Petroleum news

page 15 State to open trans-Alaska oil pipeline tariff negotiations

Vol. 9, No. 5 • www.PetroleumNews.com

North America's source for oil and gas news

Week of February 1, 2004 • $1

Getting ready for transport

JUDY PATRICK

Taken in late January at the Prudhoe Bay field on Alaska's North Slope, in the above photo a Schlumberger nitrogen unit is shown in front of the Schlumberger-Nordic Calista Rig 1, a coiled tubing drilling unit that is part of a joint venture between Schlumberger and Nordic Calista. Nitrogen is being used to displace the drilling fluids left in the tubing which lightens it for transport, reducing the impact as the rig moves across the North Slope.

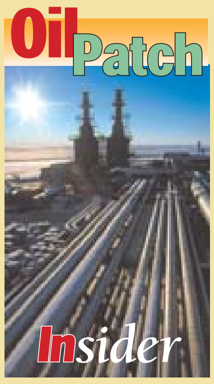
Kerr-McGee hopeful Yorktown oil prospect can be salvaged

Partners Kerr-McGee and Devon Energy apparently believe their Yorktown oil prospect in the deepwater Gulf of Mexico is worth saving, despite spending an unheard of $86 million on a troublesome exploration well that was never completed.

"We still see this as a viable prospect," Dave Hager, Kerr-McGee's head of exploration and production, told analysts in a Jan. 28 conference call on 2003 fourth-quarter earnings.

see **KERR-MCGEE** page 18

Kerr-McGee files for North Slope unit



ACCORDING TO COMPANY SPOKESWOMAN DEBBIE SCHRAMM Kerr-McGee Oil & Gas filed a unit application with the state of Alaska on Jan. 29 for the acreage it recently acquired from Armstrong Alaska on the North Slope. (See story in the Jan. 11 edition of Petroleum News.) The

see **INSIDER** page 19

BREAKING NEWS

7 Oil prices to stay high: Petroleum News' favorite oil price guru predicts prices likely to remain at current levels through 2004

5 Jackup market improving: GlobalSantaFe believes the jackup rig market worldwide is stable and improving

5 Incentives could spur gas drilling boom: MMS incentives for the Gulf of Mexico could encourage explorers to drill deeper

CANADA

Full throttle

Alaska gas line action causes buzz in Canada; Mackenzie line fans wary

By GARY PARK

Petroleum News Calgary Correspondent

The flurry of Alaska gas pipeline activity has generated a sense of urgency among Canadian pipeline companies and gas producers involved in both the Alaska Highway scheme and the Mackenzie Gas Project.

Hal Kvisle, CEO, TransCanada

For TransCanada, which has a large foot in both camps, the primary focus is on its role in carrying North Slope gas across Canadian territory, Chief Executive Officer Hal Kvisle told a conference call Jan. 27.

For Imperial Oil, the lead player in the Mackenzie project, the back-to-back pipeline filings in Alaska "remind us very emphatically that time is of the essence," spokesman Hart Searle told Petroleum News.

Although 100 percent owners of the rights to ship Alaska gas across the state, TransCanada is "very focused on the Canadian side," Kvisle told analysts.

However, he said his company, the largest gas carrier in Canada, would be willing to participate as a builder or investor in Alaska and was interested in collaborating on an end-to-end project as an owner or non-owner.

Kvisle says economics of LNG, Alaska North Slope gas to Chicago similar

But making the economics work is "something the netback owners have to wrestle with," Kvisle said.

see **THROTTLE** page 13

COOK INLET, ALASKA

Redoubt flame dwindles

Reserve estimates cut at field once seen as spark of new activity in Cook Inlet

By KRISTEN NELSON

Petroleum News Editor-in-Chief

The dream that was Redoubt Shoal — solid new oil production from Alaska's mature Cook Inlet basin — started to fade in August when Forest Oil said it had unsatisfactory results from two wells and was reevaluating the reservoir.

The final wake-up call came Jan. 27: Forest said it has completed an integrated field study of the Redoubt Shoal field and is reducing estimated proved reserves by 49 million barrels, to 8 million barrels.

Forest also said it replaced the Nabors Alaska Drilling rig with a workover rig.

The new reserves estimate reflects both lower-than-expected production rates and new data evalua-

see **REDOUBT** page 19

JUDY PATRICK

Forest Oil's Osprey platform in Alaska's Cook Inlet.

NORTHWEST TERRITORIES

Deh Cho set bargaining position

Want 'flawed' regulatory process fixed in exchange for cooperation on Mackenzie line

By GARY PARK

Petroleum News Calgary Correspondent

The Deh Cho First Nations of the Northwest Territories want to overhaul the existing regulatory process in exchange for their cooperation in assessing the proposed Mackenzie Valley gas pipeline.

While assuring the Canadian government that they are ready to "move forward" on the project, the Deh Cho said the agreement covering the regulatory review has been "flawed from the beginning."

In a submission to Indian Affairs and Northern Development Minister Andy Mitchell on Jan. 23, the Deh Cho said the process does not include their interests, fails to streamline the involvement of the National Energy Board and falls short of current legislation and established best practices elsewhere in Canada.

The Deh Cho, representing 13 communities along and near the Mackenzie River in the lower Northwest Territories, are attempting to negotiate regional self-government on their land. About 40 percent of the pipeline route crosses Deh Cho lands.

Pending a settlement, they have refused to join other aboriginal communities as partners in the Aboriginal Pipeline Group that stands to gain one-third ownership of the pipeline and have warned

see **DEH CHO** page 18

Alaska - Mackenzie Rig Report

The Alaska - Mackenzie Rig Report as of January 27, 2004. Active drilling companies only listed.

TD = rigs equipped with top drive units WO = workover operations CT = coiled tubing operation SCR = electric rig

This rig report was prepared by Wadeen Hepworth

Alaska Rig Status

North Slope - Onshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Doyon Drilling			
Dreco 1250 UE	14 (SCR/TD)	Milne Point, drilling on G pad, well MPG-16	BP
Sky Top Brewster NE-12	15 (SCR/TD)	Stacked, Endicott Island, demobing in February	Available
Dreco 1000 UE	16 (SCR)	Startup expected April 2004	BP
Dreco D2000 UEBD	19 (SCR/TD)	Alpine, drilling CD1-07	ConocoPhillips
OIME 2000	141 (SCR/TD)	Meltwater, drilling 2P-419	ConocoPhillips
Nabors Alaska Drilling			
Trans-ocean rig	CDR-1 (CT)	Stacked, Prudhoe Bay	Available
Dreco 1000 UE	2-ES (SCR)	Prudhoe Bay, H-05A	BP
Mid-Continent U36A	3-S	Stacked at Prudhoe Bay	Available
Oilwell 700 E	4-ES (SCR)	Prudhoe Bay, D-31A	BP
Dreco 1000 UE	7-ES (SCR/TD)	Prudhoe Bay, Z-30A	BP
Dreco 1000 UE	9-ES (SCR/TD)	Prudhoe Bay, L-200	BP
Oilwell 2000 Hercules	14-E (SCR)	Caribou, 2611 #1	Total
Oilwell 2000 Hercules	16-E (SCR/TD)	Stacked, Prudhoe Bay	Available
Oilwell 2000	17-E (SCR/TD)	Stacked, Point McIntyre	Available
Emsco Electro-hoist -2	18-E (SCR)	Stacked, Deadhorse	Available
OIME 1000	19-E (SCR)	Stacked, Deadhorse	ConocoPhillips
Emsco Electro-hoist Varco TDS3	22-E (SCR/TD)	Stacked, Milne Point	Available
Emsco Electro-hoist	28-E (SCR)	Stacked, Deadhorse	Available
OIME 2000	245-E	Stacked, Kuparuk	ConocoPhillips
Nordic Calista Services			
Superior 700 UE	1 (SCR/TD)	Drill site 1, well #2-B	BP
Superior 700 UE	2 (SCR)	Drill site L-2, well 14-A	BP
Ideco 900	3 (SCR/TD)	Commissioning at 1-Q, prior to move to 3-F pad	ConocoPhillips

North Slope - Offshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Nabors Alaska Drilling			
Oilwell 2000	33-E (SCR/TD)	Northstar, NS-25	BP
Emsco Electro-hoist Canrig 1050E	27-E (SCR/TD)	Northwest Milne	Kerr-McGee

Cook Inlet Basin – Onshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Marathon Oil Co. (Inlet Drilling Alaska labor contractor)			
Taylor	Glacier 1	Cannery Loop Unit #8	Marathon
Inlet Drilling Alaska/Cooper Construction			
Kremco 750	CC-1	Stacked, Kenai	Forest Oil
Nabors Alaska Drilling			
Rigmasters 850	129	Cook Inlet, Falls Creek #1	Marathon
National 110 UE	160 (SCR)	Stacked, Kenai	Available
Continental Emsco E3000	273	Cook Inlet, KS #1	Marathon
	51	Steelhead platform, done 12-1-03	Unocal
IDECO 2100 E	429E (SCR)	Stacked, removed from Osprey platform	Available
Aurora Well Service			
Franks 300 Srs. Explorer III	AWS 1	Stacked, Nikiski	Available
Evergreen Resources Alaska			
Wilson Super 38	96-19	Stacked in yard	Evergreen Resources Alaska Corporation
Engersol Rand	1	Stacked in yard	Evergreen Resources Alaska Corporation
Water Resources International			
Ideco H-35 KD		Trading Bay, spud Nov. 4 Dec. 12 at 3517' TD Idle, waiting for breakup	Pelican Hill

Cook Inlet Basin – Offshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
XTO Energy (Inlet Drilling Alaska labor contract)			
National 1320	A	Idle	Idle
National 110	C (TD)	Idle	Idle
Unocal (Nabors Alaska Drilling labor contractor)			
Not Available			
Kuukpik	5	Rigging up, Happy Valley #3	Unocal
Cudd Pressure Control	340K	Workover, Osprey Platform	Forest Oil

Mackenzie Rig Status

Mackenzie Delta-Onshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
AKITA Equtak			
Dreco 1250 UE	62 (SCR/TD)	Moving in, rigging up to drill Umiak N-16	EnCana
Dreco 1250 UE	63 (SCR/TD)	Moving in, rigging up to drill Ellice I-48	Chevron Canada
National 370	64	Stacked, Inuvik, NT	Available

Central Mackenzie Valley

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
AKITA/SAHTU			
Oilwell 500	51	Moving in and rigging up to drill the first of 3 wells on EL399	Apache Canada
Rigmaster P850	40	Drilling Summit Creek B-44	Northrock Resources
National 370	55	Moving in, rigging up to drill Begadeh J-66	EnCana
Nabors Canada			
	62	Stacked, Norman Wells	Available

JUDY PATRICK

Baker Hughes North America rotary rig counts*

	January 23	January 16	Year Ago
US	1,087	1,127	862
Canada	576	563	528
Gulf	98	101	106

Highest/Lowest

US/Highest	4530	December 1981
US/Lowest	488	April 1999
Canada/Highest	558	January 2000
Canada/Lowest	29	April 1992

*Issued by Baker Hughes since 1944

Rig start-ups expected in next 6 months

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator
Doyon Drilling			
Dreco 1000 UE	16 (SCR)	Startup expected April 2004	BP

The Alaska - Mackenzie Rig Report is sponsored by: ConocoPhillips

ANCHORAGE, ALASKA

Judge orders Exxon Mobil to pay $7B

A federal judge in Anchorage on Jan. 28 ordered Exxon Mobil Corp. to pay nearly $7 billion in punitive damages and interest to thousands of fishermen and others affected by the 1989 Exxon Valdez oil spill.

"We have now closed the trial court doors for the last time in this litigation after 15 years," said David Oesting, lead attorney for the plaintiffs. "We're definitely on track to the end of the entire dispute."

In the Jan. 28 ruling, U.S. District Judge Russel Holland ordered Exxon Mobil to pay $4.5 billion in punitive damages and about $2.25 billion in interest.

The money is to go to 32,000 fishermen, Alaska Natives, landowners, small businessmen and municipalities affected by the nearly 11 million gallon spill in Prince William Sound. An ExxonMobil official said the Irving, Texas-based company plans to appeal the 81-page ruling. The 9th U.S. Circuit Court of Appeals has twice vacated Holland's decision in the case, said Exxon spokesman Tom Cirigliano. Holland had been ordered by the appellate court to reconsider the damages of an earlier ruling.

The judge was to consider a U.S. Supreme Court decision involving a Utah traffic accident and damages awarded in that case. "This ruling flies in the face of the guidelines set by the appeals court," Cirigliano said. When the matter was sent back to Holland, Exxon Mobil lawyers predicted this would be the result — "serious further delays" — from having to appeal rulings from a court "that has already made numerous mistakes." The spill occurred March 23, 1989, less than three hours after the 987 foot ship Exxon Valdez left the Alyeska Pipeline terminal in Valdez. The ship grounded at Bligh Reef, rupturing eight of its 11 cargo tanks and spewing 10.8 million gallons of crude oil into the sound.

—**RACHEL D'ORO,** The Associated Press

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Petroleum news

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Petroleum News and its supplement, Petroleum Directory, 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.

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Petroleum News (ISSN 1544-3612) Week of February 1, 2004
Vol. 9, No. 5
Published weekly. Address: 5441 Old Seward, #3, Anchorage, AK 99518
(Please mail ALL correspondence to:
P.O. Box 231651, Anchorage, AK 99523-1651)
Subscription prices in U.S. — $52.00 for 1 year, $96.00 for 2 years, $140.00 for 3 years. Canada / Mexico — $165.95 for 1 year, $323.95 for 2 years, $465.95 for 3 years.
Overseas (sent air mail) — $200.00 for 1 year, $380.00 for 2 years, $545.95 for 3 years.
"Periodicals postage paid at Anchorage, AK 99502-9986."
POSTMASTER: Send address changes to Petroleum News, P.O. Box 231651 • Anchorage, AK 99523-1651.

Canada Publications Mail Agreement Number 40882558
RETURN UNDELIVERABLE CANADIAN ADDRESSES TO:
Petroleum News, Attn: Circulation Dept.
#99 - 4404 12th Street N.E.
Calgary, AB T2E 6K9 Canada
email: circulation@PetroleumNews.com
NOTICE: Prior to April 6, 2003, Petroleum News was known as Petroleum News Alaska.

NORTH SLOPE, ALASKA

Pioneer Natural Resources farms in on ConocoPhillips Kalubik acreage

Pioneer Natural Resources and Armstrong Alaska have effectively doubled their acreage at Oooguruk on Alaska's North Slope.

Pioneer said Jan. 29 that the companies concluded an agreement with ConocoPhillips Alaska under which ConocoPhillips will farm out its 100 percent interest in approximately 23,000 acres of Alaska state oil and gas leases to Pioneer and Armstrong. The leases, in the shallow waters of the Beaufort Sea, are approximately five miles northwest of the ConocoPhillips operated Kuparuk River unit and immediately adjacent to approximately 25,000 acres under lease by Pioneer (70 percent) and Armstrong (30 percent).

Last winter Pioneer and Armstrong drilled three wells in the Northwest Kuparuk prospect within what later became the Oooguruk unit that "established the existence of potentially commercial quantities of oil in Jurassic-aged sands," Pioneer said.

"The field may extend beneath the acreage covered under the farm-in agreement," the company said.

The agreement gives Pioneer and Armstrong the right to purchase 3-D seismic and obtain access to other proprietary data that will be used for a study of the commercial potential of the area, which Pioneer said it expects to complete in 2004. ConocoPhillips retains the right to participate in any project ultimately sanctioned by Pioneer and Armstrong.

Four discovery wells in acreage

In July the state approved formation of the Oooguruk unit over the Pioneer and Armstrong leases where the companies drilled last winter. The Division of Oil and Gas said oil-bearing Jurassic sands southwest of the unit had been tested in several Colville Delta exploration wells: the Texaco Colville Delta No. 1 (1,075 barrels per day of 25 degree API oil); the Texaco Colville Delta No. 2 (409 bpd of 24-40 degree oil); the Texaco Colville Delta No. 3 (374 bpd of 27.7 degree oil); and the ARCO Kalubik No. 1 (410 bpd of 21 degree oil).

These four Colville River area exploration wells are on the leases farmed out by ConocoPhillips.

"This farm-in was a critical step for Pioneer to move forward in evaluating potential development," Scott Sheffield, Pioneer's chairman, president and CEO, said in the company's statement. "We look forward to continuing to work with ConocoPhillips with the joint goal of expanding oil production from the area."

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

NOVA SCOTIA

Nova Scotia urges speedy end to flag flap

An organization representing 500 Eastern Canadian oil and gas companies is urging a federal agency to solve a flag-of-convenience dispute that could scuttle an offshore exploration well. The Offshore/Onshore Technologies Association of Nova Scotia told the Canadian Transport Agency that unless it comes to a quick decision there could be lasting damage to the province's petroleum industry.

Association Managing Director Paul McEachern said a viable energy industry requires a decision long before the end of March deadline.

"Taking the full 120-day period allowed under (law) to decide would be unacceptable," he wrote. "In fact, if a resolution to this dispute is not rendered quickly, the entire exercise may prove theoretical as no actual work may take place."

Beyond that, McEachern warned that unless the transport agency fast-tracks its work "the delay could prove extremely costly for the operator and consequently for the entire Nova Scotia supply and service community as well."

Marathon Oil wants to use the drillship Deepwater Pathfinder, owned by Houston-based Transocean, to drill a follow-up deepwater well near its 2002 Annapolis gas discovery, Nova Scotia's first deepwater breakthrough.

Transocean asked the transportation agency in November for approval to import the drillship in Canada. Three weeks later Norway's Ocean Rig said its semi-submersible Eirik Raude would be available and should get preference because it was crewed by Canadians and was retrofitted in Halifax for about C$250 million.

Ocean Rig also said it had applied to switch the Eirik Raude's registration from the Bahamas to Canada. The transport agency agreed on grounds of procedural fairness to hear Ocean Rig, despite Marathon's claims that the Eirik Raude would add almost C$10 million to its costs, is technically unsuitable and would force Marathon to abandon its drilling plans.

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

EL SEGUNDO, CALIF.

Unocal executive dies unexpectedly

Timothy Ling, 46, Unocal Corp.'s president and chief operating officer, died suddenly Jan. 28 in El Segundo, Calif. Charles Williamson, Unocal's chairman and chief executive officer, will assume Ling's responsibilities as president and COO on an interim basis. "Tim Ling was a brilliant executive with boundless energy and enthusiasm," Williamson said. "The entire Unocal family is shocked and saddened by Tim's sudden passing. We will miss him terribly."

Ling is survived by his wife, Kimberly, and three children.

● ALASKA

Bill addresses Alaska shallow gas issues

House Bill 395 takes away DNR's authority to override municipal land-use laws for coalbed methane development

By LARRY PERSILY
Petroleum News Government Affairs Editor

Legislation introduced in the Alaska House looks to address many of the concerns raised by Kenai Peninsula and Matanuska-Susitna Borough residents fearful of potential coalbed methane development in their neighborhoods.

"We got together and said, 'What are the problems we need to solve,'" said Homer Rep. Paul Seaton. "We tried to address all of the problems without swinging the pendulum too far back."

House Bill 395 would go back and repeal a provision adopted by the Legislature last year that gave the Department of Natural Resources — in cases of coalbed methane development — the authority to override municipal land-use laws.

"To my mind, it was a real sea change," said Seaton, who voted last session against final passage of the measure, House Bill 69.

In addition to ensuring local control, this year's eight-page bill would allow the state to regulate drilling to protect underground water sources, increase public notice requirements of leases, set up a public forum process for resolving residents' complaints and set rental payments to property owners for use of their land by shallow gas developers.

Sponsors don't want to hurt development

The bill's four co-sponsors are not against development of Alaska's coalbed methane reserves, but rather want to cure "real problems" without ruining what could be a source of natural gas for residential and commercial users throughout Southcentral Alaska, said Seaton, a Republican.

Republican Reps. John Harris of Valdez, Bill Stoltze of Chugiak and Carl Gatto of Palmer are the other co-sponsors of House Bill 395. Stoltze and Gatto, like Seaton, are freshmen legislators. Harris is co-chairman of the House Finance Committee.

This year's measure was introduced Jan. 23 and referred to four committees for hearings and possible amendments: Oil and Gas, Resources, Judiciary and Finance. No hearings were scheduled as of Jan. 28.

Alaskans have spent the past six months asking a lot of questions about water quality, developer access to their property and potential damages to their property from drilling for coalbed methane — ever since residents realized last summer that the state had leased more than 250,000 acres near Homer and throughout the Matanuska-Susitna Borough for coalbed methane exploration.

Land access a real issue

Many residents were surprised to learn that although they owned the surface rights to their land, the state owned the subsurface rights and had leased the property to companies exploring for shallow gas.

"It was important to all of us that the message sent by our constituents concerning public property rights and water quality were addressed in this bill," said Harris, who along with Gatto and Stoltze co-sponsored last year's House Bill 69 that led to much of the controversy.

In addition to repealing the Department of Natural Resources' Division of Oil and Gas authority to override municipal land-use laws, the bill proposes:

- Allowing the Alaska Oil and Gas Conservation Commission to regulate shallow gas drilling to protect water quality by requiring the re-injection of coal seam dewatering flow to depths below any known sources of drinking water or wells used for farming.
- Calling on the commission to set up a public forum process for resolving complaints about health, safety and environmental issues at exploration and development sites. The bill also would require the agency to set up a procedure whereby residents could petition the commission to act on a complaint if the public forum process fails to settle the issue.
- Requiring the Department of Natural Resources to publish notices of shallow gas lease applications in at least two newspapers in the lease area over a two-week period, with notices also going to each municipality and community council in the area. Much of the criticism of the Kenai Peninsula leases near Homer came after the department failed to publish a notice of lease applications in either Homer newspaper.
- Requiring additional notices in at least two newspapers in the area before the department may issue a coalbed methane lease.
- Setting the rental payment to property owners at $300 per month for each wellhead and $600 a month for each compressor station on their land. Existing statute does not specify how much rent, if any, developers must pay property owners for installing equipment on their property.
- Requiring property line setbacks for compressor station installations, and requiring developers to take "reasonable and appropriate measures" to reduce compressor noise. In addition to requiring that property owners and developers negotiate setbacks and noise reduction efforts, the bill also says property owners may not "unreasonably withhold" their agreement.
- Requiring developers in some cases to prove to the state that access to private land is "reasonably necessary or convenient" to reach the lease area. ●

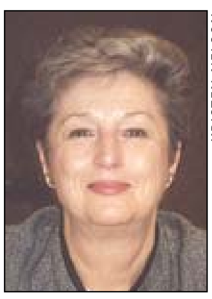
● GULF OF MEXICO

MMS incentives could spur gas drilling boom in Gulf of Mexico

PETROLEUM NEWS

A long-awaited package of government incentives designed to encourage explorers to drill deeper for natural gas on existing federal leases could be the key to unlocking trillions of cubic feet of reserves on the Gulf of Mexico's already heavily exploited continental shelf.

The initiative, in the making for several years, would help offset declining U.S. natural gas production by tapping reserves that industry otherwise would leave in the ground because of expense issues, U.S. Interior Secretary Gale Norton said in a Jan. 23 conference call.



KRISTEN NELSON

MMS Director Johnnie Burton

JUDY PATRICK

Secretary of the Interior Gale Norton

"This is an important step to stabilizing production as our demand for natural gas climbs," Norton said. "Gas demand is out-pacing production (and) the gap is expected to increase over the next decade."

Interior's Minerals Management Service already offers royalty suspension for the first 20 billion cubic feet of production below 15,000 feet from discoveries on newly issued leases. The new package dramatically expands both the size and scope of the government's royalty relief program to include some 2,400 existing leases offshore Texas, Louisiana, Mississippi and Alabama.

Under the new program, MMS is offering a royalty suspension on the first 15 billion cubic feet of gas produced from depths greater than 15,000 and less than 18,000 feet, or on the first 25 billion cubic feet produced from 18,000 feet or deeper. A royalty suspension volume of 15 bcf can be increased to 25 bcf from a second successful well to 18,000 feet or deeper. The rule applies to all qualified wells on a specific lease. In the event of a dry hole below 18,000 feet, a producer would qualify for a royalty suspension supplement of 5 bcf of gas equivalent that could be applied to future oil or gas production from any depth. Two supplements are available per lease prior to production from a deep well. The maximum relief a lease can earn from either successful or unsuccessful deep wells is 35 bcf.

Additionally, sidetrack wells could earn royalty suspensions in amounts based on drilling depth and sidetrack length.

Relief goes away with high prices

Royalty relief would be discontinued if natural gas prices exceed $9.34 per thousand cubic feet. Drilling must have started on or after March 26, 2003, and production must begin within five years of the rule's effective date.

Effected leases are located in relatively shallow waters of the Gulf up to 656 feet or 200 meters. And because platforms, pipelines and other infrastructure are largely in place, the cost of accessing and producing from deeper geologic formations is expected to dramatically reduce exploration and development costs.

"We believe there are significant quantities of gas available from drilling further from (existing) platforms," Norton said.

MMS estimates that drilling and platform upgrades associated with the extra deep gas production would generate up to 26,000 jobs that could be sustained for at least the next six years.

"We believe the incentives offered in this rule will spur industry to explore and produce these deep, undiscovered resources," MMS Director Johnnie Burton said.

5 % of shelf wells have gone deep

Industry actually has been drilling and producing natural gas below 15,000 feet in the Gulf for years, with recent discoveries made at Anadarko's Hickory platform, El Paso's ST 204 unit, and Shell's Alex discoveries. But only 5 percent of total wells drilled on the continental shelf have gone deep and that has not been nearly enough to offset the overall production decline. In fact, annual shelf output has plummeted from 4.8 tcf in 1996 to less than 3.3 tcf today.

MMS estimates that undiscovered gas of up to 55 tcf of gas may exist in this new frontier area. "There is a substantial accumulation of gas much deeper than being produced today," Burton said, "and we are proposing an incentive that will give them (producers) a certain amount of gas they can produce without paying royalty on it."

Norton said that based on assumed production until 2010, the U.S. treasury would lose about $1.1 billion in royalties. Once the program expires, she added, the treasury would expect to collect about $1.4 billion in royalties. However, she noted that the resource likely would not be developed without government incentives and therefore would not generate any royalties.

Norton also noted that 40 percent of U.S. industry currently depends on natural gas and that about 90 percent of new electricity plants to come online in the next decade will be fueled by natural gas. And she said that some businesses are moving gas-based manufacturing overseas where gas is available at a fraction of the price in the U.S.

The royalty relief program also was characterized a short-term solution to the gas-supply problem and is not part of President George W. Bush's comprehensive energy package, Norton said.

"This has been under consideration for three years," she said. "It is something that has gone through the proposed rule process. This was just an administrative proposal progressing at its own pace. It's not in the bill any where." ●

HOUSTON, TEXAS

Offshore driller GlobalSantaFe says jackup market improving worldwide

Offshore contract driller GlobalSantaFe believes the jackup rig market worldwide is stable and improving, reflecting a tightening in supply and demand.

"In particular, we are seeing positive indications in 2004 for our heavy duty harsh environment jackup rigs in the North Sea, where we experienced difficult market conditions in 2003," Jon Marshall, GlobalSantaFe's chief executive officer, said Jan. 28.

Marshall said his company also is encouraged that its customers are moving ahead with deepwater projects in the Gulf of Mexico, Brazil and West Africa, "which could lead to more balanced market conditions for our deepwater assets in 2004 and beyond."

GlobalSantaFe reported a 2003 fourth-quarter profit of $24.5 million or 10 cents per share on revenues of $506.2 million, compared to a profit of $52.4 million or 22 cents on revenues of $512.9 million for the same period a year earlier. The decline in net income was attributed largely to decrease in contract drilling operating income, the result of lower day rates and rig utilization during the recent quarter.

—PETROLEUM NEWS

Orders for subsea equipment expected to surge by 43 percent in 2004

Global orders for subsea equipment in 2004 are expected to increase 43 percent from 2003 levels, another indication the deepwater sector is rebounding.

"We do believe we are in the early stages of a recovery-sustainable growth period for the next two or three years," Paul Hillegeist, president of Quest Offshore, said Jan. 26. Quest publishes the Quarterly Global Subsea Market Outlook and Industry Survey.

Based on its latest survey, Quest is projecting 325 subsea production tree awards this year with an upside potential of 385. The largest growth area is being led by the strengthening demand for subsea equipment associated with major deepwater projects in West Africa, Quest said.

"Quest estimates point to a 150 percent surge in subsea tree orders this year offshore Africa compared to 2003," the firm said, adding that another "buoyant" market for subsea tree awards in 2004 is Asia Pacific, where a 67 percent growth rate over the previous year is anticipated.

Of all orders for subsea trees projected for 2004, West Africa is expected to receive 56 percent, followed by the North Sea with 12 percent, Asia Pacific with 12 percent, the Gulf of Mexico with 11 percent, and 8 percent for Brazil and other offshore areas of South America.

Quest tabulated 226 booked orders for subsea production trees in 2003, in line with the firm's previous estimate of 218 awards for the year. Projects generally require a six to 24 month delivery period.

—PETROLEUM NEWS

ANCHORAGE, ALASKA

Norman named to public seat on AOGCC

Alaska Gov. Frank Murkowski has named Anchorage attorney John Norman to the public seat on the Alaska Oil and Gas Conservation Commission.

The commission had gotten down to a single member, Dan Seamount, who holds the geologist seat.

Former Wasilla Mayor Sarah Palin resigned from the public seat effective Jan. 20. Randy Ruedrich, chair of the Alaska Republican Party, resigned from the petroleum engineer seat in November in the midst of a controversy over potential conflicts of interest.

Norman also replaces Palin as chair of the commission.

When the governor announced Norman's appointment at a press conference Jan. 23, he said he had asked Norman, "among his other duties, to review some of the recommended efficiencies in the operation" of the commission proposed by Palin and Seamount under the administration's missions and measures evaluation.

Norman holds law and geology degrees from the University of Missouri.

Since 1971 he has been with the law firm of Hartig Rhodes Hoge & Lekisch, where he was a founding partner and shareholder. He was an assistant attorney general with the state of Alaska's natural resources section from 1969-72, and an exploration representative for Skelly Oil in Alaska and Texas from 1967-68.

Norman was admitted to the bar in Missouri in 1964, in Alaska in 1969 and at the U.S. Supreme Court in 1972.

—PETROLEUM NEWS

ALBERTA

Alberta nudges C$90 million for two oil and gas land sales in 2004

Alberta notched a second impressive sale of petroleum, natural gas and oil sands rights, collecting C$32.7 million from its Jan. 21 auction, bumping the year-to-date to almost C$90 million.

The latest round of bidding saw 107,897 hectares (266,613 acres) change hands, raising the year's total to 250,298 hectares (618,486 acres).

The top bidder was Maverick Land Consultants for an unnamed client, which paid C$1.15 million for 3,136 hectares (7,749 acres) near Provost in central Alberta. Its average price was C$368.17 per hectare, compared with the average per-hectare bid for the sale of C$293.75.

—GARY PARK, Petroleum News Calgary correspondent

● ALASKA

Alaska lawmakers add to list of bills for review this session

PETROLEUM NEWS

Alaska legislators have four new bills and one revised measure added to their growing list of oil and gas bills this session. Counting the 18 or so left over from last year, the Legislature has almost three dozen oil and gas bills for its consideration — though most likely will die in committee when lawmakers face their scheduled May 12 adjournment deadline.

The recently introduced bills are:

• House Bill 382, submitted by the governor. This is identical to Senate Bill 264 and would repeal the Dec. 31, 2003, sunset provision in state law for reimbursable services agreements between the Department of Natural Resources and pipeline right-of-way applicants.

The department says failure to adopt the legislation would leave it without funding for pre-application review work, which could delay final application reviews.

• House Bill 383, submitted by the governor. This is identical to Senate Bill 266 and would close certain lands in the Bristol Bay region to oil and gas exploration licensing and shallow gas leasing, holding back the acreage for the administration's anticipated, large-scale competitive lease sale in the area.

• House Bill 384, submitted by the governor. This is identical to Senate Bill 265 and would amend requirements for the state's five-year oil and gas leasing program to allow adding potential competitive sales to the schedule each year instead of only every other year. The practical effect is the bill would allow the department to present to legislators this year a report on potential Bristol Bay leases instead of waiting until 2005.

• House Bill 386, sponsored by Anchorage Democrats Reps. Eric Croft and Harry Crawford. This is identical to Senate President Gene Therriault's proposal, Senate Bill 253, and would exempt the Alaska Natural Gas Development Authority from the state procurement code. The authority says it needs the exemption from competitive bidding laws to avoid delays in its planning work for a state-owned North Slope natural gas pipeline and liquefied natural gas terminal at Valdez.

• A new version of House Bill 296, revised by the sponsors of the measure originally submitted last year. The revised bill would appropriate $2.15 million in state funds to the gas development authority to finish its planning work this year. Last year's unsuccessful measure asked for $1.3 million.

The revised House bill is identical to Senate Bill 241, introduced a week earlier by Therriault, R-North Pole. Sponsors of the House bill are Croft and Crawford and Rep. David Guttenberg, D-Fairbanks. ●

NORTHWEST TERRITORIES

Paramount Resources leads drilling operators in Northwest Territories

Paramount Resources, focused on its interests in the Fort Liard area of the Northwest Territories, led the operators of new wells in Canada's North last year.

The Calgary-based E&P company logged three exploratory wells (two striking gas and one a dry hole), to lead all other explorers in the Northwest Territories.

Chevron Canada Resources and Anadarko Canada logged one gas discovery each, while Devon Canada and Devlan Exploration had one dry hole each. Chevron also completed one gas development hole.

—GARY PARK, Petroleum News Calgary correspondent

SAN FRANCISCO, CALIF.

Environmentalists sue EPA over permits for California oil platforms

Environmental groups filed a lawsuit Jan. 22 against the U.S. Environmental Protection Agency, claiming the federal government has failed to update clean water permits for nearly two dozen oil drilling platforms off the California coast.

The suit, filed in U.S. District Court in San Francisco, alleges that the EPA hasn't issued new water permits for 22 oil platforms off Southern and Central California. It seeks to require that the agency issue updated permits under the Clean Water Act.

Clean water permits are intended to control the discharge of pollutants into public waterways under state and federal standards.

Some oil facilities are operating with expired permits issued 20 years ago. The lawsuit asserts that the EPA has reported finding several toxic pollutants, including ammonia and arsenic, in discharges from the platforms.

The EPA would not comment directly on the lawsuit, but the agency said it is preparing new water permits for the platforms. An EPA official said the agency is awaiting approval from the California Coastal Commission, which it expects in April or May.

"We are anxious to issue these permits," said Alexis Strauss, director of the EPA's water commission.

—THE ASSOCIATED PRESS

finance&economy

CANADA

Suncor response to Australia: Thanks, but no thanks

Alberta oil sands pioneer Suncor Energy has shown no interest in rescuing an Australian shale oil project that uses Canadian technology.

Southern Pacific Petroleum, which owns a 2.6 billion barrel reserve in the state of Queensland, went into receivership in December, just three months after forecasting a turnaround in its fortunes in 2004.

Southern Pacific said it was counting on positive cash-flow after spending A$400 million over 40 years trying to squeeze a profit out of the world's only large-scale shale project.

Calgary-based Suncor, enticed by the prospect of using its oil sands know-how and its worldwide rights in the extraction technology developed by an Alberta engineer to achieve production of 150,000 barrels per day, took a 50 percent operator role in Southern Pacific.

A 4,500 bpd demonstration plant was launched in 1999, in the face of strong environmental opposition.

In 2001, Suncor made a surprise exit, retaining only a 5 percent royalty interest, after recording a C$3 million write-off and an C$80 million write-down.

Last August, a Southern Pacific spokesman held out hope of producing 600,000 barrels in 2003 and a "breakeven" 1 million barrels in 2004.

But the company entered receivership after its largest shareholder, Texas-based Sandefer Capital Partners refused to make the second payment in a promised A$51 million investment.

Suncor, the last hope of a lifeline, said it will not exercise its options to buy shares in Southern Pacific, preferring to keep its focus on the Alberta oil sands.

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

NEW ORLEANS, LA.

McMoRan reports loss; spent $4.3 million on start-up for LNG hub offshore Louisiana

Petroleum developer McMoRan Exploration Co., while saying it was encouraged by its deep gas prospects in the Gulf of Mexico, posted a $20.5 million loss during the fourth quarter of 2003.

The New Orleans-based company reported that it spent $4.3 million on start-up costs for its proposed Main Pass Energy Hub in offshore Louisiana. It would be one of the first U.S. offshore liquefied natural gas terminals.

The loss translated into $1.22 per share on revenue of $4.8 million. Analysts surveyed by Thomson First Call had forecast a loss of 76 cents per share.

During the fourth quarter of 2002, McMoRan earned $5.8

see **MCMORAN** *page 8*

● WORLDWIDE

Oil prices likely to remain at current levels through '04

World economic growth to drive continued oil demand, economy thriving on $30 oil, says oil and gas consultant Roger Herrera

By STEVE SUTHERLIN
Petroleum News Associate Editor

Oil prices are likely to maintain current higher levels over the coming year, according to Petroleum News' favorite oil price guru, Roger Herrera, a long-time oil and gas consultant who works with Arctic Power in Washington, D.C.

"The world is used to $30 oil," Herrera said. "Economic growth is thriving at that level."

Growth in world oil demand is the main factor that will keep the air under prices, he said. The coming year looks stable, even placid for a voluble-priced commodity such as oil.

"I would be surprised if oil prices came down significantly," Herrera said. "The evidence of the world economy growing is self-evident."

The global thirst for energy is growing, but one customer, China, stands large above the rest.

"China is so large, it is the deciding consumer," Herrera said.

The growth in oil demand will likely continue.

"Chinese demand — if they don't shoot themselves in the foot or do something silly to hinder growth — will continue," he said. "The rest of the world is chugging along with 1 or 2 percent growth, while China is at 8 or 9 percent."

see **PRICES** *page 8*


FORREST CRANE

"I would be surprised if oil prices came down significantly. … OPEC is not regulating the upside of oil prices because it doesn't have to. OPEC can smile all the way to the bank while it builds its cash reserves." —Roger Herrera

● HOUSTON, TEXAS

Burlington in shopping mode

Independent beats Wall Street expectations on fourth quarter earnings, with acquisitions expects to be at upper range of production

PETROLEUM NEWS

Big Houston independent Burlington Resources, which handily beat Wall Street expectations on 2003 fourth-quarter earnings, said it wants to do more deals this year like its recently announced $71.5 million acquisition of ChevronTexaco properties in South Louisiana.

However, Burlington intends to exercise capital discipline and fully intends to stay within its $1.5 billion capital program this year, which is roughly flat with last year's spending, Steve Shapiro, Burlington's chief financial officer, told analysts in a Jan. 22 conference call.

"We love to do transactions, but we don't depend on them for the short term," he said. "But we would like to do more of these kinds of deals."

The oil and gas properties being acquired from ChevronTexaco are situated near a major Burlington core area in South Louisiana. In fact, Burlington already holds acreage positions in four of the 10 acquired fields and will gain an immediate production of 15 million cubic feet gas equivalent per day along with upside potential.

The ChevronTexaco properties are in an area where Burlington's production is on the rise. Burlington also holds title to 660,000 acres of mineral fee lands and numerous state leases in the

see **BURLINGTON** *page 8*

"We love to do transactions, but we don't depend on them for the short term. But we would like to do more of these kinds of deals."
—Steve Shapiro, Burlington Resources

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PRICES

Nobody knows where the price of oil will go, Herrera said, but there doesn't appear to be anything on the horizon that would greatly upset the trend of worldwide rise in oil demand.

Portent for the future:

This new stability isn't without its limits. Higher demand, along with economic and physical limits on production levels, is likely to have a profound effect on oil markets, perhaps in the near future.

"Peak oil production occurs when supply will not meet demand," Herrera said. "As the world gets closer to peak oil production, cracks and groans will begin to appear in the energy supply system."

Peak oil production will be a world changing, but not a world-shattering, event.

"It will probably take a year or two to recognize that a peak has occurred," Herrera said. "It won't be a disaster, but it's irreversible, and if that's not incentive to do something about it, I don't know what is."

The coming of the point of peak production is hard to pinpoint.

"Careful and calculated attempts have been made to predict the timetable of peak oil production, but no general consensus has been reached," Herrera said. "It's a bit like explaining climate change and what causes it.

"I would suspect we will reach peak oil production in the next decade," he said.

"Demand will at least outstrip supply."

No magic bullet

Herrera questioned the notion that hydrogen, wind, solar or other technologies would supplant petroleum in the foreseeable future.

"Hydrogen won't happen in a timeframe that is going to rescue the situation," he said. "All of the alternatives, especially the more exotic ones like fuel cells and hydrogen, have been studied for 50 years."

There will be a shift to other hydrocarbons such as natural gas, which we have plenty of, and coal — available and practical substitutes, Herrera said.

Conservation will also reduce oil demand, but it won't be a product of the political process.

"There is no political will on either side of the political spectrum to address conservation, the general public won't agree to it," he said. "People's minds will be changed if it is in their own self interest to change.

"Why are auto companies bringing out fuel efficient cars on their own? Perhaps they are leading the market, before the market has spoken."

It takes a catalyst for change, Herrera said, but it's not true that it takes a hurtful situation upheaval, or shortage to make people change.

"Sometimes change happens because thinking people lead the way," he said, adding that the success of hybrid cars in the marketplace is an example of that sort of rational thinking.

OPEC not in control

The Organization of Petroleum Exporting Countries won't be the deciding factor in determining oil prices because the organization can't manipulate growth, Herrera said.

Although recent prices above $33 dollar per barrel exceed OPEC's recently stated limits of comfort for oil prices, it is unlikely to step in to attempt price reductions.

"OPEC is not regulating the upside of oil prices because it doesn't have to," he said. "OPEC can smile all the way to the bank while it builds its cash reserves."

Herrera said he doesn't expect OPEC to be successful at regulating oil prices because it is not solid and can't agree among members. Saudi Arabia, because of its changed position in Middle Eastern politics and in the world, he said, is less able to influence the organization. ●

● CANADA

Canadian dollar gains come at price

Dollar's 22% surge in past year is taking bite out of oil patch investment; Burlington shifts some spending back to Lower 48

By GARY PARK
Petroleum News Calgary Correspondent

It has been a treat for those who like to escape Canada's winter clutches and head for California, Arizona or Florida. It has also been a boon to industries that make heavy equipment purchases from the United States.

But there is an emerging downside to the 22 percent rise over the past year in the value of the Canadian dollar against the U.S. currency.

Canada's once-burgeoning trade surplus, because it is so dependent on the two-way flow of goods with the United States, has started to evaporate.

Now the U.S.-based oil and gas companies who scooped up assets in the late 1990s and early 2000s when the Canadian dollar was at a low ebb are rethinking their investment in Canada.

Burlington Resources delivered the harshest blow yet when it announced plans to "ration" its Canadian spending.

"We have actually reduced our Canadian capital budget $50 million to $100 million in 2004 from 2003 on a Canadian dollar basis and in effect shifted this capital to the Lower 48, where we are not facing some of the same margin pressures," Chief Operating Officer Randy Limbacher told a conference call Jan. 22.

He said that with the exchange rate moving against Burlington, the Houston-based independent will be "very prudent" with its capital in Canada.

Burlington spent US$695 million in Canada last year and has actually earmarked US$741 million for 2004, but if current exchange rates prevail that translates into a drop from C$999 million in 2003 to C$953 million in 2004.

Canada's once-burgeoning trade surplus, because it is so dependent on the two-way flow of goods with the United States, has started to evaporate.

Other companies looking at reductions

Now attention is shifting to Anadarko Petroleum, Apache and Devon Energy, the other three largest U.S.-based companies with Canadian operations.

Anadarko Senior Vice President Richard Sharples told a Houston conference in December that the stronger Canadian dollar has affected the relative attractiveness of Canada against the rest of the company's portfolio.

He said "you can't take a 25 percent hit (in currency values) and not feel the impact."

Anadarko spent about C$500 million in Canada in 2003, but is not expected to disclose its 2004 spending plans until February, although a spokeswoman has said the company is in talks with contractors to reduce costs.

Devon Energy has indicated it will likely come close to repeating its 2003 spending of C$1 billion, but president John Richels told the Financial Post that the stronger Canadian dollar "certainly makes a difference."

Calgary-based EnCana is reportedly taking another look at its capital program, with an eye on a more aggressive spending strategy in the United States. ●

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MCMORAN

million, or 27 cents per share, on revenue of $9 million.

For the past three years, the company has focused on deep-gas deposits, which are in shallow waters of the Gulf of Mexico, but require drilling thousands of feet into the seafloor. Interest in those deposits was revived with the rising price of natural gas over the past few years.

For 2003, McMoRan lost $32.7 million, or $1.97 per share, on revenue of $16.1 million, compared with earnings in 2002 of $17 million, or 91 cents per share, on revenue of $43.8 million, in 2002.

—THE ASSOCIATED PRESS

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BURLINGTON

vicinity.

Burlington said that because of acquisitions, developments and international projects, the company expects to reach the upper end of its 3 to 8 percent production growth target in 2004. Company acquisitions last year in the San Juan and Fort Worth basins and elsewhere totaled $228 million and added proved reserves amounting to 228 billion cubic feet of gas equivalent. All acquisitions were in Burlington core areas.

In the fourth quarter of 2003, Burlington said it increased overall daily production by 11 percent to 2.723 billion cubic feet of gas equivalent from 2.464 bcf in the year-ago period. Natural gas output was up nearly 4 percent to 1.9 bcf, while natural gas liquids increased 16.1 percent to 69,200 barrels per day and oil 56.5 percent to 58,500 bpd. The company is about 90 percent weighted to natural gas.

Adjusted for property divestitures, Burlington's production last year increased 10 percent from 2002, which included increases of 8 percent in Canada and 5 percent in the United States in the 2003 fourth quarter. International production increased 13 percent from the prior quarter, an all time high for the company.

Reported reserves at year-end 2003 were 11.8 trillion cubic feet of gas equivalent, up about 3 percent from 11.4 tcf of equivalent for the previous year. The company said it also replaced 142 percent of it worldwide production in 2003.

Burlington posts $404 million profit

Burlington, the first of the major independents to weigh in with 2003 fourth-quarter earnings, also surprised to the upside, posting a profit of $404 million or $2.04 per share compared to $157 million or 78 cents per share for the same period a year earlier. When deducting 88 cents per share due to Canadian taxes, the company earned $1.16 per share in the fourth quarter, surpassing analysts' consensus by 10 cents. Strong commodity prices contributed to earnings, the company said.

Burlington's total debt-to-capitalization ratio last year declined to 41 percent from 51 percent the previous year. The company reported $3.8 billion in debt, as well as $757 million in cash and cash equivalents at year-end 2003, compared to $443 million at the end of 2002.

"Our objectives for 2004 include a continued focus on profitability, while turning our attention to longer-term growth initiatives for 2005 and the years beyond," said Bobby Shackouls, Burlington's chief executive officer. He said the company was able to achieve its financial goals last year through cost controls and increasing volumes from "high-quality asset positions." ●

ALBERTA

Canadian Natural revises oil sands plan, ponders mega-scheme

While edging towards a final decision on its massive C$8 billion Horizon oil sands project, Canadian Natural Resources has trimmed plans to increase output from a second oil sands venture in northeastern Alberta.

The Calgary-based independent has indicated its board of directors will deliver a verdict this summer or fall on the 270,000 barrels per day Horizon plan. Its C$250 million Primrose expansion in the Cold Lake area is likely to be scaled back to 90,000 bpd from an authorized 120,000 bpd.

The changes at Cold Lake will see Canadian Natural reduce its anticipated wells to 360 from about 600.

Delineation drilling will also be completed this winter on a lease east of the Primrose property and if a project is deemed feasible, planning will start this fall.

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

NORTH AMERICA

U.S. loses 40 rigs, Canada gains 13 in weekly count

The number of rotary rigs operating in North America, following a week in which the count rose by 96 rigs, fell by a net 27 rigs to 1,663 during the week ending Jan. 23, according to rig monitor Baker Hughes. However, the rig count was up by 273 compared to the same period last year.

Canada's latest weekly rig count actually increased by 13 to 576 rigs as drillers continued to ramp up for the winter drilling season. The count also was 48 ahead vs. the year-ago period.

Canada's latest weekly rig count actually increased by 13 to 576 rigs as drillers continued to ramp up for the winter drilling season.

The number of operating rigs in the United States fell by 40 to 1,087, with 32 attributed to the land rig market alone, which stood at 971 rigs. Offshore rigs fell by five to 99, while inland water rigs fell by three to 17. However, the total U.S. rig count during the recent week was up 225 compared to the same period a year earlier.

In the United States, 946 rigs were drilling for natural gas and 137 for oil, while four rigs were being used for miscellaneous purposes. Of the total, 724 rigs were drilling vertical wells, 267 directional wells, and 96 horizontal wells.

Among the leading producing states in the United States, Texas' rig count fell by nine to 457, while New Mexico's dropped by nine to 61 rigs. Louisiana's fell by eight to 155 rigs. California's fell by eight to 18 rigs. Baker Hughes said Alaska's rig count was down by two to eight rigs, although an Alaska source said the state lost only one rig. Oklahoma's count was unchanged at 146, as well as Wyoming's at 71.

—**PETROLEUM NEWS**

● GULF OF MEXICO

Newfield, Nexen shares climb on word of discovery

Shell-operated Shark exploration well believed to have broken 25,000 foot barrier on Gulf of Mexico's continental shelf

PETROLEUM NEWS

Exploration and production independents Newfield Exploration and Nexen saw their stock prices jump as word spread of a possible first "ultra-deep" gas discovery in the relatively shallow waters of the Gulf of Mexico's continental shelf.

Nexen is a 40 percent owner of the Shell-operated Shark exploration well at South Timbalier 174, while Newfield's look-a-like Treasure Island prospect is in close proximity to Shark.

Shell would not comment on Shark. However, industry sources said Jan. 21 that the well penetrated the elusive 25,000 foot barrier to become the first well to reach those depths on the continental shelf, where pressures and temperatures are said to be extreme. The well, drilled from Ensco's 75 jack-up rig, reportedly encountered pay on its way to touchdown around 26,000 feet.

The well, drilled from Ensco's 75 jack-up rig, reportedly encountered pay on its way to touchdown around 26,000 feet.

In fact, sources believe the Shark well may have uncovered a significant reserve of up to 2 trillion cubic feet or more of gas and that Shell is preparing to drill a sidetrack off the main well bore to further test the prospect. Moreover, Shell reportedly ordered an exceptionally high pressure wellhead, indicating the possibility of a major gas discovery.

see **DISCOVERY** *page 10*

● ALBERTA

Giant oil sands project clears regulatory hurdle

Final OK needed from feds, Canadian Natural for 232,000 b/d operation

By GARY PARK
Petroleum News Calgary Correspondent

Regulators have given a green light to the largest single oil sands application to come before them — a C$8.5 billion integrated operation by Canadian Natural Resources that could produce 232,000 barrels per day by 2012.

Although the existing Syncrude Canada and Suncor Energy projects have greater output, with plans for further expansion, they reached their current levels with staged additions.

Canadian Natural submitted its entire proposal for an oil sands mine, bitumen extraction plant, upgrader and associated facilities in a bundled package, although it has scheduled a phased-development, starting at 113,400 bpd in 2008.

The two agencies said the Horizon project was "unlikely to result in significant adverse environmental effects provided that the mitigation measures ... are implemented."

The approval, following extensive public hearings last year, was issued Jan. 27 by Alberta's Energy and Utilities Board and the Canadian Environmental Assessment Agency.

see **HURDLE** *page 10*

● ALBERTA

Gas well shut-in carries billion-dollar cost

Energy and Utilities Board staff report recommends shutting in 485 gas wells, less than 938 wells originally targeted

By GARY PARK

Petroleum News Calgary Correspondent

Natural gas producers in northeastern Alberta could lose C$1 billion in cash flow, if the province's Energy and Utilities Board shuts-in 485 wells to protect more valuable oil sands reserves, says Paramount Energy Trust.

The Calgary-based trust, which has led the fight against idling the gas production, believes the gas producers would be entitled to payments or royalty breaks of C$200 million a year in compensation, said President and Chief Operating Officer Susan Riddell Rose.

The producers would seek 100 percent of cash flow, which would still leave them passing up the value of future gas development, she said Jan. 27 in response to an Energy and Utilities Board staff report proposing the shut-in of 485 wells — more than the 337 currently idled but far less than the 938 that were originally targeted by the regulator.

> *"The bitumen resource risk is immense. If associated gas is not immediately shut in, conservation of a high-quality bitumen resource may be moot."* **—Energy and Utilities Board staff report**

Under an interim compensation package, producers have been receiving 60 cents per thousand cubic feet from the Alberta government.

If the staff proposal is adopted, the operators — led by Paramount, Canadian Natural Resources and Devon Energy — will lose production of 136 million cubic feet per day from 300 billion cubic feet, or 0.7 percent of Alberta's total accessible gas reserves.

The arm's-length staff report said there is "compelling evidence" that the gas pools in the 5,700 square mile Wabiskaw-McMurray area are draining reservoir pressures, endangering the future extraction of 25.5 billion barrels of bitumen.

"The bitumen resource risk is immense," the report said. "If associated gas is not immediately shut in, conservation of a high-quality bitumen resource may be moot."

The staff calculated that the energy content of the bitumen deposit is 540 times greater than the affected gas production.

The findings will go before a March 8 interim Energy and Utilities Board hearing, when the drawn-out dispute between gas and bitumen producers will give both sides a chance to challenge the recommendations.

A final hearing may be needed to settle the production status of the disputed wells, although Paramount said Jan. 27 that it will pursue all avenues to obtain "reasonable" compensation of lost gas production.

But the trust has stalled legal action against the province, preferring to "come up with a negotiated solution," Riddell Rose said.

However, Paramount brushed off the Energy and Utilities Board staff report, arguing that the gas pools are at "varying stages of pressure depletion" and not all bitumen in the region is of "uniform quality or commercial viability." ●

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DISCOVERY

Extension of structures in deeper waters

The so-called ultra-deep zone is said to be an extension of giant structures that have produced large discoveries in deeper waters of the Gulf. Explorers have avoided the shelf's ultra-deep zone primarily because of expense and other risks. Analysts had speculated it could cost up to $60 million and take at least six months to reach those depths at Shark. However, Shell is said to have reached its goal with relative ease, requiring only three months of drilling at a cost of less than $30 million.

Sources said there also may be a geologic connection between Shark and Newfield's nearby Treasure Island acreage. Since partner BP decided against drilling an ultra-deep well there last year, Newfield has been shopping around for a new partner while continuing negotiations with BP, Newfield's first choice to drill the well.

> *Sources said there also may be a geologic connection between Shark and Newfield's nearby Treasure Island acreage.*

"We're talking to several companies," a spokesman for Newfield said. "This is a play type that the majors should be interested in."

In addition to BP, ExxonMobil, BHP Billiton and possibly ChevronTexaco, Shark partner Nexen is said to be among companies bidding to drill a first ultra-deep well at Treasure Island. However, Newfield is anxious to drill before Treasure Island leases begin expiring in March 2005.

"Our primary goal is to get a well drilled to test the Treasure Island prospect in 2004," the Newfield spokesman said. "We would have to strike a new deal with BP or with another party to come in and sign a similar deal."

Under its initial agreement with Newfield, BP had to spud a well by the end of 2003 or relinquish its 75 percent interest in the 27 blocks that make up Treasure Island to 25 percent owner Newfield. Although BP obviously missed the deadline, Newfield said it is trying to negotiate a new deal with the major. ●

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HURDLE

Federal cabinet, board approval still needed

However, Steve Laut, Canadian Natural's chief operating officer, cautioned that two hurdles remain — approval from the federal cabinet and the company's board of directors, which expects to make its decision this summer.

If Canadian Natural proceeds, it will join the big league of oil sands producers, comprising Syncrude, Suncor and Shell Canada, and put Canada on the road to combined output of 1.9 million bpd within a decade.

The two agencies said the Horizon project was "unlikely to result in significant adverse environmental effects provided that the mitigation measures ... are implemented."

Last year's hearings faced harsh claims of environmental and health problems if Horizon proceeded.

David Schindler, an environmental scientist from the University of Alberta, said the physical impact on the land and water would be similar to a hydrogen bomb, should development go unchecked for the next 20 years.

The Sierra Club of Canada estimated Horizon would boost Canada's greenhouse gas emissions by 1 percent, and accused Canadian Natural of failing to include climate change into its planning.

Deer Creek Energy, a Calgary-based junior company that owns an oil sands lease directly south of Horizon, told the hearing that Horizon would use substantial volumes of water, with an adverse impact on its planned commercial operation.

David Holgate, an attorney for Canadian Natural, assured the regulators the company would undertake reclamation work to create lakes and wildlife habitat that don't currently exist.

He said there was little hard scientific evidence to support those who worry about the impact on the water threshold of the Athabasca River, the major waterway in the region. ●

natural gas

HEALY, ALASKA

Usibelli puts coalbed on hold

Usibelli Coal Mine, Alaska's only commercially producing coal mine, has put a hold on its budding coalbed methane development program, launched last spring with an application to the state for eight shallow gas leases.

"Right now we aren't developing it further because of regulation changes," company President Joe Usibelli Jr. said Jan. 22. "There's quite a bit of legislation proposed in Juneau … we will have to assess where all that goes and what all will happen."

The company is continuing to conduct geological assessment of the area, Usibelli said, although plans to drill up to five test wells this summer have been "put on hold."

Usibelli Coal applied in May for eight shallow gas leases under the state's non-competitive leasing program. The 46,000 acres are located on and northeast of existing mining claims held by the company. Terms offered by the state's shallow gas leasing program could be altered under new regulations proposed by state legislators: "We don't know what the rule changes are going to be," Usibelli said. "When the rules change in the middle of the game, it can be very frustrating."

—**PATRICIA JONES,** Petroleum News contributing writer

CANADA

Canada's gas exports retreat

Canadian natural gas shipments to the United States dipped for the second year in a row after a run of 15 straight annual increases, the National Energy Board has reported.

For the 2002-03 contract year which ended Oct. 31, exports tallied 3.55 trillion cubic feet, a 4.1 percent drop from the previous year's 3.71 tcf, which declined from the all-time peak of 3.84 tcf in 2000-01.

Even so, the 2002-03 year was still the third best on record and one of only six years to surpass the 3 tcf mark. For the final month of the sales year, shipments were 281.6 billion cubic feet, a sharp drop of 12.5 percent from the 321.9 bcf in October 2002 and continuing an 11.2 percent overall decline for the first nine months of 2003.

The U.S. Energy Information Administration expects Canadian net imports will hover around 3.6 tcf for the rest of this decade, before starting a steady downward path to 2.6 tcf in 2025, far short of earlier predictions of 4.8 tcf. The agency said the drastic revisions stem from projections about Canada's natural gas production, notably coalbed methane and conventional supplies in Alberta, that have been developed by the National Energy Board and other sources.

Meanwhile, U.S. demand is forecast to grow at an average annual rate of 1.4 percent to 31.3 tcf in 2025 from 22.6 tcf in 2002.

For the 2002-03 contract year, Canadian producers raked in C$25.76 billion in revenues, up 54.2 percent from the previous year, despite an 21 percent increase in the value of the Canadian dollar against its U.S. counterpart. The federal regulator estimated the average export prices at C$6.71 per gigajoule, a gain of 61.3 percent from 2001-02, although the October export price eased to C$5.45.

Measured in U.S. currency, export prices averaged $4.98 per million British thermal units, up 75.4 percent from 2001-02.

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

● ALASKA

Natural gas pipeline plans not the same

MidAmerican, North Slope producers propose different projects

By LARRY PERSILY

Petroleum News Government Affairs Editor

The two applications for a fiscal contract with the state of Alaska to build and operate a natural gas pipeline propose the same result — moving North Slope gas to mid-America markets — but the proposals are very different in several key aspects.

MidAmerican Energy Holdings Co., a Lower 48 pipeline operator, wants to build the Alaska gas line but is not looking to get into the business of buying and selling the gas and taking the price risk. That would be up to North Slope producers or other shippers on the line who would pay the tariff regardless of the market price for their gas.

"Of necessity, commercialization of the project will require concurrent contractual arrangements by shippers," the company said in its application.

The producers propose building the line themselves, shipping their own gas and that of any other companies that take capacity during the open season. However, the producers said they still need to overcome the financial fear of the commodity price risk on the $20 billion construction project that could carry more than $5 billion worth of natural gas a year. Without an answer to that problem and other financial and permitting issues, the companies said it's too soon to talk about breaking ground.

They would have much the same risk whether they build and own the line or guarantee payments to ship their gas on a line owned by MidAmerican.

Construction costs still a concern

"We still have to make an economic project work," said Kevin Meyers, president of ConocoPhillips Alaska Inc. The goal isn't to build a pipeline at any cost, but to build a low-cost line, he said.

In addition to the always present fear of construction cost overruns when working in the Arctic, the producers keep looking at natural gas market demand and price projections.

"The question is not what gas prices are today," Meyers said. "The question is, what are gas prices going to be in January 2015 or January 2020?"

Despite the initial cheering and optimism of the two competing project applications under Alaska's Stranded Gas Development Act, the state and project developers still face the dilemma of which company (producers or pipeline operator), and/or which government treasury (state or federal), or all of the above

see **PLANS** page 12

State adds more cities to advisory panel for stranded gas contract talks

As the state looks to start negotiations with MidAmerican Energy Holdings Co. and North Slope producers on their separate applications for an Alaska natural gas pipeline fiscal contract, it also will start meeting with municipalities that would be affected by the proposed multibillion-dollar construction project.

The state will listen as representatives of communities along the pipeline route discuss their concerns over how the state might structure a fiscal contract for the project. Under Alaska's Stranded Gas Development Act, the state is to negotiate with each project sponsor for a contract for payments over the life of the pipeline in lieu of all state and municipal taxes.

Although municipalities do not get a seat at the negotiating table or a vote on the contract, the law provides for a municipal advisory group to advise state officials on the contract terms. Among other issues, municipalities are concerned that the state not negotiate a deferral of local property taxes or other revenues to reduce the early cost of the project without finding an alternative funding source for cities and boroughs faced with heavy expenses during the construction boom.

Municipal revenues will be biggest issue

Municipal revenues will be the biggest concern to cities and boroughs along the pipeline

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PLANS

are willing to shoulder or share the risk that at any point in the future gas prices may not cover the pipeline tariff and a reasonable profit for the gas owners.

"We have a long journey ahead of us," Meyers said. "We want realistic expectations. … You don't want people making bad personal economic decisions," based on overly optimistic projections of construction and start-up dates, he said.

Partnership depends on value

Whether the producers and MidAmerican might eventually join up as partners would depend on whether the pipeline company is willing to accept some risk in the undertaking and whether it could add value to the project or reduce costs, Meyers said.

Simply passing on all the risk to the owners at the wellhead is not adding value, he said.

MidAmerican project leader Kirk Morgan said it's too early to speculate on the potential for a future partnership between his company and the producers.

The pipeline company already has two Alaska partners in Cook Inlet Region Inc. and Pacific Star Energy, a consortium of regional Alaska Native corporations led by former ARCO Alaska Inc. President Ken Thompson. Pacific Star and CIRI, the regional Native corporation for Cook Inlet, hold options to share a 19.9 percent stake in MidAmerican's newly formed Alaska Gas Transmission Co.

The Stranded Gas Act allows the state to negotiate a schedule of payments from a pipeline developer in lieu of all state and municipal taxes for the life of the project. In an effort to help move along the project, the state could include a price factor in the contract to help lessen the risk to the gas owners and/or pipeline developer at low prices.

But it's too early to speculate on what may end up in the contract, said state officials and representatives of the producers and MidAmerican. Neither application provides any details, or even hints, of what the companies might seek in their negotiations with the state.

Applicants will not negotiate exact same items

A difference between the two applications is how much would be up for negotiation with the state.

MidAmerican, without any gas of its own, mostly would be limited to negotiating a contract to replace state corporate taxes on its profits, state and municipal property taxes and municipal sales taxes on its purchases. The producers, as owners of the gas, could negotiate those same taxes along with a fiscal contract in lieu of production taxes and also terms for the state's option to take its royalty gas in-kind or in-value.

The state accepted the producers' application Jan. 23. It received MidAmerican's application Jan. 22 and formally accepted it Jan. 28, after determining the proposal met the standards required under the law. Gov. Frank Murkowski called the company and its partners "highly qualified to construct the project they have proposed."

MidAmerican Energy, of Des Moines, Iowa, is proposing to build and operate a 745-mile pipeline to the Alaska-Canada border, where it expects TransCanada or another pipeline company would build an extension of Canada's network to carry the gas through the Yukon Territory, British Columbia and Alberta on its way to U.S. markets.

Although the company's project would stop at the border, "the application as written contemplates taking the gas to market," which is good enough to meet the terms of the Stranded Gas Act, said Steve Porter, deputy commissioner at the Alaska Department of Revenue.

MidAmerican sees faster start-up

MidAmerican, controlled by Warren Buffet's Berkshire Hathaway Inc., says it can start moving gas by December 2010.

To meet that hurried schedule, the company needs to quickly hold an open season to collect firm commitments from producers or others to ship gas on the line. Its application to the state shows the open season before the end of June, but Morgan said it wouldn't do any good to take bids without a solid tariff rate and operation schedule and MidAmerican has pushed back the open season to the end of the year. The delay will not slow down plans to open the line in December 2010, he said.

ConocoPhillips, BP Exploration (Alaska) and ExxonMobil said it will take nine years for design, permitting and construction after the state and federal governments settle on financial issues affecting the project vs. MidAmerican's six-year estimate. The producers' application shows the open season in the second year after settling on a government framework for the project.

The producers' line would run 1,800 miles, carrying 4 billion cubic feet of gas per day to the North American distribution grid in central Alberta. MidAmerican proposes to move 4.5 bcf per day.

MidAmerican doesn't propose building conditioning plant

The producers would build a $2.6 billion plant on the North Slope to condition the gas for shipment down the line. MidAmerican, in its application, said it anticipates the producers would take on that assignment even if MidAmerican built the pipeline. However, the company said it "is willing to construct and own such a facility if required."

The steel pipe would be different, too. The producers propose using 52-inch pipe vs. MidAmerican's plan for 48-inch pipe. Both lines would be pressurized at about 2,500 pounds per square inch, using gas-turbine compressor stations along the route.

Though MidAmerican's $6.3 billion project budget is one-third of the producers' estimate, comparisons are invalid because it does not include the North Slope conditioning plant and 1,100 miles of pipe in Canada.

The state negotiating team will start in early February, meeting with the two applicants separately, Porter said, working toward completing the contracts and bringing them to the Legislature in enough time for consideration and a vote before scheduled adjournment May 12. Before legislative approval, the law requires a 30-day public comment period on the contract, putting negotiations in a tight time squeeze.

State negotiators will include staff from the departments of Revenue, Natural Resources and Law, with team members changing as needed for different issues, Porter said. The state has contracted with international oil and gas tax consultant Pedro van Meurs to lead its negotiating effort. Van Meurs has advised the state on fiscal issues since the mid-1990s.

State expects to bring in experts

The Stranded Gas Act also allows the lead agency, the Department of Revenue, to charge each applicant up to $1.5 million to cover the state's cost of hiring consultants for the negotiations. In addition to van Meurs, the state may contract for help on tariffs, a benefits analysis of the project and its effects on municipalities, Porter said. "We could have a lot of technical experts we'd want to bring to the table."

In addition to whatever is set on the state's table to help encourage either applicant to build the pipeline, the producers and MidAmerican agree they also need the provisions in the federal energy bill currently stuck in the Senate to help make the project a reality. Those include coordinated and expedited permit reviews, tax savings from accelerated depreciation of the pipeline, tax credits for the North Slope gas treatment plant, and a federal loan guarantee of up to 80 percent of the project debt.

Applicants agree on need for federal legislation

"We think it's very critical," said MidAmerican's Morgan, who also serves as a vice president for the company's Kern River Gas Transmission Co., of Salt Lake City, which operates a pipeline from the Rocky Mountain states to California. MidAmerican's lobbyists will add the Alaska gas line provisions to their work list for the energy bill, Morgan said.

If the energy bill fails to pass, Meyers said, supporters will look for other bills to amend to carry the gas line provisions.

The producers also are looking for technological, cost-saving advancements in pipe welding and high-strength steel, said Dave MacDowell, BP's gas project spokesman. Lower construction costs would mean lower tariffs and less worry about future commodity prices, he explained. ●

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route, said Mayor Jim Whitaker of the Fairbanks North Star Borough. The advisory group also includes the North Slope Borough and the cities of Fairbanks, Delta Junction and North Pole.

The state also plans to expand the group to include municipalities not directly on the pipeline route but likely to see effects from construction or operation of the gas line, said Steve Porter, deputy commissioner at the Department of Revenue and liaison to the advisory group. Those will include Anchorage, Seward, Valdez, the Kenai Peninsula Borough, Haines and Skagway, all of which could serve as ports of entry for supplies and equipment or construction sites for components for the project, Porter said.

The original group met at the end of October in Fairbanks, though Porter said it was not an official start of work. He expects the full group will hold its first meeting in early February.

In addition to revenue issues, the municipalities don't want to see all of the gas shipped out of state without any consideration for in-state uses, Whitaker said.

Although the Stranded Gas Act includes in-state access among the negotiating points, the Fairbanks borough mayor said municipalities have other options for ensuring gas comes to their doorsteps for residential and consumer needs and to promote economic development.

Local access to gas on the list

The municipally organized Alaska Gasline Port Authority and the state-organized Alaska Natural Gas Development Authority are both looking at promoting in-state distribution and hoping to piggyback their plans on a gas pipeline running from the North Slope toward mid-America.

"All of those now come into play," Whitaker said.

Either the municipally owned or state-owned authority could build a line to connect with the main pipe at Delta Junction, regardless whether it's MidAmerican or the producers that build and operate the main line, he said.

The state negotiating team will begin talks with MidAmerican and the producers in early February, Porter said. The administration is required to submit any contract to the Legislature for approval.

—LARRY PERSILY, Petroleum News government affairs editor

● JUNEAU, ALASKA

Bill expands Alaska gas authority's options

If passed, authority could extend work assignment to a gas pipeline, evaluate private-sector involvement in a state-owned gas project

By LARRY PERSILY

Petroleum News Government Affairs Editor

The Alaska Senate Resources Committee is considering a bill to expand the project options for a state-owned natural gas pipeline, while also directing the Alaska gas authority to look at taking in private-sector partners for actual construction and operation of any state-owned line.

Resources Chairman Sen. Scott Ogan said his bill would give the Alaska Natural Gas Development Authority the option of building a pipeline and liquefaction plant to move North Slope gas to market via LNG tankers or owning a pipeline to take the gas directly to mid-America. Existing law limits the state authority to building only an LNG project.

The Palmer Republican said it's a good time to expand the authority's work assignment, to determine if it could help the North Slope producers or pipeline operator MidAmerican Energy Holdings Co. in their separate efforts to build a pipeline from Alaska's gas fields through Canada and into Lower 48 markets.

In addition to needing more money to analyze two potential routes to market — pipe or LNG tankers — the gas authority would need more time, too, said Harold Heinze, chief executive officer for the gas authority.

Bill would give authority more time

Ogan's legislation would extend the deadline for the authority to present a development plan to lawmakers from June 2004 to January 2005.

Senate Bill 271 also would direct the state gas authority, which was created by a citizens' initiative on the November 2002 ballot, to evaluate the merits of private-sector involvement in the planning, construction and operation of a state-owned gas project. The committee heard the bill Jan. 26 and held it for further review.

"Philosophically, I feel better about the private sector taking more of a risk role in this project." —Sen. Scott Ogan

Ogan said he believes state ownership could bring tax savings to a gas pipeline that could make it more attractive for the producers and MidAmerican Energy, while private-sector construction and operation would relieve the state of substantial financial risks.

The existing law calls for full state ownership, construction and operation of any project put together by the gas development authority.

"Philosophically, I feel better about the private sector taking more of a risk role in this project," Ogan said at the Jan. 26 committee hearing.

North Slope producers and MidAmerican Energy have filed separate applications under Alaska's Stranded Gas Development Act to negotiate fiscal terms for a gas pipeline along the Alaska Highway to feed into Lower 48 markets. The applications are not for right-of-way permits or construction plans, but merely to start negotiations for a contract of regular payments over the life of the project in lieu of state and municipal taxes.

Measure does not favor either project

Ogan's amendment to the state gas authority does not favor either the highway route or the authority's original plan to build a line to Valdez and an LNG shipping terminal at the port. In fact, he said it's possible that a highway-route pipeline to mid-America could increase the odds for an LNG project at Valdez by bringing the gas that much closer.

"I think this makes LNG to tidewater a more viable project if the LNG line could piggyback," starting from the highway line near Delta Junction instead of building its own pipeline all the way to Prudhoe Bay.

Heinze did not provide committee members with an estimate for how much more it might cost the authority to expand its work to cover two potential gas projects. The authority already is asking for $2.15 million for the last five months of this fiscal year to complete its analysis of an LNG project, which Heinze called the "people's pipeline."

In answer to committee questioning, Heinze explained the state gas authority is getting a lot of help in its planning work from Yukon Pacific Corp., which tried unsuccessfully for 20 years to build an LNG project at Valdez before closing down its effort more than two years ago.

State could buy Yukon Pacific permits

"There's no doubt that Yukon Pacific's cooperation with us has a motive at the end of the day," Heinze said. It may be cheaper for the state authority to buy some of Yukon Pacific's permits and work instead of starting over on its own, he said.

The authority plans to use some of the $2.15 million it is requesting from lawmakers to pay for a consultant to advise which of Yukon Pacific's assets might be worth buying, Heinze said. ●

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THROTTLE

"The big challenge is whose credit will stand behind the project," given the capital and wellhead price risks, he said.

Asked if Alaska gas could compete with offshore liquefied natural gas in the Chicago market, Kvisle said the economics look similar, with infrastructure costs estimated at about US$2.15 per thousand cubic feet in either case.

But he noted that it is the magnitude of the commitment to the Alaska project, along with the volatility and risk, that "causes some people to favor LNG."

TransCanada moved decisively into the Alaska picture last spring when it acquired control of Foothills Pipe Lines, paying Duke Energy C$257 million in cash and debt for its 50 percent interest.

Foothills already operates the so-called pre-build portion of the Alaska Highway pipeline, with more than 600 miles of pipelines across Alberta, British Columbia and Saskatchewan that carry 3.3 billion cubic feet per day of Canadian gas to U.S. markets.

Subsidiaries of Foothills and TransCanada hold certificates dating from the 1970s to build the Alaska portion.

Kvisle said TransCanada made an effort five years ago to "get things going" on the Alaska project and tried to reconstitute a partnership with various other pipelines, but that was scuttled when the "major meltdown in the U.S. pipeline sector occurred."

With the Mackenzie project showing every sign of proceeding first, TransCanada scrambled on board last June, by agreeing to pay C$80 million to fund one-third of the Aboriginal Pipeline Group's share of the project definition phase and position itself for a 5 percent ownership stake in the pipeline.

TransCanada also agreed to extend its sprawling Alberta gas-gathering network about 45 miles north to connect with the proposed Mackenzie pipeline.

For TransCanada, securing access to either Mackenzie or North Slope gas is vital as it faces the prospect of shrinking gas production in Western Canada and growing capacity on its mainline system to Eastern Canada and the U.S. Midwest.

'Spare capacity' essential to Mackenzie economics

And having access to that "spare capacity" is an essential component of the Mackenzie project economics.

Thus the Mackenzie proponents "feel the need to stay abreast of the Alaska pipeline developments," because Alaska gas "could pose a threat to the commercial viability of our project," Imperial Oil's Searle said.

In addition to pipeline access, he said that if both projects proceed there will be pressure on supplies and materials, the availability of experienced contractors and the impact on gas markets.

"We're working hard to do all we can to improve the economics of our project," he said, while conceding that "we probably need some luck along the way."

Meanwhile, Yukon Premier Dennis Fentie, reacting to the MidAmerican Energy Holdings application, said there is "reason to be very optimistic" that a pipeline will cross the Yukon.

But he cautioned that "there's a lot of work ahead of us," with the application being just one step.

He told the Whitehorse Star Daily that the agenda includes obtaining assurances from the Canadian government that the Yukon will have an aboriginal pipeline group similar to that involved in the Mackenzie pipeline.

Fentie said the Yukon government is encouraging TransCanada to work closely with the Alaska Highway Aboriginal Pipeline Group, which was formed last fall by Yukon and British Columbia first nations.

He wants all parties to deal with "any regulatory hurdles early on, to do the social-economic impact work ... and, above all, ensure that we can maximize the benefits for Yukoners." ●

● CALIFORNIA

Alaska's other gasline group may have buyer for LNG

Alaska Gasline Port Authority, California company Crystal Energy will start negotiating letter of intent in February

By LARRY PERSILY
Petroleum News Government Affairs Editor

The Alaska Gasline Port Authority, a consortium of municipalities working since 1999 to put together a project to ship and sell liquefied North Slope natural gas, will soon start negotiations to possibly supply LNG for a proposed offshore California receiving terminal.

The port authority Jan. 28 announced it had signed a memorandum of understanding with Crystal Energy LLC, calling for the authority and company to start negotiating a letter of intent for an LNG supply contract.

> *The memorandum of agreement says the port authority, which has no assets and was formed solely to build the LNG project, will negotiate to supply Crystal Energy with up to 800 million cubic feet of gas per day for 20 years.*

The port authority, comprised of the North Slope Borough, Fairbanks North Star Borough and city of Valdez, wants to sell bonds to build a gas pipeline to Valdez, a liquefaction plant and shipping terminal to sell LNG anywhere it can find buyers around the Pacific Rim.

In addition to finding financing and buyers for the gas, it also needs to strike a deal for North Slope producers to sell gas to the port authority.

The memorandum of agreement says the port authority, which has no assets and was formed solely to build the LNG project, will negotiate to supply Crystal Energy with up to 800 million cubic feet of gas per day for 20 years.

Project would use 1979 production platform

Crystal Energy, of Ventura, Calif., is working to develop an LNG receiving terminal 11 miles offshore of Oxnard, in the Santa Barbara Channel, about midway between the coast and Santa Cruz Island, 50 miles up the coast from Los Angeles.

The offshore platform is among seven projects proposed by seven different developers for supplying LNG to the U.S. West Coast, either from new receiving terminals in Southern California or just past the border on Mexico's Baja Peninsula. None have started construction, though several are into the permitting process.

Crystal Energy has not submitted any permit applications to the U.S. Coast Guard, state land-use agencies or the Federal Energy Regulatory Commission for construction or operation, but expects to start turning in its paperwork early in February, said Lisa Palmer, company spokeswoman.

The company plans to convert a former production platform into an LNG receiving terminal, with total cost for the tanker dock, platform conversion, regasification facilities and pipelines to shore and connecting to Southern California Gas Co.'s existing pipeline grid estimated at $300 million, Palmer said.

Crystal Energy last year signed a lease with Venoco of Carpinteria, Calif., to use the company's Platform Grace for the LNG project. The platform, built by Chevron in 1979 for its offshore California production, was idled in 1997 except for serving as an oil and gas transportation hub for production from nearby Platform Gale.

Chevron sold the platform to Venoco in 1999.

Start-up date projected for 2007

Crystal Energy hopes to obtain the necessary permits in 2005 and start operations in 2007, Palmer said. Because the port authority could not deliver LNG that quickly, she said, Crystal Energy is considering Alaska as a possible long-term supplier while also looking for a short-term supply to fill the gap.

The company also is talking with other potential, long-term suppliers, she said.

And just as Crystal Energy is looking at potential LNG suppliers other than Alaska, the port authority is searching for other buyers, said Bill Walker, city attorney for Valdez and spokesman for the port authority.

The proposed Valdez project needs to sell 2 billion cubic feet of gas per day to meet the economic feasibility test for financing, Walker said, and will continue looking for other possible buyers to fill out its capacity.

One problem facing the port authority is the lack of LNG tankers to carry the gas to a California terminal. Federal law — the Jones Act — requires the use of U.S.-built, U.S.-flagged and U.S.-crewed vessels for interstate shipments. No U.S. shipyards have built an LNG tanker in 25 years, and all of the old vessels have been reflagged as foreign vessels.

The domestic shipbuilding industry has said it could take up to five years before it could deliver a new LNG tanker. Cost also is an issue, with domestic tanker construction estimated at twice the cost of foreign shipyards.

Walker said the port authority has some ideas on how to deal with the Jones Act, but he declined to discuss any of the possibilities. "That's not a killer," he said of the tanker issue.

Negotiations to start in February

The port authority and Crystal Energy will start negotiations on the letter of intent in February, with a deadline to finish the talks by the end of the year, Walker said.

And although the port authority has worked since its beginning toward the possibility of building its own line from the North Slope to Valdez, Walker said it makes sense to talk with the North Slope producers and pipeline operator MidAmerican Energy Holdings Co., both of which have proposed a gas line from the slope and through Canada to mid-America markets. The port authority could save a lot of time and money by simply building a line branching off from the main pipe instead of coming from the slope with its own line, Walker said.

Time, however, could be an issue, as MidAmerican, with the fastest schedule of the two proposals, doesn't expect to start moving gas before December 2010, three years after Crystal Energy wants to start operating its LNG terminal.

Crystal Energy does not operate any gas receiving or distribution facilities or pipelines, Palmer said. It was formed after the California energy crisis of 2000-2001 specifically to build an LNG project, she said. "We set out to design a project that has the fewest environmental impacts possible."

The gas line from the offshore platform would follow an existing marine pipeline corridor and land near a power generating station. Using an existing platform and feeding into a nearby gas distribution network will help reduce project costs, Palmer said.

Former energy trader leads effort

Crystal Energy is wholly owned by Small Ventures USA LLC, a Houston-based privately held firm headed by William Perkins III, who founded Small Ventures in 1997 after working as a director and managing partner at energy trading companies, according to his biography at a June 2003 LNG conference in Houston.

Perkins set up Small Ventures to provide "venture capital access and consulting services," according to the biography.

Crystal Energy's competitors for the Southern California LNG market include projects proposed by Shell, Marathon, Sempra Energy, ChevronTexaco, Mitsubishi and BHP Billiton, an Australian resource development company. The Mitsubishi project is targeted for the Port of Long Beach, next door to Los Angeles. The BHP receiving terminal also would be offshore of Oxnard, Calif., with a projected 2008 in-service date. ●

● ALASKA

Alaska opens oil pipeline tariff talks

Pipeline owners BP, Phillips, ExxonMobil, Williams and Unocal ready to renegotiate 1985 settlement with state

By LARRY PERSILY

Petroleum News Government Affairs Editor

The state of Alaska and the five companies that own the trans-Alaska oil pipeline have agreed to start talks this month to negotiate revisions to the line's almost 20-year-old tariff structure.

Any reduction in pipeline tariffs could be a plus to the state treasury, with lower transportation costs resulting in higher wellhead values and larger production tax and royalty payments to the state based on those higher values.

Advocates of lower tariffs also say it could encourage additional oil development by lowering the cost for new entrants on the North Slope.

Alaska Attorney General Greg Renkes and the pipeline owners signed the memorandum of understanding Jan. 22-23, calling for negotiations to start sometime in February and acknowledging the talks could take as long as two years.

The memorandum says negotiations will cover the tariff structure for interstate and intrastate shipment of North Slope oil.

"Tariffs have been a controversial and litigated topic throughout the (pipeline's) life," the memorandum says, explaining that a negotiated settlement is preferable to fighting the issue before regulatory agencies and eventually in court.

Negotiated settlement subject to FERC approval

The state and pipeline owners will not negotiate an actual tariff but rather a method for calculating the tariff, which would then be subject to approval by the Federal Energy Regulatory Commission, which regulates interstate oil pipeline tariffs, and the Regulatory Commission of Alaska for in-state deliveries of oil.

The existing tariff structure, or methodology as it is called, includes a provision for the pipeline owners to receive a return on their original investment in the 800 mile line, which opened in 1977. Opponents of the per-barrel methodology argue the tariff structure allows the owners to recover too much money on their investment and say the tariff should be calculated on a more traditional depreciated rate base.

The Alaska pipeline tariffs are calculated under a methodology accepted by the state and owners in 1985 and later approved by FERC. That agreement, called the TAPS Settlement Methodology, expires in 2011, with a provision calling for negotiations on a revised tariff structure to start no earlier than Jan. 1, 2007. The Jan. 22-23 memorandum between the state and owners moves up that date by almost three years.

Alternative to lengthy legal battle

"Unless successor agreements are executed, the parties anticipate litigation before the Federal Energy Regulatory Commission, the Regulatory Commission of Alaska and ultimately the courts will occur that will be lengthy, costly and recurring, which is not in the parties' or the public's best interest," the memorandum said.

Alaska Attorney General Greg Renkes

While FERC regulates interstate tariffs, the state regulatory commission governs tariffs for the in-state shipment of oil.

"I believe that starting earlier will benefit all the interested parties, particularly explorers, if we can be successful in establishing lower and more predictable tariffs for the future," Renkes said in a prepared statement announcing the agreement.

In addition to holding direct talks with the pipeline owners, Renkes said the state will be meeting with legislators, municipalities along the pipeline route, shippers and explorers "to solicit their concerns and ideas" for the state's position in the tariff talks.

Pipeline owners are BP Pipeline (Alaska) Inc., 46.93 percent; Phillips Transportation Alaska Inc., 28.3 percent; ExxonMobil Pipeline Co., 20.34 percent; Williams Alaska Pipeline Co., 3.08 percent; and Unocal Pipeline Co., 1.35 percent.

Williams still at negotiating table

Although Williams in November announced a deal to sell its stake to Koch Alaska Pipeline Co., a subsidiary of Koch Pipeline Co., of Wichita, Kan., the sale has not been completed and Williams is still a part owner of the oil line and will be at the negotiating table until Koch takes over. The sale is scheduled to close this spring.

Another subsidiary of Koch Industries Inc., Flint Hills Resources, is buying Williams' refinery at North Pole, which processes North Slope crude taken from the pipeline.

The state's negotiating team will include officials from the attorney general's office and the departments of Revenue and Natural Resources. The statement from Renkes' office did not say who will serve on the state's team, and the attorney general was out of state and unavailable for comment, according to Theresa Woelk, his press aide.

Negotiations under two-year deadline

Provisions in the memorandum include:

- If the parties cannot reach a settlement, the agreement to begin early talks will expire in February 2006.
- The pipeline owners will set up a TAPS Renegotiation Committee to present joint proposals and counterproposals in negotiations with the state.
- Nothing in the agreement prevents any of the pipeline owners from having separate talks with the state at any time for its own interests, as long as the owner notifies the other companies of the private talks. The other companies would then have the option of suspending or continuing the committee's joint negotiating effort.
- All press releases related to the negotiations will be issued jointly by the state and companies.
- All communications between the parties will be held confidential.
- The state and each of the companies will pay their own costs in the proceedings.

Regulatory decision prompted push for early talks

The state's push for an early start on renegotiating the tariff structure was prompted by a November 2002 ruling from the Regulatory Commission of Alaska that said the pipeline owners' charges for shipment of North Slope oil to in-state refineries from 1997 to 2000 were unreasonable.

The RCA rejected the FERC-approved tariff methodology as it related to depreciation of the line and the owners' return on their investment.

The RCA ruling said the pipeline charged $1.50 per barrel too much and ordered refunds and a new rate structure. The pipeline owners are appealing the order in state court.

Williams and Tesoro Alaska Co. started the case when they filed a complaint with the RCA in 1997, alleging they were charged too much to move oil to their Alaska refineries.

Pipeline owners collect about $1 billion a year in tariffs on North Slope oil, more than 90 percent of which is shipped aboard tankers to West Coast refineries. The rest is processed instate. The average tariff for interstate shipments in the past fiscal year was about $3.25 per barrel. ●

Want to know more?

If you'd like to read more about the trans-Alaska oil pipeline tariff, go to Petroleum News' web site and search for these articles, which were published in the last couple of years.

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- **Feb. 23** Governor looking at well workover tax credits and other production incentives
- **Feb. 16** Murkowski, Renkes say state will join pipeline owners in court appeal of RCA tariff ruling
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- **Dec. 8** RCA: Intrastate oil pipeline tariff too high
- **May 19** Conoco returns to Alaska's North Slope

LIVENGOOD, ALASKA

Rock sample analysis shows gold mineralization in creek watershed

The Alaska Division of Geological and Geophysical Surveys has released rock sample analysis showing gold mineralization in the Livengood Creek watershed. The geochemical data is for surface rock samples collected in 2001 and 2003 in the central Livengood Quadrangle some 60 miles north of Fairbanks, Alaska.

Sixty rock samples were analyzed for geochemical trace-element analysis and 50 samples were analyzed for whole-rock analysis. One highly anomalous sample from a known lode prospect in the area yielded slightly more than one ounce of gold per ton of rock.

The mineralized zone drains into the Livengood Creek watershed, along which 10 inactive and two active placer mines are located.

Since 1914, more than 500,000 ounces of placer gold have been mined from the Livengood subdistrict.

Part of the Tolovana mining district, the sample collection area covers approximately 130 square miles, including the Money Knob area, which contains eight known lode gold prospects.

The Jan. 20 data release is part of the Alaska Airborne Geophysical/Geological Mineral Inventory Program, which provides both airborne and ground-based geological mapping.

—**PATRICIA JONES,** Petroleum News contributing writer

ALASKA

EPA wins dispute with state of Alaska over Red Dog emission permits

The U.S. Supreme Court ruled Jan. 21 in a 5-4 decision against the Alaska Department of Environmental Conservation in a dispute with the Environmental Protection Agency over emission permits sought by the Red Dog zinc and lead mine in northwest Alaska.

The dispute started four years ago when mine operator Teck Cominco Alaska applied to the state for a new diesel power generator permit.

The dispute started four years ago when mine operator Teck Cominco Alaska applied to the state for a new diesel power generator permit.

After prolonged negotiations regarding the appropriate technology required by the Clean Air Act, EPA and the department reached impasse. Although EPA ordered the state not to issue the permit, it did, contending that EPA had exceeded its authority.

During the initial legal arguments, estimated costs to retrofit emissions equipment for the diesel engines under the state's plan were $370,738 for each generator, assistant attorney general Cameron Leonard told Petroleum News Jan. 28.

EPA's requirements for emissions control equipment was estimated at $2.9 million for each engine, he said. While the agencies argued the case, Red Dog operators opted to install equipment that complied with EPA, which reduces pollution by 90 percent, rather than the 30 percent under the plan state regulators proposed.

—**PATRICIA JONES,** Petroleum News contributing writer

● FAIRBANKS, ALASKA

Partners release encouraging results from Gil gold project

Second phase of drilling released for Fort Knox Alaska area gold resource; mineralization seems to be holding up

By PATRICIA JONES
Petroleum News Contributing Writer

Partners in the Gil gold project northeast of Fairbanks, Alaska, some six miles east of the operating Fort Knox gold mine, have released "encouraging" results from the 2003 second phase program in early 2004.

In two press releases, one on Jan. 8 and another on Jan. 20, junior partner in the project, Teryl Resources, released drill intercepts taken from the property during the fall 2003.

PATRICIA JONES

"The numbers they got out of Gil are pretty good. The thing is holding together. Each time they update the drilling, the project seems a little more assured that Gil will be the next pearl on the string." —Curt Freeman, Teryl's consultant in the Fairbanks area

The drilling was part of an additional or second phase of exploration for the gold project, which, if found to be economically feasible, could provide additional feedstock for the neighboring Fort Knox gold mine.

"The Gil is a relatively small satellite deposit at the moment, but it has upside potential. The drilling results that were released have some good hits and they give us a number of targets for follow up. We've seen some encouraging results at the deposit, but they will require future confirmation," Lorna Shaw, spokeswoman for Fairbanks Gold Mining Inc., told Petroleum News Jan. 21.

Fairbanks Gold Mining, the operator of the neighboring Fort Knox gold mine and mill, is a subsidiary of mining giant and Toronto, Ontario-based Kinross Gold, the major partner and operator of the Gil project.

In production since late 1995, Fort Knox churns through more than 17 million tons of rock to produce more than 400,000 ounces of gold per year. One satellite deposit — True North — has been tapped to provide additional feedstock for Fort Knox.

"The numbers they got out of Gil are pretty good. The thing is holding together," said Curt Freeman, Teryl's consultant in the Fairbanks area. "Each time they update the drilling, the project seems a little more assured that Gil will be the next pearl on the string."

Company updating model

Fairbanks Gold Mining spent $1.3 million on Gil in 2003, Shaw said. Drilling results are currently being used to update the block model to estimate the deposit's reserves.

"The Gil is a relatively small satellite deposit at the moment, but it has upside potential. … We've seen some encouraging results at the deposit, but they will require future confirmation."
—Lorna Shaw, Fairbanks Gold Mining Inc

"It then becomes an economic decision whether to proceed with development. The model isn't finished yet, and our future exploration plans for the project hinge on completion of the modeling exercise and a pre-feasibility study," Shaw said. "As the results from this past summer's exploration are modeled, the exploration plans and budget are being set for the upcoming season."

Teryl's president, John Robertson, said he is waiting for a budget and detailed plans for 2004, and to see how much his company's 20 percent share will cost. Some of that work will include engineering studies that would estimate the cost of putting in a road from the Gil prospect to the Fort Knox mill, he said.

"It's pretty encouraging assays they're getting on the Main Gil," Robertson told Petroleum News Jan. 20. "We're quite enthused about the results. They seem to be better all the time."

Work last year focused on the Main Gil mineralization, Robertson said. Encouraging results from the North Gil zone and the Sourdough zone may warrant additional work in those areas, he said.

Detailed assay information

Drilling totals for the 2003 exploration program included 27,590 feet of reverse circulation samples in 127 holes and 8,917 feet of diamond core drilling in 31 holes, according to the Jan. 8 press release.

Best results came from a 135 foot intersection that assayed 0.087 ounces of gold per ton of rock. Included in that interval was an 85 foot section of 0.121 ounces of gold per ton of rock.

That drill intercept provided some of the deeper mineralization reported in the Jan. 8 release. But some of the assays showed significant mineralization just below the surface.

A 10 foot section, grading 0.155 ounces of gold per ton, was found 25 to 35 feet below surface. Some of the assays showed mineralization at surface, indicating a deposit with little overburden or waste rock to remove.

Most of the past drilling at Gil indicates a relatively shallow level of mineralized rock. Robertson said work in 2003 indicated a zone of mineralization at the Main Gil that is 3,000 feet in length and 70 feet thick. ●

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Business Spotlight

By PAULA EASLEY

FORREST CRANE

Farrah McLaughlin, office manager

CONAM Construction Co.

CONAM Construction Co., a long-time Alaska contractor, specializes in heavy industrial construction – oil and gas processing, power distribution, communication, and distribution and treatment facilities – as well as pipelines and water/sewer mains. Anchorage-based CONAM also provides comprehensive oil field maintenance services.

Farrah McLaughlin joined CONAM in 1999 and has worked on several remote construction contracts in North Slope Borough villages and other Alaska sites. She previously held an administrative assistant position at Nabors Alaska Drilling. Farrah is married to Drew McLaughlin whose free time is spent exploring the countryside on his Harley, camping and fishing. Farrah believes in dreaming "as if you'll live forever and living as if you will die today." Her dream includes retiring at 40 and traveling extensively.

FORREST CRANE

Steven W. Ellsworth, senior scientist, environmental specialist

ENSR International

ENSR has operated in Anchorage, Alaska since 1977, providing environmental and energy development services. The firm has 70 offices worldwide and 45 in the United States. In Alaska the firm's committed workforce focuses on environmental compliance, planning, and permitting; also assessment and integrated closure of contaminated sites for industrial, commercial and military clients.

Steve Ellsworth is a wildlife and fisheries biologist, with extensive experience in the public and private sectors. He has worked with ENSR in the oil patches of Alaska, Louisiana, the Russian Far East, West Africa and South America for 15 years, specializing in permitting and impact assessment of petroleum exploration in frontier areas. He and wife Audrey have three children — Emily, Eli and Keegan.

Deh Cho offer seized mineral claim as gift to new cabinet minister, but it came with a twist

The Deh Cho First Nations have welcomed one of Canada's newly appointed cabinet ministers to the job with a gift.

They've delivered a mineral claim from the Mackenzie Valley to Indian Affairs and Northern Development Minister Andy Mitchell.

But it's more than the usual claim stake. It comes with a twist.

The Deh Cho have wrapped the claim in a proposed memorandum of understanding that outlines their conditions for participating in the C$5 billion Mackenzie gas pipeline project. (See MOU story this page.)

The package Mitchell received on Jan. 23 included one of the stakes from mineral claims filed along the planned pipeline route by Maureen Bernier, the wife of Paul Bernier, who is on paid leave from his job as vice president of the Canadian Environmental Assessment Agency.

Last summer, the Deh Cho discovered that Maureen Bernier held what they described as 12 "fishy" mineral claims that were filed in 1998.

Paul Bernier has been with the environmental agency since 1994 and, in that role, helped broker a deal to streamline approval of the Mackenzie pipeline.

"The role played by Paul Bernier in securing the cooperation agreement further invalidates the (pipeline review process)," the Deh Cho said in their statement Jan. 23.

The Deh Cho said it was "illegal, under the Territorial Lands Act, for a federal employee to have a direct or indirect interest in land in the Northwest Territories."

Investigation of claims under way

The Canadian government has named Vincent O'Donnell, a Montreal attorney and conflict-of-interest specialist, to investigate the matter. His findings are expected early this year.

In the meantime, the Deh Cho asked Mitchell to nullify the Bernier claims.

Instead, Mitchell's department "extended the rights of the claim holders," at which point the Deh Cho "declared a bounty ($100 for every stake removed) on the claim posts, which have become a symbol of the government's disregard for the wishes of the local people."

One of those stakes landed on Mitchell's desk, along with a proposal for involving the Deh Cho in the pipeline review.

Grand Chief Herb Norwegian said in a statement that the Deh Cho were "disappointed in the response" from Mitchell's predecessor, Robert Nault.

"We are hoping that Mr. Mitchell will take another look at our very reasonable requests, to cancel (the Bernier claims) and to meaningfully involve the Deh Cho communities in reviewing the pipeline which is set to cross our land.

"We have sent him these gifts as symbols of our desire to move forward with a new minister, a new government and a new relationship," Norwegian said.

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

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DEH CHO

authorities they have a "legal right to veto the project."

MOU calls for full assessment

Deh Cho Grand Chief Herb Norwegian was adamant that the Deh Cho are "not just criticizing or blocking the pipeline. We are prepared to move forward and review the proposal, as long as the government and other parties cooperate in giving us meaningful involvement in the review."

A proposed memorandum of understanding — sent to Mitchell, Environment Minister David Anderson, the National Energy Board, the Mackenzie Valley Environmental Impact Review Board and the Inuvialuit Game Council — calls for the current review process to be dismantled and replaced by one that includes a full assessment of alternatives to the pipeline and the contribution of the project to "sustainable development on a local and a national scale."

Hart Searle, a spokesman for Imperial Oil, the lead partner in the Mackenzie Delta Producers Group, told Petroleum News the memorandum is a matter to be handled by the Deh Cho and the authorities, although the Mackenzie proponents are "obviously very interested" in the response of governments and regulators.

The Deh Cho want to establish a seven-person panel, with two seats for Deh Cho representatives.

Draft MOU calls for sustainable development

The draft MOU said a new review must compare the "technical and economic feasibility" of the pipeline with possible alternatives.

It must also deal with three objectives of sustainable development:

• Preservation of the ecosystem integrity, including the capability of natural systems to maintain their structure and functions and to support biological diversity.

• Respect for the right of future generations to the sustainable use of renewable resources.

• Attainment of durable and equitable social and economic benefits.

Further bolstering their position, the Deh Cho selected George Erasmus as their new chief negotiator for land claim and self-government talks.

Erasmus, a former national chief of Canada's Assembly of First Nations and a former president of the Dene Nation, took over the post Jan. 26.

He dismissed those who portray the Deh Cho as a "radical" group, arguing the communities must be cautious about any resource development while their land and political rights remain unresolved.

Erasmus said that in some ways the Deh Cho "find themselves in the same position that the Dene did as a whole, some 25 years ago, when the first Mackenzie Valley pipeline and other development was on the horizon."

At that time, Erasmus led the Dene Nation, with Norwegian as his vice president, in stalling the first Mackenzie pipeline plan until land claims agreements were reached.

Norwegian said the new "dream team" of negotiators is designed to "bring some good energy to the table," and reach a resolution on the pipeline issues. ●

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KERR-MCGEE

Hager said no decision had been made to resume drilling at Mississippi Canyon Block 886, where operator Devon encountered numerous drilling delays because of downhole problems and strong ocean currents, known as "loop currents," that disrupted operations at Yorktown for nearly a year. Drilling was suspended in October.

Nevertheless, Kerr-McGee and Devon are completing engineering work on Yorktown, crunching expense numbers and formulating "a go forward plan" for the prospect, Hager said. He gave no indication whether the partners might spud a new well or attempt to re-enter the original well bore. Drilling was halted just shy of the well's 25,000 foot target where deterioration of the hole's lower section was detected.

Although Kerr-McGee and Devon are 50-50 owners in Yorktown, Devon's share of the $86 million in drilling-related expenses amounted to about $60 million. The prospect is located in 2,100 feet of water.

Despite the setback at Yorktown, Kerr-McGee has an aggressive deepwater drilling program planned for 2004, Hager told analysts. He said the company would participate in about 12 exploration wells, four to six of which would be "pure wildcats" or frontier wells. He also said satellite wells would be drilled near producing fields, including Nansen, Boomvang and possibly recent startup Gunnison.

"We feel we are going to put together a quality program this year," Hager said. "But we're still working on geoscience and partner-related issues." He said drilling likely would get under way during the 2004 second quarter.

Company earnings up 50 cents per share

On the earnings front, Kerr-McGee reported net income of $50.5 million or 50 cents per share in the 2003 fourth quarter, compared to a loss of $345 million or $3.43 per share for the same period a year earlier. After extracting special items and other charges from the recent quarter, the company turned a profit of $86.9 million or 86 cents per share, surpassing analysts' consensus by 6 cents.

The company said it was aiming to reduce its year-end 2003 debt of $3.656 billion by another $550 million in 2004. Its year-end 2002 debt was $3.904 billion, about 6 percent higher that the current level, the company said.

Company production for the 2004 first quarter is expected to average daily between 257,000 and 274,000 barrels of oil equivalent, roughly flat compared to the 271,000 barrels Kerr-McGee averaged for full-year 2003. On the oil side, production averaged 139,000 barrels per day compared to 178,000 bpd in the year-ago period. The decrease was attributed to the sale of nearly $1 billion of "high-cost, non-core producing properties." Daily natural gas production averaged 742 million cubic feet compared to 792 million cubic feet a year earlier.

Kerr-McGee said it replaced 135 percent of its 2003 worldwide production and that year-end reserves totaled 1.026 billion barrels of oil equivalent, which included reserves gained from property acquisitions. Hager said "exploration success" accounted for 80 percent of the company's reserve additions, resulting in 105 percent production replacement coming via the drill bit. The Gulf of Mexico alone accounted for 60 percent of Kerr-McGee's reserve replacement.

—**PETROLEUM NEWS**

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INSIDER

Houston independent bought a 70 percent interest from Armstrong and took over operatorship of the 12,000 acre Northwest Milne prospect where the companies are drilling one to three exploration wells this winter.

In a Jan. 28 conference call Dave Hager, Kerr-McGee's senior vice president of exploration and production, said his company viewed the North Slope as a low-cost basin with huge reserve potential. He said Kerr-McGee's first well at Northwest Milne is expected to cost $7-10 million.

"We think that given that type of cost, we get significant reserve exposure on lower risk prospects for a low entry cost," Hager said, adding that more acreage divestitures are likely in Alaska, which will provode his company with more acquisition opportunities. Alaska's government, he said, is interested in getting "more companies like ourselves up there to kick off the next generation of prospecting."

Kerr-McGee, like Pioneer Natural Resources before it, entered the North Slope under the guidance of Armstrong Alaska, an affiliate of Denver–based Armstrong Oil & Gas. According to Armstrong Vice President Stu Gustafson, Armstrong identifies and acquires North Slope prospects and then puts together a comparatively low-cost exploration, development and production program prior to seeking majority partners as operators.

Kerr-McGee participated in a table-top oil spill drill in late January with its oil spill response contractor Alaska Chadux, Minerals Management Service, the Alaska Department of Environmental Conservation and the Coast Guard.

"I understand the drill went very well," Schramm said. "Care for the environment and safety are high priorities for us."

Pioneer hires Mike Dunn, Pat Foley

PIONEER NATURAL RESOURCES said Jan. 28 that it has hired two oil and gas professionals as managers for its Anchorage office. Pat Foley will serve as Pioneer Alaska's manager of land, commercial and regulatory affairs and Mike Dunn as manager of engineering and development. Both will report to Pioneer's resident Anchorage manager, Ken Sheffield, president of Pioneer Alaska.

Pat Foley comes to Pioneer from Foley Commercial Services where he was owner and founder. Foley brings to his new job 23 years of international and domestic professional land experience primarily with ARCO and later with BP, including 15 years in Alaska. Mike Dunn was last employed by New Tech Engineering where he served as vice president of its Anchorage operations. Dunn brings 22 years of industry experience to his new job, including engineering positions with ARCO from 1982 to 2000, one and half years with a drilling contractor and two years as an engineering and economic consultant. Twelve of those years were in Alaska.

"We are very pleased to add two high-caliber Alaskans to our local management team in Anchorage. Pat and Mike bring the experience and expertise to allow Pioneer to advance our growth plan in the state," Sheffield said.

ASRC Energy Services acquires Lynx Enterprises

ASRC ENERGY SERVICES, a subsidiary of Arctic Slope Regional Corp., has acquired Alaska-based environmental consulting firm Lynx Enterprises Inc., ASRC said in a press release in late January.

Lynx specializes in strategic regulatory planning, National Environmental Policy Act planning, documentation, compliance, permitting and right-of-way process management, stakeholder relations, land administration, GIS products and professional labor resources. The firm, which has experience in both onshore and offshore permitting, recently received Minerals Management Service's 2003 Corporate Leadership Award for work on the McCovey offshore oil and gas exploration project.

"The acquisition of Lynx Enterprises enhances our competitive posture by broadening the suite of integrated network services now covering the total lifecycle of projects," said Mike Stophlet, president and CEO of ASRC Energy Services. "From exploration to development to production optimization and to final environmental rehabilitation/restoration, we are now even better positioned as a one-stop shop for environmental services."

Lynx will be part of ASRC Energy Services' Engineering & Technology business unit and will continue to be managed by Mark Schindler, president. The firm will have offices in ASRC's Anchorage facility and is opening a new office in Denver, Colo.

ASRC farms into Placer prospect

ARCTIC SLOPE REGIONAL CORP., which represents the business interests of 9,000 Inupiat Eskimos in Arctic Alaska, has quietly entered into what might be its first North Slope investment as an independent oil and gas company under its mentoring agreement with BP Exploration (Alaska).

ASRC's name appears as a working interest owner on state documents for the Placer No. 1 well, which is being drilled this winter by operator ConocoPhillips in a unit expansion area in the western part of the Kuparuk River unit. BP, Unocal, ChevronTexaco, ExxonMobil and unit operator ConocoPhillips are partners in the area where Placer No. 1 is expected to be spud Feb. 15. ASRC has farmed into BP's acreage, assuming a portion of the cost of the well in exchange for a 35 percent working interest, leaving BP with no production from the well.

In July, ASRC announced it was expanding its scope to become an independent oil and gas producer on the North Slope and had entered into a "mentoring" agreement with North Slope producer BP. The agreement includes sharing information on unit and near-unit oil and gas investment opportunities, ASRC and BP told Petroleum News (see story in July 13 issue of Petroleum News). The companies hoped to have an exploration or development agreement in place by the end of 2003. (As of Jan. 28, no deals had been announced.)

In July, BP said the mentoring arrangement would help get unit and near-unit North Slope prospects explored and developed that might not get approved by BP's board in London due to stiff competition from investment opportunities outside Alaska.

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REDOUBT

tions showing "significantly lower oil in place … lower overall recovery efficiencies and economic cutoffs," the company said in a statement.

Thirty-six million of the 49 million barrels had been categorized as proved undeveloped.

Craig Clark, Forest Oil's president and CEO, told analysts on a Jan. 27 conference call that the company is "very disappointed" in the reduction in proved reserves at Redoubt. He said Forest finished its detailed technical review and also has results back from the independent third-party review. The technical review combined geological and geophysical data gathered in 2003 with previous data, he said, and the reservoir was remapped using new seismic and new well data.

Clark said the new data, production to date of more than a million barrels and the drilling of the No. 7 well close to the earliest producers, the No. 1 and No. 2 wells, "was helpful in providing additional oil-in-place calculations to compare to the 2002 data."

Lower productivity, which had become apparent earlier in 2003, combined with lower reserves and high drilling costs made it "apparent that there was some oil that could not be recovered on the fringe or lower productive areas due to economic cost," Clark said.

All of those factors contributed to lowering the company's estimate of economically recoverable oil by some 50 million barrels, Clark said. Forest "also reduced the total recovery factor to 18 percent." Cook Inlet fields have been averaging in the range of 25 percent to 42 percent oil recovery rates, he said: "We will now be below this range."

A legacy project for Forest

Redoubt Shoal development was begun by Forcenergy, which merged into Forest in 2000.

Forcenergy acquired leases at the prospect and ordered a drilling platform, the Osprey, to drill an exploration well and, if reserves were proved up, to drill production wells. The company chose to build a platform to avoid the cost of mobilizing a jack-up rig to Cook Inlet. The platform, designed to be moved to another prospect if drilling results at Redoubt were not commercial, was set in place in Cook Inlet in July 2000.

In February 2001 Forest announced success at the Redoubt Unit No. 1 well, which tested at 1,010 barrels per day from the Hemlock formation. In June 2001 Forest announced a second successful well and said it "estimates that recoverable oil in Redoubt Shoal will exceed 50 million barrels." Production was expected to be 2,500 bpd from the No. 1 well and 3,000 bpd from the No. 2. The No. 3 well was completed in October but was not production tested. Forest said "logs indicated reservoir quality similar to the No. 2 well" and expected similar rates. The company said that as of Dec. 31, 2000, it had "reported 9.8 million barrels of estimated proved reserves at Redoubt Shoal."

In May 2002, with early results promising, the company said it had increased its "estimate of recoverable oil for the Redoubt Shoal field" to "at least" 100 million barrels.

Drilling continued, but by August 2003, Forest was reporting that results from a sidetrack of the No. 4 well and the No. 6 well "are below our original expectations and will result in a change in our existing geologic model of the Redoubt Shoal field." The company said it would "undertake an integrated study on the field and develop geologic and reservoir models that appropriately reflect the apparent reservoir complexity and heterogeneity."

Redoubt production began in December 2002 and state records show it peaked in May 2003, averaging almost 3,500 barrels per day. It then dropped, to 2,500 bpd by August, and for October through December production averaged only some 1,900 bpd.

Clark said Jan. 27 that the No. 1 well, the field's best producer, was offline due to problems with the electrical submersible pump, used to bring oil to the surface. Production is coming from three wells, he said, and the company plans to repair the No. 1 and get it back on production and perforate the No. 7, a horizontal well completed in December in the same area as the No. 1 and No. 2.

Drilling rig off platform

The No. 7 well was drilled horizontally and cased in mid-December, Clark said.

"Our current contract on our drilling rig expired and we moved the drilling rig off the platform and moved in a less expensive hydraulic rig from the Gulf Coast," he said.

"Basically we had a three-year term contract and that expired," Clark said, "so we don't want any term contracts.

"We have a rig that's basically allowing for remedial work and testing," he said of the rig the company brought in. The smaller rig, he said, represents a 15 to 20 percent cost savings.

"By eliminating the rig it gave us room and it also stops the meter running with a $100,000 a day spread," he said.

The first thing the smaller rig will be used for is to repair the electric submersible pump in the No. 1 well, which went down late last year. It will then be used to complete the No. 7 well.

Moving the drilling rig off the platform allows Forest "more room for repair, diagnostics and stimulation work."

Most of the equipment has already been installed for waterflood, Clark said, and "we will certainly start the waterflood in the future."

As for the future of Cook Inlet, where Forest is a major leaseholder?

The company believes activity in Cook Inlet "should now focus on smaller oil targets," Clark said, "with much lower start-up costs, and also shallow gas." ●