Petroleum news

Vol. 8, No. 23 • Anchorage, Alaska | www.PetroleumNews.com | Week of June 8, 2003 • $1

page 7 Ireland: Facilities expansion will sustain Alpine oil output

New Arctic rig ready for work

COURTESY NIED LLC

NIED's new Arctic Millennium drilling system, formerly called the light automated drilling system or LADS. See story on page 2.

Alaska proposes changes to spill contingency planning regulations

The Alaska Department of Environmental Conservation is considering changes to oil exploration and production facility oil spill contingency planning regulations. Its goals are to reduce ambiguity and conflicting interpretations and to improve the clarity and certainty of the regulations, which would result in consistent application of the requirements.

'Umbrella' plan proposed

One of the many changes under consideration would be to "accept a single plan to address multiple facilities based on geographic area, similarities in operations, logistical considerations or

see **CHANGES** *page 11*

Alberta plans gas shut-ins to protect Athabasca oil sands

Alberta's struggle to hold the line on its natural gas production has taken a heavy setback from an Alberta Energy and Utilities Board proposal that would shut-in 900 billion cubic feet per year of production. The regulator says "immediate action" is needed to protect reservoir pressures in the Athabasca oil sands.

The Alberta EUB decided June 3 to shut down 900 gas wells on Aug. 1, effectively removing 1 trillion cubic feet from the province's storehouse.

It said the gas resource, equivalent to 175 million barrels of oil,

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INSIDE

EXPLORATION & PRODUCTION

Drilling in the fast lane

Alpine drilling passes million-foot drilling mark on 69th well

By KRISTEN NELSON
Petroleum News Editor-in-Chief

In four years of continuous drilling, ConocoPhillips Alaska and partner Anadarko Petroleum have drilled more than a million feet of well bore at their Alpine field on the western North Slope of Alaska.

That million-foot mark was passed in April on the field's 69th well, Chip Alvord, Alpine drilling team leader, told Petroleum News May 28, almost 50 miles a year of drilling since Doyon Drilling's rig 19 moved out to Alpine in February of 1999.

"Doyon's done a super job managing the rig and the people and everything out there," Alvord said. "They've really done a great job of keeping the rig up and running and managing the people … keeping the best people they can."

FORREST CRANE

CHIP ALVORD

The last couple of winters Doyon rig 19 has left Alpine on ice roads for exploration drilling, and that may happen again this winter, but the rig's always come back, he said.

One of the reasons for the drilling success at Alpine is that ConocoPhillips and Anadarko "agreed to a plan of development ahead of time for all 94 wells, so getting them approved and processed through the approval process has been a lot easier," Alvord said.

Mark Ireland, ConocoPhillips' development manager for the western North Slope, said funding for all of the drilling "was all part of the original AFE (authority for expenditure), so the dollars were already approved and then it was just a question of agreeing

see **DRILLING** *page 16*

NORTH AMERICAN GAS

Alberta's gas output waning

Regulator says province entering 10 year decline; future hangs on oil sands

By GARY PARK
Petroleum News Calgary Correspondent

Natural gas has joined conventional crude on a downward path in Alberta, with production and reserves entering at least 10 years of decline, the Alberta Energy and Utilities Board reported June 2.

Reinforcing other increasingly gloomy forecasts, the province's energy regulator said that despite a blip this year, when output is expected to rise by 1.5 percent above last year's 4.8 trillion cubic feet, volumes are likely to fall by an average 2 percent a year to the end of the forecast period in 2012.

AEUB reserves analyst Andrew Burrowes said the "long term projection is for decline," despite expecta-

The reserves report listed Alberta's initial established gas at 153 trillion cubic feet, of which 112 tcf has been produced. The ultimate recoverable reserves were rated at 200 tcf in 1992. An updated report on that potential is due for completion this year.

see **ALBERTA** *page 15*

EXPLORATION & PRODUCTION

B.C. showered with changes

Neufeld sees oil, gas as way to 'revitalize' economy; new gas plays to gain from reforms

By GARY PARK
Petroleum News Calgary Correspondent

Troubled by the rapid depletion of the once-prized Ladyfern natural gas discovery, British Columbia has is chasing a rebound.

Energy and Mines Minister Richard Neufeld unveiled sweeping changes on May 30 to its energy royalties and regulations that are tailored to benefit the Greater Sierra field, Canada's hottest current gas play, and the Foothills of the Canadian Rockies.

"Our goal is to develop B.C.'s oil and gas industry to revitalize the economy, create new opportunities ... and improve B.C.'s competitive position," he said in a statement.

see **CHANGES** *page 15*

COURTESY ANADARKO CANADA

Anadarko Canada drilling operations in northeast British Columbia

● OILFIELD SERVICE & SUPPLY

Arctic Millennium rig complete

LADS rig successfully commissioned and tested, says NIED President Masakazu Okamura

By KRISTEN NELSON
Petroleum News Editor-in-Chief

NIED LLC said June 4 that it has successfully commissioned and tested its new Arctic Millennium drilling system, formerly called the light automated drilling system or LADS.

First steel was cut for the rig in February 2001, Conrad Perry, NIED project manager, told Petroleum News June 4. The rig was expected to be drilling on the North Slope in 2002, but that timeline was not met.

Last October Masakazu Okamura, president of NIED, told Petroleum News the company had restructured the project and committed more than $3 million to complete construction and commissioning of the rig.


FORREST CRANE
MASAKAZU OKAMURA


FORREST CRANE
CONRAD PERRY

Okamura told Petroleum News June 4 that a new management team for the rig was assembled in November and the company has been concentrating on completing the rig.

Opportunities for using the Arctic Millennium rig are the next step, he said.

Drilling test well

After completion, the rig was disassembled at the construction site in Brady, Texas, and moved a mile and a half to drill a water well. The six modules of the basic rig can be moved in various ways, depending on location, Perry said.

In Brady, NIED used a Caterpillar D8 with 300 horsepower to move the modules. The Brady test well will be converted to a water supply well for the city of Brady. "Drilling through chalk and hard limestones provided time for a significant shakedown of all systems," the company said, including "automated control and hydraulic systems necessary to provide a step change in drilling safety." Perry said the rig move went well, "a single D8 pulled our heaviest module which was the drill module, fairly easily," including up a 6 degree grade hill.

And assembly at the water well site took about 26 hours, he said, compared to an estimated three days.

Once the derrick was up, he said, it took five hours to park the other modules.

NIED, a subsidiary of N-I Energy Development, describes the rig as a rapid deployment drilling system, and calls it "the first fully automated Arctic class drilling rig."

Perry said NIED is estimating six crew members per tower plus a tool pusher. "With the complexity of the rig," he said, "we're heavy in electronic technicians and mechanics. We have one each per tower. … Multi-discipline type crew where people can handle different things.

The rig requires fewer people — thus reducing exposure to safety hazards. Its performance is equal to other rigs, Perry said: "We're not touting it as being a rig that will trip faster, that will drill quicker."

Fast rig-up

What the company is touting, however, is the fast rig-up time.

The time for moving and resetting the rig is "much shorter" than conventional rigs, Okamura said.

The fast set-up is one of the side benefits, Perry said: "It is a great development drilling rig. It's a fantastic exploration rig."

Typically an operator can only drill one North Slope winter exploration well, Perry said: for some $20 million they get one shot.

"Well for that amount — maybe a little bit more — you could have three shots" with the Arctic Millennium rig, he said, because of the very short rig-up time. One operator could drill three wells, or the rig could be shared among operators over a single winter exploration season.

But, "it's not a compromise rig," Perry said. "It's a very powerful rig... (with) a million pound derrick, 4,500 horsepower worth of mud pumps if you want it. It's a fully operational rig to do whatever you need."

For North Slope development drilling, he said, the rig has a weight advantage in moves: you're not moving 4 million pounds in one load. "Our biggest load is 800,000 pounds over 152 different tires."

Alaska, Sakhalin, Siberia

Okamura said there are opportunities for the rig in Alaska, Sakhalin Island and Siberia. "This rig is suitable for Arctic areas," he said. "There are lots of possibilities for us."

The rig could be transported by sea, Perry said, but can also be moved in eight trips on a Russian Antonov 124 cargo plane. And, because of Jones Act shipping requirements, that would actually be cheaper, he said. For the North Slope, the rig would be flown into Fairbanks and trucked to the North Slope. ●

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OIL SANDS

is at an "advanced stage" of depleting bitumen reserves, which are estimated at 500 billion barrels, of which 100 billion — or 60 times the remaining conventional oil reserves in Alberta — are recoverable using existing technologies.

Paramount Energy Trust chairman Clayton Riddell told analysts June 4 that if he can't overturn the Alberta EUB plan, which could shut 44 million cubic feet per day of Paramount gas production, his company will seek compensation "for any resulting loss in revenues and other damages."

But a spokesman for Energy Minister Murray Smith said it was too soon for the government to discuss compensation when the board has scheduled a public hearing for July.

However, the Alberta EUB has warned that its normal lengthy hearing and application process would prevent it from achieving its overall objective of conserving the bitumen resource.

Paramount has described the EUB action as "dictatorial, oppressive and with scant regard to the effort of entities to have spent billions of dollars" to explore and develop gas in northeastern Alberta.

The issue has been haggled over for eight years, driving a wedge between gas and oil sands operators and leaving many of the oil sands players in a quandary.

Shut-ins are endorsed by Petro-Canada, Imperial Oil, Nexen, ConocoPhillips and Japan Canada Oil Sands, all of them with major operating or proposed oil sands operations.

The gas producers include EnCana, Canadian Natural Resources, Talisman Energy, Husky Energy, Devon Canada (all of which have oil sands interests), BP Canada Energy and Viking Energy.

EnCana has insisted, in a filing with the Alberta EUB, that both resources can be fully produced by applying technological solutions.

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

NORTHERN GAS

Gas exploration at Red Dog deferred

Teck Cominco, the world's largest producer of zinc at its mine in northwest Alaska, has deferred for at least a year plans to drill two shallow natural gas test wells this summer. Gas exploration work may start sometime next year, although company officials have not yet decided whether to drill in summer or in winter, said Wayne Hall, senior environmental coordinator at the Red Dog Mine, located about 85 miles northeast of Kotzebue.

"Right now, we're mainly focusing on procuring the necessary permits to do that program," Hall told Petroleum News May 26. "We decided rather than to try to fast track something, to take a step back … we're weighing all the different ways to go about this project."

Some of the shallow gas targets identified by past mineral prospecting are located about a mile from the mine and mill complex. Other targets are within a 10-mile radius, Hall said.

"It makes sense to drill the area closest first. If it pans out, you have the least amount of transportation costs associated with it," Hall said. "Areas identified in the permit are the close sites."

Teck Cominco submitted permit applications earlier this spring, an effort to replace the 18 million gallons of diesel used each year at the mill. "It's exciting from the standpoint of cost savings and environmental emissions," Hall said.

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

Issue Index

Message from the publisher

Petroleum News, formerly Petroleum News Alaska, is a weekly newspaper that covers the North American energy market with regional reporting preferences in the following order: Alaska, northern Canada, western Canada, Gulf of Mexico, continental United States, eastern Canada and Mexico. Between April 6 and Dec. 31, Petroleum News is adding more and more oil and gas news outside of its prime coverage areas of Alaska and northern Canada but will not reduce the amount of attention it gives to those primary areas. Input from readers is welcome. Please email your comments, suggestions and news tips to Kay Cashman at publisher@petroleumnews.com

Petroleum news

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NORTH AMERICAN GAS

Tight natural gas markets lift value of Canada's exports; summer prices could hit $6

The value of Canadian natural gas exports to the United States surged in the first two months of 2003 and shows no signs of slackening over the next 18 months, say U.S. and Canadian government agencies. Canada's National Energy Board reported May 26 that shipments to the Lower 48 generated revenues of C$2.41 billion, compared with C$1.1 billion in January and February 2002. Average export prices of US$5.13 per million British thermal units soared far above last year's US$2.41, even though volumes declined to 602.5 billion cubic feet from 643.6 billion.

A spokesman for the U.S. Energy Information Administration forecast that continuing pressures on supply, a spillover from tight oil markets and expected growth from the industrial and electric power sectors should sustain high prices through 2003 and possibly to the end of 2004. The EIA said an "exceptionally large current shortfall in natural gas storage relative to normal levels" will bolster near-term prices because companies will need to obtain "large amounts of gas from other uses in order to refill storage" for next heating season.

If the United States is hit with a sizzling summer there could be a mid-year price spike of US$6 per million British thermal units.

An EIA pipeline report said import capacity from Canada "appears to have reached a temporary plateau," given that only 207 million cubic feet per day has been added since 2000, while 163 million cubic feet per day was recently scrapped.

"No additional new projects have been proposed to increase import capacity from Canada into the (U.S.) Midwest or Central regions through 2005," the report said, but added that the U.S. Northeast could be an exception if offshore Nova Scotia has enough exploration success to support proposals for a combined increase of 2.11 billion cubic feet per day.

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

● FINANCE & ECONOMY

ExxonMobil shareholders defeat dissidents

CEO Lee Raymond touts company's environmental record at annual meeting May 28, says oil and gas are way of the future

PETROLEUM NEWS HOUSTON STAFF

ExxonMobil shareholders overwhelmingly defeated proposals from critics who believe the cash-rich energy giant isn't doing enough to support causes that run the gamut from human rights to fighting climate change.

Dissident shareholders at the company's annual meeting May 28 in Dallas, Texas, also were unsuccessful in changing the makeup of the board of directors and separating the positions of board chairman and chief executive officer, both jobs which are currently held by legendary oilman Lee Raymond.

Raymond, who monitored the contentious three-hour meeting, was obviously prepared for the onslaught, particularly on the issue of climate change, in a lengthy speech he delivered before opening the floor to questions and comments.

"In addition to our efforts to develop technologies that address the long-term risks of climate change," he declared, "we are taking steps today to improve efficiency and reduce greenhouse gas emissions."

He said ExxonMobil investments in co-generation facilities alone have reduced emissions up to 50 percent in some cases, noting that co-generation now accounts for more than 90 percent of the company's generating capacity at its chemical and refining facilities.

"As a result, carbon dioxide emissions have been reduced by almost 7 million tons a year from what they would otherwise have been," Raymond said.

He said that ExxonMobil is "collaborating" with automobile manufacturers on developing technologies for next-generation internal combustion systems, hybrid vehicles, fuel cell systems and emissions controls.

Raymond also reminded shareholders that ExxonMobil last year committed $100 million "in a groundbreaking research effort" at Stanford University.

"We believe the only practical way to address the long-term risk of climate change is through the development of commercially viable, next-generation technologies that can be applied worldwide," he said.

No substitute for oil and gas

However, Raymond made it clear that he believes there is no practical substitute for oil and gas. He said the prospects for growth in the hydroelectric and nuclear industries are limited.

ExxonMobil does expect solar and wind energy to grow rapidly, he said, but only because of government policies and incentives, not because of market economics. He said solar power alone can cost from $100 to $250 per barrel of oil equivalent.

He also said that starting from a low base today, wind and solar are unlikely to exceed a 1 percent share of the world's energy needs by 2020, even with double-digit growth rates.

"As a result, we believe oil and gas, which represent about 60 percent of energy supplies today, will remain the dominant energy sources," Raymond said.

Still, Raymond said producing enough oil and gas to meet future demand would be challenging for industry given the 5 percent annual decline of existing fields. He projected a supply gap of nearly 100 million barrels of oil equivalent barrels by 2015, or close to 80 percent of today's production levels.

"Undeveloped and undiscovered oil and gas fields should provide a sufficient resource base to meet projected demand, at least through the middle of this century," Raymond said. "However, the industry must have access to these resources. Effective regulatory and legal frameworks to support industry investment in countries with promising resources are essential." ●

NORTH AMERICAN NEWS BRIEFS

Spinnaker unveils four oil, gas discoveries in GOM

Houston independent Spinnaker Exploration has made four natural gas discoveries since the end of April on the Gulf of Mexico's continental shelf, the company said May 28. The Brazos A-17 No. 1, located in 130 feet of water about 55 miles southwest of Freeport, Texas, encountered two productive sands in the Cib Carst section above 8,600 feet. The new field will be serviced by a braced caisson platform and should begin production by Nov. 1, the company said.

The East Cameron 312 No 1 and 2 wells, located in 210 feet of water about 115 miles southeast of Cameron, Louisiana, found hydrocarbons in separate structural traps, Spinnaker said. No. 1 found natural gas at the 4,826-foot level in the Trim A section, and the No. 2 found oil and gas at the 8,282-foot level in the Ang B sand. First production is expected in the fourth quarter.

The High Island 47 No. 1, situated in 30 feet of water, was drilled to a depth of 10,595 feet and encountered a thick section of productive Marg A sand, the company said, adding that another well will be drilled into a fault block that is related to the discovery. First production is expected in the fourth quarter.

Edge Petroleum buys independent for $12.7 million

Houston's Edge Petroleum says it has agreed to take over Miller Exploration, a struggling family-run exploration and production independent based in Michigan, in a stock deal valued at $12.7 million.

Miller's operations are concentrated primarily in the Mississippi Salt Basin of Central Mississippi. The company also has about 103,000 net undeveloped acres, including a large undeveloped position in northern Montana.

At year-end 2002, Miller had net proved reserves of 6.8 billion cubic feet of natural gas equivalent. Production was about 6,700 million cubic feet of equivalent. Edge would get about 4.6 billion cubic feet of proved reserves after Miller sells Alabama properties to an unidentified buyer.

Under terms of the deal announced May 29, Miller shareholders would receive about 2.54 million shares of Edge common stock, giving Miller a 21 percent of Edge equity. Miller stock is about 19 percent owned by family members and 18 percent by Detroit glassmaker Guardian Industries. Miller has no reported debt.

The $12.7 million transaction was based on Miller stock valued at between $4.70 and $5 per share, roughly one-third of its peak value of $14 per share in 1998.

Miller had net income of $437,000 in the 2003 first quarter after taking a $450,000 accounting charge. Edge posted first-quarter net of $580,200 and had 14,600 million cubic feet of gas equivalent, down 30 percent compared to the same period last year. Debt was $22 million.

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FINANCE & ECONOMY

XTO Energy completes acquisitions

XTO Energy said May 30 that it has completed its previously announced acquisition of natural gas and coal bed methane producing properties in the Raton basin of Colorado, the Hugoton field of southwestern Kansas and the San Juan basin of New Mexico, from units of Williams of Tulsa, Okla., for $381 million. XTO said the final closing price reflects adjustments of $17 million for net revenues and other items from the effective date of the transaction and $2 million for preferential right elections.

XTO said internal engineers estimate proved reserves to be 308 billion cubic feet of natural gas of which 77 percent are proved developed. The acquired properties began contributing some 60 million cubic feet per day of natural gas to the company's production June 1.

XTO said internal engineers estimate proved reserves to be 308 billion cubic feet of natural gas of which 77 percent are proved developed. The acquired properties began contributing some 60 million cubic feet per day of natural gas to the company's production June 1.

"We are proud to complete this timely acquisition. The properties perfectly reflect the characteristics which have built XTO's legacy asset base today — long-lived production, high operating margins and significant upsides," Bob Simpson, XTO chairman and chief executive officer, said in a statement.

—PETROLEUM NEWS HOUSTON STAFF

Offerings flood Canadian asset market

The buyers of recent years have turned into sellers, swamping the Canadian mergers and acquisitions market with assets and companies, according to Calgary-based Sayer Securities, which tracks the M&A scene.

It put a value on first-quarter offerings of C$2.8 billion, compared with the quarterly average in 2001 and 2002 of C$1.1 billion, and estimated they represented combined production of 102,715 barrels of oil equivalent per day.

Sayer credited the surge to companies who are rationalizing their portfolios after joining the earlier buying spree, combined with high selling prices over the 2002-03 winter and the fact that some U.S. companies can now make sales after complying with U.S. securities and accounting rules.

Topping the list of vendors were U.S.-based Marathon Canada, National Fuel Exploration and Vintage Petroleum Canada, which represented 41 percent of the total production on the block. Marathon led the way with 27,000 barrels of oil equivalent per day.

—GARY PARK, Petroleum News Calgary correspondent

ALASKA

ANS production tops 1 million barrels

After dropping below the 1 million barrel-per-day mark in April, Alaska North Slope crude oil production averaged 1,006,545 barrels per day in May, up 1.8 percent (17,600 bpd) from April production averaging 988,945 bpd.

April production was pulled down by planned maintenance at Point McIntyre and a compressor seal replacement at Northstar. Impacts on May North Slope production included downtime at Northstar, where valves were replaced in the gas-injection header May 6, and a system default led to a plant shutdown May 7. The Alaska Department of Revenue also reported that planned compressor work May 9-22 on the east side of Prudhoe Bay decreased total production from that field by about 40,000 bpd.

Prudhoe Bay production averaged 464,332 bpd in May, down 6.2 percent from the April average of 494,795 bpd, a 30,463 bpd difference. Prudhoe Bay production figures include satellites at Midnight Sun, Aurora, Polaris, Borealis and Orion.

Prudhoe Bay production averaged 464,332 bpd in May, down 6.2 percent from the April average of 494,795 bpd, a 30,463 bpd difference. Prudhoe Bay production figures include satellites at Midnight Sun, Aurora, Polaris, Borealis and Orion.

Endicott production (including Sag River, Eider and Badami), averaged 32,489 bpd, down 2.4 percent (793 barrels) from an April average of 33,282 bpd.

All other North Slope fields had increased production, May over April, led by Northstar which averaged 66,559 bpd, up 47.4 percent (21,403 bpd) over an April average of 45,156 bpd. Lisburne production (including Point McIntyre and Niakuk) averaged 65,973 bpd in May, up 43.3 percent (19,931 bpd) from an April average of 46,042 bpd. April's planned maintenance at the greater Point McIntyre area extended over a two-week period (April 4-17), pulling production from Lisburne down well below its recent 65,000-bpd production range.

Kuparuk River field production (including West Sak, Tabasco, Tarn, Meltwater and Palm) averaged 219,963 bpd in May, up 3.2 percent (6,788 bpd) from the April average of 213,175 bpd. Milne Point production (including Schrader Bluff) averaged 52,884 bpd in May, up 0.8 percent (436 bpd) from April's average of 52,448 bpd.

Alpine averaged 104,345 bpd in May, up 0.3 percent (298 bpd) from an April average of 104,047 bpd.

Cook Inlet production averaged 28,851 bpd in April, down 1.4 percent (404 bpd) from a May average of 29,255 bpd.

The average May temperature at Pump Station No. 1 in Deadhorse was 27.7 degrees Fahrenheit, compared with a three-year average for May of 22 degrees F.

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

● GULF OF MEXICO

Target 25,000 feet: BP plans expensive gulf well

BP aims to be first company to drill ultra-deep well on continental shelf

PETROLEUM NEWS HOUSTON STAFF

BP Exploration & Production could become the first to drill an offshore wildcat into an untested and extremely deep geological target situated some 25,000 feet beneath the Gulf of Mexico's continental shelf.

Joint venture partner Newfield Exploration, a Houston-based exploration and production independent, said June 2 it received a notice from operator BP that it intends to drill a well to test the so-called "Treasure Island exploration concept."

Other companies, including independent Pioneer Natural Resources, have expressed interest in ultra-deep plays on the continental shelf, but so far no one has taken the plunge.

BP said it plans to drill the well this fall.

Treasure Island covers various horizons below specified depths on 116 blocks in the relatively shallow waters of the shelf offshore Louisiana.

It specifically refers to "ultra-deep horizons" located below a salt weld typically found at 18,000 feet but often as deep as 22,200 feet, Newfield said. Treasure Island acreage is spread across South Timbalier, Ship Shoal and Eugene Island.

"There is no production and there are no proved reserves currently associated with Treasure Island and no wells have yet been drilled to test the exploration concept," the company added.

"As a result, ultimate commercialization of any one or more of the currently identified prospects may never be realized because the prospects are never tested, because oil or gas is not discovered or, if discovered, because the costs of development may make commercialization uneconomic."

Costs could exceed $30 million per well

The Treasure Island play is therefore considered to be a highly risky venture with costs possibly exceeding $30 million per well, Newfield said.

However, BP is caught between a rock and a hard place. Under terms of their Treasure Island agreement, BP would have to assign 20 leases to Newfield should BP fail to begin drilling an ultra-deep well by Jan. 1, 2004. BP would absorb the entire cost of the initial well, Newfield said.

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

Because of the extreme pressures and temperatures at depths below 25,000 feet, there likely would be more gas than oil, geologists believe. The sedimentary sand systems that make up the play across the shelf are said to be so immense they rival California in size.

Other companies, including independent Pioneer Natural Resources, have expressed interest in ultra-deep plays on the continental shelf, but so far no one has taken the plunge.

One problem relates to the relatively short, five-year term limits for federal leases located on the continental shelf. The U.S. Minerals Management Service says companies want to extend terms to seven years, to give them more time to properly evaluate leases for ultra-deep drilling and to arrange for rigs and equipment. MMS says it is considering the request. ●

GULF OF MEXICO

Baker Energy to operate Apache facilities in gulf region

Oilfield service company Baker Energy has been awarded "multi-million dollar" contracts to operate and maintain oil and gas properties in the Gulf of Mexico region for big Houston independent Apache, Baker said May 28.

The new agreements bring to 43 the total number of onshore and offshore facilities that Baker operates for Apache in the gulf area.

Under the offshore agreement, Baker said it provides more than 76 operators and technical personnel to operate and maintain Apache facilities in the West Delta, Grand Isle, East Cameron, West Cameron and High Island areas of the gulf.

The onshore agreement provides more than 15 operators and technical personnel to operate and maintain wells in four fields owned by Apache, including Mecom Ranch, Bayou Penchant, Bayou Pigeon and Lake Decade.

Including the Apache properties, Baker operates more than 350 manned and unmanned facilities throughout the gulf region.

—PETROLEUM NEWS HOUSTON STAFF

NORTH SLOPE, ALASKA

Winstar lease added to Pioneer's Oooguruk unit application

The Alaska Division of Oil and Gas said May 28 that Pioneer Natural Resources Alaska has amended its application for the Oooguruk unit at its Northwest Kuparuk prospect in Harrison Bay off Alaska's North Slope to include an additional lease, ADL 388576. That lease, formerly held by Winstar Petroleum, was assigned to Pioneer Natural Resources Alaska (70 percent) and Armstrong Alaska (30 percent) effective May 1. Winstar retained an overriding royalty interest.

ADL 388576 is on the northern edge of the proposed unit, just north of a lease — not part of the proposed unit — held by Anadarko Petroleum on which ExxonMobil drilled the 1 Thetis Island well. That lease, ADL 379301, was acquired in a 1983 state lease sale. The 1 Thetis Island well was certified by the state as capable of producing in paying quantities, holding the lease beyond its expiration date of 1993. As originally proposed, the Oooguruk unit included 11 state oil and gas leases covering some 18,500 acres. With the addition of the 12th lease the proposed unit area now covers approximately 20,394 acres.

Armstrong, an affiliate of Denver-based Armstrong Oil and Gas, assembled most of the acreage in the unit and the partners drilled three wells last winter, the 1 Ivik, the 1 Oooguruk and the 1 Natchiq. Those wells complete the proposed work commitment for the five-year unit plan.

Two Phillips Alpine Alaska leases in the original unit application, ADL 388569 and ADL 388570, were assigned to Pioneer (70 percent) and Armstrong (30 percent) effective March 1. Phillips retained an overriding royalty.

—KRISTEN NELSON, Petroleum News editor-in-chief

● NORTH SLOPE, ALASKA

Expansion will help sustain Alpine field's crude output

Water, gas handling facility upgrades allow crude production to stay at present level

By KRISTEN NELSON
Petroleum News Editor-in-Chief

Phase one of the Alpine facilities expansion, announced in May, allows for an increase of about 5 percent in oil production — but more importantly, it allows the present level of oil production to continue as more water and gas have to be removed from the crude oil produced at the field.


FORREST CRANE
MARK IRELAND

The field, on Alaska's western North Slope, began production in November 2000 and is currently producing some 100,000 barrels of oil per day. (See related story on page 1.)

Phase 1 of the expansion will allow gas handling to increase by 23 percent, from 130 million standard cubic feet per day to 160 million, Mark Ireland, ConocoPhillips Alaska's western North Slope development manager told Petroleum News May 28.

And water handling capacity will increase from 10,000 barrels per day to 100,000 barrels per day, he said.

The increase in produced water handling is the biggest component of the expansion, and it's something ConocoPhillips and partner Anadarko Petroleum knew they would have to do.

"We can only currently handle about 10,000 barrels a day of produced water and we're currently injecting almost 100,000 barrels a day of seawater," he said. But the flood performance of the Alpine reservoir "is very good. … we knew we could inject for a number of years before we'd start producing that water back. So we delayed the construction of the produced water handling unit closer to the time that we'd need it."

Started up by end of 2004

Ireland said the phase 1 expansion is planned to be

see **ALPINE** *page 9*

● NORTH SLOPE, ALASKA

Exploring the upper Jurassic

There's plenty of oil in these North Slope sands but the challenge is to hit just the right combination of oil quality and reservoir characteristics

By ALAN BAILEY
Petroleum News Contributing Writer

The upper Jurassic sands of Alaska's North Slope pose some tantalizing questions for oil exploration — people know that the sands contain lots of oil but you need to hit just the right combination of oil quality and reservoir characteristics to find an oil accumulation that's commercially viable. The 1990s discovery of the North Slope's Alpine field by ARCO Alaska proved that these intriguing rocks can carry a valuable payload.


MARK MYERS

The Alpine sandstone that forms the reservoir for the Alpine field, the major field in the ConocoPhillips-operated Colville River unit, is the youngest of three major upper Jurassic sandstone rock bodies on the North Slope.

The ways in which these sandstones formed help explorers understand their viability as oil reservoirs.

A shallow ocean

During the upper Jurassic period, at a time when dinosaurs ruled the earth, the geography of the North Slope region was very different from today. Sand and other detritus from a long since disappeared landmass to the north or northwest flowed out into a shallow sea. The seabed sloped gently south from the shoreline. A so-called rifting event, in which the earth's crust extended and cracked apart, was just starting. As a

see **JURASSIC** *page 8*

continued from page 7

JURASSIC

result of this upheaval, some sections of the crust dropped between flanking fault lines.

"The ocean shelf at that time was very flat, with low relief, so that there was very little space to deposit sediments," Mark Myers, director of the Alaska Division of Oil and Gas, told Petroleum News.

But periods of extension of the crust created localized holes or spaces that sand and other sediments could fill, Myers said. In addition, changes in sea level resulted in the erosion of valleys that could accommodate more sediment. Periods of higher sea level might also give rise to more extensive areas of sand.

"You have localized areas where you may get much thicker accumulations. Then you have much broader spread areas where, if you get enough space, you'll preserve the whole sand package," Myers said.

Many of these accumulations remain today beneath the earth's surface, both as isolated sandstone pockets and as more widely spread sandstone layers.

Want to know more?

If you'd like to read more about the Alaska North Slope's Jurassic sands, go to Petroleum News' web site and search for these published articles.

Web site: www.PetroleumNewsAlaska.com/

2003
- **May 4** Pioneer gives Alaska top billing
- **April 13** Pioneer looking at fast-track development
- **April 6** Too early to tell
- **March 30** Anadarko says Foothills, NPR-A hold huge oil, gas potential
- **Jan. 26** BLM issues draft plan, EIS for northwest NPR-A

2002
- **July 28** A winning package
- **May 26** Alpine trend shows best NPR-A oil potential
- **March 17** Phillips drilling at Hunter
- **Jan. 13** Geologists find evidence of oil in gas-prone Brooks Range Foothills

1999
- **Sept. 28** Second plan of development approved for Thetis Island
- **Sept. 28** Western North Slope focus of operators' winter exploration plans
- **Aug. 28** BLM okays all 133 NPR-A lease applications
- **July 28** ARCO, Anadarko announce 50 million barrel field at Fiord
- **May 28** Bidders pay $105 million for oil and gas leases in the NPR-A

Very sophisticated toolbox needed

Anchorage-based petroleum geologist Doug Hastings, considered by Myers to be one of the most knowledgeable geologists on the subject of the North Slope's upper Jurassic sands, told Petroleum News that locating the sands requires high-quality seismic data.

"A key to all that is getting good three-dimensional seismic data," he said.

Hastings, who currently consults with Petrotechnical Resources of Alaska but spent 22 years in Alaska with ARCO Alaska and Phillips Alaska, said "Alpine is up to 100 feet thick, but there's a lot of (the sands) 50 feet thick and that's below (seismic) tuning." There are quite a few wells in the region, so that the seismic can be tied back to well data, Myers said. However, with oil traps resulting from the rock stratigraphy rather than folding or faulting of the rocks, tracing the sands can prove challenging.

"It takes a very sophisticated toolbox to try to determine the individual sands," Myers said.

Poor reservoir rocks

During the upper Jurassic, below the surface of the shallow sea, wave action and a multitude of burrowing critters churned the sediments and mixed fine quartz sand with muddy silt. As a consequence, many of the sands make rather poor oil reservoirs — the silt and mud reduce both the porosity (the ability of the rock to store oil) and the permeability (ease with which oil flows through the rock).

"They weren't particularly great sands in the first place and then (the animals) churned them until there's virtually no permeability," Hastings said.

However, the sands tend to become coarser towards their top surfaces and in proximity to the ancient shoreline. These coarser sands exhibit better reservoir characteristics than the finer sediments. So an understanding of the geological setting provides a key to locating the presence of a usable reservoir. Because the ancient shoreline lay in the north of the region, geologists expect to find the best upper Jurassic oil reservoirs towards the north of the western North Slope.

"If you understand where the old shorelines were ... then you understand the broader-based ... sands, then if you can go to the next stage and understand where some of these (valley) incisions or fault relief areas are ... you might pick up even more sand," Myers said.

To the south, towards the Brooks Range foothills, the rocks should become finer grained because the sands that formed them had carried some distance from the shoreline. The rocks to the south should also suffer from compression and compaction by an increasing depth of younger sediments above them. The joint "strikes" of finer grain and stronger compaction may limit the ability of the rocks to hold economic oil deposits.

Two strikes you're out?

"It may be that two strikes and you're out," Hastings said, "but we don't know because we haven't shot the data."

However, Myers said that there are indications of Jurassic sands to the south.

"The overall extent of the (sea) shelf was very broad, so subtle changes in sea level can make a big difference (to the distribution of the sands)," he said.

Although geologists expect better quality sands to the north, exploration in the north runs into another problem — upheavals in the earth's crust during ancient times resulted in erosion of the sandstone bodies. This erosion becomes progressively worse the further north you go, until the rocks disappear completely.

"You play a game between having the best quality sands and them actually being preserved," Myers said.

Abundant oil

Despite the poor reservoir quality of the sandstones they often contain oil.

"Some of these Jurassic sands have very large volumes of in-place oil," Myers said. "There are stratigraphic traps in most every place you look — the sands are all charged in the public wells."

The oil has probably come from a variety of source rocks through different migration paths. So, the composition of the oil at a particular location will depend on several factors.

"You've got to know the timing issues, you've got to look at your structural plays, you've got to know the relation to source rocks," Myers said.

Hastings said that the Jurassic sands themselves have provided a source of oil.

"There's not a single, say 50 foot, highly concentrated interval like the Shublik or like the HRZ (formation), " Hastings said, "... (but) as much as 2,500 feet of rock can generate a lot of oil just through the sheer volume of rock, not necessarily through the concentration of organics."

But, although there's a high probability of finding oil in the sands, the oil has generally proved too heavy for economic production, given the poor reservoir characteristics of the rocks. For example, Texaco and Amerada Hess drilled in the northern Colville River Delta area in the mid-1980s and encountered oil in the middle of the three upper Jurassic sands. However, the flow rates proved too low for viable field development — a viable field requires either lighter oil or a better reservoir.

Alpine and where else?

With the Alpine field, however, ConocoPhillips struck a combination of both a good reservoir rock and a relatively light oil. For some reason an oil migration path from a suitable source rock coincided with an unusually good sandstone reservoir — the Alpine reservoir rock has a higher permeability than is normally found in the upper Jurassic sands, Hastings said.

Could these conditions occur elsewhere? The Alpine field and a couple of satellites in the National Petroleum Reserve-Alaska are the only upper Jurassic fields currently known in the area, Myers said.

Hastings said that people still don't fully understand why the Alpine field is where it is.

"The key questions for all explorationists are 'Why is that sand better? What's the depositional environment?'" Hastings said.

However, the potential for other productive Alpine deposits, especially to the east of the Alpine field, intrigues Hastings. The small extent of some of the pockets of Alpine sand means that another deposit could exist between some of the wells that have been drilled in the area.

"There's a lot of well information, but the real question is 'Can you have hidden Alpine sands between ... the wells?'" Hastings said.

And could some of the other upper Jurassic sands contain areas with a favorable combination of reservoir characteristics and oil quality?

"I think Alpine's shown just how prolific these sands can be and how well they can produce," Myers said. ●

● NORTH SLOPE, ALASKA

State approves addition to Kuparuk unit

Well must be drilled on Winstar lease by next June to prove up potential

BY KRISTEN NELSON
Petroleum News Editor-in-Chief

The Alaska Division of Oil and Gas has approved the addition of lease ADL 388584 (the Winstar lease) to the Kuparuk River unit.

The division approved expansion of the unit May 21 subject to drilling of a well on the lease and said the plan is to drill one exploration well to the offshore lease from the Kuparuk River 3R drill site, with a follow-up well if the first well is successful.

The Winstar lease lies just offshore Oliktok Point north of the 3R pad, the northernmost development pad in the Kuparuk River unit, and west of the Milne Point unit. No wells have been drilled within the expansion area, the state said. The proposed primary target on lease ADL 388584 is the Kuparuk A sands. Oil production from Milne Point unit F and L pads and Kuparuk O, Q and R pads is primarily from Kuparuk A sandstone members, "where reservoir sand is preserved above the oil/water contact."

"The structural complexity of the area and the interrelationship between sediment deposition and faulting and the subsequent distribution of reservoir sand in the northern fairway and northwest extension area between the Milne Point and Kuparuk River fields remains untested due to lack of well log control and the uncertainty of oil-water contacts in the vicinity," the state said.

Area once in Milne Point unit

The Winstar lease, sections 28 and 33 of township 14 north, range 9 east, Umiat meridian, was added to the Milne Point unit in 1992 as part of the third Milne Point unit expansion — the northwest Milne Point expansion.

Some 94 million barrels have been produced from the northwest Milne Point area, but BP did not drill in the area including sections 28 and 33 of T14N-R9E, UM, and the acreage contracted out of the Milne Point unit in 1996. Winstar acquired the acreage in the state's 1997 areawide lease sale and has remapped the area with new 3D seismic data and incorporated well log control from Kuparuk 3R, 3Q and 3O pads, and well data from Milne Point F and L pads.

"The structural complexity of the area and the interrelationship between sediment deposition and faulting and the subsequent distribution of reservoir sand in the northern fairway and northwest extension area between the Milne Point and Kuparuk River fields remains untested due to lack of well log control and the uncertainty of oil-water contacts in the vicinity," the state said.

Winstar's plan is to test this Kuparuk play by drilling "a down-thrown structural block" through the base of the Kuparuk at a 6,700 foot true vertical depth with a 7,700 foot departure.

Well must be drilled by June 2005

The assessment of the lease's potential will create jobs, the state said, and if drilling is successful, the state will earn royalty and tax revenues. The lease expires Dec. 31, 2004, and if a well is not drilled — or if the exploration attempt is not successful — the tract could still be included in the state's 2005 areawide lease sale.

A well must be drilled to test the Kuparuk interval on lease ADL 388584 by June 1, 2005, or the lease will automatically contract from the Kuparuk River unit. All or part of the lease must be included within a participating area by June 1, 2006, or it will automatically contract from the unit.

Kuparuk Unit operator ConocoPhillips Alaska will drill for Winstar. ●

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ALPINE

in place and started up by the end of 2004. The companies said in mid-May that design engineering was being done by NANA/Colt Engineering in Anchorage and that truckable module fabrication would be put out for bid once engineering was complete.

Ireland said the companies anticipate that the modules will be built in Alaska, and when completed will be driven to the North Slope to go out on ice roads next winter and be put in place at Alpine. Then work would then begin to connect the modules to prepare for startup.

The modules will probably go out to Alpine next April, Ireland said.

Some improvement in oil rate

The facilities expansion will allow the companies to increase the oil production rate by about 5 percent, he said. More importantly, it will extend by a number of years the time that production can stay at that rate, estimated by the companies to be some 105,000 barrels a day.

"We've been producing almost three years now and we're only producing about 1,000 barrels of water per day currently," Ireland said. The Alpine facilities, originally designed to produce at 80,000 barrels of oil per day, have been producing at a higher rate, some 100,000 barrels per day.

The primary purpose of the facilities is to separate oil, gas and produced water so that oil can be pumped down the pipeline, he said. With production at 100,000 barrels of oil per day, a number of the facilities "needed to be upgraded just to … allow us to be at that kind of rate for the long term."

COURTESY CONOCOPHILLIPS

Alpine is the largest onshore oil field discovered in the United States in more than a decade. The field is located in the Colville River unit, approximately 34 miles west of the Kuparuk River field, eight miles from the Inupiat village of Nuiqsut and near the border of the National Petroleum Reserve-Alaska.

At the beginning of production, Ireland said, the facility basically produced 100 percent oil with some gas dissolved in the oil. The gas is reinjected and seawater is injected.

"Eventually, the water we inject and the gas we inject starts to break through at the producing wells and you have an increase then in the amount of gas you need to handle and the amount of water you have to handle."

If the produced water handling capacity wasn't increased, "once we started making significant amounts of water, we'd have to cut back our oil rate to less than 100,000 barrels a day. And the same is true with the gas handling side. As we start to produce more gas, we'd have to decrease our oil off take."

The increase in water and gas handling will allow production to stay at 105,000 barrels a day "for a longer period of time than we could have otherwise." ●

● KENAI PENINSULA, ALASKA

Kenai Kachemak Pipeline files initial tariff

Company says natural gas shipments to begin Aug. 20

By KRISTEN NELSON
Petroleum News Editor-in-Chief

Kenai Kachemak Pipeline has told the Regulatory Commission of Alaska that it expects to begin natural gas shipments Aug. 20 and has filed an initial tariff for intrastate natural gas shipments, with rates for both firm and interruptible transportation.

The pipeline will transport gas from the Ninilchik unit discovery, announced last year by Marathon Oil and Unocal Alaska, and will interconnect with existing pipelines in the Kenai field area. From there gas will move to markets on the Kenai Peninsula and in the Anchorage area.

Last August the Kenai Kachemak Pipeline said it had secured two long-term capacity commitments and finalized the design of a 33-mile-long, 12-inch diameter natural gas pipeline. The pipeline is designed to transport as much as 120 million cubic feet of natural gas per day and is projected to cost $25 million to design and construct.

Kenai Kachemak Pipeline is jointly owned by Marathon (60 percent) and GUT LLC, a wholly owned subsidiary of Unocal (40 percent), with ownership interests in direct proportion to the gas shipment commitments made by Marathon and GUT LLC's producer affiliate, Unocal Alaska.

COURTESY KENAI KACHEMAK PIPELINE

Kenai Kachemak Pipeline has told the Regulatory Commission of Alaska that it expects to begin natural gas shipments Aug. 20. Pictured is work on the project from this winter.

The companies committed to ship through the line for 15 years.

Work began in January

Clearing for the pipeline began in January and the Joint Pipeline Office said June 4 that with the exception of pipe associated with horizontal directional drilling, the entire pipeline is now buried.

Crews were cleaning and dressing up the right of way in areas where pipe installation was complete, the JPO said, and milepost signs were being placed at one-mile intervals along the right of way.

A legal wrinkle was ironed out in mid-May with the passage by the Alaska Legislature of Senate Bill 151, which clarifies that the Regulatory Commission of Alaska has the authority to authorize "firm" and "interruptible" services for other Alaska gas transmission pipelines — not just a North Slope gas pipeline.

The Legislature authorized "firm" and "interruptible" service on a North Slope gas pipeline in 2000, when that was the only pipeline proposing to offer such service. When the Kenai Kachemak Pipeline asked the RCA to authorize it to offer firm and interruptible services, the RCA declined, noting that the 2000 amendment dealt only with transportation of gas from the North Slope.

A legal wrinkle was ironed out in mid-May with the passage by the Alaska Legislature of Senate Bill 151, which clarifies that the Regulatory Commission of Alaska has the authority to authorize "firm" and "interruptible" services for other Alaska gas transmission pipelines — not just a North Slope gas pipeline.

Senate Bill 151 deletes references to the North Slope, making "firm" and "interruptible" options available statewide.

Shippers with interruptible service, Kenai Kachemak Pipeline said in its proposed tariff, are subject to curtailment or interruption at any time their interruptible deliveries would interfere with deliveries of gas under firm service. The pipeline also noted that it "is not obligated to add any facilities or expand the capacity of its pipeline system in any manner in order to provide interruptible transportation service." Parties seeking a pipeline connection must bear the costs associated with construction of connecting facilities. ●

EL PASO, TEXAS

ChevronTexaco sells El Paso refinery

ChevronTexaco said June 2 that it has reached a definitive agreement to sell its interest in its El Paso, Texas, refinery and certain associated assets to Western Refining Co.

The sale also includes Chevron Products's El Paso light products terminal. Since 1993, Chevron Products and Western Refining have had an operating agreement whereby Chevron Products operates Western's part of the 90,000 barrel per day refinery complex. The sale does not include Chevron Products' El Paso asphalt plant. Chevron Products will continue to market its branded gasoline, asphalt and other petroleum products. The agreement also calls for Chevron Pipe Line to sell an associated oil pipeline system to Kaston Pipeline, a subsidiary of Western Refining. The sale is expected to close after all regulatory approvals and financing are obtained. Financial details of the agreement were not disclosed.

Dave Reeves, president of Chevron Products said the sale reflects a shift in the company's strategic focus. Paul Foster, president and owner of Western Refining, said his company had been interested for some time in buying the refinery and associated pipeline assets, "and we look forward to being the owner and operator."

OKLAHOMA CITY, OKLAHOMA

Murkowski to head IOGCC

The Interstate Oil and Gas Compact Commission named its 2003-04 officers May 29.

New Mexico Gov. Bill Richardson was named chairman; Donald Mason of Ohio was selected as vice chairman and Randy Ruedrich of Alaska was named second vice chairman.

Mason, a member of the Public Utilities Commission of Ohio, is the current second vice chairman of the IOGCC. Ruedrich is a member of the Alaska Oil and Gas Conservation Commission.

Richardson, a former United Nations ambassador and U.S. Secretary of Energy during the Clinton Administration, was chosen at the IOGCC's midyear meeting in Williamsburg, Va. He will succeed the current chairman, North Dakota Gov. John Hoeven, at the organization's annual meeting in Reno, Nev., Oct. 19-21.

Alaska Gov. Frank Murkowski was named chairman-elect, and will serve as chairman in 2004-05, with Ruedrich as vice chairman and Don Likwartz, state oil and gas supervisor for Wyoming, as second vice chair. Wyoming Gov. Dave Freudenthal was tabbed to serve as chairman in 2005-2006.

The IOGCC, founded in 1935 to ensure the efficient recovery of domestic petroleum resources while protecting health, safety and the environment, represents the governors of 30 oil and gas producing states. Seven states are associate members, and the IOGCC international program has seven affiliates. For more information on the IOGCC, visit its Web site at www.iogcc.state.ok.us.

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CHANGES

other factors."

Designed to clarify regulations, this proposed change, DEC says, would allow more than one oil exploration well within a single region to be covered under an "umbrella" plan submitted by an operator along with site-specific data for each well. The change would also allow contingency plans to cover multiple facilities within a geographic area to facilitate regionally based response planning.

Currently, an exploration or production facility C-plan must include "a plan and time frame for drilling a relief well or otherwise controlling an exploration or production well blowout."

DEC proposes to instead mandate that a C-plan must include "the planned method to control a well blowout within 15 days; the holder of an approved contingency plan must have a well blowout contingency plan; the well blowout contingency plan shall be made available to the department for review and verification upon request."

Other DEC proposed changes

Other proposed changes deal with adopting current practices, such as the ongoing development of stand-alone response references — the North Slope Tactics Manual, for example; clarification of definitions, such as "typical environmental conditions" for designing summer and winter response scenarios; the supplemental information required in a C-plan, allowing nonmechanical response methods to be among the measures proposed for certain conditions; changes to make the specific compensatory measures to reduce the environmental consequences of a discharge subject to best-available technology requirements; clarification of regs dealing with state registration of a spill contractor; reduce ambiguity and clarify issues related to the calculation of the response planning standard for an exploration or production facility, which, among other things, would allow flexibility in determining the response planning standard for operations such as the proposed Point Thompson development, where a large proportion of volatile gas is associated with the oil and significant reductions in the amount of oil discharged to the lands or waters of the state could be realized by voluntary ignition of a well blowout; address confidentiality concerns by providing for the protection of certain proprietary data required by DEC to determine compliance; and specification of a 15-day total timeframe for calculating the response planning standard.

Under DEC's proposed changes, the well blowout contingency plan would not be part of the oil discharge prevention and contingency plan application, but would be available to the department "for review and verification on request, and any shortcomings discovered through such inspection could be cause for modification of the operator's plan approval"

DEC has developed a discussion draft of proposed changes to the contingency plan requirements that includes the department's rationale for each proposed change.

Comments are due to DEC no later than June 25.

See website http://www.state.ak.us/dec/dspar/cpr/cprhome.htm

NORTH SLOPE, ALASKA

DOE joins tundra travel study

Goal to establish science-based model to replace 30-year-old ad-hoc rule

PETROLEUM NEWS ANCHORAGE STAFF

The U.S. Department of Energy said June 3 that it will assist the state of Alaska in the first scientifically based study to determine when oil companies can transport equipment over the Arctic tundra without damaging the fragile ecosystem.

The DOE said the study will replace a 30-year-old 'ad hoc' rule with a science-based model.

"Sound science offers the best way to protect sensitive environments. Today, however, all we have is a general 'rule of thumb' for determining when it is environmentally safe to move oil exploration equipment across the Arctic tundra," Assistant Secretary of Energy for Fossil Energy Mike Smith said in a statement.

Smith said this "project will apply the latest in scientific instrumentation and modeling to refine our understanding of the tundra's resistance to disturbances. The result will be better environmental protection and a much more scientific basis for determining when oil operations can be conducted."

The DOE said the new ecological model will be a major improvement over the current ad-hoc standard established more than 30 years ago without the benefit of systematic scientific analysis. The standard now limits oil exploration and ice road construction to time periods when there is a minimum of 12 inches of frozen ground and six inches of snow cover over the tundra.

Joint funding of study

The Energy Department will provide $270,000 for the study. Another $70,000 in funding and technical services is being provided by Total, Anadarko Petroleum, ConocoPhillips and Yale University under an agreement these organizations have with the Alaska Department of Natural Resources.

JUDY PATRICK

A Crowley rolligon on the North Slope

Research personnel from Yale and the Alaska Department of Natural Resources will carry out the analyses and modeling. The U.S. Army Corps of Engineers' Cold Regions Research & Engineering Laboratory will provide researchers to assist in evaluating the study's design effectiveness and the accuracy of the modeling techniques.

DOE said the researchers plan to develop an ecological model that accounts for factors such as snow depth, snow density, ground hardness and the type of vegetation and soil, and how they interact to protect the tundra from being compacted or deformed.

The Alaska Department of Natural Resources is responsible for determining when the tundra is ready

see **TUNDRA TRAVEL** *page 13*

TULSA, OKLAHOMA

DOE assists six independents

Agency pledges $590,000 to small oil producers for technology-assisted projects

By PATRICIA JONES
Petroleum News Contributing Writer

Six technology-driven oil production projects proposed by small independent producers have been selected for funding by the U.S. Department of Energy, through its National Petroleum Technology Office in Tulsa, Oklahoma.

The federal funds, part of a matching grant program administered by NPTO since 1995, provide a way for small companies to use higher-risk production technologies, said Jim Barnes, project manager for the Technology Development with Independents program.

"We want to increase recovery in known fields," he said. "The program is looking for ways to reduce the costs to get more oil out of the ground and extending production for small wells."

Sharing risks and expenses has resulted in innovative methods and technologies that have boosted oil production and prevented the premature shutdown of some endangered oil fields, according to the NPTO press release issued May 22, announcing the six new grant recipients.

Program criteria limits funding to companies that operate in the United States, employ 50 or fewer full-time employees and generate less than $100 million in gross revenues a year, Barnes said.

"We have all kinds of folks involved — some are almost mom and pop operators," he said.

Sixty-three projects in 19 states funded since '95

Since the program's inception in 1995, 63 projects have been funded in 19 different states, none in Alaska. "The smaller companies in Alaska are still bigger-sized," Barnes said.

Total federal funding has been about $4 million, he said. Originally, grants were limited to $50,000 per project, Barnes said, but now that maximum is $100,000.

NPTO, a part of DOE's National Energy Technology Laboratory, issues solicitations for the grant program and advertises its availability on its website. Currently, all available DOE monies for the independent technology have been awarded, and Barnes said he is waiting to see if the program receives additional funding before starting another selection process.

Arnell, Grand Mesa, Peden, Terra get $100,000 each

Companies with projects recently selected include:

• Arnell Oil Co. of Littleton, Colo., will receive $100,000, matched by $100,000 from the company. The project will demonstrate alkaline-surfactant-polymer chemical flooding designed to produce economical, incremental oil reserves in the Poison Spider field in Natrona County, Wyo.

• Bass Enterprises Production Co. of Fort Worth, Texas, will receive $90,000, matched by $220,000 from the company. Working with the University of Texas and Trend Technology, the project will demonstrate how independent producers can acquire and analyze advanced imaging data from small seismic test patches embedded in large-scale seismic surveys — a

see **ASSIST** *page 13*

ONTARIO, CANADA

Nickel climbs as strike shuts down Inco

Nickel prices are predicted to rise as 3,400 Inco workers shut down the world's largest mine in Ontario amidst the hottest market in years.

Bitter negotiations ended in a strike June 1 that union and company officials have warned could be prolonged, wiping out 9 percent of global production.

The core of the dispute is disagreement over pensions, after faltering stock markets left Inco with a US$805 million pension shortfall last year.

The company's offer of an increase in its contributions to US$140 million this year from US$67 million in 2002 was rejected by 95 percent of Local 6500 of the United Steelworkers of America.

In addition, the union wants a "significant" increase in the average miner's pay of C$25 an hour, plus bonuses tied to operating profits.

Inco is now left with only 55 million pounds of nickel to carry it through a strike, the lowest level since 1994, and only 25 percent of last year's production.

With prospects of a strike looming, spot nickel prices have climbed to 52-week highs over the past month on the London Metals Exchange topping US$4 a pound.

An Inco spokesman said that with the two sides so far apart no talks have been scheduled.

—GARY PARK, Petroleum News Calgary correspondent

NORTHWEST TERRITORIES, CANADA

BHP expands Canadian diamond interests

BHP Billiton, the world's largest mining company, is pouring C$7.1 million into a diamond exploration venture in Canada's Northwest Territories.

In return it will get a 20 percent stake in the Aviat Joint Venture from Hunter Exploration Group. Aviat was created by three Vancouver-based juniors — Hunter, Northern Empire Minerals and Stornoway Ventures — to hunt for diamonds on the Melville Peninsula.

Northern Empire and Stornoway said May 29 they would not exercise rights of first refusal on the Hunter interest, opening the door to BHP.

BHP already operates the Northwest Territories' Ekati mine, which produced diamonds valued at US$492 million in 2002, it fourth year of operation.

With the diamond business in full swing in Canada's North one of the obstacles in its way is a shortage of qualified labor from mine operators to diamond cutters and pol-

see **DIAMOND** *page 13*

● FAIRBANKS, ALASKA

Drilling Ester Dome

Alaska's largest gold producer gets approval to drill Ryan Lode mine

By PATRICIA JONES
Petroleum News Contributing Writer

State mining regulators approved this week a gold exploration drilling program proposed at the closed Ryan Lode gold mine on Ester Dome, adjacent to a rustic residential area about 10 miles west of Fairbanks.

In a letter sent May 28 to individuals interested in the exploration program, Alaska Division of Mining, Land and Water geologist Brent Martellaro outlined restrictive exploration stipulations unique to Ryan Lode exploration. The stipulations — along with a public open house and comment period that was held for the Ryan Lode project — are not part of typical state requirements for mining exploration.

"DNR believes this public feedback was important because of past concerns that nearby residents expressed about previous exploration drilling activities of similar magnitude," Martellaro wrote in his letter.

Martellaro told Petroleum News on May 28 that prospecting can begin June 1.

Fairbanks Gold Mining, owner of the closed heap leach mine site on Ester Dome, submitted an application in mid-April for an extensive drill program at Ryan Lode.

Feedstock for Fort Knox possibility

A subsidiary of mining giant Kinross Gold, Fairbanks Gold operates the Fort Knox gold mine and mill, located about 20 miles northeast of Fairbanks.

In 2003, Fort Knox will churn through 17.7 million tons of ore to generate about 407,000 ounces of gold, Alaska's largest gold producer. Exploration at Ryan Lode will help the company determine whether it could possibly provide additional feedstock for Fort Knox in the future.

Exploration plans at Ryan Lode include up to 68 drill holes, with a maximum depth of 300 feet, involving both core and reverse-circulation rigs. Access will be from existing roads and trails on the property.

Fairbanks Gold asked for approval to explore through the end of the year, although the actual time when equipment will be on-site is significantly less, Martellaro said.

"They wanted to leave the option open. Their goal is to be done drilling before the winter months," he said. "They want to drill half of it, look at the results and then drill other holes, so there could be a gap in the program."

Permit allows no drilling at night, or Sundays

Stipulations included in DNR's permit approval for Ryan Lode call for drilling operations to be limited to 7 a.m. to 7 p.m., Monday through Saturday, barring unforeseen circumstances.

Martellaro noted that by limiting hours, drilling might be extended, as drill crews typically operate long hours when equipment is on-site. Typically, state regulators

see **ESTER DOME** *page 13*

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TUNDRA TRAVEL

for cross-country vehicle travel related to oil exploration and development. In 1970, the current standard was adopted under the assumption that frozen ground and snow cover protects vegetation from being crushed or torn and the soil from being rutted or compressed by oil exploration traffic.

Tundra travel has been limited

In recent years, DOE said, the ad hoc standard has limited the number of days during the winter work season in which oil exploration activities can occur in the northern region of Alaska. Last year exploration activity was permitted for only 103 days. If the scientific studies provide a more credible assessment of the tundra's resistance to damage, DOE said, it may be possible to extend the number of workdays without harming the environment.

The study will build on a previous effort by the Alaska Department of Natural Resources to determine if seismic exploration could take place outside the current standards without disturbing the tundra That phase of the effort was completed last year.

It will also add to an ongoing effort, due to be completed this year, which is evaluating several techniques for measuring when the tundra is sufficiently hard to allow ice roads to be built. In recent years, with the development of specialized technology, industry has been constructing ice roads as a more environmentally acceptable alternative to gravel construction, DOE said.

The new tundra study will be conducted during the autumn and winter of 2003 and the summer of 2004. ●

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ASSIST

low-risk, low-cost option for acquiring seismic data.

• Grand Mesa Operating Co. of Wichita, Kansas, will receive $100,000, matched by $106,319 from the company. Working with Tiorco Inc. and the University of Kansas, the project will demonstrate the feasibility of polymer gel technology, to increase the recoverable reserves from Mississippian reservoirs in Kansas.

• Peden Energy of Fort Worth, Texas, will receive $100,000, matched by $100,000 from the company. The project will demonstrate that using micro-turbines at well sites is more efficient and less costly than operating with traditional internal combustion engines and generators. In addition, Peden Energy will install variable frequency drives with computerized pump off controllers on two pump jacks. The VFD, which adjusts pumping speed of the well, should increase oil production by 10 percent and reduce capital expenses.

• Teneco Energy of Wheatridge, Colo., will receive $89,862, matched by $101,703 from the company. The project will use regenerating bio-chemicals such as microbes and organic surfactants to reverse formation damage, restore permeability and improve production in the East Texas Field. Other partners include Micro-Tes Inc. and Oil Patch Pipe and Supply.

• Terra Oil Exploration and Production Co. of Signal Hill, Calif., will receive $100,000, matched by $100,000 from the company. The project will run newly developed cased hole well logs in a selected deep well in the Santa Fe Springs oil field in Los Angeles, Calif., to identify bypassed oil. Past flooding of preferable sands may have bypassed lower permeable, oil-saturated sand intervals, and the project will identify potentially productive zones. The project will also re-complete nearby wells to increase recovery and add bypassed oil to improve production. ●

WHITEHORSE, YUKON

New rules on Yukon placer mining planned

A new system of regulating placer mining in the Yukon will be developed by the federal Fisheries Department, the Council of Yukon First Nations and the Yukon government.

"A harmonized, nationally consistent and timely approach to the regulation of placer mining is very important," Robert Thibault, minister of Fisheries and Oceans Canada, said in a statement.

Community leaders and miners in the Dawson area had painted a bleak picture of the economy of that area if new regulations designed to protect fish were put in place.

"It's a good start," Tara Christie, president of the Klondike Placer Miners Association, said from Dawson City May 28. "But we still have a long way to go."

In December, Thibault, the fisheries minister, said he was scrapping the Yukon Placer Authorization, the existing regulatory regime, and replacing it with guidelines that miners said would shut down half of the industry in the Yukon. The guidelines were to be phased in over four years.

The new system for regulating the miners is to be developed by next April, while the regime itself will be implemented by 2007, according to a joint news release by the three parties.

The new regime must establish a process that is fair and understandable to the industry, said Archie Lang, Energy, Mines and Resources minister for the Yukon.

To help achieve this, the Klondike Placer Miners' Association will be an active participant in discussions, Lang said.

"The active involvement by First Nations in this work should lead to guidelines that are achievable and incorporate local experience and traditional knowledge," said Grand Chief Ed Schultz of the Council of Yukon First Nations.

—THE ASSOCIATED PRESS

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DIAMOND

ishers.

Canada's Indian Affairs and Northern Development Minister Robert Nault acknowledged the problem in a mid-May speech to an industry roundtable in Edmonton, Alberta, amid fears that Sirius Diamonds could be forced to move its cutting and polishing operations from the Northwest Territories to China or India.

That would do serious damage to Canada's hopes of becoming a world diamond center over the next 10 years, based heavily on its proximity to the U.S. market, which buys more than 50 percent of the world's diamonds.

The need for workers is so desperate that skilled workers are being flown in from Armenia, Ukraine and Mauritius.

The pressures will only grow, with about 400 companies involved in various stages of exploration and 2,500 claims covering almost 6 million acres now staked in Nunavut Territory, the third of Canada's northern territories, which was broken off the Northwest Territories about three years ago.

—GARY PARK, Petroleum News
Calgary correspondent

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ESTER DOME

do not set hours that exploration drill crews can work.

In addition, Fairbanks Gold agreed to work to control dust on local roads, watering them if necessary, Martellaro said.

The company will plug all drill holes from top to bottom, although state regulations require only the top 10 feet to be plugged. "It prevents surface penetration to the groundwater," Martellaro said.

In addition, Alaska Department of Environmental Conservation requested samples from water monitoring wells, both before and after the drilling, as part of that department's ongoing reclamation monitoring program.

Public comment process a concern

The stipulations address nearly all specific concerns raised by 16 people who sent written comments about the proposed drill program, Martellaro said.

In a spreadsheet detailing concerns, some people said they were opposed to mining in the area. Martellaro noted in his letter that the exploration proposal does not include mining. "If a mine is proposed at some future date, DMLW will conduct all required and appropriate public notice and procedures," he wrote.

In addition, three people submitted written comments supporting the exploration program, but noted DNR was soliciting comments when no regulatory or statutory requirements required that additional step.

"They were concerned that DNR is setting a potential precedent for everyone who wants to go drill — that they will have to go through this (public comment) process," Martellaro said. ●

Companies involved in North America's oil and gas industry

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

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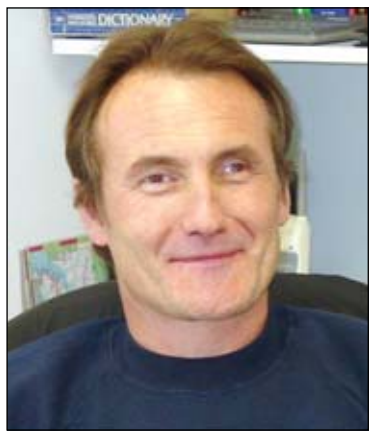

COURTESY ALASKA DREAMS

Meini Huser, founder

Alaska Dreams

Alaska Dreams was established by Meini Huser in 1985. The Anchorage-based company specializes in the construction of fabric covered steel buildings for industrial use. It has erected many buildings on the North Slope including one at Alpine that is 130 feet by 180 feet. The quality materials make these buildings rugged and durable. Alaska Dreams has expanded to include work in the Russian Far East and continues to grow.

Meini Huser was born and raised in mountainous country in Switzerland, near the Austrian border. He transferred skills learned while building steel tramways to start his business in Alaska. Meini enjoys the typical outdoor winter and summer activities including fishing.

COURTESY OF ASTAC

Tim Kavanagh, Deadhorse exchange manager

Arctic Slope Telephone Association Cooperative

Arctic Slope Telephone Association Cooperative has operated in Alaska's Arctic for 23 years. It offers local, long distance, cellular and internet services. Recent upgrades and reinvestments into ASTAC's network have brought higher-quality communications services to subscribers, who smile more these days and write nice letters to management.

Tim Kavanagh's 18 years in electronic communications led to a new, exciting relationship with ASTAC in September 2001 when he became exchange manager. A 1988 military transplant, Tim fell in love with Alaska's people and unequaled beauty. The transplant "took," allowing Tim to participate in the state's ongoing developmental history, a task he finds personally and professionally rewarding. He and wife Teresa enjoy their many friends and out-of-control passions for adventure and travel.

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CHANGES

Neufeld said the oil and gas strategy is an "integral component" of his government's strategy for the province's heart lands, including the resource-rich interior and northeast.

15 percent of U.S. natural gas

Northeastern British Columbia is also a vital element in Canada's struggle to sustain production and continue meeting about 15 percent of the United States' gas needs.

The announcement is an extension of a two-year campaign by the Liberal government of Premier Gordon Campbell to turnaround a decade of despair in British Columbia's mining, forestry, fishing and tourism sectors.

With the petroleum industry seen as the underpinning of recovery, the sector is projected to contribute C$1.77 billion to government coffers this fiscal year, compared with C$1.44 billion in 2002-03. And that makes no allowance for income taxes from sector workers.

The major elements of the new strategy include:

• Royalty credits of up to C$10 million a year towards the construction, upgrading and maintenance of road infrastructure in support of resource exploration and development and stabilizing employment in remote communities.

• Upgrading 110 miles of a road northeast of Fort St. John to allow summer use and make exploration and development a year-round activity in a muskeg region that is inaccessible to heavy equipment.

• Lower royalties for less productive wells to promote development of marginal plays.

• Royalty credits for deep-gas exploration to advance high-cost, high-risk projects, with wells in the Foothills eligible for credits of up to C$4.1 million..

Energy and Mines Minister Richard Neufeld

• Royalty credits for summer drilling to stretch operations beyond the usual three or four freeze-up months.

Credits will be more than offset

Neufeld said that turning the taps down on some royalties will be more than offset by higher returns from taxes and drilling permits.

"At the end of the day we will see an increase in revenue of about C$250 million (a year), " he said.

The changes have been welcomed by the Canadian Association of Petroleum producers, which has lobbied for a fiscal and regulatory regime that puts British Columbia on the same footing as Alberta.

The association's president, Pierre Alvarez, said in a statement that the British Columbia government "clearly understands the economic potential of the province's petroleum resources and the need to remain competitive in an increasingly global industry."

He predicted the reforms will "spur long-term investment by our industry" by allowing companies to "pursue resources that would otherwise have been left untouched."

Last year, it was calculated that profits in British Columbia averaged about 19 percent after accounting for operating costs, capital costs, royalties, prices\differentials and taxes, compared with about 24 percent in Alberta and 37.5 percent in the Lower 48.

Greater Sierra front and center

Front and center is Greater Sierra, which EnCana, after years of quietly assembling the pieces, is openly extolling as a big part of its future.

A combination of the government's push to open up roads along with EnCana's own use of wooden mats to access swampy sites will let EnCana speed up development to its projected level of 300 million cubic feet per day by 2005, or about 10 percent of its North American volumes.

EnCana chief operating officer Randy Eresman told analysts in May that the company plans 50 to 60 wells this summer (boosting the year's tally to about 150) and hopes for a "proportionally larger summer program going forward."

With all of the attention on Ladyfern, EnCana, using brokers, stole a march on its rivals five years ago by starting to round up nearby Greater Sierra properties before land prices hit the stratosphere.

Eresman registered his surprise by remarking "it's almost unheard of for one company to capture this high a percentage of any play."

Now, with analysts projecting that Ladyfern will effectively be drained by the end of 2004 after peaking a year ago at 665 million cubic feet per day, the spotlight is shifting to Greater Sierra's discovery of 5 trillion cubic feet and Talisman Energy's deep find a year ago at Monkman, in partnership with Anadarko Canada, National Fuel Exploration and Oiltec Resources, that could unlock 1 trillion cubic feet of recoverable reserves, plus its successes this year.

Other than proximity, however, there is not much in common with Ladyfern and Greater Sierra.

Greater Sierra tight gas

Ladyfern is high porosity; Greater Sierra is tight gas, which usually requires some form of stimulation to produce; Ladyfern had well production of up to 100 million cubic feet per day; average wells at Greater Sierra are restricted to about 3 million to 4 million cubic feet per day.

Along with cooperation with First Nations and regulatory authorities, EnCana has relied heavily on technology, notably horizontal and under-balanced drilling techniques, to turn what a company official said last year was "potentially 5 trillion cubic feet from nothing to a resource."

Without those tools, EnCana has suggested the field might have been uneconomic. Now, summer drilling has moved Greater Sierra even higher on its ranking list.

One of the leaders in deep-well drilling, Talisman has shown it is ready to pay the C$12 million-C$16 million per well for the high rewards in a tricky environment.

From its six-well Monkman program this year, it has drilled and put into production two wells, both of which tested at rates of better than 20 million cubic feet per day.

Talisman's partners in this year's successes were Burlington Resources Canada, Dominion Exploration Partnership and Enco Resources.

The potential of the deeper play means the Monkman region "will continue to be a long-life, high value, core natural gas area for Talisman," the company said. ●

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ALBERTA

tions of about 10,000 wells a year over the decade, compared with 8,064 in 2002.

With conventional crude having shrunk over the past 20 years to 660,400 barrels per day in 2002, leaving only 1.17 billion barrels of remaining established reserves, Alberta's hopes are pinned on crude bitumen and coalbed methane.

The report lists remaining bitumen reserves in the oil sands region at 260 billion barrels, with an ultimate recoverable resource of 3.13 trillion barrels.

Coalbed methane activity up

Although coalbed methane activity has increased in recent years, the AEUB said there is insufficient information to publish reserves estimates, but that could change in the 2004 reserves report.

For now the focus of most concern will be the outlook for gas, especially with Alberta accounting for 70 percent of Canada's production and forecasters such as the Conference Board of Canada estimating that Canada's share of the U.S. market will rise to 23 percent from 15 percent over the next 20 years.

Ken Vollman, chairman of the National Energy Board, Canada's federal regulator, told a spring seminar that the Western Canada Sedimentary Basin, with Alberta as the anchor, has satisfied 75 percent of incremental U.S. gas demand since the late 1980s.

"However, as production from the WCSB appears to be flattening out, it will no longer be possible to satisfy a large portion of incremental requirements," he warned.

The AEUB echoed that assessment, noting that the province's gas production showed a "significant flattening" in 1999.

It said much of Alberta's gas development has centered on easily-accessible shallow gas in the southeastern region, which contains more than half the province's producing wells but only 16 percent of last year's production of 4.8 trillion cubic feet.

New pools smaller

The regulator said new pools are smaller and new wells are exhibiting lower initial production rates and steeper decline rates.

Taking that into account, the AEUB said "new wells drilled will not be able to sustain production levels over most of the forecast period (to 2012)."

However, it anticipates that the focus of exploration activity will shift to deeper plays in western Alberta, where higher-productivity wells match the higher drilling costs.

The reserves report listed Alberta's initial established gas at 153 trillion cubic feet, of which 112 tcf has been produced. The ultimate recoverable reserves were rated at 200 tcf in 1992. An updated report on that potential is due for completion this year.

Exploration, development drilling and enhanced recovery schemes accounted for the bulk of the 127 million barrels of conventional crude that were added to initial established reserves in 2002, replacing 41 percent of production.

Although remaining established reserves are posted at 1.6 billion barrels, the AEUB estimates ultimate recoverable reserves at 19.7 billion barrels — a figure it regards as "reasonable," given that technological advances could improve the current average recovery efficiency of 26 percent.

Crude bitumen, having surged ahead of conventional production at 830,000 barrels per day vs. 723,000 barrels per day, is forecast by the AEUB to triple by 2012.

"The share of non-upgraded bitumen and synthetic crude oil production in the overall crude oil and equivalent supply is expected to increase from 48 percent in 2002 to some 77 percent by 2012," the report said. ●

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DRILLING

on final bottomhole locations" and those are reviewed "as we get more information from previous wells."

Teamwork in a showcase development

Ireland characterized the drilling success at Alpine as the result of "just excellent teamwork, with people on site, regardless of what company they work for, people in town… It's been an important project for us and I think everybody… recognizes the importance for us and for the industry and the state… and are really going that extra mile to make sure everything is successful. And that's definitely paid off."

"It's all pride in the operation," he said. "Because it is kind of a flagship for future developments," so the project gets a lot of visitors coming through "and there's a lot of pride in being able to work there."

"It's basically the showcase field for new developments on the North Slope," Ireland said.

Horizontal section substantial

All of Alpine's wells, producers and injectors, are horizontal, with the well angled to pass horizontally through the producing reservoir. Horizontal footages within the reservoir range from 3,000 feet to 6,000 feet, with one 6,000 foot horizontal section and three wells with horizontal sections more than 5,000 feet in length, Alvord said.

Of the 1 million feet drilled, 232,000 feet have been horizontal section in the reservoir, Ireland said, "so that gives us over 23 percent of the feet drilled are productive in the reservoir section."

Compare that, he said, to vertical wells — those probably would have had less than 1 percent of footage drilled in the reservoir section.

Benefits of continuous drilling

Drilling performance has continued to improve, Alvord said. "At Alpine we started out doing the wells in about 16 days — over time we've worked that down to an average of 12 days.

"Pretty good considering that we drill three different hole sections per well, these are all horizontal wells and we're not drilling the deeper, more challenging wells."

The wells for 2003, Alvord said, have been averaging 17,000 to 18,000 feet.

And since startup the drilling trend — measured in days to drill 10,000 feet — has been decreasing, he said. "Even after 70 wells we're still continuing to optimize."

One reason the drilling is going so well is that Alpine is continuous drilling at a new development.

"Typically you drill a few wells at a pad and then you go somewhere else. We've got the benefit of four years of continuous work," he said. And because Alpine is a continuous drilling program "you're not shutting down and then starting up with new people." There has been a change in the drilling crews, "but we've been able to keep the core people — tool pushers and drillers," Alvord said.

"Doyon's done a great job of managing the rig and the people. MI Drilling Fluids manages all the fluids out there … and about the last year we've been using an oil mud that's really doubled or tripled our production," Alvord said. Another plus is that MI has a mud plant at Alpine to process muds "and that's really helped optimize a lot of our fast drilling productivity," he said.

Drilling mud change

The drilling work has gone smoothly, Alvord and Ireland said.

With one exception. The new drilling mud is the solution to that problem.

"Alpine wells have outperformed our expectations," Ireland said, but that changed when the rig moved to the second drill pad, CD2. "The first few producing wells at CD2 didn't out perform our expectations," Ireland said. "They were a bit below our expectations." At that point they switched to a mineral oil based mud system.

"And we've seen that product basically increase well rates there by two to three times over what the other wells were producing at CD2."

Alpine is the only field on the North Slope using mineral oil based drilling mud. Unlike diesel-oil based mud systems, the mineral oil is biodegradable, Ireland said.

"More expensive, but from an HSE (health, safety and environment) perspective it really is the way to go," Alvord said.

Doyon and MI and ConocoPhillips had to train using the new mud, but first they had to get it to the field.

Logistics at Alpine

Since Alpine is a roadless development, all the drilling consumables have to be moved out on ice roads during about a two-month window. It's some 450 truckloads of things like casing, muds and cement, Alvord said, about 20 wells worth of supplies per winter.

Most of those supplies go to Fairbanks by rail and are trucked to the slope "and then they'll stockpile all the flatbeds waiting for the ice road to get in and then it's like the Oklahoma land rush when the ice roads get built."

It wasn't winter when they switched to the mineral-oil based drilling mud, Ireland said, so MI had to work out the logistics of getting the mud to the field. They couldn't truck it out.

And, said Alvord, there isn't enough storage for all the fluid needed for a whole year.

"We had to pump that fluid through our diesel supply line that connects us back to Kuparuk," Ireland said.

The mud comes out of Louisiana and is barged, railed and trucked to Kuparuk, and then pumped through the two-inch diesel line about 3,000 barrels at a time, "usually enough to do three wells," Alvord said. ●

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NEWS BRIEFS

Harken hires investment banker to review assets

Financially troubled Harken Energy, a Houston-based exploration and production independent, has hired investment banker Petrie Parkman to evaluate its U.S. oil and gas assets and to make recommendations "to maximize their value."

Harken's first-quarter production fell to about 10,000 million cubic feet of natural gas equivalent, down one-third from the same period last year. The company's domestic properties are located along the Texas Gulf Coast and Louisiana, as well as the Texas Panhandle.

"We have asked … Petrie Parkman to help us take a fresh look at these assets," Harken Chairman Alan Quasha said.

Harken has "effectively dealt" with its short-term debt, he said, but it "is still burdened with significant long-term debt." It reported more than $45 million in debt at the end of the first quarter. Quasha controls about 60 percent of Harken's equity.

"While we are mindful that much work on the liability side needs to be accomplished, we are now turning our attention to our asset side to properly assess its value, particularly our domestic asset base," Quasha said.

Transocean buys Conoco Phillips stake in drillship

ConocoPhillips has sold its 40 percent interest in the drillship Deepwater Frontier to joint venture partner Transocean, the companies said May 30.

Transocean, the world's largest offshore driller, said it took over Conoco Phillips' share for $4.5 million in cash and assumed $80 million in debt, valuing the rig at $210 million.

Frontier is on contract in Brazil to state-owned Petrobras. It can operate in up to 10,000 feet of water.

Purcell takes aggressive view of Fort Liard

Canadian junior Purcell Energy will press its partners to step up their commitments to the Fort Liard natural gas play of the lower Northwest Territories.

Having sorted out water problems that constrained production in 2002, Purcell told shareholders at its May meeting that it anticipated further growth over the balance of 2003. Infrastructure improvements to water-handling capacity over the winter helped to increase output from the M-25 and F-25 A wells.

In addition, the 2K-29 development well, operated by Chevron Canada Resources, was drilled to 11,800 feet and came in 20 percent below budget.

Purcell said the success of that well reinforces its belief that the eight-mile-long pool needs more drilling to optimize production and reserve recovery.

Purcell president CEO Jan Alston said "there is more to be had," and his company "push our partners" to improve management of the field and improve recovery.