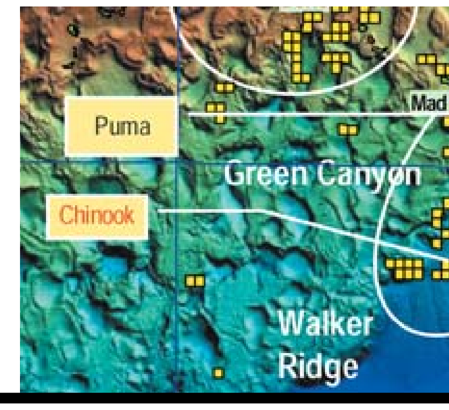
Petroleum news



page 14 Puma discovery adds to Gulf of Mexico's geologic promise

Vol. 9, No. 3 • www.PetroleumNews.com

North America's source for oil and gas news

Week of January 18, 2004 • $1

Mobilizing for action in NPR-A


JUDY PATRICK

Total E&P USA Inc. and its partner, Fortuna Energy Inc., continue to mobilize equipment to their Caribou 26-11 No. 1 well in the National Petroleum Reserve-Alaska. (Fortuna is a subsidiary of Calgary-based Talisman Energy.) The above photo, taken in mid-January, shows Veco's Watson drill setting conductor pipe. It was hauled to the remote site by Catco rolligons. In mid-2002, Total re-entered Alaska with the lease acquisition of 229,000 acres in northeast NPR-A, later bringing in Fortuna as a partner. The companies permitted three oil prospects, electing to drill one wildcat this winter. All of Total's predecessors —Total, PetroFina and Elf Aquitaine — have owned oil and gas leases in Alaska but this is the first time the company is an operator in the state. When asked in May why Total had elected to move into Alaska, Alaska area manager, Jack Bergeron said, "Because we want to grow in the United States . . . and Total considers Alaska to have "one of the largest — if not the largest — potential for exploration in the whole world."

State of Alaska investment in gas pipeline under discussion

While the Alaska Natural Gas Development Authority continues its effort to determine if the state should build, own and operate a liquefied natural gas project, others are talking about how to help finance the estimated $12 billion venture if it goes forward.

A Juneau legislator wants to amend state law to give specific permission for the Alaska Permanent Fund Corp. to loan money for the project.

And a member of the Alaska State Pension Investment Board believes the gas project might be a good investment for public employee and teacher retirement funds.

see **INVESTMENT** *page 23*

B R E A K I N G   N E W S

NORTHWEST TERRITORIES

Gas line on track

Aboriginal veto threat, shipping talks not expected to derail Mackenzie filings

By GARY PARK

Petroleum News Calgary Correspondent

Owners of the Mackenzie Gas Project see no delays in their plans to file major regulatory applications in 2004, despite threats of an aboriginal veto and some rumblings of discontent among potential shippers.

Imperial Oil, the lead partner, is confident that the pieces are coming together for what is probably the largest project in Canadian industrial history, External Relations Manager Hart Searle told Petroleum News.

"There is a very aggressive push on to complete the work, but we want to do it right," he said. "It has always been our wish to submit as complete a suite of applications as possible."

see **GAS LINE** *page 22*

Deh Cho remains project's wild card


Newly appointed Northwest Territories Premier Joe Handley said he wants to meet with the Deh Cho to find out exactly what they want, while meeting with other aboriginal communities along the Mackenzie Valley to discuss socio-economic agreements relating to the pipeline project.

The Deh Cho First Nations have been the unyielding holdout for four years and show no signs of buckling.

While other aboriginal communities in the Northwest Territories decided to support the Mackenzie Gas Project in hopes of benefiting from a natural gas pipeline through their land, the Deh Cho made their participation contingent on success in self-government negotiations.

Now they have revived memories of the late 1970s when initial proposals for pipelines to carry

see **DEH CHO** *page 22*

NORTH SLOPE, ALASKA

The beat moves west

Conoco wants 34,000 state, ASRC acres onshore and offshore added to Colville unit

By KRISTEN NELSON

Petroleum News Editor-in-Chief

ConocoPhillips Alaska has filed preliminary paperwork with the state of Alaska to expand the Colville River unit on Alaska's North Slope to the northwest, adding some 34,000 acres onshore and offshore at Harrison Bay.

ConocoPhillips is the unit operator and has been producing the Alpine field at the Colville River unit since November 2000.

About half of the proposed expansion acreage, 17,149 acres, is in two onshore Arctic Slope Regional Corp. leases in the National Petroleum Reserve-Alaska (see story on Alpine satellite draft EIS), and about half in 13 state of Alaska leases, 17,027 acres, in Harrison Bay.

The state leases are approaching their expiration dates, and inclusion in a unit would extend the life of the leases.

Nine of the leases came from BP

Nine of the state leases were acquired by BP Exploration (Alaska) in 1997 and expire Jan. 31, 2004. ConocoPhillips acquired them in June 2003,

see **BEAT** *page 23*

NORTH SLOPE, ALASKA

Alternatives to Alpine satellite project proposed

By KRISTEN NELSON

Petroleum News Editor-in-Chief

State and federal agencies have completed the draft environmental impact statement for ConocoPhillips Alaska's Alpine satellite project on Alaska's North Slope, and have proposed alternatives for public comment which range from roadless development to connecting all of the proposed new drilling pads by road.

The draft EIS, released by the U.S. Department of the Interior's Bureau of Land Management, the lead agency for the EIS, also includes a full field development analysis for the 890,000 acre project area, representing what BLM calls "hypothetical scenarios that could occur during the next 20 years." (See map, pages 12 and 13.)

The EIS looks at five alternatives, Jim Ducker, BLM environmental program analyst, who is managing the EIS for BLM, told Petroleum News Jan. 13. In addition to ConocoPhillips Alaska's proposal, it looks at an alternative "in accordance with the Northeast NPR-A EIS," an alternative with no roads to the new pads, one with roads to

see **ALPINE** *page 12*

Alaska - Mackenzie Rig Report

The Alaska - Mackenzie Rig Report as of January 13, 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 F pad, well MPL-43	BP
Sky Top Brewster NE-12	15 (SCR/TD)	Stacked, Endicott Island	Available
Dreco 1000 UE	16 (SCR)	Stacked, Deadhorse	Available
Dreco D2000 UEBD	19 (SCR/TD)	Alpine, drilling CD2-43	ConocoPhillips
OIME 2000	141 (SCR/TD)	Meltwater, drilling 2P-424	ConocoPhillips
Nabors Alaska Drilling			
Trans-ocean rig	CDR-1 (CT)	Stacked, Prudhoe Bay	Available
Dreco 1000 UE	2-ES (SCR)	Prudhoe Bay, L2-14	BP
Mid-Continent U36A	3-S	Stacked at Prudhoe Bay	Available
Oilwell 700 E	4-ES (SCR)	Prudhoe Bay, WGI-05	BP
Dreco 1000 UE	7-ES (SCR/TD)	Prudhoe Bay, Z-30A	BP
Dreco 1000 UE	9-ES (SCR/TD)	Prudhoe Bay, L-210	BP
Oilwell 2000 Hercules	14-E (SCR)	Moving to location	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 Canrig 1050E	27-E (SCR/TD)	Northwest Mile	Kerr-McGee
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)	DS-5, well 41A	BP
Superior 700 UE	2 (SCR)	DS-15, well 4A	BP
Ideco 900	3 (SCR/TD)	Start up, Kuparuk 3F 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-5	BP

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 #7	Marathon
Inlet Drilling Alaska/Cooper Construction			
Kremco 750	CC-1	Stacked, Kenai	Forest Oil
Nabors Alaska Drilling			
Rigmasters 850	129	Cook Inlet, Falls Creek #4	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
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
Nabors Alaska Drilling			
IDECO 2100 E	429E (SCR)	Cook Inlet, RU #7	Forest Oil
Unocal (Nabors Alaska Drilling labor contractor)			
Not Available			
Kuukpik	5	Relased on Dec. 26, demobilizing off platform and will stack in Kenai	Idle
Cudd Pressure Control	340K	Workover, Osprey Platform	Forest Oil

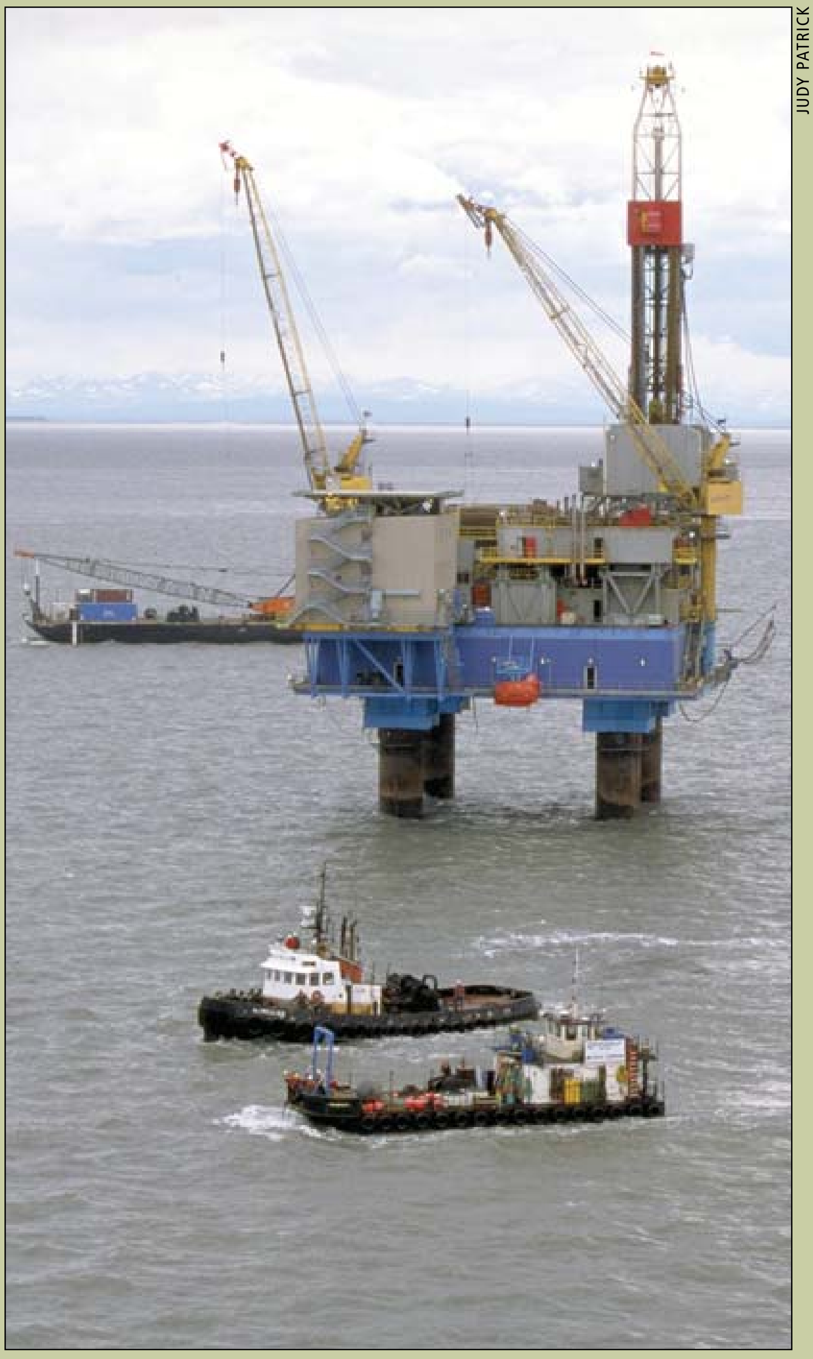
Mackenzie Rig Status

Mackenzie Delta-Onshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
AKITA Equtak			
Dreco 1250 UE	62	Stacked, Tuktoyaktuk, NT	EnCana
Dreco 1250 UE	63 (SCR/TD)	Stacked, Swimming Point, NT	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 near Colville Lake, NT	Apache Canada
Rigmaster P850	40	Riggin up near Tulita, NT	Northrock Resources
Nabors Canada			
	62	Stacked, Norman Wells	Available



JUDY PATRICK

The Osprey platform during the pipeline installation phase. Crowley Alaska's tugboat, Sea Breeze, and American Marine Corporation's vessel, Shamrock, both were instrumental in the pipe pulling operation.

Baker Hughes North America rotary rig counts*

	January 9	January 2	Year Ago
US	1,106	1,126	851
Canada	388	332	444
Gulf	98	101	107

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

AKITA/SAHTU

55	Will drill for EnCana near Tulita, NT. Move mid-January 2004.

AKITA Equtak

62	Will drill for EnCana this winter in the Mackenzie Delta. Late January early February 2004 start-up.
63	Will drill for Chevron Canada this winter in the Mackenzie Delta. Late January early February 2004 start-up.

CANADA

Canadian small caps sparkle in 2003

It was a big year for the little guys in Canada's oil patch.

A survey of 61 junior oil and natural gas companies showed an average share price increase of 63.5 percent in 2003, with one in four climbing by 100 percent or more.

The survey by Iradesso Communications listed the big gainers as Vaquero Energy, up 274 percent to C$3.10; Connacher Oil and Gas up 272 percent to C$1.60 and Kensington Energy up 216 percent to C$1.42. The losers were Terraquest Energy and Oiltec Resources, both down 46 percent at C$0.27 and C$1.22 respectively and Redwood Energy, off 29 percent at C$0.17. Companies surveyed had third-quarter 2003 production ranging from 500 to 15,000 barrels of oil equivalent per day.

Of the 17 energy trusts that constituted the intermediate sector, distributions to unit holders averaged 18 percent and unit prices rose an average 31 percent, led by Petrofund Energy Trust with a 91 percent total return. Of the six conventional producers who converted to trusts during the year, Peyto Energy Trust showed the way with a total return of 151 percent. The Toronto Stock Exchange S&P/TSX Energy index grew by 3 to end 2003 at a record high of 161. Ivanhoe Energy, a U.S.-based operator listed on the TSE in December, posted a 574 percent gain for the year to reach C$10.40 before sliding back to C$4.85 on Dec. 31. Husky Energy led the domestic integrated majors with a 43 percent rise to C$23.95, followed by Suncor Energy's 32 percent jump to C$32.50 and Shell Canada's 24 percent increase to C$61.25.

Drilling stocks had only moderate gains despite the pace of upstream activity. Ensign Resource Service Group led with a 24 percent return to close the year at C$20.60. Akita Drilling added 15 percent for a year-end trading price of C$24.16 and Precision Drilling, Canada's largest oilfield service company, gained 11 percent to C$56.75.

—GARY PARK, Petroleum News Calgary corresponden

YUKON TERRITORY

Kaska, Yukon progress on Alaska pipeline

An agreement in principle between the Kaska Nation and Foothills Pipe Lines is another step towards breaking a logjam over resource development in the southeastern Yukon.

The Jan. 15 signing moves the two parties closer to a deal that specifies benefits and opportunities for the five communities that make up the Kaska Nation if the Alaska Highway gas pipeline is built across the Yukon. The first stage was completed in November 2001, but completion of the second and third phases is almost two years behind schedule.

Foothills, its 100 percent owner TransCanada, and their subsidiaries hold certificates to build the Canadian and Alaska portions of the highway project.The Kaska Nation traditional territory covers about 25 percent of the Yukon, adjacent areas of the Northwest Territories and about 10 percent of British Columbia.

David Porter, chair of the Kaska Dena Council, said the latest agreement is an "important step forward" in achieving Kaska input in the planning stage for the pipeline and deciding how benefits will be delivered.

"It does not limit the Kaska from working with our pipeline companies, nor does it commit us to any one project," he said.

Foothills Chief Executive Officer Tony Palmer said the agreement "reaffirms our commitment to work cooperatively to achieve mutual objectives" on the project.

Opening the southeastern Yukon to resource development has been prolonged process, but Yukon Premier Dennis Fentie hopes to see the first sale of mineral rights this year under an interim agreement that was signed last May by his government and the Kaska.

That bilateral pact laid the groundwork for sharing benefits from any land and resource development within the Kaska territory. It also committed the two sides to work co-operatively to conclude Kaska land claim negotiations with the Canadian government.

Fentie's government is eager to kick-start energy exploration more than five years after responsibility for oil and gas resources was transferred from the federal government. However, the federal mandate covering land claim agreements has expired, prompting Fentie to accuse the federal government of "abdicating its responsibility."

The interim agreement produced a flurry of criticism from Yukon's opposition leaders, who accused Fentie of going outside the land claims process and running the risk of stalling resource development and discouraging the settlement of claims.

Former Premier Pat Duncan said the agreement gave the Kaska veto over resource development, including the Alaska pipeline, while the official opposition leader Todd Hardy said deals outside the land claims "create more uncertainty" causing other Yukon first nations to revisit their claims settlements.

—GARY PARK, Petroleum News Calgary correspondent

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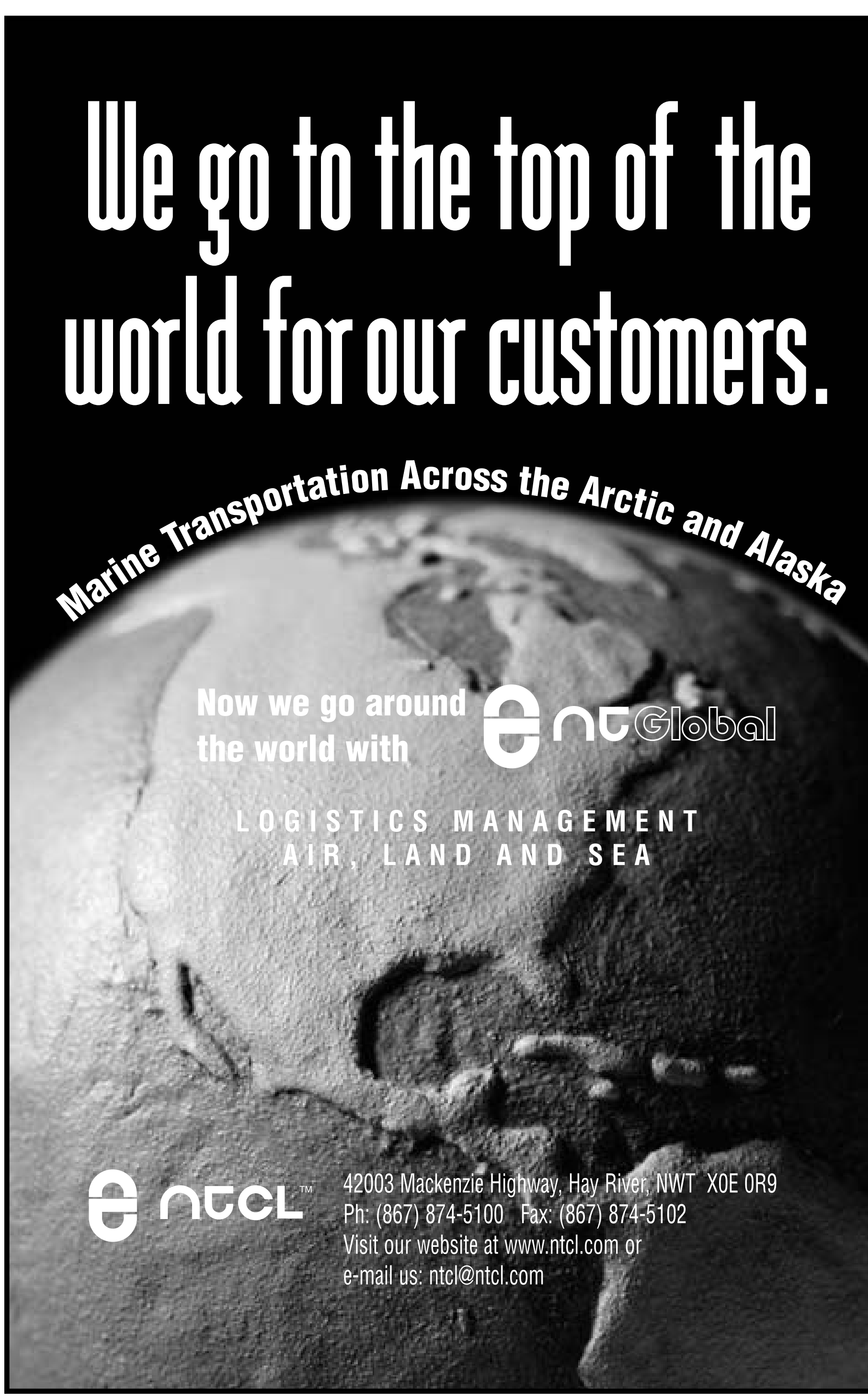

Companies in the news

Companies which appear in articles in this issue of Petroleum News are listed below. The page number indicates the page where the company name first appears. If it is continued from another page the number will be hyphenated – i.e. "1-22" means the story starts on page 1 but the company name first appears on page 22. The company names in the rig report on page 2 are not included in the following list.

● UK NORTH SEA

Report gives North Sea 2 to 3 years

PETROLEUM NEWS

Stakeholders have a two to three year window to take action to "contain" the United Kingdom Continental Shelf's production decline, the UK Offshore Operators' Association said Jan. 14 when it released the results of an annual survey of the investment and development plans of 29 oil and gas producers active in the UK North Sea. The joint survey is conducted jointly by the offshore operators group and the UK's Department of Trade and Industry.

> *"We seem to have failed to convince government that time is of the essence if we are to utilize existing infrastructure to maximize the recovery of oil and gas from the North Sea."*
> **—Steve Harris, UK Offshore Operators' Association's acting director general**

The trade report on the 2003 activity survey said "that while capital investment in offshore oil and gas developments remains strong, rising unit costs and declining production volumes point to deteriorating economics in the UK North Sea and the challenge ahead for companies to remain competitive and attractive to future investment."

The trade association said "urgent action by all stakeholders, including government" is needed to increase investment in marginal fields and maximize recovery in producing fields, as well as stimulate exploration for future production.

"Increasing regulatory burden" also needs to be addressed, the association said.

Still drawing $5.5 billion per year

One key finding indicated capital spending by industry in new UK North Sea offshore developments continues to meet and exceed projections set by Pilot, a government/industry task force which targeted investment to remain above $5.5 billion per year through 2010.

The report said unit operating costs are expected to rise by 60 percent by 2010, "based on currently sanctioned development plans."

10 new field developments approved in 2003

Despite 10 new field development approvals in 2003, forecasts for near-term oil and gas production continue to slip. Production in 2003 was estimated at just over 4 million boe per day, the report said. 2004 volume predictions are just over 3.7 million barrels of oil equivalent per day, 280,000 boe per day short of last year's projection.

Pilot's goal for 2010 daily production was 3 million boe per day. According to the report, 2010 production will fall short by 570,000 boe per day.

Industry production plans "will develop up to a total of 10 billion boe of reserves by 2010, and may develop up to a total of 14 billion boe by 2030."

But "the challenge: will be to identify ways to find and develop the additional 9-16 billion boe in the UK North Sea "not covered by current plans," the report said.

"We seem to have failed to convince government that time is of the essence if we are to utilize existing infrastructure to maximize the recovery of oil and gas from the North Sea," Steve Harris, UK Offshore Operators' Association's acting director general, said.

EnCana's Booth calls for combined effort

Alan Booth, the association's president and senior vice president and managing director of EnCana (UK) Ltd., said the strength of investment in the UK Continental Shelf "reflects the ongoing commitment of existing players to maximize the economic recovery of UK oil and gas reserves. It also confirms the sector's continuing attraction for new companies who see opportunity in the North Sea.

"But ultimately, the sector's long-term success will depend on the ability of the industry to arrest the current trend that is seeing it spending more to produce less. This will take the combined efforts of industry, the supply chain and government to find new ways to enhance the region's commercial attractiveness through cost reductions, technology breakthroughs, fiscal incentives and containing the increasing regulatory burden," Booth said.

Wanted: prolonged self-sufficiency, 100,000 more jobs

Pilot, which has 23 members and meets quarterly, was established in January 2000 to secure the long-term future of the oil and gas industry in the United Kingdom.

In addition to 3 million boe per day and $5.5 billion in capital and exploration spending, Pilot's other goals for 2010 include prolonged self-sufficiency in oil and gas; 100,000 more jobs in addition to earlier forecasts; a 50 percent increase in exports by 2005; and to establish the United Kingdom as the safest place in the world to work in the oil and gas industry. ●

● ANCHORAGE, ALASKA

Gas authority drops lobbyist idea

Board also decides against filing Alaska Stranded Gas Act application

By LARRY PERSILY

Petroleum News Government Affairs Editor

The Alaska Natural Gas Development Authority has dropped its plan to hire a lobbyist to help push for additional legislative funding, while also backing away from submitting a project application under the state's Stranded Gas Development Act.

Meanwhile, the authority has approved a $50,000 contract for an economic benefits analysis of its proposal to build a $12 billion pipeline and liquefied natural gas shipping terminal in Alaska.

Board members did not explain how the Stranded Gas Act, which allows a project developer to negotiate a schedule of contractual payments to the state in lieu of all state and municipal taxes on the project, could benefit the authority that already is exempt from state and local taxes for its proposed LNG project.

"After looking at the work involved, it's just too much work," Chief Executive Officer Harold Heinze said of the stranded gas application process.

The authority, however, would want to participant in the contract negotiations if North Slope gas producers or other parties apply to the state for a stranded gas contract, Chairman Andy Warwick said at the board's Jan. 12 meeting in Anchorage.

Gas supply could be part of the deal

Warwick suggested that perhaps in addition to financial terms, the state could insist that any contract for a gas pipeline project include a provision requiring producers to sell gas to the authority, which needs a supply for its LNG project.

The board had voted Dec. 15 to instruct Heinze to prepare a draft stranded gas application for what it calls the Alaska Big Capacity, or ABC Line, which the gas authority would build to carry 4.5 billion cubic feet per day of producer gas and 2 bcf per day for the authority's own project. The line would end near Delta, southeast of Fairbanks, where the producers' pipeline would continue to mid-America and the authority's separate line would head south to tidewater at Valdez.

"It's not an option that is totally off the table," board member Scott Heyworth said Jan. 12. Instead of pursuing the combined ABC Line, Heinze and Heyworth said, the authority will simply send a letter to the governor, telling him, "We've got an idea." Then, if the governor wants to hear more, he can contact the authority.

As for spreading their ideas among legislators, board members agreed to accept offers of assistance from two legislative leaders instead of spending money to hire a gas authority lobbyist.

Legislators offer to help

Senate President Gene Therriault, R-North Pole, and House Finance Co-Chairman John Harris, R-Valdez, have offered their staff to help monitor and support the authority's funding request and other relevant legislation, Heinze said, alleviating the need to hire a lobbyist or liaison.

Although Heinze and the board at their December meeting talked exclusively of hiring a lobbyist to help push for more state funding, the CEO said at the Jan. 12 meeting that he had meant to use the word "liaison."

Regardless of the name, some board members were skeptical that legislative staff could adequately represent the authority. "The problem is, are we going to get by with Therriault's and Harris' office? I hope so," Heyworth said.

An additional reason for dropping plans to hire a lobbyist is that the authority is out of money, Heinze told the board. "The $350,000 is gone," he said of this year's state funding, although the board is seeking an additional $2.15 million for the last five months of the fiscal year.

Therriault has introduced legislation to appropriate the $2.15 million.

Draft economics report due March 15

Heinze told board members Jan. 12 he had approved a $50,000 contract with Northern Economics, an Anchorage-based consulting firm, for an analysis of the economic benefits to the state and its residents of the proposed state-owned LNG project. A preliminary report is due March 15.

The CEO also said he has contracted with a Washington, D.C., law office — Morrison & Foerster — to advise the authority on what changes might be needed in state law to give it its best shot at winning an exemption from federal income taxes. The firm has previously assisted the state on oil and gas tax work.

If all the authority does is provide a pipeline for others to move gas, it's likely tax exempt, Heinze said. But if the authority buys and sells gas, similar to a commercial operation, it probably will need changes in its statutes if it is to have a chance at qualifying for tax-exempt status with the Internal Revenue Service. The authority's cost of service would be lower — and its competitiveness in the marketplace would be better — if it is exempt from federal taxes.

The law firm's draft report is due March 15.

Natural Resources to help with gas supply issue

The board also asked the Department of Natural Resources to assist the authority in "gas acquisition issues." The authority does not own any gas, and would need to reach a deal with North Slope producers if it is going to have any gas to convert into LNG.

Lawmakers this fall gave $50,000 to the Department of Natural Resources so that it could help the gas authority in its effort to build a state-owned project.

Though board member John Kelsey of Valdez spoke in favor of considering state condemnation to take away gas from North Slope producers, Natural Resources Deputy Commissioner Marty Rutherford suggested a different approach: "Incentivize the gas out of the producers." ●

● THE NETHERLANDS

Shell cuts proved reserves by 20 percent

Move sends shock waves through oil industry

PETROLEUM NEWS

Shell's decision to reduce its proved reserves by 20 percent or an astonishing 3.9 billion barrels of oil equivalent has cast a cloud over oil and gas companies worldwide and the manner in which they book reserves, a key factor in valuating a publicly traded company.

Shell's Jan. 9 disclosure also came at a time of increasing scrutiny by the U.S. Securities and Exchange Commission, which is said to be calling on companies big and small to account for their bookings. The SEC recognizes only proved oil and gas reserves, or those that can be economically produced.

In a conference call with analysts, Shell said it had talked to the SEC but did not say whether the agency had pressured the company into reclassifying reserves. Rather, Shell said "a number of in depth studies" conducted by Shell and concluded in the 2003 fourth quarter prompted the company to make changes.

"It is anticipated that most of these reserves will be re-booked in the proved category as field developments mature," Shell said in a prepared statement, adding that reclassification of proved reserves would not "materially change" its estimated total hydrocarbons in place, nor volumes the company expects to ultimately recover.

Shell said its action also would have "no material effect on financial statements for any year up to and including 2003."

Affected reserves in Nigeria, Australia

Reserves affected by Shell's action are located primarily in Nigeria and Australia, in particular the $8 billion offshore Gorgon natural gas project in northwest Australia, where Shell has booked reserves for years, despite the fact the project has not yet evolved into a commercial operation. Shell holds a 28.6 percent stake in Gorgon.

One analyst told Petroleum News that Shell's "recategorisation" of proved reserves likely was a "pre-emptive strike" designed to avoid further SEC scrutiny and to appease investors, a strategy which at least partly failed. Shell's stock plummeted on the news, dragging down the shares of other oil and gas companies as well, including Gorgon partner ChevronTexaco, a 57.1 percent stakeholder in the LNG project. ExxonMobil holds a 14.3 percent share of Gorgon.

Shell's announcement also prompted an immediate response from ChevronTexaco, which asserted in a prepared statement that Shell's decision would not affect its current worldwide reserve categories, including Nigeria and Australia. ChevronTexaco noted thus far it had not booked any reserves at Gorgon.

Of the 3.9 billion barrels of equivalent reserves taken off the books by Shell, 2.7 billion barrels involved crude oil and natural gas liquids and 7.2 trillion cubic feet of natural gas, Shell said. Over 90 percent of the total change entailed a reduction in the proved undeveloped category, and the rest in the proved developed category, the company said.

Reserves booked between 1996 and 2002

The company did not provide a regional breakdown of the reserves, but did say they were booked between 1996 and 2002. "A significant proportion of the recategorisation relates to the current status of project maturity," Shell said.

Some industry observers believe the SEC is partly at fault, charging that the agency has failed to issue clear industry guidelines when it comes to booking reserves. "The fact Shell booked reserves at Gorgon and ChevronTexaco didn't, makes no sense," one analyst said, suggesting the SEC "needs to establish speed limits so people will drive the speed limit."

He said there is little doubt the SEC is putting the screws to industry on the reserve issue. "I've heard from several companies that the SEC is putting tremendous pressure on them to come clean," he added.

Meanwhile, investment banks like Deutsche are trying to figure out whether Shell's problem is contagious.

"Shell's shocking announcement ... has thrown the spotlight on one of the sector's most important — but in many ways opaque — measures," Deutsche Bank said in a notice to investors. "We know that annual reserve replacement and finding costs are not reliable guides to value or earnings, but they are crucial metrics of corporate success and management — and thus crucial guides to relative valuation." ●

NORTH SLOPE ALASKA

ConocoPhillips gets new NPR-A well permit, proposes 2 wells south of Kuparuk

ConocoPhillips Alaska is advancing permitting for wells in the west and also the central North Slope.

The company received another drilling permit for work in the National Petroleum Reserve-Alaska Jan. 7. The Scout No. 1 well is in section 20, township 11 north, range 1 east, Umiat Meridian, about a mile southwest of the U.S. Navy's 1949 Fish Creek test well, which was drilled to 7,020 feet and pumped on test 10 barrels a day of heavy black oil from 2,920 feet and 3,060 feet, with additional shows of oil below 5,400 feet. This well was drilled near the apex of a gravity high, and the U.S. Geological Survey reported that the well penetrated a little more than 7,000 feet of Cretaceous shales and a small amount of siltstone and fine grain sandstone.

Some three miles to the northwest of the proposed Scout 1 is the West Fish Creek No. 1, where oil and gas shows were found in 1977 by Husky Oil NPR-A Operations which drilled to 11, 427 feet.

Central North Slope

ConocoPhillips is also proposing the Winter Trails No. 5 and No. 6 wells some two miles southeast of drill site 1J on the southern edge of the Kuparuk River unit. The company told the state that approximately 3.1 miles of ice roads and two ice drilling pads would be used to drill as many as two wells and two sidetracks for an exploration/stratographic test drilling program in the 2003-04 winter season. The West Sak reservoir is the target.

These wells at the southeast corner of the Kuparuk River unit appear to be in one of the unit expansion areas, where wells are required this drilling season to hold the acreage. That expansion area is defined as tracts 160-163, and ConocoPhillips told the state in May that it was committing to drill two wells in the area, one on tract 160 or 161 and the other on tract 162 or 163, both by June 1, 2004.

When the state approved the unit expansion in 2002 it said the area north of this expansion area, "has a long history of West Sak formation evaluation programs," with exploration beginning in the area in 1975 and a waterflood pilot program in 1983. The Winter Trails No. 1 well was drilled in the area in 1986 and the Winter Trails No. 4 in 1987.

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

● ANCHORAGE, ALASKA

State gas authority sees competition

State board concerned that North Slope producers' LNG projects outside Alaska are rivals for potential buyers

By LARRY PERSILY
Petroleum News Government Affairs Editor

Members of the Alaska state gas authority are starting to see North Slope producers as competitors.

The authority's job is to build a state-funded pipeline and terminal to ship liquefied natural gas to U.S. West Coast and maybe also Asian markets, while the producers are working toward a pipeline from Alaska, through Canada and into mid-America to serve the Lower 48.

"Each one of them is a competitor to our project," gas authority Chief Executive Officer Harold Heinze said of the three major North Slope producers: ExxonMobil, ConocoPhillips and BP.

The producers also all have interests in LNG projects worldwide, many of which could serve the same markets the state gas authority is chasing.

The issue came up at the Alaska Natural Gas Development Authority's Jan. 12 board meeting, at which Heinze announced he wants the board to go into closed-door session for all future discussions of possible LNG sales. "I don't see any reason to disseminate at large" any information about the authority's possible gas buyers, Heinze said.

Marketing discussions in private

"I would prefer not to have the marketing discussions in open session."

The authority currently has no buyers or financing for its proposed project, and also no agreement with producers to sell any of their gas to the authority for conversion into LNG.

The board's attorney advised that such closed-door sessions would be allowable under an exception in the state's open meetings law. That exception allows for executive sessions if public knowledge of the discussions could harm the state's finances.

Board members also discussed their concern that not everyone wants them to succeed in building an LNG project.

"This is about more than building a pipeline. This is a political war," said board member David Cuddy of Anchorage. He suggested the board set up a "war room" so that it can respond quickly to newspaper editorials and other criticisms of the proposed state-owned pipeline project.

"I'm not going to say," Cuddy responded, when asked the day after the board meeting who is against the project. "That's kind of amongst the board. There are people who don't want this built. Without naming names … we ought to at least respond to the charges."

Board wants to defend its project

At the meeting, board members Cuddy, Scott Heyworth and Dan Sullivan and board Chairman Andy Warwick said they believe the authority needs to be more vocal in countering misinformation about the state-funded project.

"I think we need to have some kind of a public awareness press response team," Cuddy said.

The board rejected a suggestion that they ask North Slope producers to review financial projections for the LNG project, with board member John Kelsey concluding, "They've lied to us in the past and we're just asking then to continue to lie to us."

Board members also voted Jan. 12 to deny a request from a citizens group for a copy of the authority's draft response to the governor's questions of last fall about the authority's work and its possible project. The authority has yet to submit its answers to the governor.

The request came from Backbone II, a pro-LNG project citizens group comprised mostly of businesspeople involved in past, unsuccessful efforts to promote an LNG terminal at Valdez.

The gas authority board cited "competitive reasons" in keeping its draft response confidential. ●

WYOMING

Methane project gets approval

The Bureau of Land Management has approved a small natural gas drilling project in southwest Wyoming.

Houston-based Burlington Resources Oil and Gas Co. will drill 31 additional exploration and development wells within the Fontenelle natural gas fields about 12 miles southeast of LaBarge in Sweetwater County.

Ted Murphy, BLM assistant field manager, said the agency found no significant environmental impact from the project as long as certain protective measures are taken. Drilling would begin in May and would continue over the next three years, depending on the success of the drilling program.

—**THE ASSOCIATED PRESS**

EL DORADO, ARK.

Murphy Oil cuts 2004 E&P spending by 15% to $843M

Murphy Oil plans to spend $843 million on capital projects in 2004, roughly a 15 percent decrease from 2003 levels, the company said Jan. 12.

Murphy attributed the decrease to the sale of most of its western Canadian exploration and production business and the completion of deepwater developments in the Gulf of Mexico and completion of its clean fuels project at its Meraux refinery in Louisiana.

The move positions the company "to more easily" develop its recent Malaysian deepwater discoveries, said Claiborne Deming, Murphy's chief executive officer. "Our focus on higher growth frontier areas is reflected in the exploration program," he said.

Murphy said it would spend about $225 million on exploration, which includes investment in its deepwater Gulf program, an extensive drilling program on blocks K and H offshore Malaysia, two wells on Block 311 in Peninsular Malaysia, and an exploratory well offshore Congo. An additional $426 million is earmarked for its Front Runner development in the Gulf, Phase II development at West Patricia in Malaysia and continued expansion of Syncrude.

Murphy said it budgeted $184 million this year for refining and marketing operations, a decrease of about 17 percent from 2003 levels.

—PETROLEUM NEWS

DALLAS, TEXAS

Toreador Resources closes $45 million asset sale

Toreador Resources Corp. has closed the sale of its U.S. mineral and royalty assets for $45 million. The company is now focusing on its international holdings, notably in France, Turkey and Romania.

The new owner is Black Stone Acquisitions Partners I L.P. of Houston. The properties include about 2.6 million gross acres (1.4 million net) along with various royalty interests in roughly 4,000 wells. The wells are scattered across nine states, with most of them in Alabama, California, Louisiana, Mississippi and Texas.

Toreador expects to record a pretax gain on the sale of about $28 million. The Dallas-based Toreador still has some U.S. assets, mostly non-operated working interests in about 900 wells.

Black Stone is part of a group of partners that now hold interests in about 14,000 wells producing more than 2 million barrels of oil equivalent annually.

—PETROLEUM NEWS

FORT WORTH, TEXAS

Range Resources boosts capital budget to $126M

Exploration and production independent Range Resources has set its 2004 capital budget at $126 million, a 21 percent increase from last year, the company said Jan. 8, adding that the budget does not include possible property acquisitions in the new year.

The 2004 budget includes $109 million for drilling and recompletions, $15 million for land and seismic and $2 million for the expansion and enhancement of gathering systems and facilities, the Fort Worth, Texas-based company said.

Range said that acquisitions, particularly those in proximity to existing properties, "will continue to be pursued but are considered too unpredictable to be specifically budgeted." In 2003, Range spent about $104 million on capital projects and $93 million on acquisitions.

About half of this year's $109 million capital budget is earmarked for Southwest region, including the Permian Basin, the Midcontinent and East Texas, with the remainder equally divided between the Gulf Coast and Appalachia regions, the company said.

This year Range said it expects to drill or participate in 409 wells and do 35 recompletions, compared to 359 wells and 56 recompletions last year.

—PETROLEUM NEWS

● WASHINGTON, D.C.

Earnings for U.S. majors up 34 percent

Higher gas prices, foreign earnings, refinery profits power 23 firms

By ALLEN BAKER

Petroleum News Contributing Writer

The third quarter of last year was a great one for big U.S. oil companies, with a new government study showing just how much their combined profits rose.

Bottom line: $9 billion in earnings, up 34 percent from the 2002 quarter.

Major factors for the 23 big firms were higher prices for natural gas and a huge jump in refining earnings, according to the Energy Information Administration.

The companies in the EIA compilation span a broad range — from vertically integrated majors such as ExxonMobil and ChevronTexaco to smaller specialized operations including Tesoro and XTO Energy.

Upstream improves

Higher prices gave upstream operations a 61 percent gain in profits, to $4.9 billion, even though domestic production of both oil and gas declined by more than 3.5 percent for the listed companies. The major companies said that asset divestitures, often to smaller firms, and natural field declines caused the reduction.

Add foreign operations and the overall upstream gain was 56 percent, to $10.7 billion, as foreign earnings continued to run ahead of domestic profits.

Foreign production was 7 percent higher for oil and 3.1 percent higher for natural gas, and the companies that report separate foreign upstream showed a profit gain in that arena of 19 percent.

Foreign oil production represented 56 percent of the total crude flow for the big companies, while domestic natural gas amounted to 59 percent of the total gas production.

Domestic natural gas was a big profit driver, with U.S. wellhead prices rising 65 percent from the third quarter of 2002 to the same period in 2003. The 2003 quarter was the fourth straight period of rising prices for gas, after five consecutive quarters of falling prices, with the numbers compared to the year-earlier period.

The world crude price rose 6 percent from the third quarter of 2002 to the third period of 2003, averaging $27.37 a barrel in the 2003 quarter compared with $25.91 a year earlier. Those figures are based on the average U.S. refiner cost for imported crude.

Refining net skyrockets

Refinery throughput rose nearly 8 percent domestically and close to 4 percent internationally. But it was higher margins that more than quadrupled profits to $3.1 billion from $650 million a year earlier.

Looking at domestic refining alone, third-quarter 2002 profits rose 362 percent to nearly $2.2 billion from $467 million in the same quarter a year earlier.

Chemical operations of the majors were the lag-

see **EARNINGS** *page 8*

● FORT WORTH, TEXAS

XTO Energy begins new year with a bang

Independent looking to spend $650 million on acquisitions in 2004

PETROLEUM NEWS

Acquisition-minded XTO Energy, on the heels of buying $625 million worth of oil and gas properties in 2003, began the new year with another $249 million in deals and said in a Jan. 8 conference call it would buy another $400 million or more in properties by year-end.

The Fort Worth-based independent also unveiled a $1.5 billion capital budget for 2004, which in addition to roughly $650 million in acquisitions includes about $500 million for development and exploration, slightly above the 2003 level.

"This is another mark in the growth of the company (and) gives us more presence in core areas," Bob Simpson, XTO's chief executive officer, said after announcing the company's latest acquisitions located primarily in East Texas and northern Louisiana. The sellers were not disclosed.

XTO said the acquired properties contain an estimated 182 billion cubic feet of natural gas equivalent, 50 percent of which is proved developed. The acquisitions would add about 30 million cubic feet of equivalent per day to XTO's production base — output the company said it would increase to 40 million cubic feet by year-end. Production is about 90 percent gas.

The company said it would operate more than 85 percent of the assets which cover 100,000 gross acres, or 55,000 net acres in XTO's development corridor. Most of the acquisitions are expected to close before Jan. 30, the company added.

The acquisitions caused XTO to revise its production increase target for 2004 to 16 to 18 percent over 2003, up from previous company guidance of 13 to 15 percent. "Even more important, we see additional growth from acquisitions in 2004 as we have established a budget ... to buy more producing properties during the year," Simpson said.

East Texas, northern Louisiana acquisitions

Of the 182 billion cubic feet in gas equivalent reserves acquired by XTO, 77 million cubic feet are located in numerous East Texas fields, including Carthage, Oak Hill, Beckville, Damascus and Willow Springs. Daily production from these properties amounts to about 14 million cubic feet, with "significant volume growth" expected during the year, XTO said.

The remaining 105 billion cubic feet of proved reserves, 60 percent of which are developed, are located in "multiple, long-lived fields" in northern

see **XTO** *page 8*

Prices hit new highs; regulators scrutinize markets

By BRAD FOSS

Associated Press Business Writer

Oil and natural gas prices climbed to their highest levels in more than nine months Jan. 9 as traders responded to a cold snap in the Northeast, tight supplies and rising demand.

"The weather made people realize just how tight supplies are," said Phil Flynn, an analyst at Alaron Trading Corp. in Chicago. But some analysts contended supplies of natural gas are adequate and said they were surprised when prices first began to rise quickly in late November.

Utah Sen. Orrin Hatch, chairman of the U.S. Senate Judiciary Committee, said in December that he would hold hearings to determine if the recent increases in natural gas prices were caused by market manipulation.

Also Jan. 9, the Commodities Futures Trading Commission and the New York Mercantile Exchange said they have stepped up their surveillance of natural gas trading in the past week and industry sources said traders' telephone records have been subpoenaed as part of that effort.

R. David Gary, a spokesman for the trading commission in Washington, D.C., said the agency has increased surveillance because of recent volatility and high prices of natural gas trading activity on Nymex since the start of the month. But, as a matter of policy, he said the agency would neither confirm nor deny the existence of any formal investigation.

Nymex spokeswoman Nachamah Jacobovits said the focus of the scrutiny is to "make sure that futures prices are reflective of what's happening on cash markets and that there's no manipulation." The nation's commercially available inventory of crude is 3 percent below last year's levels.

Commercial inventories of natural gas, meanwhile, stood at 2.6 trillion cubic feet for the week ended Jan. 2, or 8 percent above the five-year average for this time of year.

Flynn said the five-year average was misleading since demand for natural gas has been rising.

Crude oil for February delivery closed up 33 cents to $34.31 on the New York Mercantile Exchange — the first time it has closed above $34 since March 17, just a few days before the invasion of Iraq.

Natural gas for February delivery rose 19.3 cents to $7.287 per 1,000 cubic feet Jan. 9.

"I personally don't believe we should be up at these levels," Tom Bentz, an analyst at BNP Paribas Commodity Futures in New York, said.

He noted that traders have ignored recent fuel-inventory reports that were bearish and focused instead on bullish factors such as the cold weather and the weak dollar.

"When it's cold, the market does tend to have an upward bias," he said. ●

continued from page 7

EARNINGS

gard, with profits declining by 43 percent as the companies had to pay more for their feedstocks. Revenues rose 27 percent to $180 billion for the 23 companies, up from about $142 billion in the 2002 quarter. The Energy Department agency subtracted unusual items from the totals in its compilations.

The full report is available at www.eia.doe.gov/emeu/perfpro/news_m/index.html. ●

continued from page 7

XTO

Louisiana that include Haynesville, Middlefork, Cotton Valley and North Shongaloo. In total, the properties produce daily about 12.5 million cubic of natural gas and 500 barrels of oil.

XTO said it will pay for the acquisitions through a combination of existing credit facilities, cash flow or the placement of long-term debt.

From the $500 million XTO plans to spend on development and exploration activities in 2004, the company said it expects to drill 420 wells and perform about 350 workovers and recompletions.

Activities in East Texas and Louisiana will account for $340 million of the total, while the San Juan, Raton and Arkoma basins will absorb about $100 million in development funds, the company said. It said development plans for Alaska, the Permian Basin and Hugoton Royalty Trust properties in the Lower 48 will take about $35 million. The remaining $25 million is earmarked for exploration. ●

PAC COM 2004 to feature top LNG buyers for Chinese Petroleum Corporation

9th Annual
Pacific Rim Construction Oil & Mining Expo & Conference

February 18-19, 2004
Anchorage, Alaska, USA

One of the important international speakers at the 2004 PAC COM conference will be Ms. Jane Liao, General Manager of LNG Purchase Division, Natural Gas Business Unit of Chinese Petroleum Corporation.

The Chinese Petroleum Corporation (CPC) is hundred per cent funded by the National Treasury and operated under the Ministry of Economic Affairs. CPC was founded in Shanghai in June 1946 and subsequently transferred headquarter to Taiwan in 1949. With a dedicated workforce approaching 16,000 individual, CPC has been entrusted with the active exploration, development, refining, transportation, marketing and sales of petroleum and natural gas and has served as the prime mover in Taiwan's petrochemical industry since the 1960s. The company's sales turnover in 2002 was around NT$ 391 billion in total.

Natural Gas Business Unit (NGBU)

NG's sales turnover accounts for 16% of company's overall turnover.

Natural Gas Business Unit, amongst the various functional units around the island to carry out the divers operations, has been set up since May 2002 to integrate the natural gas business including LNG importation.

JANE LIAO

Natural gas, known to be a clean, efficient and economical fuel was considered a real option for Taiwan as early as the 1980's and in the past 15 years, CPC, a state-owned company, is the one responsible for LNG importation and has been running the monopoly business since the beginning and has continued to address and promote LNG as a fuel of choice for the new millennium through a series of multi-million dollar infrastructure initiatives covering receiving, storage and distribution.

Located at Yungan in Kaohsiung, the current operating LNG receiving terminal was completed in 1990 with an annual handling capacity of 1.5 million tonnes. An expansion project that enlarged storage facilities and extended gas trunklines has boosted the handling capacity to 7.44 million tones of LNG annually. CPC is to complete a new terminal with receiving capacity of 3 million tones at Taichung Harbor (central Taiwan) as the Second Terminal.

The LNG volume imported by the state-owned CPC, the sole importer has increased from 1.7 million tons in 1992 to 5.57 million tons in 2003 and expected to import 6.4 million tons in 2004.

CPC has maintained three long- term LNG contracts with total contractual volume of 5.60 million tons per year to supplement the current market demand. With demand for natural gas continuing to outstrip predictions, CPC further consolidated their supplies with Ras Laffan Liquefied Natural Gas Company Limited (II) (RasGas II) for the supply of 3 million tones per annum (MTA) of LNG for 25 years, commencing in 2008.

PAC COM EXPO

With workforce around 830 individule, NGBU is responsible for the security of natural gas supply in Taiwan. With the integration of the existing southern terminal, trunk lines, the transmission system, the future northern terminal and a further extension of sub-sea pipeline, an entire loop of gas delivery along the well-developed west coast of Taiwan will enhance CPC's reliability of gas supply.

General Manager Liao will address "LNG demand and supply in Taiwan and extended market" as part of the Energy Track at the PAC COM Conference. Other presentations in the Energy Track will include project updates from major and independent oil and gas operators, State of Alaska, Department of Natural Resources, the Alaska Natural Gas Development Authority among other topics.

PAC COM is a state-of-the art trade exhibition and conference that brings together key individuals, companies and government organizations from every aspect of construction, oil and mining industries focusing on opportunities for business development in Alaska and the Pacific Rim. Over 200 companies display the latest in products, equipment and services for these industries. Revolutionary new oilfield, mining and environmental technology and innovations will be unveiled at the show.

For complete schedule and event information log on:
http://www.paccomexpo.com.

Contact - Rada Khadjinova-Jones: 888-509-7469. In Anchorage: 907-277-7469

government

JUNEAU, ALASKA

Governor introduces three oil and gas leasing, right-of-way bills

Alaska Gov. Frank Murkowski has introduced three bills intended to assist the state's oil and gas leasing and development programs.

The measures, introduced Jan. 14, could help advance the governor's plans for leasing in the Bristol Bay area of Southwest Alaska and ensure that the Department of Natural Resources is able to continue signing agreements so that it can be reimbursed for its preliminary work on oil and gas pipeline right-of-way lease applications.

Senate Bill 264 would repeal the Dec. 31, 2003, sunset provision in state law for such reimbursable services agreements between Natural Resources and pipeline right-of-way applicants. Failure to adopt the legislation extending the department's authority would leave it without funding for the pre-application review work, which, according to the department, could delay final application reviews.

Without preliminary review of land issues, the governor said in submitting the bill to lawmakers, "Incomplete applications or applications that must be revised later are costly … (and) create delays that could cost a producer the construction season."

Want to know more?

If you'd like to read more about Bristol Bay and the proposed leasing activity there, go to Petroleum News's Web site and search for these articles, published in the last year.

Web site:
www.PetroleumNews.com

2003

- **Dec. 28** Alaska asks for competing proposals for Bristol Bay basin exploration license
- **Dec. 21** Murkowski budget plan seeks lease sale funding
- **Nov. 23** Bush signs law removing Bristol Bay Congressional restrictions
- **Nov. 30** MMS working on economic ecosystem
- **Nov. 2** Three companies interested in Bristol Bay oil and gas exploration licenses
- **Nov. 2** Bristol Bay project driven by jobs, local energy
- **Oct. 26** Bristol Bay looks to oil and gas for economic diversification
- **Sept. 21** Alaska posts Bristol Bay study
- **Aug. 31** State receives notices of interest in Bristol Bay exploration licenses
- **July 27** Alaska solicits Bristol Bay exploration license proposals
- **July 20** Bristol Bay road considered
- **July 20** Bristol Bay Naives ask Stevens to pull OCS drilling moratorium from bill
- **July 6** Alaska to lease Bristol Bay lands; one year-plus to first oil and gas sale
- **June 15** Opportunity beckons
- **May 25** BLM sets aggressive agenda for NPR-A issues (Bristol Bay included)
- **April 27** DOE funds $5.5 million in Alaska research

Two bills to assist with Bristol Bay leasing

The governor's Senate Bill 266 would close certain lands in the Bristol Bay region to oil and gas exploration licensing and shallow gas leasing, thereby holding back the acreage for the administration's planned, large-scale competitive lease sale in the area.

The measures, introduced Jan. 14, could help advance the governor's plans for leasing in the Bristol Bay area of Southwest Alaska and ensure that the Department of Natural Resources is able to continue signing agreements so that it can be reimbursed for its preliminary work on oil and gas pipeline right-of-way lease applications.

"Closure avoids potential conflicts in land use for these areas later," Murkowski said.

And Senate Bill 265 would allow the Department of Natural Resources to get started a year earlier on preparing a report to lawmakers on proposed oil and gas lease sales.

The measure 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 that the bill would allow the department to present to legislators in January 2006 a report on potential Bristol Bay leases instead of waiting until 2007.

"These amendments will ultimately allow Natural Resources to hold sales in the frontier areas sooner," the governor said in his statement on the legislation.

—PETROLEUM NEWS

● CANADA

New government sets lively pace on issues

Canada under Martin: patching U.S. relationships, Petro-Canada sale, opening B.C. offshore, nuclear power on minds of cabinet ministers

By GARY PARK

Petroleum News Calgary Correspondent

The new Canadian government under Prime Minister Paul Martin has filled the sky over the energy sector with trial balloons.

Blazing into the new year, cabinet ministers have declared:

- Mending Canada-U.S. relationships is a "must" if Canada is to build on its energy exports.
- Selling the government's remaining 19 percent stake in Petro-Canada could be on the horizon.
- Exploration of British Columbia's offshore poses no obstacles.
- More government support, but not necessarily money, is needed to expand the nuclear industry.

Efford works on fence mending

Describing himself as a person of "action," Natural Resources Minister John Efford has wasted no time in his first month on the job, holding a meeting with U.S. Energy Secretary Spencer Abraham and spending three days with industry leaders in Calgary.

He said his advisers are pressing for a national energy strategy for Canada to expand infrastructure in the Alberta oil sands, develop Arctic gas reserves and build two liquefied natural gas terminals in Nova Scotia and New Brunswick to serve U.S. markets.

Less than a week after his appointment Dec. 12, Efford met with Abraham to seek agreement on a transportation policy for gas from the North Slope and Mackenzie Delta and to make a case for the two LNG terminals.

Less than a week after his appointment Dec. 12, Efford met with Abraham to seek agreement on a transportation policy for gas from the North Slope and Mackenzie Delta and to make a case for the two LNG terminals.

"Improving the relationship between Canada and the U.S. is a must," he told reporters in Calgary Jan. 12 in an indirect reference to the tensions that built up last year under his predecessor Herb Dhaliwal, who questioned President George W. Bush's statesmanship on the Iraq invasion and threatened to withhold permits for an Alaska Highway gas pipeline if the United States subsidized the project.

Efford said he endorsed accelerated energy development in Canada to help the United States achieve its goal of greater energy security.

Efford: protect environment, 'but not at the expense of business'

He also said that the first principle governing

see **PACE** page 10

● JUNEAU, ALASKA

Collecting on surface damage

New laws would deal with damage claims from CBM development in Alaska

By LARRY PERSILY

Petroleum News Government Affairs Editor

The 86 lines of proposed new laws in Senate Bill 240 are intended to solve several of the most contentious issues for development of coalbed methane reserves in Alaska — determining if private property is damaged by drilling for its subsurface resources, putting a dollar amount on any damages, and collecting for any harm to the property's value.

Senate President Gene Therriault said he took legislation that former Sen. Rick Halford had attempted several years ago, "dusted it off" and introduced it for consideration this year.

The legislation also would impose new requirements for notifying property owners when the state leases out the ground beneath their surface rights.

Property owners in the Matanuska-Susitna Borough and near Homer this past year learned three things about their land: they don't own the subsurface rights; the state, which holds the rights, has leased more than a quarter-million acres for coalbed methane exploration; and, third, state law doesn't give property owners veto power over access to their land by companies wanting to drill.

A lack of any requirement in state law for notice to individual property owners of such leases also added to the debate this past year.

Lawmakers expected they would see legislation dealing with the issue of coalbed methane, or shallow gas, when they returned to work Jan. 12 for the start of their annual 121-day session. Senate President Gene Therriault did not disappoint them. He said he took legislation that former Sen. Rick Halford had attempted several years ago, "dusted it off" and introduced it for consideration this year.

"It's a starting point for discussion," Therriault said.

Halford, a Chugiak Republican, represented the Matanuska-Susitna Borough until his retirement in 2002. Therriault, a North Pole Republican, represents a large district that stretches as far away as Sutton at the northern end of the gas-prospect borough.

Therriault's bill defines "damages" as interference or interruption with the owner's use of or access to the property, including the "the actual cost of repair, relocation, replacement or restoration of the property … not to exceed the fair market value." A claim for damages must be based on "the owner's actual use of the property" before any on-site exploration activity started. State statute requires coalbed methane exploration companies and other subsurface leaseholders to pay property owners for damages to their land, although

see **DAMAGE** page 10

● JUNEAU, ALASKA

Bill's goal is water quality, local control of CBM

Legislation answers calls for more regulation of coalbed methane in Alaska

By LARRY PERSILY

Petroleum News Government Affairs Editor

One of the major worries over coalbed methane production in Alaska is possible harm to streams and underground drinking water, so an Anchorage freshman legislator has introduced a bill to significantly strengthen state laws protecting water quality in lease areas.

Among other provisions, House Bill 370 would require that all state leases for coalbed methane exploration and production include conditions to protect any fish-bearing waterways in the area. Those conditions would require approval by the Department of Fish and Game, a provision certain to create controversy in the Republican-led Legislature that last session endorsed Gov. Frank Murkowski's move to take away some permitting authority from Fish and Game.

"I wanted to make sure there was a discussion this year," said the bill's sponsor, Democratic Rep. Les Gara, whose downtown Anchorage district is an hour's drive away from any of the coalbed methane lease areas.

Bill seeks safe disposal of water

In addition to provisions protecting fish habitat, House Bill 370 includes a section requiring leases to govern the safe disposal of all water produced in shallow gas drilling and production. The de-watering of coalbed methane reserves presents operators with the choice of disposing the water on the surface — generally opposed by critics — or the more expensive option of injecting it back into the ground.

The bill would require that any water disposal plan "not add to or contaminate surface water supplies."

And, in a further effort to address skeptics' concerns that the state lacks adequate laws for oversight of coalbed methane operations, the bill would require the Department of Natural Resources to adopt regulations "to ensure that shallow natural gas exploration and development activities do not materially interfere" with recreational, sport and subsistence activities.

The bill is intended to do more than just protect water quality, Gara said. It is to protect the public's access to fish streams in areas of shallow gas exploration and development.

Gara introduced the bill Jan. 9 in the final batch of prefiled legislation before the Jan. 12 start of the 2004 session.

Measure restores local control

His bill also would reverse legislation adopted last year that blocks municipalities from regulating coalbed methane development. Gara's bill would allow cities and boroughs to adopt land-use laws to protect residents' safety and neighborhoods, and limit noise from drilling and production operations.

Lawmakers last year passed House Bill 69, sponsored by Wasilla Republican Rep. Vic Kohring, blocking municipalities from regulating coalbed methane operations. Kohring, who has spent his nine years in the Legislature promoting business development and opposing government regulation, has come under criticism the past year from constituents worried that coalbed methane production could harm water quality and property values in their own yards.

"They took away local control in coalbed methane," Gara said of last year's legislation, adding that his bill is specific in making certain that communities have as much zoning authority over shallow gas development as possible under the state constitution.

Gara voted against final passage of HB 69 last year. Half of his colleagues in the House and Senate signed on as cosponsors for the bill. ●

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continued from page 9

PACE

any decisions on implementing the Kyoto Protocol in Canada is that the energy industry "must grow."

"We have to protect the environment, but not at the expense of business," he said, announcing that he will meet with Environment Minister David Anderson this month to explore what changes, if any, are needed in the Kyoto implementation plan.

For now, Efford said it is too early to know whether the government will have to take measures over and above its commitments to cap greenhouse gas emissions and protect energy jobs. "Maybe there will be some, maybe there will be none," he said.

Goodale exploring sale of Petro-Canada shares

Finance Minister Ralph Goodale aroused interest by declaring a personal preference to sell the government's 49.4 million shares in Petro-Canada and spend the windfall on environmental technology.

At current trading levels, the holding is worth close to C$3.2 billion, but net return would be about C$2.6 billion after deducting the government's original investment of C$570 million.

A government source told The Globe and Mail a decision will be made in the "short-term," hinting it could be part of a budget expected in late February or early March.

Goodale was more cautious on the target, noting that the divestiture would need an "elaborate" selling process.

By Jan. 12 he said that no decision had been taken and he "wouldn't want to speculate" because that could be seen as "improperly interfering in the marketplace."

Federal restrictions prevent any single investor or group from holding more than 20 percent of Petro-Canada, which was created as a state-owned company in 1975 to provide the government with a "window" on the oil and gas industry and to promote Canadian ownership of energy resources.

Petro-Canada and Suncor Energy are the only two of Canada's five integrated oil producers and gasoline marketers that are not controlled by foreign investors, unlike Imperial Oil, Shell Canada and Husky Energy.

Among analysts there are doubts that the government would be happy to see the shares sold off at a discount at a time when their value has climbed from C$50 to about C$65 in the past year and could push closer to C$80 in a bull market.

There are also questions about who might be interested in snapping up Petro-Canada widely diversified assets that include interests in Canada's Arctic, oil sands and offshore East Coast, plus its profitable, but widely-scattered international division.

However, Martin indicated several times during his campaign for leadership of the governing Liberal party that the proceeds from a Petro-Canada sale could be used to make Canada a world leader in environmental technologies aimed at reducing greenhouse gas emissions.

Atlantic offshore could be model for British Columbia

On the British Columbia offshore, Efford said Newfoundland and Nova Scotia have provided optimism that offshore resources can be developed without harming fish stocks or the marine environment.

While declaring that he has the "same thinking" for British Columbia, he promised an open mind for views from those who oppose drilling in Pacific waters.

He also promised to work closely with Environment Minister David Anderson, an implacable opponent of hasty decisions on opening up the British Columbia offshore.

Efford also supports nuclear power

In other interviews, Efford emerged as an advocate of expanding Canada's use of nuclear power, describing it as a "clean environmental thing to do."

However, he promised no additional money for government-owned Atomic Energy of Canada Ltd., which received C$179 million in federal subsidies last year, suggesting that would need the backing of Goodale.

Atomic Energy of Canada has been promoting a revival of nuclear power after a hiatus of 10 years, making a case for 20 new reactors across Canada over the next two decades.

That thinking follows recent comments by Phil Prince, president of the Canadian Energy Research Institute, who predicted Canada will need more nuclear plants to meet electricity demands that can't be satisfied by oil, natural gas, coal and renewable fuels.

Meanwhile, Atomic Energy of Canada has been pitching the merits of a new advanced reactor in the United States — a so-called light-water reactor that can generate 730 megawatts for about US$700 million, or enough electricity for 700,000 homes.

Currently, the United States is relying on 103 old commercial reactors in 32 states that meet about 20 percent of total U.S. energy demand, while coal-fired plants produce about 51 percent.

Although it has never sold a reactor in the United States, Atomic Energy of Canada has built 22 reactors in Canada and another dozen in South Korea, Romania, Argentina and China. ●

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DAMAGE

it provides no definition for damages. Companies may either negotiate with landowners to cover potential damages before entering the property or, if negotiations fail, post a bond to cover possible damage claims.

Therriault said his intent is to clarify the process for all sides. Under his legislation, damage claims would be limited to the greater of any loss of income to property owners or loss in value of their land caused by drilling or other activity under the subsurface lease. The bill also would allow punitive damages if the property owner could prove that the leaseholder knowingly violated "a material term or condition" of an operating plan for the lease activities.

Because existing law provides no guidance for determining the amount of surety bond required to protect property owners who are unable to negotiate a contract to cover potential damages, Therriault's bill directs the Department of Natural Resources to set the bond at the assessed value of the property or $100,000, whichever is greater.

The bill also bars claims against property owners for any damages incurred by leaseholders entering the property, unless it can be proven that the land owner acted with "intentional misconduct."

A new section of law in the bill would require the Department of Natural Resources to notify individual property owners of subsurface leases on their property before any activity occurs on the property. The notice would have to include a copy of a state-approved plan for the activity, a summary of the activity, and "a brief description in writing of the legal rights of the owner." ●

CANADA

Canada shatters records in 2003 for new well permits

Regulators across Canada issued a staggering 27,454 permits last year to drill oil, natural gas, bitumen and other wells, easily toppling the previous high of 21,967 in 2000.

The breakdown included 18,244 development holes and 6,360 exploration permits, both new records, while many of the 2,739 evaluation and observation wells were directed at new oil sands and bitumen projects.

Alberta passed the 20,000 mark for the first time, reaching 20,887; Saskatchewan logged 4,784 permits, British Columbia 1,517, Manitoba 103, Eastern Canada 131 and Northern Canada 32, its highest level in 16 years.

EnCana easily outstripped the operators with 5,713 new well licenses, followed by Canadian Natural Resources at 1,713, Husky 1,381, EOG Resources 1,182 and Apache Canada 999.

Adding to the momentum entering 2004, governments sold 12.2 million acres of exploration land for C$1.71 billion and collected another C$707 million for another 7.86 million acres of work bid commitments in Eastern Canada, Northern Canada, British Columbia and Saskatchewan.

The Northwest Territories attracted only C$1.1 million in bids for 197,000 acres.

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

NORTH AMERICA

Canada's rig count surges, United States count falters

The North American rotary rig count, lifted by winter demand in Canada, jumped by 136 to 1,594 rigs for the week ending Jan. 9, according to rig monitor Baker Hughes.

The number of rigs operating in Canada compared to the previous the week surged by 156 to 488, also up by 44 rigs versus the same period a year earlier.

In contrast, the United States took a beating as the weekly count tumbled by a net 20 rigs to 1,106, but was still up by 255 rigs compared to the same period last year. Land rigs alone fell by 20 to 988, while offshore rigs slipped by three to 101. Inland waters saw an increase of three rigs to 22.

Of all rigs operating during the week in the United States, 957 were drilling for natural gas and 147 for oil, while two rigs were being used for miscellaneous purposes. Of the total, 737 rigs were drilling vertical wells, 277 directional wells, and 92 horizontal wells.

Among the leading producing states in the United States, Texas was hardest hit during the week as its rig count plummeted by 29 to 449. New Mexico's fell by three to 72 rigs. Alaska's dropped by two to 10 rigs. And California's slipped by one to 25. Louisiana's rig count increased by four to 162, while Oklahoma's was up by four to 149. Wyoming gained two rigs to end the week with 68.

—**PETROLEUM NEWS**

● NEWFOUNDLAND

Deepwater Orphan Basin a big-time oil prospect

Independent seismic rates reserves at 6-8 billion barrels, bigger than anything in North America except Alaska's Prudhoe Bay field

By GARY PARK

Petroleum News Calgary Correspondent

Speculative seismic could thrust Newfoundland's deepwater Orphan Basin into the big leagues, if drilling is able to back up the results.

Geophysical Service Inc., which operates primarily out of Calgary and Houston, has rated the potential of the basin at 6 billion to 8 billion barrels — surpassing anything in North America except Prudhoe Bay.

GSI Chief Executive Officer Davey Einarsson told Petroleum News that the seismic points to oil-bearing sands that are three to four times the size of the nearby Jeanne d'Arc Basin, which is currently Newfoundland's only producing area and is estimated to hold about 2 billion barrels of recoverable oil.

He described Orphan as "broader, bigger and less complex" than Jeanne d'Arc, where the Hibernia and Terra Nova fields are on stream and White Rose is targeted for start-up by early 2006.

The findings from three summers of seismic — 1,500 miles of 2-D and 200 square miles of 3-D in a 52,000-square-mile basin — lend weight to the startling pre-Christmas land sale, when Chevron Canada Resources (the 50 percent operator), Imperial Oil and ExxonMobil (each holding 25 percent) made C$673 million in successful work commitments for eight parcels.

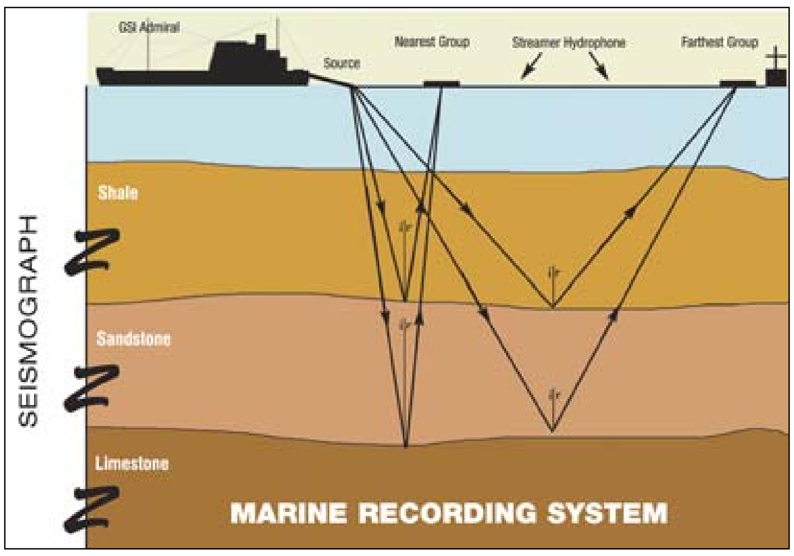
Einarsson said Jeanne d'Arc is "much more faulted and complex," while Orphan "is more uniform and bigger in the same geologic zone, so it's got more potential."

Water depths 6,600 to 10,000 feet

Water depths for Orphan are 6,600 to 10,000 feet and the oil deposits are thought to lie another 6,600 to 16,400 feet below the ocean floor.

The region is notorious for icebergs and storms, but Einarsson said technological advances have reduced most of those dangers, with floating production storage and offloading vessels able to be moved from the path of any approaching icebergs.

He said "all of the majors" have participated in the seismic work, which GSI hopes to continue this year with two vessels — one owned and one leased, but he said the company has not been involved in negotiations with Chevron, Imperial or ExxonMobil.



TOM KEARNEY

However, Einarsson believes the bidders will likely start drilling in 2006.

A spokeswoman for Chevron told Petroleum News that more seismic work is likely to be conducted within two years before a decision is made on drilling.

However, she said Chevron views its record bids as an "exciting move into a new and unexplored basin," and an element of the company's focus on growth opportunities in the Mackenzie Delta, Alberta oil sands and Atlantic Canada.

Indications of potential "really spectacular"

Kevin Roche , chairman of the 500-member

see **ORPHAN** page 14

continued from page 1

ALPINE

all of the five pads, and the no-action alternative — no new development. (See sidebar on alternatives in draft EIS.)

The draft EIS will be available online Jan. 16 at www.ak.blm.gov and the 45-day public comment period runs through March 1.

Hypothetical full-field development also studied

In addition to analysis of the five alternatives, the draft EIS includes an analysis of what full-field development could look like based on the four development alternatives (the fifth is the no-development alternative).

The full-field development analysis for the 890,000 acre project area represents hypothetical scenarios that could occur during the next 20 years. New production facilities — not just drilling pads — would be required if production occurred farther to the west than ConocoPhillips' proposal, "because three-phase flow from the wells (the mixture of oil, water and gas which flows from the reservoir) is limited to a maximum distance of approximately 25 to 30 miles without processing and pump station support," the agencies said in the EIS.

One reason the agencies included the hypothetical full-field development, Ducker said, is that other environmental impact statements "have been criticized for not looking out farther," because once facilities are built, it makes it cheaper to do more development in an area. Previous documents have been criticized for not looking at what logically could come next.

"We were determined not to be in that situation," he said.

There was some concern, he said, that an analysis of the hypothetical full-field development case would deny the public an opportunity to comment on further developments — a concern that the agencies would make all the decisions now.

"That's not the case," he said.

The decision this year will be only on the five pads ConocoPhillips is proposing now, CD-3 through CD-7.

For analysis only

"We've got a lot of people working on this and thinking about this now," Ducker said, and it made sense to look at "these issues in a broader sense, because this can help us later on" if there are applications for additional development.

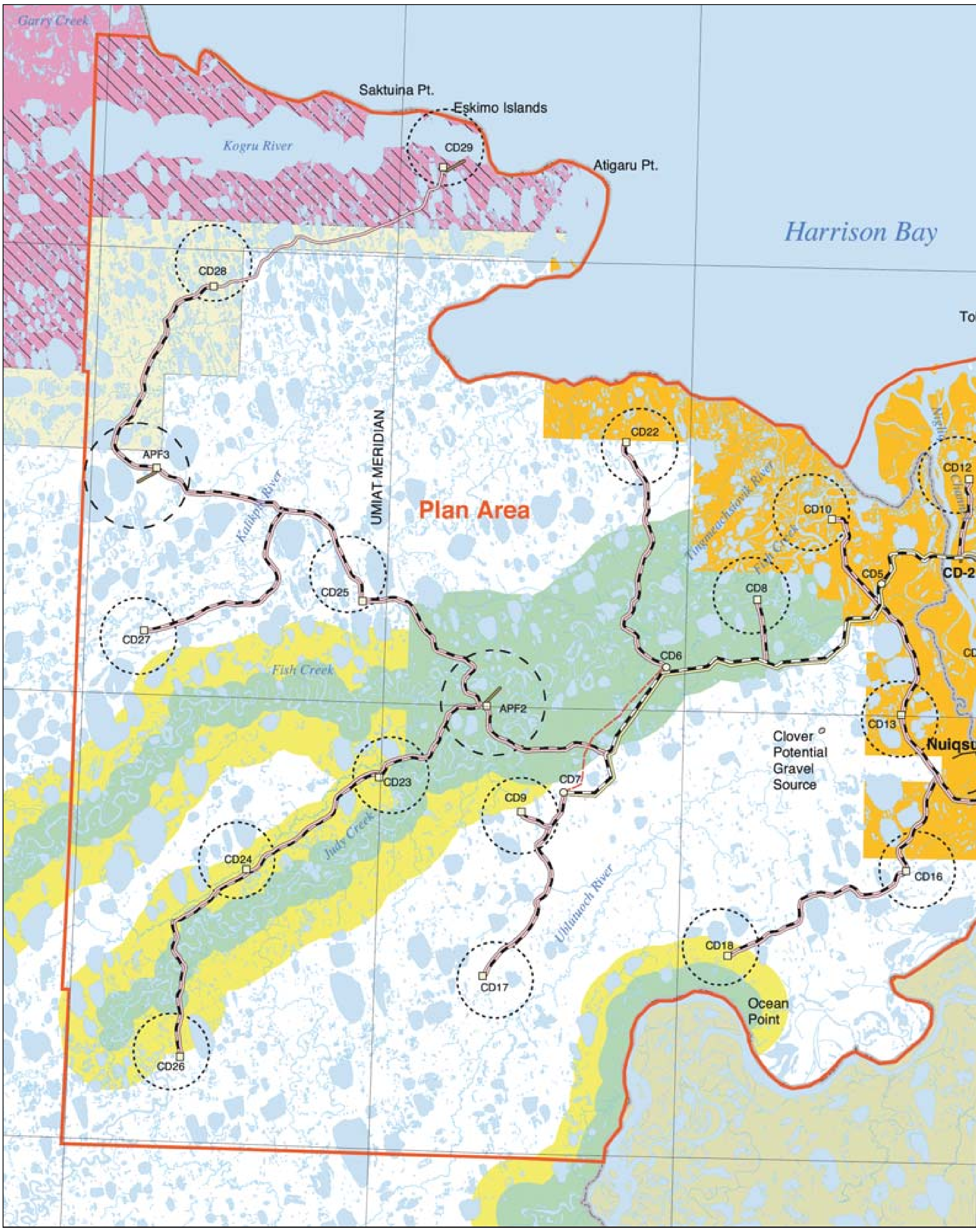
Because the hypothetical pads were sited in a broad range of habitat areas, regulators could find that for future proposals they already have analysis that is analogous.

And mitigating measures, not useful for the five pads, might be useful for development farther west.

Ducker said the agencies included the hypothetical full-field development "for analysis purposes" only. Hypothetical drill sites do not indicate oil and gas discoveries, he said, but instead indicate "different sorts of habitat. We're capturing birds here. We're capturing caribou here. We're capturing a polar bear den here … And so that the analysis will be as full, as robust as possible, covering as many of the resources that we know are there."

In the hypothetical case, the agencies said in the draft EIS, they "identified hypothetical locations for 22 production pads and two pads that would have both

see **ALPINE** *page 13*



This map shows a hypothetical full-field development in the northeast corner of the National Petroleum Reserve-Alaska and on adjacent state lands. In addition to the five pads in the ConocoPhillips Alaska proposal, the map shows possible pad locations illustrating types of habitat in which oil and gas development might occur in the future. The hypothetical pad locations do not reflect known accumulations. "The conceptual FFD (full-field development) portrayed and evaluated in this EIS is believed to overstate the anticipated FFD," the agencies said in the draft environmental impact statement for Alpine satellite development. While 24 additional pad sites are shown, in addition to the five proposed, the agencies said ConocoPhillips Alaska "projects that their leases … would not support more than a total of 12 production pads within the Plan Area, including existing CD-1 and CD-2 and the five proposed pads."

And the EIS alternatives are…

The draft environmental impact statement for ConocoPhillips Alaska's Alpine satellite development includes five alternatives: ConocoPhillips' proposal; an alternative which conforms with stipulations in the Northeast National Petroleum Reserve-Alaska EIS; an alternative with roads to all of the satellites; an alternative roads to none of the satellites; and a no-action alternative, which would allow no new development.

"The alternatives we chose address specific concerns raised during the scoping period and through our consultations with tribal governments and North Slope governing bodies," BLM Alaska State Director Henri Bisson said in a Jan. 12 statement.

The draft EIS does not recommend an alternative. That step will be taken as the cooperating agencies — BLM, the Environmental Protection Agency, the Corps of Engineers, the Coast Guard and the state of Alaska — prepare the final EIS.

Jim Ducker, the BLM environmental program analyst who managed the project for BLM, told Petroleum News Jan. 13 that the preferred alternative in the final EIS "may well be different than alternative A, ConocoPhillips' proposal."

Alternative A proposes five satellite drilling pads, all tied back to the Alpine production facility, with four of the five satellites tied back to Alpine with roads and a road and pipeline crossing of the Nigliq Channel near existing Alpine facilities, CD-1 and CD-2.

Alternative B conforms with 1998 decision

Alternative B reflects requirements in the BLM's Northeast NPR-A EIS issued in 1998, particularly the location of CD-6, which ConocoPhillips wants to put within a three-mile setback from Fish Creek. BLM's 1998 decision specifies no permanent oil and gas facilities within that three-mile buffer. Ducker said the 1998 decision also specifies no connection to an outside road network. The two mile road between Alpine CD-1 and CD-2 isn't really a road network, he said, "but once you get there we've lost control over keeping road development in NPR-A separate from road development elsewhere."

So Alternative B, "in an abundance of caution," specifies

see **ALTERNATIVES** *page 13*

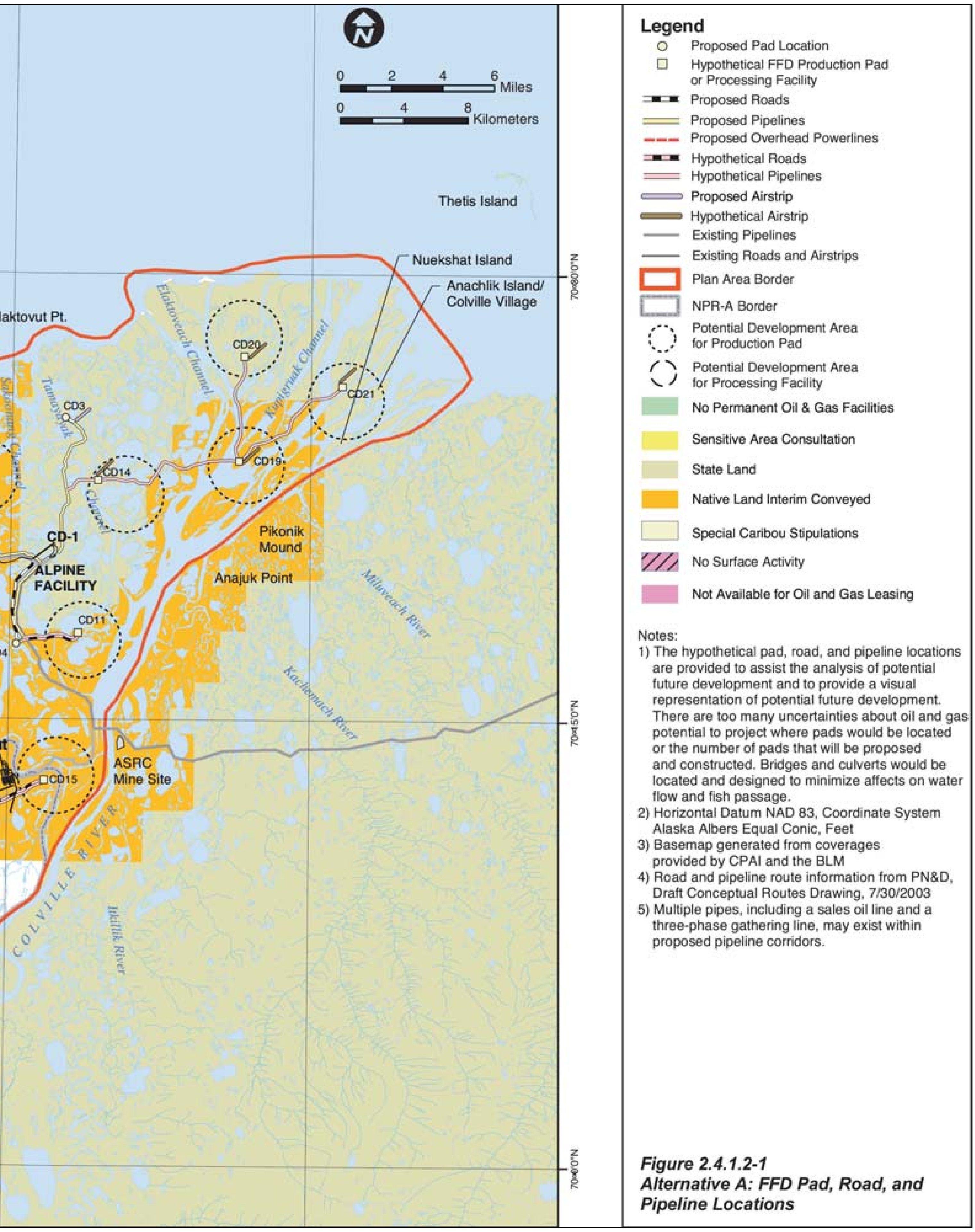


Figure 2.4.1.2-1
Alternative A: FFD Pad, Road, and Pipeline Locations

COURTESY OF BLM

continued from page 12

ALPINE

processing facilities and production wells.

"The actual location and number of production pads and (processing facilities) that would be required to accomplish FFD are not known. The conceptual FFD portrayed and evaluated in this EIS is believed to overstate the anticipated FFD."

The agencies said in the draft EIS said that ConocoPhillips Alaska has projected that its leases in the full-field development area "would not support more than a total of 12 production pads within the Plan Area, including existing CD-1 and CD-2 and the five proposed pads."

Final EIS expected out in late June, early July

After the public comment period closes March 1, BLM and the cooperating agencies — the U.S. Environmental Protection Agency, the U.S. Army Corps of Engineers, the U.S. Coast Guard and the state of Alaska — "will move on to defining a preferred alternative, which will come out in the final EIS," expected out at the end of June or very early July, Ducker said. The BLM's record of decision is expected in early August.

Each federal agency issues its own record of decision, as the agencies have different authorities. The EIS, however, is a joint document, and there will be one preferred alternative, "fashioned by multiple agencies," which is the basis of decisions by all the agencies, Ducker said.

ConocoPhillips will submit permit applications for the project Jan. 16, Ducker said, and permits for the project are expected to be issued "very shortly" after the record of decision.

First production could be in 2006

Construction would begin at CD-3 and CD-4, east of NPR-A, and even though work would not begin on BLM-administered lands for a couple of years, BLM intends to issue its permits, Ducker said.

The agencies said in the draft EIS that the development would be phased, with the first commercial production from new pads in the Colville Delta in 2006. The first commercial production from the National Petroleum Reserve-Alaska could occur in 2008.

Alpine has been in production since November 2000. There are two pads at the field. Discoveries have been announced north of the Alpine field at Fiord, south of the field at Nanuq and west of the field in the National Petroleum Reserve-Alaska. The five proposed new pads include activity on state and federal lands both in the existing Colville River unit and to the west of the unit.

ConocoPhillips Alaska spokeswoman Dawn Patience told Petroleum News Jan. 13 that the company is happy that the draft EIS is out, is pleased with the energy the agencies put into the draft and with the fact that they are "keeping with the schedule."

ConocoPhillips supports alternative A, which is its original proposal for satellites in NPR-A and the Colville River unit.

But, Patience said, while ConocoPhillips is "excited about the potential of these satellites, a final decision (to go ahead) will be based on the EIS and permit outcome — and we also have work to do to improve the economics of these opportunities." ●

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ALTERNATIVES

that there are no roads or pads within the three-mile setback, and requires that CD-6 move about a mile farther from Fish Creek, "and our geologist estimated that that would drop the production from CD-6 by 10 to 30 percent." Alternative B also does not have a bridge road connection from the NPR-A side to non-BLM land, just a pipeline crossing.

Alternative C provides roads to all pads

Alternative C has a different bridge crossing, upstream near CD-4, rather than near CD-2, with "road connections far to the south of what ConocoPhillips has proposed." There would be less intrusion into the three-mile setback at Fish Creek because the road would run at right angles to the stream, instead of paralleling the stream within the setback for a number of miles.

The road goes so far south under this alternative, Ducker said, that it would hook up to Nuiqsut. Some Nuiqsut residents believe that with a road connection it would be easier to get jobs at Alpine or the new satellite sites.

There was also concern about aircraft noise, particularly at CD-3 in the northern part of the delta (the Fiord discovery) where ConocoPhillips proposes to reach the site by aircraft. It is an important bird habitat, Ducker said, so the agencies looked at what it would take put a road to CD-3. It's an engineering challenge, he said, but the agencies analyzed putting

Alternative D is the roadless alternative, including sub-alternatives for fixed-wing and helicopter access. Drilling would take longer, based on a single drill rig which could only be moved on ice roads in the winter.

a road in so that there would be less noise in the bird habitat.

Both alternatives C and D raise the pipeline from five feet to a minimum of seven feet at the vertical support members.

Alternative D: no road access

Alternative D is the roadless alternative, including sub-alternatives for fixed-wing and helicopter access. Drilling would take longer, based on a single drill rig which could only be moved on ice roads in the winter.

"Where C brackets us in roads everywhere, D brackets us the other way," Ducker said.

Alternative E is the no-development alternative.

"It's important for us to have a range. There's an infinite number of alternatives, you can mix and match all these features," Ducker said. "We've tried to get a range of alternatives that together, cumulatively, address all of what we think are viable, reasonable alternatives.

"And the preferred alternative may well be a mix and match of some of these."

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

● GULF OF MEXICO

Puma discovery adds to region's geologic promise

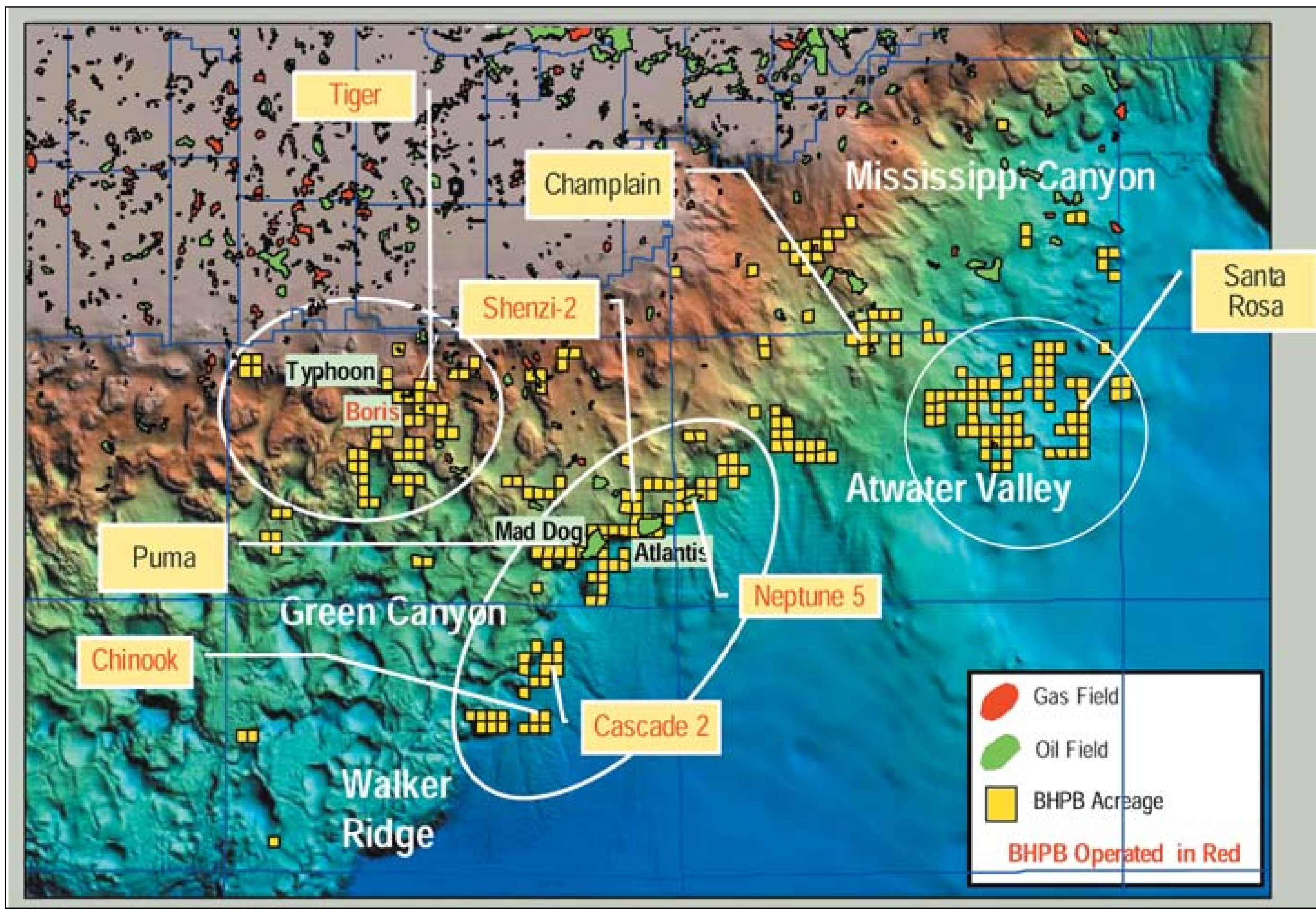
PETROLEUM NEWS

The announced Puma oil discovery in the Gulf of Mexico demonstrated once again the richness of the Atwater Fold Belt, a huge trend that has produced numerous large reservoirs in recent years and a growing reputation as the hottest play in deepwater Gulf.

Prospect owners BP, BHP Billiton and Unocal said Jan. 13 that more drilling will be required to determine Puma's reserves, but there is no sneezing at the impressive 500 feet of net oil pay penetrated by the Puma-1 exploration well and two sidetrack bores.

"We know hydrocarbons are there and we are excited," said a spokesman for Puma operator BP, which also operates major fields in the southeast Green Canyon that includes Holstein, Atlantis and Mad Dog, all currently under development.

In fact, Puma is situated just west of Mad Dog on Green Canyon Block 823 and, if deemed commercial, would give the owners options to develop Puma as a stand-alone facility, or as a subsea tie-back to the Mad Dog platform, expected to commence production in late 2004 or early 2005.



COURTESY BHP BILLITON

Not ready to declare victory

However, none of the owners is quite ready to declare victory at Puma, despite an oil column that ranks alongside some of the thickest pays found in the deepwater Gulf. For one, Puma has complicated geology and existing seismic imaging data used to evaluate the prospect "is of moderate quality," said Mike Bell, vice president of Unocal's Deepwater USA unit.

"Puma is structurally complex and will require additional seismic data and appraisal drilling to determine the size of the field," Bell said.

Australia's BHP agreed more work needs to be done at Puma. "This is an encouraging find ... but we're going to have to do some more drilling and collect more data," a company spokesman said.

Prospect owners BP, BHP Billiton and Unocal said Jan. 13 that more drilling will be required to determine Puma's reserves, but there is no sneezing at the impressive 500 feet of net oil pay penetrated by the Puma-1 exploration well and two sidetrack bores.

Still, Bell said that the Puma 1 discovery well, drilled in a little over 4,000 feet of water to a total depth of 19,034 feet, confirmed the prolific lower and middle Miocene sands and "further enhances prospectivity in southeast Green Canyon," where Unocal is currently drilling its Myrtle Beach prospect.

"We are very pleased with what these (Puma) results mean for the value of our prospect inventory in this area," Bell said.

BP holds a 51.66 percent interest in Puma, followed by BHP with a 33.34 percent stake and Unocal with a 15 percent interest.

Discoverer Spirit will move to deeper water

Bell noted that after finishing work at Myrtle Beach, Unocal's Discoverer Spirit drillship will move into deeper waters of the Gulf to drill an exploratory well on the Tobago prospect at Alaminos Canyon Black 859. Tobago is situated between Shell's Great White discovery and Unocal's Trident discovery, both located in nearly 10,000 feet of water and close to Mexico's territorial waters.

In addition to Myrtle Beach and Tobago, Unocal's deepwater Gulf drilling plan for 2004 includes an appraisal well at the St. Malo discovery in Walker Ridge 678.

The discovery well is said to have encountered more than 450 feet of net oil pay over a gross hydrocarbon column of 1,400 feet, indicating that St. Malo is a major hydrocarbon accumulation. ●

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ORPHAN

Newfoundland Ocean Industries Association, told the St. John's Telegram that the indications of Orphan's potential are "really spectacular," although there is much work ahead to define drilling targets.

He said more 3-D seismic is needed, followed by an evaluation to define geological targets, along with environmental assessments.

Roche doubted any drilling would be possible before 2005.

Seven exploration wells were drilled in the basin and northeast Newfoundland shelf over the decade to 1985, but none was drilled in the parcels sold last month.

The Newfoundland government, which included GSI's seismic findings in a study of the basin, has said the region is similar to the Porcupine Basin off the west coast of Ireland, where the Irish government has been trying to reignite an exploration program.

Einarsson said he was very surprised that the Orphan parcels were cornered by all three bidders, but was critical of Newfoundland's policy of allowing companies to carve out the blocks they want to bid on.

He said Newfoundland offers the "oil companies one heck of a deal," while regulators in the Gulf of Mexico, North Sea and Norway establish their own grid pattern for lease sales.

Einarsson said Newfoundland is employing an "archaic system" that stems from its old mining leases and in the process is not ensuring the best returns for taxpayers. ●

● BRITISH COLUMBIA

Offshore coalition loses its leader

By GARY PARK

Petroleum News Calgary Correspondent

Brian Peckford says his job is done and it's time to move on, which means that boosters of British Columbia's offshore future have lost their highest-profile advocate.

As premier and energy minister of Newfoundland in the 1980s, Peckford was instrumental in establishing a framework to give his province a share of its offshore oil royalties.

Since moving to Vancouver Island 10 years ago, he has been a central figure in the fight to persuade the Canadian government and British Columbians to end a ban on developing its offshore resources.

As chairman of the Pacific Offshore Energy Association he turned a small group of people into a lobbying force and just three months ago he boldly predicted that offshore drilling would take place by 2007.

But, with the offshore still a hot-button issue for the government, coastal communities, environmentalists and aboriginals, Peckford was resigned as chair.

He told the Nanaimo Daily News that he wants to "feel free to comment on the issue without having ties," turning the leadership over to Russ Hellberg, a former mayor of Port Hardy on Vancouver Island.

Effort shifting to public education

Hellberg credited Peckford with setting the offshore association in the right direction. Now the emphasis has shifted from lobbying to public education, he said.

In recent speeches and interviews, Peckford has predicted that Canada's newly installed Prime Minister Paul Martin will lift the federal moratorium on exploration by the end of 2004, clearing the way for seismic surveys in 2007.

Although he argued the federal government can merely change policy and does not require legislation to open up the offshore, he said legislation will be needed to establish an offshore oil and natural gas industry.

Peckford was adamant that Canada's experience with environmentally safe offshore development of the east coast over 20 years and Alaska's expertise can be transferred to the British Columbia coast.

"There is a very strong case to make that all the major issues around drilling off the coast of British Columbia can be addressed," he said.

From a physical standpoint, British Columbia has the advantage of a narrow shelf, compared with Newfoundland's shelf which stretches 180 nautical miles, suggesting British Columbia wells could be drilled for C$15 million-$20 million, compared with Newfoundland's C$40 million-$60 million.

Looking at other offshore basins with comparable geology he said British Columbia is likely to yield "a couple of large oil finds and several gas finds" that would provide a major infusion to the B.C. economy. ●

GULF OF MEXICO

Production begins at Pioneer's deepwater Harrier field in Gulf

Oil and gas production has begun from Pioneer Natural Resources' deepwater Harrier field in deepwater Gulf of Mexico with daily output of about 120 million cubic feet of gas and 300 barrels of condensate, Pioneer said Jan. 12.

COURTESY OF PIONEER

The Falcon Nest platform is owned and operated by GulfTerra Energy Partners.

The Harrier discovery well, located in 4,100 feet of water, was developed as a single-well subsea tie-back to Pioneer's Falcon field facilities at East Breaks. The field is producing into a 47 mile flowline through the Falcon manifold back to the Falcon Nest platform on the Gulf's continental shelf. That platform is owned and operated by GulfTerra Energy Partners.

"The development team will now concentrate on completing the tie in of our two other Falcon corridor satellite discoveries, Tomahawk and Raptor, expected during the third quarter," said Scott Sheffield, Pioneer's chief executive officer.

—PETROLEUM NEWS

HOUSTON, TEXAS

IADC Safety conference Feb. 3-4

The International Association of Drilling Contractors will hold its annual conference on health, safety, environment and training Feb. 3 and 4 in Houston.

Presentations will be made by managers from major companies, including ExxonMobil, BP and Noble Drilling, as well as representatives from governmental agencies including the Minerals Management Service and the Coast Guard.

The conference, sponsored by Noble Corp., will be at the Omni Houston Hotel Westside. For more information, contact Leesa Teel at 713-292-1945, ext. 210, or check the website at www.iadc.org/conferences.htm.

—PETROLEUM NEWS

OKLAHOMA

Oklahoma activity highest in 15 years

Producers taking advantage of higher oil and natural gas prices are drilling more new wells in Oklahoma than at any time in the last 15 years, energy regulators say.

The Oklahoma Corporation Commission issued 5,119 drilling permits to oil and gas producers last year, the most in a year since 1988, the commission said Jan. 8.

"It's the best environment for our business in 20 years," said Mickey Thompson, president of the Oklahoma Independent Petroleum Association.

State permits peaked at 22,685 in 1981.

Tight supplies and increased demand have sent prices of gas and oil up in the last year, and they are expected to remain high for some time before softening, analysts say.

Oklahoma natural gas prices averaged $4.42 per thousand cubic feet in the first eight months of 2003, up from $2.65 during the same period in 2002, state figures show.

Gas closed at $7.09 per mcf Jan. 8 on the New York Mercantile Exchange.

Oklahoma oil averaged $30.43 per 42-gallon barrel during the first eight months of 2003, up from $18.21 during the same period in 2002, the state says.

Oklahoma City-based Chesapeake Energy Corp., the top producer of Oklahoma gas, was the most active driller in the state last year by a wide margin, spending more than $500 million on new drilling projects in state fields.

"We have expectations that prices are going to stay at historically higher levels," said Chesapeake spokesman Tom Price.

Oklahoma, the nation's third-largest gas producing state, has several trillion cubic feet of proven gas reserves, the U.S. Department of Energy says.

"A great deal of this state is unexplored at significant depths," Price said.

—THE ASSOCIATED PRESS

HOUSTON, TEXAS

Special honor for IADC and OOC

The International Association of Drilling Contractors and the Offshore Operators Committee are being recognized for their development of deepwater well control guidelines. The special citation from the Offshore Technology Conference will be presented at an awards luncheon May 4.

The IADC and the OOC formed a deepwater well control task force in 1997 to address safety and environmental issues as the industry moved into operations in deeper water, and published its original guidelines in 1998. The task force was led by Moe Plaisance, a vice president at Diamond Offshore Drilling.

In 2000, a supplement was added to the guidelines to address unplanned disconnects of the risers that carry drill pipe and drilling fluids to the well.

Well control involves the safeguards needed to prevent discharges of hydrocarbons during drilling operations.

—PETROLEUM NEWS

CALGARY

Devlan plans at least 30 wells in 2004

Devlan Exploration Inc. says it's planning to drill 30 wells this year, nearly double the number the company planned for 2003 at the beginning of that year.

The Calgary-based company says it has historically raised its expenditures after the winter drilling season.

For 2003, Devlan spent more than $29 million participating in a total of 28 wells (19.0 net) with a net success rate of 83 percent, the company announced Jan. 13.

—PETROLEUM NEWS

GULF OF MEXICO

Kerr-McGee to develop $600 million Constitution field in Gulf of Mexico

Oklahoma City-based Kerr-McGee said Jan. 14 that its board of directors has approved a $600 million development of the company's 100 percent owned Gulf of Mexico Constitution field utilizing a truss spar facility.

Constitution is in 5,000 feet of water at Green Canyon blocks 679 and 680. The company said the field has estimated proven and probable resources of approximately 110 million barrels of oil equivalent. The $600 million project cost includes $125 million spent to date on leases and drilling.

Constitution is in 5,000 feet of water at Green Canyon blocks 679 and 680. The company said the field has estimated proven and probable resources of approximately 110 million barrels of oil equivalent.

"A stand-alone facility at Constitution enables us to dramatically accelerate the development timetable for this significant field, therefore enhancing shareholder value. In addition, this spar will create our sixth deepwater hub, enabling us to further capitalize on our extensive acreage inventory in the Gulf of Mexico," said Luke Corbett, Kerr-McGee chairman and chief executive officer.

Kerr-McGee said the Constitution field was confirmed by 11 penetrations into predominantly oil-bearing sands in seven hydrocarbon-bearing Pliocene reservoirs at depths from 12,500 feet to 15,000 feet.

The field will be developed with a truss spar similar in design to Kerr-McGee's previous three truss spars and will have capacity to process 40,000 barrels of oil per day and 200 million cubic feet of gas per day.

The development plan includes five dry trees and one subsea tieback. Well bores from previously drilled appraisal wells will be used as part of the final development plan. First production is expected by mid-2006, with peak production expected to reach 40,000 bpd and 75 million cubic feet per day in 2007.

—PETROLEUM NEWS

● GREEN RIVER, WYO.

Proposals seek safeguards for Wyoming's wildlife

Two plans offered by coalition to allow migration through corridor

THE ASSOCIATED PRESS

A coalition charged with developing a plan to protect a key wildlife migration corridor in western Wyoming has submitted two proposals for consideration.

One plan outlines ways to address oil and gas development, private land development, fencing and vehicle collisions to animals migrating through the historic Trapper's Point area west of Pinedale.

That proposal, developed by the majority of the 22-member coalition, was submitted last month to Bureau of Land Management officials.

The Wyoming Outdoor Council and other conservation groups, meanwhile, developed a counterproposal that calls for more "no leasing" for oil and gas development areas within the Trapper's Point bottleneck. The groups felt the original plan didn't do enough to protect migrating animals.

BLM officials say both proposals will be included in revisions to its management plan for the Pinedale Field Office. An environmental impact statement is expected to be available for public review by April 2.

The coalition, which met several times this fall, was formed by state Rep. Monte Olsen, R-Daniel. It included government agencies, state lawmakers, agricultural producers, conservationists, and oil and gas industry interests.

"I think that people came together ... we didn't throw darts at each other," Olsen said. "We had some great conversations and we were very proactive as a group and, quite frankly, I think we've got a nice plan."

Bottleneck between two drainages

The Trapper's Point bottleneck is located between two drainages in the Upper Green River Basin about seven miles west of Pinedale in Sublette County. Thousands of deer and antelope migrate through it each year.

Olsen said the coalition's plan would protect a core 2,240-acre area at the heart of the bottleneck, recommending no oil and gas leases on 640 acres and no surface occupancy on the rest.

The coalition has also proposed speeding up Wyoming Department of Transportation plans to install sensors and lighting in key portions of U.S. 191 that runs through the bottleneck to reduce wildlife collisions.

"The plan also takes a better look at the fencing and makes sure fencing out there is wildlife-friendly everywhere ... 'ag' is actively involved in that," Olsen said.

The plan also explores subdivision development and hunting, though the most contentious point was oil and gas development, he said.

Conservation groups on the coalition want BLM to adopt a no leasing position for all of the public lands within the 2,240-acre core area. ●

NORTH AMERICA

Canadian has sights set on Devon's top job

A 52-year-old Calgary lawyer has turned the tide by ascending the ladder and taking over the president's job at Devon Energy, the largest U.S.-based independent producer.

Reaching such heady heights is believed to be without parallel for a Canadian and puts John Richels within reach of eventually succeeding Larry Nichols, Devon's co-founder, chairman and chief executive officer.

Richels joined Devon when it completed a C$2 billion merger in 1998 with Northstar Energy and moved up to president of the Canadian units in 1999.

Richels joined Devon when it completed a C$2 billion merger in 1998 with Northstar Energy and moved up to president of the Canadian units in 1999.

That in itself was rare for U.S.-based companies, which have preferred to send executives from the United States to run their Canadian operations.

Oklahoma-based Devon opted to retain a 100 percent Canadian management team to run its substantial Canadian operations, which were further bolstered when it acquired Anderson Exploration in September 2001.

That deal gave Devon Canada the largest holding of exploration licenses in the Mackenzie Delta and shallow water Beaufort Sea and extensive interests in the Western Canada Sedimentary Basin.

Its production for the third-quarter of 2003 averaged 761 million cubic feet of gas per day, 37,400 barrels of oil and 12,700 barrels of natural gas liquids.

In addition, it recently filed regulatory applications for its Jackfish oil sands project in northeastern Alberta. The C$400 million-$450 million venture is designed to produce 35,000 barrels per day of bitumen over 25 years.

More than any other company, Devon under Nichols has ignored the Canada-U.S. border in moving the company into a fully integrated North American energy market. Richels said Nichols' philosophy has been to view North America as "one big basin," where the 49th parallel is just a line on the map.

—GARY PARK, Petroleum News Calgary correspondent

natural gas

ALBERTA

Texas company builds Alberta coal bed methane holdings

MGV Energy, the Canadian unit of Texas-based Quicksilver Resources, has added to its coalbed methane prospects in central Alberta by acquiring a 50 percent interest in 76,800 acres of mineral rights.

The $5.4 million deal for lands in the Wood River area south of Edmonton gives MGV a 100 percent operated working interest of a net 5 billion cubic feet of proved reserves.

The properties had been jointly held by MGV and Ice Energy and are currently producing at rates of more than 100,000 cubic feet per well.

Quicksilver, in its third-quarter report, said it plans to initiate five new developments in the Edmonton group formations in 2004.

Glenn Darden, Quicksilver president and chief executive officer, said on average 125,000 cubic feet per day "may be a pretty good average across a big area."

He said the Ice Energy "set the stage for increased drilling and production in several areas" of the Horseshoe Canyon coalbed methane fairway.

Darden said in November that Quicksilver is aiming for more than 300 coalbed methane wells in Canada in 2004 and could drill 500 wells in 2005.

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

COLORADO

Colorado posts third-busiest year in natural gas drilling

There were 2,245 permits issued to drill natural gas wells in Colorado last year, the third-highest total ever, and state officials say they expect a record this year.

Some 2,500 drilling permits are expected to be granted this year, said Brian Macke, deputy director of the Colorado Oil and Gas Conservation Commission. The forecast was based on a survey of 600 gas operators.

The record is 2,378 permits in 1980, followed by 2,273 in 2001.

Macke said strong natural gas prices and a government push to open more public land to drilling are some of the reasons for the increased activity.

The top two counties for drilling activity were Weld and Garfield.

There were 756 permits issued in Weld County last year, while Garfield County had 566.

But western Colorado's Garfield County posted the largest one-year increase, with 204 more permits than in 2002. Macke said the increase is due to increased interest in the gas-rich Piceance Basin of northwestern Colorado and eastern Utah.

The two largest gas operators in the county, EnCana Oil and Gas and Williams Production, both plan to be busy again this year.

see **COLORADO** *page 18*

● ALBERTA

Gas-bitumen showdown enters a critical phase

Alberta's Court of Appeal, Alberta Energy and Utilities Board will issue findings by end of January in dispute between oil sands and gas

By GARY PARK

Petroleum News Calgary Correspondent

The next two weeks will be a nail-biting time for most of Canada's biggest oil and natural gas producers who are embroiled, directly or indirectly, in a multi-billion dollar feud.

Alberta's Court of Appeal and its Energy and Utilities Board will deliver pivotal findings in the dispute between oil sands and natural gas producers in the province's northeast.

The court will rule before the end of January on two applications challenging the Energy and Utility Board's right to order that 938 gas wells be plugged, while the board has set Jan. 26 to decide which of 777 gas pools in the Wabiskaw-McMurray formation will negatively impact future bitumen recovery if continued gas production lowers reservoir pressures.

Currently 330 wells, accounting for 95 million cubic feet per day or 40.5 percent of Wabiskaw-McMurray's total output, are closed, while 608 are producing under temporary exemptions.

Gas producers took want full hearings

Gas producers Paramount Energy Trust, Canadian Natural Resources, BP Canada Energy and Devon Canada took their fight to court, arguing that full hearings should have been conducted before the shut-in order was issued.

see **SHOWDOWN** *page 18*

● PACIFIC RIM

Too much LNG a possibility

Report's researchers warn of oversupply for West Coast, Pacific Rim

By LARRY PERSILY

Petroleum News Government Affairs Editor

Some industry watchers are worried that too many liquefied natural gas producers and proposed receiving terminals are chasing after too small a market on the U.S. West Coast.

That same oversupply concern extends throughout the Pacific Rim, said a recent Japanese research report.

"While there are differences in progress being made within each project, we can cite specific examples such as Sakhalin in Russia, Tangguh in Indonesia, Tiga in Malaysia and Gargon in Australia, and others, where the current trend in Pacific LNG markets seems to be in a state of oversupply," said a December 2003 research paper commissioned by Japan's Ministry of Energy, Trade and Industry.

The report also pointed to a list of 10 new LNG receiving terminals proposed for the U.S. West Coast as an illustration of too many projects chasing after the same market.

West Coast LNG surplus expected

International consulting firm Cambridge Energy Research Associates has similar concerns. "Several LNG projects target the California market with supply from the Pacific Basin, an area where CERA expects a surplus of LNG to emerge," said the company's winter 2004 North America natural gas report.

There also is concern that too much of a good thing could do more harm than good, Cambridge Energy said in a separate report.

"The North American market is moving rapidly from deep skepticism to a perhaps excessive enthusiasm reminiscent of the early stages of the recent overinvestment in gas-fired electrical generations," CERA said in a January report, The Incoming Tide: LNG Surges into North America.

"It is … premature to call the surge in propos-

see **TOO MUCH LNG** *page 18*

● ANCHORAGE, ALASKA

Natural gas authority counts LNG votes

Board members remind governor, legislators of public support for project

By LARRY PERSILY

Petroleum News Government Affairs Editor

As it pursues additional state funding to build a multibillion-dollar liquefied natural gas project, the Alaska Natural Gas Development Authority figures it's good to remind the governor and legislators of how many Alaskans voted for the venture in 2002.

And to help board members as they talk with lawmakers about the authority's need for more money, Harold Heinze, chief executive officer of the gas authority, has passed out a list showing the 2002 vote totals in all 60 House and Senate districts.

It's good to remind legislators how well the ballot initiative did in their own districts, Heinze said.

Alaskans by a 2-to-1 margin approved the citizens initiative creating the gas authority, which is supposed to present a project plan to the Legislature by June 2004 for the state to build, own and operate a gas pipeline from the North Slope to Valdez, where the gas would be liquefied and shipped to anyone who might want to buy it.

"I think Ballot Measure 3 beat almost every legislator," said David Cuddy, one of seven men Gov. Frank Murkowski appointed to the gas authority last year.

Heinze passed out the list at the board's Jan. 12 meeting in Anchorage. Board member and initiative sponsor Scott Heyworth compiled the list.

Heyworth has been critical of what he believes is the state wasting its time waiting for the three major North Slope producers to build their preferred gas pipeline from the slope, through Canada to mid-America markets, while he sees an LNG project at Valdez as Alaska's best hope to get its gas to market.

He sent a note Jan. 11 to Heinze and others on his email list, informing them of a recent opinion poll — paid for by the Alaska Democratic Party — that showed Alaskans continue to support the LNG project over a pipeline to the Lower 48 by a 2-to-1 margin.

"Our numbers are holding, easily!" Heyworth said in his email. "Frank is cooked meat on this one."

Heyworth acknowledged his email refers to Alaska Gov. Frank Murkowski.

"If the governor is going against the will of the people, it's not a good sign," he said of Murkowski's continued encouragement of a producer-led pipeline project instead of coming out solidly in support of a state-owned LNG project.

"Gee Frank, don't you get it," Heyworth said.

The governor has generally said he supports any project that could bring Alaska gas to market and millions of dollars a year in taxes and royalties to the state treasury, though he has concentrated on the proposed gas pipeline to mid-America. Heyworth had filed as a candidate for lieutenant governor in the 2002 Democratic primary but withdrew in support of Murkowski's Republican gubernatorial candidacy.

The gas authority has gone through all of the $350,000 in state funds it was given for this year, and is asking for an additional $2.15 million from the Legislature for the balance of the fiscal year that ends June 30. Heinze has said the authority could need $200 million more for next year, if the board and the Legislature decide to proceed with designing the pipeline, liquefaction plant and tanker terminal.

The initiative placed before voters in November 2002 did not include any estimates of how much state money would be needed to plan and design the project.

Heyworth said he put together the list of district vote totals to show lawmakers the strength of constituent support for the project. "I'm kind of a numbers guy. It just fascinates me. I see trends in it." The vote totals show the initiative's strongest support was in Fairbanks, along the pipeline route, in Valdez and the Matanuska Valley. It did not lose in any of the state's 40 House districts, but came closest in downtown Juneau, downtown Anchorage, the upscale Hillside area of Anchorage and the North Slope and Northwest Arctic district.

Heyworth praised Senate President Gene Therriault for the North Pole Republican's support for the additional $2.15 million this legislative session for the gas authority. More than 70 percent of voters in Therriault's district — which stretches from just outside the city of Fairbanks to Valdez — cast ballots for the initiative.

"I think he's savvy and knows those numbers mean something in that district," Heyworth said. ●

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COLORADO

EnCana spokeswoman Sherry Long said the company plans to drill nearly 300 wells in the Mamm Creek field south of Rifle and Silt. A Williams official, Steve Soychak, said about 200 wells are planned this year in the Rulison and Grand Valley fields from Rifle to Parachute.

Macke said 1,619 active wells have been drilled in Garfield County over the years and 1,465 of those are considered producing wells.

Rio Blanco County also had a sharp increase in drilling permits last year — 179 compared with 105 in 2002. That was enough to tie the county with Las Animas County for the third-highest total in the state.

—THE ASSOCIATED PRESS

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SHOWDOWN

Attorneys Len Sali for Paramount and Al McLarty for BP said the board had an obligation to follow due process — a demand that Rod McLennan, the Energy and Utility Board's attorney, said would be "absolutely impossible" to meet.

To conduct hearings on a well-by-well basis would take years, McLennan said, noting that previous shut-in orders affecting the Surmont and Chard-Leismer areas involved two years of hearings and only one-quarter the number of wells in the Wabiskaw-McMurray case.

He said the board must have the right to act where it believes "serious harm" is being done to a resource.

He said Alberta is in trouble if the Energy and Utilities Board is denied the right to protect a bitumen deposit with an estimated 100 billion barrels of reserves, or 600 times the energy content of the 1 trillion cubic feet of gas reserves.

Alberta government could expropriate gas wells

Sali said the board has other options, including a recommendation that the Alberta government expropriate the gas wells, rather than issuing a blanket shut in. Instead, he said the gas producers and their shareholders are taking the brunt of the costs. Paramount has estimated the shut-in order could cost it C$8 million of cash flow a year.

A geological study of Wabiskaw-McMurray issued by the Energy and Utilities Board on Jan. 2 reported that 464 of the 777 gas pools were in contact with the bitumen, creating an "acceptable risk" to bitumen recovery using techniques such as steam-assisted gravity drainage.

The board plans to release a list on Jan. 26 of the pools it believes would negatively impact the bitumen deposits. An interim hearing has been set for March 8, when gas and bitumen producers can challenge the proposed shut-in list, and, if required, a final hearing will be scheduled. ●

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TOO MUCH LNG

als an overbuild of regasification facilities, but it is not too early to recognize that it could become one."

Overbuilding could hurt prices

And if the United States builds too many LNG receiving terminals to serve the East, West and Gulf of Mexico coasts, said Cambridge Energy, the very industry pushing the projects could be hitting itself where it hurts most — in gas prices. "In CERA's view the biggest risk of a sustainable sharp decline in North America natural gas prices that jeopardizes the viability of North American LNG lies in the potential for an overbuild of the North American LNG industry itself."

The West Coast market and distribution system can't absorb more than 1 billion cubic feet per day of LNG before the end of the decade, said Stephen Baum, president and chief executive office of San Diego-based Sempra Energy. All of that demand, if accurate, would be met by the joint Sempra-Shell LNG receiving terminal set to open in 2007 on Mexico's Baja Peninsula, just 35 miles south of the California border.

Baum offered his market assessment at last fall's Merrill Lynch Power & Gas Leaders conference in New York City.

CERA, as Baum, believes there is a limit as to how much LNG the West Coast can absorb. "CERA believes Pacific LNG is economically viable on the West Coast up to about 2 bcf per day in this decade. However, the fact that the West will be relatively well supplied will mean that western markets will generally price below the Henry Hub."

North America market the prize

"There is a sweepstakes," said Robin West, chairman of the Washington, D.C.-based consulting firm PFC Energy. "This is about access to the North American natural gas market, which is the great prize," he was quoted recently in the Financial Times of London.

Cambridge Energy's Incoming Tide report also offered the same conclusion as the Japanese research paper on anticipated oversupply around the Pacific Rim.

"CERA believes there is a surplus of gas in the Pacific Basin. It will be difficult for all currently planned LNG projects on the Pacific Coast to find market outlets before 2010. Growth in demand in the Pacific Basin, even with a return to strong economic growth, is unlikely to keep pace with this potential supply build."

Predictions of too much LNG chasing after too little market demand could be a serious problem for supporters of a project to export Alaska LNG to the West Coast or Asia. In addition to Sempra's announced deal to bring Indonesian LNG to its proposed Baja terminal, Shell has its own interests in Russian LNG and ChevronTexaco last year announced its plan to import LNG from Australia's Gorgon field to its own proposed Baja receiving terminal.

Alaska project more costly

Cost estimates in the Cambridge Energy report also don't offer much encouragement for an Alaska LNG project. "The cost of a complete LNG value chain, including liquefaction, shipping and regasification, is typically $3 billion to $5 billion for a 1 bcf per day project," the Incoming Tide report said. The LNG project being promoted by the state-funded Alaska Natural Gas Development Authority, at 2 bcf per day, is estimated to cost at least $12 billion, or $6 billion per bcf.

The Cambridge Energy report does acknowledge, however, that projects "can and do exceed the high end of this band."

The report also restates the consultant firm's assumption that although Alaska LNG is not part of the expected supply chain to the West Coast, North Slope gas eventually will get to U.S. consumers via a pipeline to mid-America.

"Beyond 2010, prices are expected to firm as investment in LNG facilities pauses in anticipation of the construction of the Alaska pipeline in the middle of the next decade." ●

● ALABAMA

Add another LNG proposal to the list

Cheniere Energy takes option for its fourth possible Gulf Coast LNG site

By LARRY PERSILY

Petroleum News Government Affairs Editor

Houston-based Cheniere Energy Inc. has announced it is looking at a fourth possible liquefied natural gas receiving terminal on the Gulf of Mexico, although it acknowledges the outcome of this latest proposed site will depend on whether the community wants it.

Cheniere, a shallow-water Gulf of Mexico oil and gas explorer and producer, reported Jan. 13 it has signed an option with Atlantic Marine Inc. to purchase a potential LNG receiving terminal site in an industrial zone on Pinto Island in Mobile Bay, Ala.

"The site is well suited from a technical standpoint and is located in an industrial area," said Keith Meyer, president of Cheniere LNG. "We have now begun a process of community outreach to evaluate whether the residents of Mobile and its surroundings would support an LNG receiving facility at this site. We will only proceed with this project if we feel that the community would support us."

Cheniere's Mobile site is among the more than two dozen LNG terminals proposed for the U.S. Gulf Coast, West and East coasts… . At best, say many in the industry, no more than half a dozen of the proposed terminals will be built this decade.

The proposed site — on Pinto Island — is in front of downtown Mobile. Atlantic Marine's shipyard property on the island is on a deep-water channel.

Herschel Vinyard of Atlantic Marine said in the joint press release with Cheniere, "Atlantic Marine looks forward to the use of the available site on Pinto Island for the development of an LNG receiving terminal. A facility of this type would be beneficial to the local economy and would position Mobile as a significant gateway to North America for world natural gas."

Follows last month's Texas announcement

Cheniere and ConocoPhillips last month announced plans to build an LNG receiving terminal at Freeport, Texas, about 40 miles down the Gulf of Mexico coast from Galveston, Texas. The terminal, scheduled to start operations in mid-2007, would eventually handle an average 1.5 billion cubic feet per day.

Cheniere also is working to develop two other additional LNG receiving terminals along the Gulf of Mexico coastline — at Corpus Christi, Texas, and Sabine Pass, La.

"While we have advanced three locations to the stage of submitting an application with the Federal Energy Regulatory Commission, we have reviewed numerous locations that failed to meet our criteria," Meyer said in announcing his company's fourth proposed LNG terminal.

"We are committed to continue looking for suitable locations because we think it will be difficult to permit enough sites to secure this nation's gas needs. If the community supports this project (Mobile, Ala.), we will begin preparing an application for a permit."

Cheniere's Mobile site is among the more than two dozen LNG terminals proposed for the U.S. Gulf Coast, West and East coasts as natural gas suppliers and distributors line up for new supplies to meet the nation's growing shortage of gas. At best, say many in the industry, no more than half a dozen of the proposed terminals will be built this decade. ●

MOBILE, ALA.

ExxonMobil hits snag on proposed LNG pipeline route

ExxonMobil's request to survey county-owned land in Alabama for a pipeline for its proposed liquefied natural gas plant on Mobile Bay's western shore has been rejected.

The Irving, Texas-based oil giant had requested the county's permission for a survey that was denied Jan. 8 by the Mobile County utility service board. The County Commission took no vote on the survey request, but the utility service board rejected it, according to county attorney Larry Wettermark. The board owns the 1,800 acres once considered for a sewage plant.

In a letter, the board says the potential pipeline route would not be an appropriate use of the property.

ExxonMobil spokesman Bob Davis said Jan. 9 the company would have no comment on the county's decision at this time.

ExxonMobil hopes to build a $600 million docking facility for tanker ships carrying supercooled liquefied natural gas. The LNG would be transferred off the ships, then warmed and transformed back into its gaseous state for delivery through pipelines.

Opponents of the project cited safety concerns. A circuit court hearing on the opponents' lawsuit to prevent the LNG terminal from using the old Navy homeport site is scheduled for Jan. 13.

County officials previously said they wouldn't approve a construction permit for the terminal at Hollinger's Island because it is in a federally defined flood zone.

Commission President Mike Dean, who represents Hollinger's Island, has strongly opposed the LNG project. Commissioner Freeman Jockisch said he would follow Dean's lead on any official action, because the plant would be in Dean's district.

—THE ASSOCIATED PRESS

NORTHWEST TERRITORIES

Northwest Territories' diamond mines push Canada to third place

Canada has rocketed to third place among the world's diamond producers, a mere dozen years after the gems were first discovered in the Northwest Territories.

With two mines in production, Canada contributed 15 percent of the global supply in 2003, hurdling over South Africa and trailing only Russia and Botswana, Canadian government statistics showed Jan. 13. Since the opening of the Ekati mine in 1998, followed by Diavik last year, companies have invested C$2.6 billion in developing the industry and production totaled 13.8 million carats at an average price per carat of C$228 by the end of 2002.

Production for the first six months of 2003 was already within 17 percent of the output for all of 2002.

The number of full-time miners in the Northwest Territories is about 700, with related jobs boosting the total to 2,200. In 2001, miners earned an average C$64,336, about 44 percent more than other miners, while all employees earned an average C$61,639.

Once the Snap Lake mine is opened in 2006, the three mines will generate royalties of C$1.6 billion over their working lives as well as federal business taxes of C$2.6 billion and Northwest Territories' business taxes of C$1.3 billion. The Northwest Territories, as part of its campaign to take greater control of its natural resources, wants a bigger share of the revenues and is pushing hard to develop a domestic cutting and polishing industry.

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

FAIRBANKS, ALASKA

Tours stop at Fort Knox, Alaska's largest gold mine

Operators of Alaska's largest gold mine located northeast of Fairbanks stopped its commercial tour program effective Jan. 1 in an effort to refocus its community outreach program to local residents. Although free tours for local school groups and other educational and civic groups have been provided since the Fort Knox mine opened in late 1995, the company started a commercial tour program catering to tourists visiting Alaska in 2002.

Visitors paid $21 per person to for a guided two-hour mine tour, which included a view of the gapping pit from a van, walking through the gigantic rock crusher and watching huge indoor mills pulverized gold-rich rock. The tour concluded with a Polaroid photo of the visitor holding a giant Hershey-sized gold bar and a stop in the Fort Knox gift shop that offered gold jewelry, t-shirts and caps for sale. Fort Knox operators advertised the tour in major Alaska tourism publications, including the Milepost, the Fairbanks Convention and Visitors Bureau, the local newspaper's visitor guide and with publication and distribution of colorful rack cards.

"We got great returns (on advertising)," Lorna Shaw, director of tourism at Fort Knox, told Petroleum News Jan. 12. "It was an amazing response. We were not able to accommodate everyone who requested tours."

Part of the attraction is that few operating gold mines in the United States are open for public tours, Shaw said. As in Fairbanks, mining tourist attractions are more typically based on historical operations, such as panning or dredging.

Tours not part of corporate mission

Despite the company's success with its commercial tour program, a corporate decision to eliminate the tours was made midway through 2003, Shaw said. Educating tourists was not part of the corporate mission.

"Instead of people who live here…we were primarily focused on folks visiting in Alaska," she said.

Now, marketing and public relations efforts will be focused on educating the local public about the company and its mining operation. Educational and civic groups will still be able to tour the facility, Shaw said, and more effort will be made to make mining presentations to school groups off-site.

As part of the changed outreach effort, the company is making plans to conduct a public perception survey in the Fairbanks area.

Fairbanks Gold Mining Inc., which operates Fort Knox, is a subsidiary of global mining giant Kinross Gold, based in Toronto, Ontario. Fort Knox's annual gold production of more than 400,000 ounces is Kinross' single largest producing mine.

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

● DELTA JUNCTION, ALASKA

Wetlands permit issued for Pogo gold mine

Corps of Engineers releases wetlands permit for Pogo gold project; EPA water handling permit expected in late February or early March

By PATRICIA JONES
Petroleum News Contributing Writer

Developers of the Pogo gold deposit in eastern Interior Alaska received a wetlands permit Jan. 12 from the Anchorage office of the U.S. Army Corps of Engineers.

"Now it's up to EPA," Army Corps of Engineer project manager Victor Ross told Petroleum News Jan. 12.

The 404 permit issued allows developers to place fill and conduct mechanical clearing of 303 acres of wetlands for construction and operation of the hardrock gold mine 40 miles northeast of Delta Junction, Alaska.

Contractors hired by project developers Teck-Pogo, a joint venture between Teck Cominco and Sumitomo Metal Mining Co., have already started work building a temporary winter road that will be used to haul construction camp equipment to the site. Developers received authorization from state regulators to do so in mid-December.

But according to Karl Hanneman, Teck-Pogo's manager of public and environmental affairs and special projects, developers will refrain from construction work until receiving permits from the Environmental Protection Agency, the lead regulatory agency.

"We will begin preparation of the winter road and get ready to mobilize and stage equipment for construction, if and when the final major permit is issued," Hanneman said.

Bill Riley, EPA's mining coordinator for the region 10 office, said the National Pollutant Discharge Elimination System permit should be issued the last week in February or the first week of March.

"We're on track — there's nothing that I know of (to get off-track)," Riley said.

Delay due to new water standards

EPA's permit approval process has been held up due to a change last summer in the state of Alaska's water quality standards, according to regulators.

The change makes Alaska's water quality standards more closely reflect EPA's measures of clean water, said Ed Fogels, the Alaska Department of Natural Resources project manager for the Pogo development.

To use the new standards in Pogo's permit, EPA regulators have to complete the approval process for the state's water measures, Riley said. That includes a review that the new state standards comply with the endangered species act, "an elaborate process that we've been looking to shortcut as best we can," he said. "We knew it would take some time to get through and we've had some contractor help in the short timeframe to get the permit ready for the Pogo project when they need it."

EPA's review of the new Alaska state standards begin last fall, Riley said.

"The company wanted the new permit to be tied to the new standards," he said. "Otherwise we could have issued this permit months ago."

The procedural delay has "definitely been frustrating for all of us," Fogels said.

Regulators have been working on the Pogo permits since August 2000, when developers first submitted a plan for putting the project into production.

Seasonal construction a concern

Following the Sept. 19, 2003, release of the Final Environmental Impact Statement for the Pogo project, regulators and developers were anticipating a January 2004 start of construction.

JUDY PATRICK

Palmer-based Cruz Construction building Interior Alaska ice roads last winter. Teck-Pogo hired Cruz to construct and operate a winter ice road this winter that follows the same route up the Goodpaster River valley used by Pogo prospectors during the winter season of 1997-1998.

Now that has been put off for at least two months or more, some construction work planned for winter months could be in jeopardy.

"We will do the best we can with the timing we're given," Hanneman said. "We are evaluating our options (for seasonal-dependant construction) and that is part of the reason why we are using the winter road and staging equipment to the site.

"We are trying not to lose a full construction season," he added.

Teck-Pogo hired Cruz Construction, based in Palmer, Alaska, to construct and operate the winter ice road that follows the same route up the Goodpaster River valley used by Pogo prospectors during the winter season of 1997-1998.

Following the road completion, Hanneman said a trucking contractor will haul to the site a 250-person construction camp, a sewage treatment plant and portable water plant for the construction camp, construction offices and construction equipment.

Construction crews are expected to peak at 500 workers, who will be housed on-site in the construction camp and in permanent crew quarters that will later be used for the mine and mill staff, expected to be about 250 full-time workers.

The underground Pogo deposit is believed to contain 5.5 million ounces of gold, with an average grade of about one-half ounce of gold per ton of rock, considered a relatively high-grade ratio for gold mining.

Development of the deposit is estimated at $250 million. Annual production is estimated at 375,000 ounces of gold per year, for a 10-year mine life. ●

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Petroleum news

Business Spotlight

By **PAULA EASLEY**

FORREST CRANE

Randy Bovy, EMS manager

Nabors Alaska Drilling Inc.

"Always looking for better ways to provide safe, environmentally sound and cost-efficient services" is Nabors Alaska Drilling Inc.'s mission statement. The company holds many of Alaska's drilling records and was a pioneer in horizontal drilling, which was initially applied full-scale on the North Slope. In its 40-year history, Nabors has participated in most of the world's significant oil, gas and geothermal markets.

Starting as a roustabout/carpenter 19 years ago, Randy Bovy has held several field positions before becoming the firm's environmental and camp manager in 2000. An outdoorsman, his favorite pastimes are hunting, snowmobiling, and catching kings with sons Kyle (14) and Brandon (12). Randy's wife Tammy home schools the boys, and both parents enjoy their basketball, baseball, soccer, football and swimming activities.

COURTESY NATCO CANADA

Kevin Baird, manager – business development

NATCO Canada Ltd.

NATCO Canada is a total capability company providing processing and fabricated equipment, along with associated services and technical support, to the oil and gas industry. Recent Alaska activities include projects for Unocal's Trading Bay production facility, Forest Oil's Kustatan facility and projects for BP Exploration (Alaska) and ConocoPhillips Alaska. A primary component of its total quality management culture (TQM) involves forming strategic alliances between cooperating companies.

Kevin Baird, with 24 years of industry-related experience, is responsible for sales and marketing of technology advancements. A member of the business development group, he is well recognized in the industry for his expertise in water treatment management. Kevin travels to Alaska around four times a year. To this professional, relaxing means golfing, cycling or skiing with teenage son, Connor.

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DEH CHO

Mackenzie Delta and North Slope gas through Canada to southern markets were stalled, largely because of unresolved aboriginal land claims.

The Canadian government launched an inquiry that resulted in a 10-year moratorium on pipeline development in the Mackenzie Valley while land claims were settled.

Over the next 16 years, the Inuvialuit, Gwich'in and Sahtu settled their claims covering land from Inuvik to a point about halfway between Norman Wells and Fort Simpson, leaving the Deh Cho to continue a head-to-head battle with the federal government for their own government that would have access to a share of resource royalties.

Since October 2001, the Deh Cho have steadfastly refused to join the 75 percent of Northwest Territories aboriginals who signed a memorandum of agreement with the Mackenzie Delta Producers Group that opened the way to one-third ownership in the pipeline for indigenous people.

Bargaining position ratcheted up

Last month they ratcheted up their bargaining position by telling regulators and the Mackenzie project owners that unless they get help to review all of the material gathered so far and have their rights respected they will use their "legal right to veto the project."

Just how tough-minded the Deh Cho can be was evident last fall when the first nations complained about an alleged conflict of interest involving the wife of Paul Bernier, vice president of the Canadian Environmental Assessment Agency, who was a key figure in developing the regulatory process for a Mackenzie Valley pipeline.

Maureen Bernier held 12 mineral claims on the pipeline route and the Deh Cho, while awaiting the results of an investigation into the alleged conflict-of-interest, offered $100 for every stake removed from Bernier's claims.

Imperial Oil efforts to involve aboriginals

Imperial Oil, as the lead partner in the Mackenzie project, has taken pride in its efforts to involve aboriginals at every phase and satisfy aboriginal desires for business partnerships.

In a pre-Christmas speech, Imperial Senior Vice President K.C. Williams said "one of the critical strengths of our initiative is that we have cultivated and maintained significant aboriginal direct involvement" with the project, including more than 500 meetings with the full range of interested parties.

He said the willingness of northern leaders to consider pipeline development on their land has attracted industry, community and political attention to the region.

For all the success of the 2001 memorandum of understanding and the hopes of filing the major regulatory applications in 2004, there has been a lingering unease over the aboriginal issues that remain on the table.

Without referring to any specific problem, Hal Kvisle, chief executive officer of TransCanada, told a fall conference that "regulatory delays or some kind of flare-up on the aboriginal front" could derail Mackenzie progress.

Northwest Territories plans meeting

Newly appointed Northwest Territories Premier Joe Handley said he wants to meet with the Deh Cho to find out exactly what they want, while meeting with other aboriginal communities along the Mackenzie Valley to discuss socio-economic agreements relating to the pipeline project.

Hopes of a breakthrough with the Deh Cho were raised last April when they signed an interim resource development agreement with the Canadian government, opening some Deh Cho lands for oil and natural gas exploration, while removing about 18,000 square miles from exploration.

The agreement provided "additional clarity" on how resource development might take place in the Deh Cho region and was a positive signal that the various parties could achieve such an agreement, Searle said at the time.

Since then Herb Norwegian has been elected grand chief, bringing a different style to pipeline negotiations, but just as committed to protecting traditional lifestyles without shutting the door to resource development.

In interviews, he has been emphatic that industry has nothing to fear "so long as they negotiate."

For the Deh Cho, Norwegian said the challenge is to reach a balance between drilling rigs and pipelines and aboriginal traplines and hunting territory.

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

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GAS LINE

However, Searle conceded that preparing the applications is a "bit of a moving target" that makes it difficult to set a specific timetable for the filings, including plans for each of the three Mackenzie Delta anchor fields, gas gathering systems, the main gas pipeline and a natural gas liquids pipeline.

One of those wrinkles surfaced last month when the Deh Cho First Nations, the only aboriginal community that has yet to embrace the Mackenzie Valley pipeline, issued a threat to exercise their "legal right to veto the project."

> *... the owners have described the list of demands as "principles regarding consultation" and have not formally discussed the 13 points with the Deh Cho.*
> **—Hart Searle, Imperial Oil**

Deh Cho threaten veto

The Deh Cho, whose lands in the lower Northwest Territories cover about 40 percent of the 800-mile pipeline route, made 13 demands in a document sent to the National Energy Board, other regulators and the project owners.

The manifesto said the Deh Cho, speaking for 13 Dene and Metis governments, will "carefully scrutinize consultation efforts with the view to taking whatever action is necessary if the project proceeds without proper consultation."

Deh Cho consent for the pipeline will come only "after we have received full information disclosure, have had adequate time to review the material and have been provided with adequate financial and human resources to conduct our own analysis and develop our positions."

"The consultations with Deh Cho leaders are not limited to stakeholder consultations and public reviews which the (project proponents and the governments) must conduct to fulfill regulatory and legislative requirements ... (they) must propose a process in which they will listen to what Deh Cho leaders identify as Deh Cho rights and provide a response that fully and expressly recognizes, addresses and accommodates those rights."

Some of issues surfaced in 'good faith' talks

Searle said the owners have described the list of demands as "principles regarding consultation" and have not formally discussed the 13 points with the Deh Cho.

However, he said some of the issues have surfaced in on-going "good faith" talks with the Deh Cho as part of developing benefits and access agreements with aboriginal communities along the proposed pipeline route.

Other issues are matters for the Canadian government, which is negotiating a Deh Cho claim for self-government, including a share of resource royalties.

Searle said progress with the Deh Cho was further delayed because the community did not appoint a pipeline working group until last September.

In contrast, the Inuvialuit, Sahtu and Gwich'in, who represent 75 percent of Northwest Territories aboriginals along the pipeline route, have settled land claims and also signed a memorandum of understanding that is the basis for a one-third ownership stake in the pipeline for indigenous people.

Searle said the Mackenzie proponents still hope to have benefits and access agreements concluded before they file with regulators.

'Precedent agreements' needed with shippers

Another "very important part of the whole project" is the need for "precedent agreements" with shippers to show the National Energy Board that "bona fide volumes of gas" are available to fill the pipeline, he said.

The owners — Imperial, ConocoPhillips, Shell Canada and ExxonMobil Canada — believe they will have an agreement covering 800 million cubic feet per day from the Mackenzie Delta's three anchor fields and are "reasonably confident" there will be additional agreements with other E&P companies to meet the initial target of 1.2 billion cubic feet per day, Searle said.

The independents were reminded last month that they have until March 15 to execute precedent agreements that take into account all shipper requirements.

Searle said the basic pipeline design was expanded by 50 percent to 1.2 billion cubic feet per day following strong expressions of interest from about 20 interested parties. The explorers have even made proposals to eventually increase the capacity to 1.9 billion cubic feet per day.

But the Mackenzie Delta Explorers Group — Anadarko Canada, BP Canada Energy, Burlington Resources Canada, Chevron Canada Resources, Devon Canada, EnCana and Petro-Canada — have only two discoveries to support any binding commitments.

That has prompted BP Canada President Brian Frank to argue for more flexibility in the pipeline design to make allowances for future exploration success.

Although the precedent agreements are required before applications can be filed, "we think there are ways to meet the concerns and needs of shippers," Searle said.

He would not speculate on whether the Delta producers group would proceed alone if those agreements are not forthcoming. ●

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INVESTMENT

Martin Pihl, named by Gov. Frank Murkowski to the pension investment board last year, said he raised the issue at the board's Jan. 9 meeting "just to put it on our radar screen … to be in on the ground floor.

"I just want our people (investment staff) to be knowledgeable about it … if it's a pension fund-type investment," he said in an interview Jan. 13.

Pihl, former president and general manager of Ketchikan Pulp Co. and a former acting executive director of the Alaska Permanent Fund Corp., said he believes pension board staff should find out everything they can about the proposal for a state-owned LNG project to determine if it would be a good investment for the retirement funds.

The eight-member board handles about $12 billion in retirement funds.

Bonds might be a good investment

Although he doesn't think the pension funds could be used to take an equity stake in the project, Pihl said perhaps they could invest in gas authority bonds.

Pihl made his comments at the end of the board meeting, and his colleagues took no action on his suggestion.

The $27.6 billion Permanent Fund also is a possible financing option for the LNG project, said Juneau Rep. Bruce Weyhrauch.

The freshman Republican lawmaker said he will introduce legislation this session to grant specific authority to the Permanent Fund trustees to loan money for a state-owned gas project, assuming it meets all of the fund's existing statutory investment rules.

The 27-year-old Permanent Fund gets its money from a share of state oil and gas royalties and investment earnings on stocks, bonds and real estate.

Weyhrauch said he does not expect to propose a dollar amount for the loans or a limit on how big a percentage of the project the Permanent Fund could finance, adding he has discussed his proposal with Permanent Fund officials and Harold Heinze, chief executive officer of the state gas authority.

Legislator says Alaskans want a project

Alaskans are frustrated with the lack of progress in building a project — any project — to carry North Slope natural gas to market — any market — the legislator said, and he believes there will be support for loaning money from the Permanent Fund to help the project.

"It makes sense to me to have that state financial resource available to the in-state gas authority if we can use it," Weyhrauch told the Juneau Empire newspaper earlier in January. "Under a plan like that it would be limited to simply allowing the pipeline authority to borrow money from the Permanent Fund Corporation if it met the corporation's fiduciary duties to have a return on the investment for the benefit of the public."

The Alaska Natural Gas Authority, created by voters in November 2002 to build a gas pipeline from the North Slope and an LNG export terminal at Valdez, has no money for construction and would need either a direct state appropriation or to sell bonds to finance the venture. The authority also needs to determine if the venture is financially feasible, and if it can line up any buyers for the LNG.

—**LARRY PERSILY,** Petroleum News Government Affairs Editor

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BEAT

and assigned a 22 percent working interest to Anadarko Petroleum in August 2003. ConocoPhillips and Anadarko are 78/22 percent partners in the Colville River unit.

One of the leases was originally acquired by ARCO, and also expires Dec. 31, 2004.

Three of the leases were acquired by Phillips Alaska and Anadarko, and expire Jan. 31, 2005.

There are no wells in the prospect, ConocoPhillips told the state, but three-dimensional seismic has been acquired for a portion of the area, and processing and interpretation is expected to be completed by the end of 2004.

Nearby wells include the 1976 Husky Oil S. Harrison Bay 1 and the 1996 ARCO Temptation 1 and a sidetrack, the Temptation 1A.

Iapetus prospect targeted

In exchange for having this acreage added to the Colville River unit, ConocoPhillips proposes to commit in writing by Dec. 31, 2004, to drill the Iapetus No. 1 by June 1, 2005. If that commitment is not made, the leases would contract out of the unit on Dec. 31 and expire according to their terms.

By June 1, 2005, the companies would commit in writing to drill a second well, the Iapetus No. 2, by June 1, 2006, with a bottom hole at least a mile from the Iapetus No. 1, or the expansion area would contract out of the unit June 1, 2005. If the commitment to drill is made, but the second well is not drilled, the acreage would contract out of the unit and the companies would pay $318,700 proportionately to the state and ASRC.

ConocoPhillips also proposed that the expansion area be included in an approved participating area within five years of its inclusion in the unit.

Other expansions

The Colville River unit was approved in 1998, and expanded in 2000 and 2002.

The 2000 expansion added five leases to the north of the unit "viewed as having significant exploration potential in the same or similar geologic horizons discovered in the 1999 Fiord exploration program." Owner companies (then Phillips Alaska and Anadarko), told the state the gross proven and potential Fiord reserves within the current unit were estimated at 40-50 million barrels of oil, and said they hoped to add reserves to Fiord by exploration and delineation drilling.

A major expansion, primarily to the south and southeast of the unit, some 60,000 acres, was approved in 2002. The Oberon expansion area, 26,624 acres on the southeast corner of the unit, contracted out after ConocoPhillips and Anadarko decided in 2003 not to drill a second Oberon well, following poor results from the first well.

The other large block of acreage, some 16,259 acres west of the Oberon acreage, requires a well this winter season. Smaller expansions at Fiord and Nanuq, part of the current Alpine satellite development plan, required inclusion in participating areas within five years. ●

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