

Several permit approvals have to be in hand by the end of July or so in order to undertaking several pre-mobilization and mobilization activities during the short open-water season in July or so in order to undertake several pre-mobilization and allowing drilling during the upcoming winter drilling season, should a drilling consortium be formed, division geologist Jim Cowan told Petroleum News.

**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.

**Independents sparkle**

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

By RAY TNSON
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 warming down of winter demand for natural gas and heating oil.

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

**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

B ack 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 foreign investment work only if the state granted it exclusive rights to the pipeline for at least three years — see SPARKLE page 23

**What went wrong?**

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

By LARRY PERSILY
Petroleum News Government Affairs Editor

F rom 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.
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 $90 million over five years to ensure that economic development opportunities are pursued in partnership with Northern Canadians and $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 $3.7 billion.

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 $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 6,550-foot re-entry test that was drilled in 1998 with Berkley Petroleum.

Paramount and its partners have drilled five gas wells at Cameron, south-east of the Fort Liard well, followed up by two entries, and has licensed another three re-entries.
Independent 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 mergers, acquisition and restructuring efforts in 2004, with 64 percent predicting an increase in such activity. Sixty-two percent of the respondents anticipate growth in 2004, while only 21 percent plan to increase foreign exploration efforts. The independents conducted by Grant Thornton LLP, a global accounting and consulting firm, expect an increase in 2004, as the demand for energy continues to grow.

—PETROLEUM NEWS

Issue Index

EXPLORATION & PRODUCTION .................................................. 10
FINANCE & ECONOMY .............................................................. 7
GOVERNMENT ........................................................................... 13
NATURAL GAS .......................................................................... 17
ON DEADLINE ........................................................................... 2

Dan Wilcox CHIEF EXECUTIVE OFFICER
Mary Craig CHIEF FINANCIAL OFFICER
Kay Cashman PUBLISHING & MARKETING EDITOR
Kristen Nelson EDITOR-IN-CHIEF
Gary Park CALGARY CORRESPONDENT
Larry Persdy GOVERNMENT AFFAIRS EDITOR
Ray Tyson HOUSTON CORRESPONDENT
Steve Sutherland ASSOCIATE EDITOR
Wadeen Hepworth ASSISTANT TO THE PUBLISHER
Alan Bailey CONTRIBUTING EDITOR
Pat Healy CONTRIBUTING EDITOR (HOUSTON)
Paola Farley COLUMNIST
Patricia Liles (formerly Jones) CONTRIBUTING EDITOR (FAIRBANKS)
Judy Patrick Photography CONTRACT PHOTOGRAPHER
Firestar Media Services DIRECTORY PROFILES
Mapmakers Alaska CARTOGRAPHY
Susan Crane ADVERTISING DIRECTOR
Sue Hackett ADVERTISING ACCOUNT EXECUTIVE
Forrester Crane CONTRACT PHOTOGRAPHER
Steven Mewett PRODUCTION DIRECTOR
Tom Kearney ADVERTISING DESIGN MANAGER
Heather Yates CIRCULATION MANAGER
Tim Kikta CIRCULATION REPRESENTATIVE
Dee Cashman CIRCULATION REPRESENTATIVE

ADDRESS
Petroleum
231001
Anchorage, AK 99523-1651

EDITORIAL
Anchorage
907.322.9469
Jotamau
967.586.0835

ADVERTISING EMAIL
PetroleumNews.com

CLASSIFIEDS
Petroleum
967.844.6444

FAX FOR ALL DEPARTMENTS
967.322.9560

Petroleum News and its supplement, Petroleum Publishing, are owned by Petroleum Newspapers of Alaska LLC. The newspaper is published weekly. Several of the individuals listed above work for independent companies that contract services to Petroleum Newspapers of Alaska LLC or are freelance writers.

We go to the top of the world for our customers.

Marine Transportation Across the Arctic and Alaska

Wuhan, 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’ve 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.
within the Senate and disagreements with
energy bill is still alive and could come
lost, said Chuck Kleeschulte, spokesman
chamber. Committee to settle the differences, fol-
the bill to go to a House-Senate conference
---------

Teton Petroleum Co. says it has signed an agreement to acquire an interest in a pro-
cressing 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 transac-
tion 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.

by LARRY PERSILY
Petroleum News Government Affairs Editor

Caring tradition, powerful technology,
lifesaving partnership.

You can’t schedule a medical emergency. You can have a plan. If you live or work
in rural Alaska, the best plan begins with Aeromed.

When Every Second Counts, Count on Aeromed.

As a native-owned medical service, our spirit of caring and cultural awareness
are not slogans. They are traditions. When every second counts, our two-state-
wide fleet of 35 UH-72B Lakota ASH and one Citation II jet aircraft are unsurpassed. Each is
equipped with high altitude technology for smoother flights in most weather condition.

For information on contracted services call (907) 677-7501.

---

Alaska’s Underwater Professionals
907-563-9060
Anchorage, AK

---

ANGEL

continued from page 3

in 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 guaran-
tee for the project and streamlined per-
mitting and judicial review provisions. Those could be added to a separate bill at a later date, Kleeschulte said.

--- LARRY PERSILY, Petroleum News

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

“I do think (exploration) licensing is a better deal.”

— Mark Myers, director of the Alaska Oil and

Gas Division

over-the-counter shallow gas leasing pro-
gram in urban regions of the state, take
steps to protect water quality and possibly
block new 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 sec-
tions in the bill. She testified last month in
Oil and Gas that the non-competitive shallow gas leasing program for shallow gas exp-
loitation licensing 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, direc-
tor of the state’s Oil and Gas Division. Exploration licensing allows the division to
evaluate and eliminate “hot spots” from lease areas, he said, such as controversial and environmen-
tally sensitive lands or areas with a low probability of gas.

“I do think licensing is a better deal,”

— Mark Myers, director of the Alaska Oil and

Gas Division

Shallow gas bills moving slowly

House Resources has three
bills to change Alaska’s
coaled methane laws

Joy TON, ALASKA

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 explo-
ration 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 judg-
ling 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 licens-
ing program, which includes competitive bidding and best-interest findings for leas-
es.

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 sec-
tions in the bill. She testified last month in
Oil and Gas that the non-competitive shal-
low 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, direc-
tor of the state’s Oil and Gas Division. Exploration licensing allows the division to
evaluate and eliminate “hot spots” from lease areas, he said, such as controversial and environmen-
tally sensitive lands or areas with a low probability of gas.

“I do think licensing is a better deal,”

— Mark Myers, director of the Alaska Oil and

Gas Division

Scrapping the entire shallow gas program
is industry and legislative support
for developing Alaska’s gas resources. Scraping 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 weak-
ed the measures’ protections for surface
owners, while confirming for
him a committee chair’s power to control
legislation.

The two amended bills were not
released to the public until after the hearing,
and Kohring announced just an hour
before the meeting that he would take up
the bills that day.
Alaska looks to acquire right of way in order to advance ANS gas commercialization

By LARRY PERSILY
Petroleum News Government Affairs Editor

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

“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.”

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 pipeline built.

The newest idea is that the state would acquire the right of way for the pipeline 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.”

—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 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.

“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.

“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.

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.

“Nobody Knows the Arctic Like We do!”

We bring to the table 25 years of Quality parts, service & sales experience

• $1.2 Million Parts Inventory •
• 2 Warranty Stations in Prudhoe Bay •
• Complete Line of Ford Commercial Vehicles •

Interior Alaska’s Fleet Headquarters
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

T he 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 then.

While the Alaska Division of Oil and Gas forecasts oil production from offshore Cook Inlet fields could continue to 2023, development drilling is clearly on the wane. 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 Sitz 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. Placid already has 10 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 “the kind of company that the majors look to when they are selling assets” that no longer fit their portfolios, where a smaller company can come in and do “a lot of the work in terms of in-fill drilling and development.”

“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 said.

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 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 west 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 technologically more of a challenge,” Dingmore said, “but it’s what makes drilling a well on the west flank economically viable.”

Costs vary from $2.63 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-
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.

“The take note of OPEC’s production cut, but do not see that there is ground for cutting Norwegian production,” the minister, Einar Steensnes, 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.

Steensnes 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 spokesman for the Finance Department told the Edmonton Journal.

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 percent 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 four years.

--- PETRO-CANADA page 8

UNITED STATES

Analysts predict drilling contractors to recover

Improved market conditions expected to result in 40% earnings jump

T he 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 substantial-ly 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.

--- RECOVER page 8

U.S. CONSOLIDATION CONTINUES

INDUSTRIAL BRIDGES

Available immediately, FOB Fairbanks, large quantity of temporary work trestles for rent or purchase. 100T loading, 20’-80’ lengths, professionally certified. Available as single units or lots as required.

RUSHN CONSTRUCTION LTD.

Call: 250-563-2800

SAFETY AND SERVICE IS OUR COMMITMENT TO YOU.
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 for the 2004 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. 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 missed topping Wall Street expectations. Parker is expected to post a loss of about 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 report a profit of around 5 cents per share in the current quarter, according to consensus estimates.

Transocean is expected to report 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 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.

Enso 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 previous quarter. The consensus has Enso earning about 15 cents per share in the 2004 second quarter.

Shlumberger’s 2004 first-quarter profit should come in around 47 cents per share, versus 50 cents per share in the previous quarter and 34 cents per share in the year-ago period. For the 2004 second quarter, the company is expected to earn about 50 cents per share, according to consensus estimates.

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 a loss of 11 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 offshore service companies are expected to closely track those of the contract drillers, although none of the service companies are expected to suffer 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 previous quarter and a loss of 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.

Continental 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 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 a loss of 11 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. The company could see net income of about 8 cents per share in this year’s second quarter.

Enso 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 previous quarter. The consensus has Enso earning about 15 cents per share in the 2004 second quarter.

Shareholders in the trusts and conventional oil and gas companies will be rewarded by the fact that they have been “generally able to avoid Saskatchewan’s corporation capital tax surcharge on their oil and gas production,” while conventional producers are saddled with the tax.

While undisclosed, the preferred option, the government said it will consult with the oil and gas industry to determine a new 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.

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

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.”

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

When the credit need, other than the purchasing, carrying or trading of securities, we may be able to help you with the power of the trust. For more information on the Saskatchewan, assurance and planning, and as such, may be offered by your lowest-cost credit source.

Consumer or Business Loans priced as low as 2.87%*
For $500,000 or above.

Whatever the credit need, other than the purchasing, carrying or trading of securities, we may be able to help you with the power of the trust. For more information on the Saskatchewan, assurance and planning, and as such, may be offered by your lowest-cost credit source.

Consumer or Business Loans priced as low as 2.87%*
For $500,000 or above.

Whether you’re looking for a current, Pengrowth Energy Trust 53 percent, Provider 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 Kincair said the strategy has been developed over “several months” after the trust reported a loss of 11 cents per share in the year-ago quarter.

He said the dual-class structure would limit the “amount of foreign ownership without disenfranchising the unit holders because both classes of units can 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.

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

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.

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

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

The government intends to introduce parallel legislation this spring, confirming that unit holders in publicly traded trusts are not liable.
**ALBERTA**

Front end costs not the oil sands clincher

By GARY PARK

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 Canadlet 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.

---

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 Canadlet 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.

---

**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 another 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.

---

**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.

“For 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.

---

Subscribe to Petroleum News call today 907.522.9469

D.O.D. APPROVED

Charter/Contract HAZMAT Cargo Passenger

24 hours a day / 365 days a year Toll Free: 866.479.9745 Local: 971.340.3200

American Marine Services Group 5000 A Street, Anchorage, AK 99518 907.562.5420 www.ammarine.com • globalmarine.com

Anchorage Honolulu Los Angeles

Galaxy boosts CBM position in Wyoming

Small exploration and production company Galaxy Energy, through its subsidiary Dolphin Energy, said April 5 that it acquired another 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.

---

**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 existing.

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

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 existing.

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

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 existing.

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

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 existing.

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

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:

- [Feb. 22 Dry at 25,756 feet](http://www.PetroleumNews.com)
- [Feb. 1 Newfield, Nexen shares climb on word of discovery](http://www.PetroleumNews.com)
- [Nov. 23 BP bails out of Treasure Island wildcat well](http://www.PetroleumNews.com)
- [Mar. 16 U.S. natural gas demand expected to outpace production 3-1](http://www.PetroleumNews.com)

Want to know more?

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 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.

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 the well came in 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 began 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.

Petroleum News Houston Correspondent
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

I t 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 here-to-fore 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 area.

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

D reams 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.
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 Wells drilled in the area

<table>
<thead>
<tr>
<th>Operator</th>
<th>Well Name</th>
<th>Status</th>
<th>Date</th>
<th>Location</th>
<th>TVD</th>
</tr>
</thead>
<tbody>
<tr>
<td>Aledo Oil Co.</td>
<td>Eureka 1</td>
<td>Jun 1, 1957</td>
<td>Sec 9-T2N R12E</td>
<td>4818</td>
<td></td>
</tr>
<tr>
<td>Anoco</td>
<td>Tazlina 1</td>
<td>Oct 29, 1962</td>
<td>Sec 10-T4N R7W</td>
<td>8837</td>
<td></td>
</tr>
<tr>
<td>Aledo Oil Co.</td>
<td>Eureka 2</td>
<td>May 6, 1963</td>
<td>Sec 18-T2N R10W</td>
<td>8546</td>
<td></td>
</tr>
<tr>
<td>Pan American</td>
<td>Moose Cr 1</td>
<td>Jul 17, 1963</td>
<td>Sec 29-T2N R10W</td>
<td>7869</td>
<td></td>
</tr>
<tr>
<td>Mobil Oil Corp.</td>
<td>Salmonbrt Lk 1</td>
<td>Mar 18, 1964</td>
<td>Sec 24-T6N R4W</td>
<td>7913</td>
<td></td>
</tr>
<tr>
<td>Atlantic Richfield</td>
<td>Rainbow Fed 1</td>
<td>Dec 21, 1965</td>
<td>Sec 31-T8N R5W</td>
<td>3000</td>
<td></td>
</tr>
<tr>
<td>Atlantic Richfield</td>
<td>Rainbow Fed 2</td>
<td>Jan 26, 1966</td>
<td>Sec 31-T8N R5W</td>
<td>2793</td>
<td></td>
</tr>
<tr>
<td>Consolidated</td>
<td>Tawaw Lk 1</td>
<td>Jan 17, 1970</td>
<td>Sec 24-T4N R8W</td>
<td>6721</td>
<td></td>
</tr>
<tr>
<td>Copper Valley Machine Works</td>
<td>Alicia 1</td>
<td>Jan 15, 1983</td>
<td>Sec 23-T4N R4W</td>
<td>1050</td>
<td></td>
</tr>
<tr>
<td>Amoco</td>
<td>AHTNA Inc 1</td>
<td>Apr 16, 1980</td>
<td>Sec 18-T6N R1W</td>
<td>7917</td>
<td></td>
</tr>
<tr>
<td>Amoco</td>
<td>AHTNA Inc A-01</td>
<td>Aug 6, 1980</td>
<td>Sec 28-SH R1W</td>
<td>5671</td>
<td></td>
</tr>
</tbody>
</table>
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 salable 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 and the Pan American Moose Creek No. 1 well locations. The exploration permit area includes the Unocal Tazlina No. 1, the Consolidated Tawase Lake No. 1 and the Amoco Ahnna No. 1 A 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.

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 wildcard drilling along the Lower 48. 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 continued 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.

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 Ansachutz 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 repurpose 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 Glenallen 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.”

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.

door maneuver to block off any offshore oil and gas activity.’”

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

Andersen is an ardent 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 3 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 $31 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, O’Rourke said. 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 affect-

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 Glenallen 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.”

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.

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 3 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 $31 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, O’Rourke said. 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 affect-

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 Glenallen 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.”

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.

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 3 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 $31 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, O’Rourke said. 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 affect-

The third year included collection processing and interpretation of gravity data, at a value of $120,000 done by PGS Onshore.
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 schedule 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 earlier 200-250 million barrels and by 200-250 million cubic feet of gas from the previous 1.85 trillion cubic feet, with about one-third of the oil deemed to be recoverable.

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 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 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 163 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, Louisiana, California, Colorado, Utah, Wyoming and western Canada.

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 schedule 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 earlier 200-250 million barrels and by 200-250 million 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

—RAY TYSON, Petroleum News Houston correspondent

—RAY TYSON, Petroleum News Houston correspondent
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.”

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 Oglesby, legislative director for the California Air Resources Board.

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 requirements, the additives are unnecessary and costly.

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

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

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.

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

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

see RULING page 16
continued from page 15

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 14.45 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 no 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, which 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 commission 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.

“If the extent these increases are necessary to ensure Enstar can supply the 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 floor, 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 encourage 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.”

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 given 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 price, based on inflation, rent on 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 also said 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 pipelines which 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 in 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 — 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 process to build the process was undertaken for the construction of the NorthStar pipeline.”

continued from page 15

RULING

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

Low 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.

Molvay 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 overstations.

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 Molvay erred in finding the law wouldn’t reduce retail gasoline prices. •

PANTALPIANA

幔 

www.pantalipa.com

Do you want your company’s ad to appear in the next issue of Petroleum News?

Want in! Your ad can reach North America’s oil & gas industry each week. It’s just a phone call away! Call now for advertising rates and information.

Call (907) 770-5592

WEEK OF APRIL 11, 2004

PIPELINES & DOWNSTREAM

RULING

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

Low 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.

Molvay 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 overstations.

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 Molvay erred in finding the law wouldn’t reduce retail gasoline prices. •

PANTALPIANA

幔 

www.pantalipa.com

Do you want your company’s ad to appear in the next issue of Petroleum News?

Want in! Your ad can reach North America’s oil & gas industry each week. It’s just a phone call away! Call now for advertising rates and information.

Call (907) 770-5592

WEEK OF APRIL 11, 2004

PIPELINES & DOWNSTREAM
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 possible sites on shore near the land-based site. It’s now “on hold” in favor of possible sites on shore.

A proposal by ConocoPhillips to build an offshore terminal in Mobile 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.

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 into the water intakes. The research, including the possibility of plans to build LNG facilities offshore.

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 offshore

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 offshore.”

A proposal by ConocoPhillips to build an offshore 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 regeneration process.

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

Kaktovik Hotel

Built in 2001, in the middle of ANWR, 3500 sq. ft. +/- Gift Shop, Restaurant & Office, heated garage, six rooms/14 beds, cable, phones. Potential uses: offices for ANWR oilfield service; man camp, hunting lodge, tourism. Below cost $450,000. For marketing package: contact:

Shawn Evans
Alaska Commercial Properties
907-456-6008 Phone
907-456-6474 Fax
shawn@realtyalaska.com

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 for 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 Gas Metropolitaine 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$19.3 billion) from C$18.3 billion (US$13.7 billion) as the average price rose to C$7.62 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 3.33 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 down by 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 93 billion of a million British thermal units.
State funding on its way to ANGDA

Alaska legislators approve immediate $1.65 million for gas line efforts

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.

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.

“With a 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.


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 gasoline group may have buyer for LNG
Feb. 1 Bill expands Alaska gas authority’s options
Feb. 1 Natural gas pipeline plans run aground
Jan. 25 LNG bills get first hearing
Jan. 18 Natural gas authority could LNG votes
Jan. 18 Gas authority drops lobbying 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 lobbying
Dec. 14 Alaska gas authority delays funding request
Dec. 7 Federal loan guarantee extended to LNG
Nov. 19 Gas authority wants more money
continued from page 1

FAILED

which later became a five-year demand. The state said no to that, too, and the high-profile, subsidized, 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 deficient in prop– posing,” 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 Chief Executive Officer David Sokol said of preparing for a 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 22 presser. “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 have not 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 is an issue at least since last 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 was early 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 men men tioned sole developer status or exclusive rights to the project anywhere in its Jan. 22 Stranded Gas Act application to the state. Menge said he didn’t say anything about the company’s demand when he briefed Alaska legislators in Juneau on Feb. 25, when they 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 in the late 2010s. And, looking back, no one said anything about any sort of exclusive rights at the briefing 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, company 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 Buffett, 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.”

The state also offered other assurances that it 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,” Sokol 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. “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,” Sokol said in his March 9 letter.

“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 participa tion in such a meeting does not seem appropriate or useful,” Sokol said, reject ing Murkowski’s invitation to attend a March 22 meeting with state officials, the producers and pipeline company TransAlaska Corp.

Governor denies state ever promised exclusivity

The governor replied that same day. He denied there had ever been any inconsis tency in the state’s position regarding sole developer status. “We made no com mitment 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 exclus ive 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 inter est 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 refused the deal as insufficient and broke off further discussions with the state, accusing the administration of mis leading the company about the possibility see FAILED page 20

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

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.” 
A

llegations of guilt-by-association leveled against a Canadian official who has worked 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 the governor’s chief of staff only wanted the company developer status.

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 had no reason to believe that Paul 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 development, although he will not be assigned to the Mackenzie Gas Project.

Although 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 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 MidAmerican’s request 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 March 1 letter,” said Clark. “We wanted to give other applicants,” he said. “What if it didn’t work (with MidAmerican)!”

Clark also denied MidAmerican’s allegations that it had ever misled the state.

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 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 are 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 the state would stop such a company at 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.”

“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 win.”

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 costs, construction costs and conceptual engineering.

MacDowell said, all without any guarantees that the producers would be the ones to build the line.

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 block the state from negotiating a contract with the producers for the North Slope gas line, although midAmerican’s tax on the producer-owned gas, MidAmerican’s request for sole developer status would have prevented the state from talking with the producers.

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 negoti- ating with the company. The Stranded Gas Act allows the state to recover its negotiat- ing costs — mainly consultants hired to advise the state on state tax, tariffs and tax issues — from contractors.

Almost all the time the producers signed their reimbursement agreement with the state early in their talks with the producers in December, believed the agreement was of the state’s costs.

“We understand that, because of the nature of the exclusive contract 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.

Conflict allegations dismissed against Bernier

By GARY PARK

Petroleum News Calgary Correspondent

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

continued from page 19

of reaching a deal for sole developer sta-
tus. Exclusive rights of way would not have protected the company’s investment, Sokol said at the March 26 press confer-
ence. A competing applicant could have applied to the Federal Energy Regulatory Commission and obtained a federal cer-
tificate 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 a sole developer status.

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 Sokol 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 March 1 letter,” said Clark. “We wanted to give other applicants,” he said. “What if it didn’t work (with MidAmerican)!”

Clark also denied MidAmerican’s allegations that it had ever misled the state.

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 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 are 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 the state would stop such a company at 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.”

“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 win.”

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 costs, construction costs and conceptual engineering.

MacDowell said, all without any guarantees that the producers would be the ones to build the line.

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...
<table>
<thead>
<tr>
<th>ADVERTISER</th>
<th>PAGE AD APPEARS</th>
</tr>
</thead>
<tbody>
<tr>
<td>Aeromed</td>
<td>A</td>
</tr>
<tr>
<td>Agrum</td>
<td></td>
</tr>
<tr>
<td>Air Logistics of Alaska</td>
<td></td>
</tr>
<tr>
<td>Alaska Airlines Cargo</td>
<td></td>
</tr>
<tr>
<td>Alaska Anvil</td>
<td>2</td>
</tr>
<tr>
<td>Alaska Coverall</td>
<td></td>
</tr>
<tr>
<td>Alaska Dreams</td>
<td></td>
</tr>
<tr>
<td>Alaska Interstate Construction</td>
<td></td>
</tr>
<tr>
<td>Alaska Marine Lines</td>
<td></td>
</tr>
<tr>
<td>Alaska Massage &amp; Body Works</td>
<td></td>
</tr>
<tr>
<td>Alaska Railroad Corp.</td>
<td></td>
</tr>
<tr>
<td>Alaska Tent &amp; Tarp</td>
<td>2</td>
</tr>
<tr>
<td>Alaska West Express</td>
<td></td>
</tr>
<tr>
<td>Alaska's People</td>
<td></td>
</tr>
<tr>
<td>Alliance, The</td>
<td></td>
</tr>
<tr>
<td>Alpine-Meadow</td>
<td></td>
</tr>
<tr>
<td>American Marine</td>
<td>9</td>
</tr>
<tr>
<td>Anchorage Hilton</td>
<td></td>
</tr>
<tr>
<td>Arctic Central</td>
<td></td>
</tr>
<tr>
<td>Arctic Foundations</td>
<td></td>
</tr>
<tr>
<td>Arctic Slope Telephone Assoc. Co-op</td>
<td></td>
</tr>
<tr>
<td>ArrowHealth</td>
<td></td>
</tr>
<tr>
<td>ASRC Energy Services</td>
<td></td>
</tr>
<tr>
<td>ASRC Energy Services Engineering &amp; Technology</td>
<td></td>
</tr>
<tr>
<td>ASRC Energy Services Operations &amp; Maintenance</td>
<td></td>
</tr>
<tr>
<td>ASRC Energy Service Pipeline Power &amp; Communications</td>
<td></td>
</tr>
<tr>
<td>Avalon Development</td>
<td>22</td>
</tr>
<tr>
<td>Badger Productions</td>
<td></td>
</tr>
<tr>
<td>Baker Hughes</td>
<td></td>
</tr>
<tr>
<td>Brooks Range Supply</td>
<td>23</td>
</tr>
<tr>
<td>Capital Office Systems</td>
<td>14</td>
</tr>
<tr>
<td>Carlile Transportation Services</td>
<td></td>
</tr>
<tr>
<td>Chilista Camp Services</td>
<td></td>
</tr>
<tr>
<td>CN Aqualain</td>
<td></td>
</tr>
<tr>
<td>Coveille</td>
<td>23</td>
</tr>
<tr>
<td>Conam Construction</td>
<td>13</td>
</tr>
<tr>
<td>ConocoPhillips Alaska</td>
<td></td>
</tr>
<tr>
<td>Craig Taylor Equipment</td>
<td></td>
</tr>
<tr>
<td>Crowley Alaska</td>
<td></td>
</tr>
<tr>
<td>Cruz Construction</td>
<td>15</td>
</tr>
<tr>
<td>Dowland - Bach Corp.</td>
<td>22</td>
</tr>
<tr>
<td>Doyon Doyling</td>
<td></td>
</tr>
<tr>
<td>Dynamic Capital Management</td>
<td></td>
</tr>
<tr>
<td>Engineered Fire and Safety</td>
<td></td>
</tr>
<tr>
<td>Envr Alaska</td>
<td></td>
</tr>
<tr>
<td>Epoch Well Services</td>
<td>2</td>
</tr>
<tr>
<td>Era Aviation</td>
<td></td>
</tr>
<tr>
<td>Evergreen Helicopters of Alaska</td>
<td></td>
</tr>
<tr>
<td>Evergreen Resources Alaska</td>
<td></td>
</tr>
<tr>
<td>Fairweather Companies, The</td>
<td></td>
</tr>
<tr>
<td>F.A.T.S.</td>
<td></td>
</tr>
<tr>
<td>FMC Energy Systems</td>
<td>10</td>
</tr>
<tr>
<td>Friends of Pets</td>
<td>6</td>
</tr>
<tr>
<td>Frontier Flying Service</td>
<td></td>
</tr>
<tr>
<td>F.S. Air</td>
<td>9</td>
</tr>
<tr>
<td>Golder Associates</td>
<td></td>
</tr>
<tr>
<td>Great Northern Engineering</td>
<td></td>
</tr>
<tr>
<td>Great Northwest</td>
<td></td>
</tr>
<tr>
<td>Hanover Canada</td>
<td></td>
</tr>
<tr>
<td>Hawk Consultants</td>
<td></td>
</tr>
<tr>
<td>H.C. Price</td>
<td></td>
</tr>
<tr>
<td>Hunter 3D</td>
<td></td>
</tr>
<tr>
<td>Industrial Project Services</td>
<td></td>
</tr>
<tr>
<td>Inspirations</td>
<td></td>
</tr>
<tr>
<td>Jackovitch Industrial</td>
<td></td>
</tr>
<tr>
<td>&amp; Construction Supply</td>
<td></td>
</tr>
<tr>
<td>Judy Patrick Photography</td>
<td></td>
</tr>
<tr>
<td>Kavik Asset Management</td>
<td></td>
</tr>
<tr>
<td>Kenai Aviation</td>
<td></td>
</tr>
<tr>
<td>Kenworth Alaska</td>
<td></td>
</tr>
<tr>
<td>KPMG LLP</td>
<td></td>
</tr>
<tr>
<td>Kuukpik Arctic Catering</td>
<td></td>
</tr>
<tr>
<td>Kuukpik/Veritas</td>
<td></td>
</tr>
<tr>
<td>Kuukpik - LCMF</td>
<td></td>
</tr>
<tr>
<td>Lounsbery &amp; Associates</td>
<td></td>
</tr>
<tr>
<td>Lynden Air Cargo</td>
<td></td>
</tr>
<tr>
<td>Lynden Air Freight</td>
<td></td>
</tr>
<tr>
<td>Lynden Inc.</td>
<td></td>
</tr>
<tr>
<td>Lynden International</td>
<td></td>
</tr>
<tr>
<td>Lynden Logistics</td>
<td></td>
</tr>
<tr>
<td>Lynden Transport</td>
<td></td>
</tr>
<tr>
<td>Lynx Enterprises</td>
<td></td>
</tr>
<tr>
<td>Mapmakers of Alaska</td>
<td></td>
</tr>
<tr>
<td>Marathon Oil</td>
<td></td>
</tr>
<tr>
<td>MEDC International</td>
<td></td>
</tr>
<tr>
<td>MI Swavo</td>
<td></td>
</tr>
<tr>
<td>Michael Baker Jr.</td>
<td>10</td>
</tr>
<tr>
<td>Midtown Auto Parts &amp; Machine</td>
<td></td>
</tr>
<tr>
<td>Millennium Hotel</td>
<td></td>
</tr>
<tr>
<td>Montgomery Watson Harza</td>
<td></td>
</tr>
<tr>
<td>MRO Sales</td>
<td></td>
</tr>
<tr>
<td>Naboras Alaska Drilling</td>
<td></td>
</tr>
<tr>
<td>NANA/Coalt Engineering</td>
<td></td>
</tr>
<tr>
<td>Naito Canada</td>
<td></td>
</tr>
<tr>
<td>Nature Conservancy, The</td>
<td></td>
</tr>
<tr>
<td>NEI Fluid Technology</td>
<td></td>
</tr>
<tr>
<td>Nordic Calista</td>
<td></td>
</tr>
<tr>
<td>Northern Air Cargo</td>
<td>3</td>
</tr>
<tr>
<td>Northern Lights</td>
<td></td>
</tr>
<tr>
<td>Northern Transportation Co.</td>
<td></td>
</tr>
<tr>
<td>Northwestern Arctic Air</td>
<td></td>
</tr>
<tr>
<td>Offshore Divers</td>
<td>4</td>
</tr>
<tr>
<td>Oilfield Transport</td>
<td>17</td>
</tr>
<tr>
<td>Pacific Rim Institute</td>
<td></td>
</tr>
<tr>
<td>of Safety and Management (PRISM)</td>
<td></td>
</tr>
<tr>
<td>Penalpina.</td>
<td>16</td>
</tr>
<tr>
<td>PDC/Harris Group</td>
<td></td>
</tr>
<tr>
<td>Peak Oilfield Service Co.</td>
<td></td>
</tr>
<tr>
<td>Penco</td>
<td>9</td>
</tr>
<tr>
<td>Perkins Cole</td>
<td></td>
</tr>
<tr>
<td>Petroleum Equipment &amp; Services</td>
<td></td>
</tr>
<tr>
<td>Petrotechnical Resources of Alaska</td>
<td></td>
</tr>
<tr>
<td>PGS Onshore</td>
<td>13</td>
</tr>
<tr>
<td>ProComm Alaska</td>
<td>18</td>
</tr>
<tr>
<td>Prudhoe Bay Shop &amp; Storage</td>
<td></td>
</tr>
<tr>
<td>QUADCO</td>
<td></td>
</tr>
<tr>
<td>Salt + Light Creative</td>
<td></td>
</tr>
<tr>
<td>Schlumberger Oilfield Services</td>
<td></td>
</tr>
<tr>
<td>Security Aviation</td>
<td>20</td>
</tr>
<tr>
<td>Seeks Ford</td>
<td>5</td>
</tr>
<tr>
<td>Sourdough Express</td>
<td></td>
</tr>
<tr>
<td>Span-Alaska Consolidators</td>
<td></td>
</tr>
<tr>
<td>STEELLAB.</td>
<td>19</td>
</tr>
<tr>
<td>Storm Chasers Marine Services</td>
<td></td>
</tr>
<tr>
<td>Taiga Ventures</td>
<td></td>
</tr>
<tr>
<td>Thrifty Car Rental</td>
<td></td>
</tr>
<tr>
<td>TOTE</td>
<td></td>
</tr>
<tr>
<td>Totem Equipment &amp; Supply</td>
<td></td>
</tr>
<tr>
<td>Travo Industrial Housing</td>
<td></td>
</tr>
<tr>
<td>UBS Financial Services Inc.</td>
<td></td>
</tr>
<tr>
<td>Uddevahen Oilfield Systems Services</td>
<td></td>
</tr>
<tr>
<td>Umist Commercial</td>
<td></td>
</tr>
<tr>
<td>Underwriters Laboratories</td>
<td></td>
</tr>
<tr>
<td>Unique Machine</td>
<td></td>
</tr>
<tr>
<td>Unitech of Alaska.</td>
<td>6</td>
</tr>
<tr>
<td>Univar USA</td>
<td></td>
</tr>
<tr>
<td>U.S. Bearings and Drives</td>
<td></td>
</tr>
<tr>
<td>Usibell Coal Mine</td>
<td></td>
</tr>
<tr>
<td>VECO</td>
<td></td>
</tr>
<tr>
<td>Weaver Brothers</td>
<td>7</td>
</tr>
<tr>
<td>Worksafe</td>
<td></td>
</tr>
<tr>
<td>Well Safe</td>
<td></td>
</tr>
<tr>
<td>XTO Energy</td>
<td></td>
</tr>
</tbody>
</table>

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

<table>
<thead>
<tr>
<th>ADVERTISER</th>
<th>PAGE AD APPEARS</th>
</tr>
</thead>
<tbody>
<tr>
<td>Agrium Kenai</td>
<td></td>
</tr>
<tr>
<td>Nitrogen Operations</td>
<td></td>
</tr>
</tbody>
</table>

**Business Spotlight**

By PAULA EASLEY

Judy E. Phillips, HR/Medicine
Department assistant

**Agrum Kenai Nitrogen Operations**

Cominco Fertilizers Ltd. came into being in 1931 and became known as Agrum 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.

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

**Engineered Fire & Safety**

Engineered Fire & Safety provides fire alarm, gas detection, fire suppression and intercom/systems for the petroleum, power generation and other industries. The company now operates under Kode 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.

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

verted wells to injection to "artificially press-

ure the reservoir and move the oil to our produc-

ing wells.

That’s another thing the company liked about Middle Ground Shoal: "This is essen-
tially 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.

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 roy-

alty reduction bill for Cook Inlet proper-

ties last year, and Dinmore 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 

levy but 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, rang-

ing from zero to some that are “much 
greater," Hammond said.

We like being here, he told the com-

tee, but "one of the things that I try to 

explain is, this reservoir has an inherent 

risk that does make it very chal-

lenging for us to put new present projects to 

our management."

The one, perhaps two, wells the com-
pair 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 esti-

mates 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 analyst’s consensus esti-

mates.

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 

came for the same period last year.

Apache also is expected to see its 2004 

first-quarter profit increase roughly 16 per-

cent 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 esti-

mates, Devon’s 2004 first-quarter profit 

would be down nearly 30 percent com-

pared 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 previ-

ous 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 strong 

performance across the board. The com-

pany 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 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 previous 

quarter and $1.44 per share a year ago. 

By far, Newfield Exploration is expect-

ted 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 per-

cent 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.

Brown’s 2004 first-quarter profit 

could increase 40 percent to 76 cents per 

share from 54 cents per share in the previ-

ous 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 peri-

od 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.

Cahill 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 quar-

ter, according to consensus estimates.
THE REST OF THE STORY

The rest of the story

PETROLEUM NEWS • WEEK OF APRIL 11, 2004

continued from page 1

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 out-
cast, Libya is “preparing for a prosper-
ous 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 cover-
ing only one-quarter of the country.
Hassan-Beck told reporters that pro-
duction 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 natu-
ral 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, com-
panies 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 invest-
ment.
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 con-
tributed 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 applica-
tions are being initiated will encourage partici-
pation in the project. As per last week’s
amendment to the original award, inter-
ested 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

Solid Waste Pickup

Recycling Oily Materials, Wood, Tires, and Metal

(907) 659-3198 - Fax (907) 659-3190
Pouch 340012, Prudhoe Bay, Alaska 99734

Your Source on the Slope for:

Welding Supplies, Automotive & Truck Parts, Hardware
Tools, Building Materials, Glass, Propane
Hydraulic Hoses & Fittings
Paint & Chemicals, Safety Equipment

Open 24 hours, 365 days a year

(907) 659-2550 - Fax (907) 659-2550
Pouch 340008, Prudhoe Bay, Alaska 99734

Colville

Supplier to Oil Companies
and North Slope Communities

Diesel, Bulk Fuel Delivery, Gasoline, Aviation Fuels
Lubricants, Industrial Gases, Steel, and Sorbs

(907) 659-3198 - Fax (907) 659-3190
Pouch 340012, Prudhoe Bay, Alaska 99734

Colville Solid Waste Service

Recycling Oily Materials, Wood, Tires, and Metal

(907) 659-3198 - Fax (907) 659-3190
Pouch 340012, Prudhoe Bay, Alaska 99734
ABB is a world-renowned leader in the Oil and Gas Industry for its pioneering role in "fit for purpose" safety solutions.

A significant portion of ABB’s history demonstrates its leadership position as an automation supplier to the energy industries; a direct result of harsh Oil Industry lessons learned following the tragedy of Piper Alpha. This article will attempt to put into perspective the reasons 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 Cutler Report, were the catalyst in revolutionizing the safety industry and fueling an ongoing passion to make sure that this never happens 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 on advanced ultra high availability technology known as TMR or Triple Modular Redundancy. Today, members of the replacement platform project's design and commissioning teams 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 the company’s assets are managed to achieve the lowest possible risk profile.

Today, ABB has over 2,500 safety systems installed around the world protecting people and the planet for its customers.

To meet the ever-growing MoC (Management of Change) demands of the safety market place for our customers, ABB offers a full range of HSE products and services to match customer needs for the entire lifecycle of a facility.

ABB’s safety products trade named Triguard, Flapguard and Safeguard are capable of providing system availability numbers of 99.999% and above, reducing the opportunity for a system downtime.

While each of these ABB products has its own differentiating merits, the most important message of this story is that ABB’s Triguard SC500E/SL5+ TMR Safety System has now been qualified as a Fire & Gas Alarming and Protection system conforming to the UL-584 Fire Protection and Alarmining 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 SL5+ 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 meet the harsh environmental standards of Alaska.

The open architecture approach that the ABB Triguard System offers 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 system 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.

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.

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

ABB’s safety engineering capabilities include:

- HAZOP/Fluoration
- Risk Analysis and QRA
- Hazard Analysis and QRA
- Safety / Indus. Safety P&ID
- Safety System / Boundary Planning and Management
- Safety Integrity (Local Calculation and Validation)
- Enhanced Functional Safety Assessments
- AMHar/SH21 / IEC61508 Compliance Assistance
- Training and Certification
- Maintenance Services of Fire & Gas Detection and Safety Instrumented Systems
- Software Packages - Development and Testing of Plant Safety Systems
- Asset Management Software
- On-line / Off-line Testing Optimization

ABB’s is a world-renowned leader in the Oil and Gas Industry for its pioneering role in "fit for purpose" safety solutions.