Petroleum news

page 7 Joseph Bryant named new Unocal president, COO

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Marco Polo, Red Hawk on stream

COURTESY GULFTERRA ENERGY PARTNERS

First production has been launched from two fields in the deepwater Gulf of Mexico, with Marco Polo (shown above) eventually adding 50,000 barrels per day of oil equivalent to total U.S. Gulf output and Red Hawk adding 120 million cubic feet of natural gas per day. See the complete story on page 11.

Oil captures some of spotlight in NWT's central Mackenzie Valley

The buzz is growing that word of an oil find in the central Mackenzie Valley is imminent, although partners in an C$18 million well are keeping tight-lipped.

The Summit Creek B-44 wildcat was drilled last winter by a consortium of Unocal subsidiary Northrock Resources, the 32.5 percent operator; Husky Energy 29.48 percent; EOG Resources 26.3975 percent; Pacific Rodera 6.63 percent; and International Frontier Resources 5 percent.

The well was production cased in March to a total depth of

see **SPOTLIGHT** *page 23*

XTO Energy to cool it on big deals, says property acquisition market getting expensive

Deal-minded independent XTO Energy, whose production and earnings soared in the 2004 second quarter, says it likely won't do any more gargantuan property acquisitions this year, due in part to a pricey market.

With a little over half the year gone, XTO already has done 46 deals amounting to more than $1.8 billion. That's nearly three times the $650 million the company had planned to spend on

see **XTO** *page 23*

BREAKING NEWS

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13 North Alexander to be drilled: Escopeta attracts a new player to Alaska's upper Cook Inlet basin, Altus Explorations of Mississippi

ALASKA

Devil in the details

Alaska legislators learn how tariffs for natural gas pipelines are determined

By KRISTEN NELSON

Petroleum News Editor-in-Chief

How are natural gas tariffs set? How would such a tariff be set for a proposed natural gas pipeline from the Alaska North Slope? That was the focus of a hearing held June 16-17 in Anchorage by the Legislative Budget and Audit Committee and the Senate Resources Committee.

1 2 SERIES

There are tariff rates set by the Federal Energy Regulatory Commission, called recourse rates, "and there can be negotiated rates," said Mark Myers, director of the Alaska Division of Oil and Gas. Rates can vary between shippers, based on things like length of contract, he said, but rates "cannot be unduly discriminatory."

Tariff rates can vary between shippers, based on things like length of contract, but rates "cannot be unduly discriminatory." —Mark Myers

Bob Loeffler, a Washington, D.C., senior partner with the law firm of Morrison & Foerster, said in an overview of permissible tariff methodologies that many in the audience would remember when tariffs were set for the trans-Alaska oil pipeline.

At that time "there was a huge controversy over what's the proper way to set the rates… The good news is, there is no such overarching issue here," Loeffler said. "Gas pipeline rates are set on standard utility ratemaking basis, which is original cost rate basis…" On the other hand, he noted, "there are details, and the devil is in the details,"

see **DETAILS** *page 22*

GULF OF MEXICO

Deep drilling rush puts the squeeze on operators

ExxonMobil, Apache, Devon, Anadarko, BHP Billiton among companies looking to drill deep gas wells on Gulf of Mexico's outer continental shelf

By RAY TYSON

Petroleum News Houston Correspondent

Operators with deep gas prospects in the relatively shallow waters of the Gulf of Mexico's outer continental shelf could drill as many as 18 exploration wells over the coming months to geological depths greater than 18,000 feet.

The deepest well likely would be drilled on the ExxonMobil-operated Blackbeard prospect. That well could go as deep as 38,000 feet, just a few thousand feet short of the world record of around 40,000 feet.

However, ExxonMobil isn't the only operator with designs on the so-called "ultra-deep" zone below 25,000 feet, a new frontier area on the shelf where huge gas reserves are thought to exist.

BP, a partner in Blackbeard, also is said to be discussing with contract driller Rowan the possibility of drilling a separate 35,000-foot well on a yet undisclosed prospect on the shelf.

see **SQUEEZE** *page 22*

CANADA

Canada steps up gas hunt

Analysts warn of continued price hikes to 2007 and beyond if LNG projects stalled; call for opening off-limit areas, streamlined permitting

By GARY PARK

Petroleum News Calgary Correspondent

To a background chorus warning of high natural gas prices through 2007 and a growing squeeze on North American supplies, Canadian producers are trying their hardest to keep the pipelines full.

With well completions and new permits at record levels, operators in Western Canada are chasing whatever prospects are available.

To the halfway point of 2004, companies in Alberta, Saskatchewan and British Columbia logged 3,986 gas wells, compared with 1,412 oil wells and 398 dry holes, with a further 4,453 wells having no

see **HUNT** *page 22*

COURTESY OF PETRO-CANADA

Petro-Canada is one of the largest producers of natural gas in Western Canada. Above: drilling activity in the Wildcat Hills/Benjamin Creek area

● CANADA

B.C. offshore ambitions bolstered

Prime minister dumps hard-line environment minister; industry sees successor as pragmatist

By GARY PARK

Petroleum News Calgary Correspondent

British Columbia's hopes of moving ahead on offshore oil and gas development have received a lift from a federal government cabinet line-up unveiled July 20 by Prime Minister Paul Martin.

The pivotal shakeup for the petroleum sector is the axing of David Anderson as environment minister in favor of Stephane Dion, who has built a reputation in other cabinet posts as a skilled negotiator.

Industry leaders issued a resounding welcome to Dion, describing him as someone who is ready to listen, unlike Anderson, who took a hard-line over five years on the British Columbia offshore and the Kyoto climate-change treaty and showed little tolerance for anyone who disagreed with him, including other cabinet colleagues.

Pierre Alvarez, president of the Canadian Association of Petroleum Producers, told reporters that the change could be an opportunity to begin a new dialogue with a man he described as a skilled policy maker.

Pierre Alvarez, president of the Canadian Association of Petroleum Producers, told reporters that the change could be an opportunity to begin a new dialogue with a man he described as a skilled policy maker.

He said that in addition to Kyoto, Dion could play a key role in two issues of special importance to the industry: achieving cooperation with aboriginal communities in oil and gas areas and eliminating duplication between federal and provincial regulators.

David MacInnis, president of the Canadian Energy Pipeline Association, said Dion was a "pragmatist rather than an idealist" who was willing to listen to all sides of an argument before making a decision.

Anderson cited knowledge gaps

While there is no reason to believe that Dion's appointment signals a softening of the Martin government's pledge to implement the Kyoto Protocol, the bitter debate over ending the moratorium on British Columbia offshore exploration could be taking a new direction.

Anderson, despite representing a British Columbia area in the Canadian Parliament, had taken an unyielding line on opening the offshore, insisting there were too many "knowledge gaps" on the environmental impact of exploration.

During the spring federal election campaign, Anderson insisted there was little industry desire to explore and suggested the issue "appears to be more politically driven than commercially driven" — a direct slap at the British Columbia government of Premier Gordon Campbell which has targeted 2010 to start drilling.

"Why David Anderson would not want British Columbians to have the same opportunities as other people on the East Coast of Canada (which has an active oil and gas industry) is beyond my comprehension," said British Columbia Revenue Minister Rick Thorpe.

Anderson had frequently been at loggerheads with Canada's former natural resources minister Herb Dhaliwal, also from British Columbia and a strong advocate of the province's offshore's economic potential. Those clashes continued with the appointment of John Efford last December as Dhaliwal's successor, a job he has retained in the latest cabinet shuffle.

Efford, a former member of the Newfoundland government, has been a fervent supporter of offshore development on both coasts during his short time in office.

He is believed to have other allies in the cabinet from British Columbia including newly appointed Industry Minister David Emerson and Jack Austin, the Government Leader in the Senate, who support drilling to find out what if any oil and gas exists in commercial quantities, but could also have a stern foe in Health Minister Ujjal Dosanjh, who was British Columbia premier in a New Democratic Party government before switching to the Liberals. The left-wing NDP is adamantly opposed to an offshore industry.

Dion acknowledges importance of issue to province

Dion, in a brief meeting with reporters July 20, said he is "well aware" of how important the offshore issue is to British Columbia and understands the challenges from his previous post as intergovernmental affairs minister. But he would not disclose his own preferences.

However, Martin said during the campaign that Canada's West Coast should have the same oil and gas opportunities as the East Coast so long as exploration and development proceeded in an environmentally safe and sound manner.

British Columbia Energy Minister Richard Neufeld has said since the June 28 election that he plans to hold Martin "to his word."

Anderson, meanwhile, faces an uncertain future, but hinted he will remain outspoken on the offshore moratorium.

"The issue of B.C. offshore oil and gas drilling is an issue that has once again come to the fore in recent years," he said in a written statement July 20.

"I fully expect the government of Canada to continue its clear existing policy on this issue, which is to carry out relevant scientific studies to fill existing knowledge gaps before any decision on lifting the moratorium takes place."

He promised Dion his "full support in fulfilling this commitment."

On Kyoto, Anderson urged the government to implement a plan to reduce greenhouse gases. Dion said only that he would consult on a wide basis "with all of my colleagues and with all of our partners around the world because it's a global responsibility." ●

ALASKA

Hydrology holds up Alpine final EIS

The Alaska Department of Natural Resources said July 21 that because of holdups in the final environmental impact statement for Alpine satellite development — due to agency requests for more information on hydrology — ConocoPhillips Alaska has asked the state to suspend Alaska Coastal Management Program project review.

The state said ConocoPhillips requested a Sept. 1 restart for project review, to allow time for the final EIS to be sent to the printers when the additional hydrology information is complete.

The federal Bureau of Land Management, the lead agency for the EIS, said the request for the additional information came from all the cooperating agencies, state and federal.

As this issue of Petroleum News went to press July 22, ConocoPhillips was checking on whether the suspension of the review until Sept. 1 would affect its work plans for this winter.

ConocoPhillips has said it will not sanction the project until it has regulatory approvals in hand, but had indicated in regulatory filings that Alpine satellite work could begin this winter at Fiord and Nanuq, north and south of existing Alpine facilities in the Colville River unit, with production from those satellites as early as 2006.

The final EIS had been expected out in early July, but BLM said July 7 that it had been delayed until the end of August, citing the need for additional hydrology information.

—KRISTEN NELSON, Petroleum News editor-in-chief

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● UNITED STATES

It is getting harder to find land drilling rigs

Demand for drilling services is on the verge of outstripping supply as the U.S. land market tightens

By RICHARD MASON

Publisher Land Rig Newsletter

A simple question for the E&P firms out there. Got your drilling rigs lined up for 2004?

If not, it may be an agonizing second half of 2004 while prospects lie fallow, waiting on rigs during a period of extraordinarily high oil and gas prices.

It is getting harder to find land drilling rigs as the current cycle nears boom-like activity levels. Most U.S. drilling contractors have the best equipment and crews spoken for through year-end. Several have equipment committed into 2005. Waits on rigs are now exceeding 45 days in many areas for spot market work of just a well or two. Operators wanting rigs for extensive drilling programs will find little available until 2005.

What had been an industry characterized by tight balance between demand for drilling services and the supply of crews and equipment is now evolving into an industry that is showing signs of constraint.

Richard Mason is publisher of The Land Rig Newsletter, a monthly publication that provides trends analysis for the land-based contract drilling sector of the oil and gas industry. He previously worked as a field historian for the Texas Tech University archives, collecting historical materials on petroleum, agriculture and irrigation development in the American Southwest. He is a 1974 graduate of Ohio University with a Bachelor of Arts degree, with honors, in history.

expertVIEW

Richard Mason

Rising rig rates

It registers as rising rig rates, a trend that accelerated during the second quarter. In fact, U.S. rig rates moved more in the last 90 days than in the previous year. And if demand continues to tighten, rates are headed higher yet. Expectations are that rig rates will rise an average $500 a day per quarter through year end.

It also registers as small remuneration increases for the labor that works the rigs. Usually it amounts to higher per diem, or bonuses — items that can be easily removed if the industry turns south. But it is also appearing as wage increases in highly utilized markets like the Rockies, the ArkLaTex, or the Midcontinent. Labor shortages are starting to plague the larger drilling firms who are scrambling to rework overtime schedules in order to maintain customer service, or importing workers from Canadian divisions to work in labor-constrained markets like the Rockies.

And several land drilling contractors say any additional demand will result in inexperienced employees, re-activation of marginal equipment, and the ensuing decline in efficiency — even while the charges for those services continue to increase.

Drilling activity in the U.S. land market has now exceeded the 2001 peak. When looking at rigs of all classes drilling oil and gas wells, the count at mid-July was 1,441 units, roughly 60 units higher than the peak in July 2001. And there is still a reservoir of pent-up demand flowing toward the oil patch, buoyed by surging free cash flows for operators and an influx of outside capital to pursue additional work.

Segmentation in operating community

Meanwhile the operating community has evolved into two industries now. The first is the large independents who have been solemnly insisting they are paragons of capital discipline. It is a theme that brings comfort to the folks on Wall Street, no doubt. But these same firms are paying exceptional prices to expand reserves and grow production through acquisitions and/or mergers.

The second segment of the industry includes the smaller independents and privately held E&P firms. A glance at recent press releases delineates a different business model for this group. It has nothing to do with capital discipline. Rather, it is about monetizing reserves and generating additional cash in a high commodity price environment.

Both segments are actively drilling at the moment with indications that the smaller independents are going to expand activity levels in the second half of the year.

Of course things are never as good — or as bad — as they appear at any given moment in the oil patch. So the question is what lurks over the horizon that would short-circuit a full return to boom-like conditions?

There are a couple of items to monitor. First, keep a sharp eye peeled for evidence of capital expenditure frontloading on the basis of the larger independents over the next 30 days. These are the firms employing a dozen or more U.S. land rigs currently. This group moved forward aggressively in rig employment after the first of the year. They did the same in 2003. But in the summer of 2003, they collectively pulled back. Rig count in the third quarter 2003 ended up flat because smaller independents were able to pick the rigs up about as fast as the bigger firms laid them down.

The question is whether last year represented an anomaly, or a new trend in the oil patch. This summer will bring confirmation of whether front-loading capital expenditures has brought seasonality to rig employment for the largest E&P firms.

At the moment, it appears that front-loading has gone by the wayside in a $6 gas market.

The second item is natural gas storage. Gas is moving into storage at a slightly reduced rate versus 2003. On the other hand, storage levels are slightly above the five-year average. While the U.S. Department of Energy has improved its weekly statistical sampling, the fact remains that these are estimates only and the DOE has a track record of understating the volume of gas that actually moves into storage during refill season.

Adequate storage later this summer could prove bearish for commodity pricing. Once expectations of future commodity pricing fall, operators will be less committed to pursuing field work, particularly if costs rise.

Industry at junction

As the anniversary of the 2001 peak approaches, today's oil and gas industry finds itself at the junction of two paths. The first is the natural pressures brought on by attempting to maintain volumes in an environment that has operators chasing fewer, smaller targets. Symptoms include an escalating property acquisition binge and sky-high commodity prices. This trend argues that drilling levels will stay strong in part because operators have to monetize reserves to pay for the purchases. Under this scenario, the cycle is longer and flatter at the top rather than the usual upside down 'V' that has characterized the oil patch over the last century.

The second path involves the inherent tendency in a cyclical industry to revert towards the mean. Right now, the industry resides in an historically rarified part of the cycle thanks to record-setting activity levels and commodity pricing. At some point gravity takes over, and the cycle turns.

It is about to get very interesting in the land drilling sector — whichever path the industry takes. ●

WYOMING

PYR starts drilling on Wyoming acreage

PYR Energy Corp. (PYR-Amex) has started drilling at the company's Mallard prospect in southwestern Wyoming, the company said July 19.

PYR, based in Denver, will have a 28.75 percent working interest in the initial well and all subsequent wells on the prospect nine miles northeast of Evanston, if the well is completed. The No. 1-30 Duck Federal well is targeting the Mission Canyon formation at about 14,500 feet, with total depth expected in about 90 days.

The Mission Canyon formation has accounted for 93 percent of production from the Whitney Canyon-Carter Creek field to the north of the prospect, according to PYR. That field was discovered in 1978 and is still producing.

PYR has access to 4,160 acres within the Greater Duck AMI. The company didn't say what entities held the remaining working interest.

For the quarter that ended May 31, PYR had a net loss of $391,890.

—ALLEN BAKER, Petroleum News contributing writer

ALASKA

Alaska funds 25 more oil, gas positions

A proponent of increased oil and gas investment in Alaska, Gov. Frank Murkowski has funded 25 new state oil and gas positions in his Fiscal Year 2005 budget, including 16 new positions for the state's Division of Oil and Gas.

"The administration is being very supportive and very consistent with their desire to grow oil and gas revenues," division Director Mark Myers told Petroleum News June 22. He said the funding is "a recognition that the upcoming Bristol Bay lease sale and commercial negotiations with the gas pipeline are very important to state resource development" and state revenues.The funding, announced July 20, reflects the governor's "desire to do resource development the right way— not to shortcut the process. That takes work force," Myers said. The 16 new positions bring the division's total to 79 positions, representing a 25 percent increase in the agency's workforce from FY2004, which ended June 30. The new employees will be used to administer the agency's existing workload, Myers said. The division is, among other things, responsible for leasing state lands for oil and gas exploration and development; marketing Alaska's oil and gas potential worldwide; doing a risk analysis of state investment in the North Slope gasline project; and monitoring and auditing lease and unit agreement operations, including rental and royalty payments.

—PETROLEUM NEWS

● NENANA, ALASKA

Nenana basin seismic permit on hold, Andex says no partner yet

By PATRICIA LILES

Petroleum News Contributing Writer

Approval of an exploration permit to conduct a $3 million seismic program looking for gas resources in the Nenana basin in Interior Alaska is still pending with the Alaska Department of Natural Resources.

PGS Onshore applied in May to DNR for permission to conduct a two-dimensional seismic program this winter for its client Andex Resources in the Nenana basin, a relatively unexplored play for gas west of Nenana, a Tanana River town about 50 miles southwest of Fairbanks.

Andex, a Denver and Houston-based company, holds an exploration license for nearly 500,000 acres of land in the Nenana basin. The planned seismic program, expected to take about 60 days to complete 200 line miles of data-gathering, will be the company's first on-the-ground work in the basin.

Andex, a Denver and Houston-based company, holds an exploration license for nearly 500,000 acres of land in the Nenana basin.

Andex's license approved in 2002 contains a seven-year term to convert to oil and gas leases, and contains a work commitment of $2,525,000, according to Matt Rader, natural resource specialist in the Department of Natural Resources' Division of Oil and Gas.

Originally Rader said he expected to issue the exploration permit to PGS in late June, but revised that to early July. On July 14, he had not yet issued the permit, due to clarification required by agency comments that were submitted during the public comment period. "There's no deal killer in it that I saw," he said.

When asked July 12 if rumors about Anschutz Exploration coming in as a partner in the Nenana basin project were true, Bob Mason of Andex told Petroleum News that his company was still looking for a partner for the project.

Remote cabin program the holdup

Seven comments were submitted by various agencies during the public comment period, Rader said. None came from individual citizens in the area.

The exploration permit will not be issued before Rader's return to the office on Aug. 2, according to the department. The hold-up involves a conflict with a remote recreational cabin staking program being offered by the department's Division of Lands this summer and fall along the Teklanika River, in the far southern portion of Andex's lease area. Just south of Andex's exploration license area, ARCO drilled a well called the Totek Hills No. 1 near the Teklanika River in 1984, to a total depth of 3,590 feet before plugging and abandoning it. That, and a well drilled due west of Nenana by Unocal in 1962, make up prior exploration work in the Nenana basin.

Andex has publicly said they have spent $3 million to acquire and reprocess old seismic data from that prior exploration work. In addition to its plans to spend $3 million on the seismic work this winter, Andex has said it will spend $10 to $12 million in following years for drilling and development work, hoping to tap natural gas to supply Interior Alaska.

When asked July 12 if rumors about Anschutz Exploration coming in as a partner in the Nenana basin project were true, Bob Mason of Andex told Petroleum News that his company was still looking for a partner for the project. ●

NEWS IN BRIEF

Gulfstream begins Florida pipeline construction

Mainline pipeline construction has begun on Gulfstream Natural Gas System's 110-mile mainline extension, lengthening the pipeline's reach from Central Florida to the state's east coast and doubling its service area, Gulfstream said July 16.

The expansion is expected to be completed in December. In May 2002, Gulfstream first placed its large-diameter transmission pipeline into service, providing Florida with its first new natural gas transportation source in more than 40 years.

According to the Florida Public Service Commission, Florida's power generation needs are expected to more than double in the next decade. Gulfstream said it can deliver more than 1 billion cubic feet of natural gas per day to fuel new and expanding natural gas markets across the state.

Marathon-Rosneft deal may be on hold

Rosneft, the Russian state-owned oil firm, has suspended talks with Marathon Oil Corp. on a joint venture, news agencies report.

Sergei Alekseyev, Rosneft vice president, was quoted by both Reuters and Bloomberg as saying his company had suspended talks with Marathon.

Rosneft had said in late 2002 that the two companies were looking at cooperation on selling Russian crude in the United States. Then last May, Marathon bought Khanty Mansiysk Oil Corp. for $280 million. That led to speculation in the Russian press that Rosneft and Marathon could form a joint venture for development in western Siberia.

Such a venture would be similar to the deal in which Lukoil and ConocoPhillips agreed to develop the Timan-Pechora area.

The Khanty Mansiysk deal was a return for Marathon, and the company has said it's interested in expanding its presence in Russia. Earlier, Marathon bowed out of the country by trading its Sakhalin interests to Shell.

Husky lands gas assets in takeover deal

Husky Energy has snared some prized natural gas assets in the Deep basin area of northwestern Alberta by acquiring privately held Temple Exploration for C$115 million.

The deal, which closed July 15, gives Husky proven reserves of 21.4 billion cubic feet of gas, 7.6 bcf equivalent of gas liquids and probable reserves amounting to 11.8 bcf of gas and 3.8 bcf equivalent of liquids.

Husky's proven reserves entering 2004 were 2.06 trillion cubic feet of gas, plus 381 bcf of probable reserves.

Husky President and Chief Executive Officer John Lau said in a statement that the assets give his company a good opportunity to grow its gas production in the Deep Basin over the next two years.

Kazakhstan police probe British, Canadian gas firms

Kazakhstan financial police said July 20 they are investigating allegations British Gas company BG Karachaganak Distribution and its subcontractor Orensal illegally exported gas worth US$2.7 billion to Russia.

The Anti-Economic Crime and Corruption Agency said in a statement the alleged illegal exports were carried out over the past few years and the companies are suspected of failing to pay Kazakhstan's government more than 730 million tenge (US$5.4 million) in taxes for the exported fuel.

The agency said the investigation might take up to eight months.

It also said it was investigating Canada-based PetroKazakhstan for allegedly making an illegal profit of 13 billion tenge (US$96,300) between August and September 2003 through price fixing.

—News briefs from several sources, including Petroleum News contributing writers Gary Park, Ray Tyson and Allen Baker

COLORADO

Proposed gas well first in 40 years

The natural gas boom in western Colorado has reached east into Pitkin County, with EnCana Oil and Gas proposing to drill the first exploratory gas well in the county in more than 40 years. EnCana wants to start drilling in late summer or early fall in the White River National Forest about 12 miles southwest of Carbondale.

If the well finds economically viable reserves, the U.S. Forest Service would review the company's plans for a pipeline and other required facilities. If the well is unproductive, it would be plugged and the site would be restored to its previous condition.

EnCana has a lease on the land, which the Forest Service has identified as suitable for minerals exploration. The Forest Service will accept public comment on the proposed well through Aug. 16.

—THE ASSOCIATED PRESS

● ANCHORAGE, ALASKA

How 'not' to do an Alaska gas pipeline

Legislative pipeline hearings begin with lessons learned from the state's experience with oil taxation, trans-Alaska oil pipeline tariff

By KRISTEN NELSON
Petroleum News Editor-in-Chief

Alaska legislators got something of a history lesson in mid-June at the first of three hearings on issues surrounding a proposed natural gas pipeline to take Alaska North Slope gas to market.

Although natural gas tariff issues were the focus of this hearing, royalty value and tax rates were also discussed at the June 16-17 Anchorage hearing by the Legislative Budget and Audit Committee and the Senate Resources Committee.

There was considerable interest expressed in avoiding the royalty, tax and tariff problems the state faced around oil shipment.

Sen. Scott Ogan, R-Palmer, chair of Senate Resources, asked Dan Dickinson, the state's Tax Division director, about the long-running Amerada Hess case, in which the state and North Slope producers litigated the value of the state's royalty oil.

Dickinson said that while the Amerada Hess case was about royalties, "there were parallel tax cases that touched many of the same issues."

The fundamental issues, he said, were value and transportation cost. In the period the case covered, "there was no transparent market for oil." Today, he said, you can get oil prices from the newspaper, so there would never be a case with "two experts coming in and one saying this oil was worth $22, and the other expert coming in and saying, no, it was worth $35."

And "those transparent markets already exist for gas," he said. There will be "conflicts around the margin" about gas, he said, but a case like Amerada Hess over the value of the resource wouldn't occur: "I think transparent markets have cleared the way for us."

Although natural gas tariff issues were the focus of this hearing, royalty value and tax rates were also discussed at the June 16-17 Anchorage hearing by the Legislative Budget and Audit Committee and the Senate Resources Committee.

Transportation costs were the other major item in the case, he said, and the problem there was that specifics hadn't been set out in advance. "I think the one thing that we've learned from that is it's better to figure that stuff out beforehand, if we can, than it is afterwards."

The problem arose from the language in the state's leases, which only laid out "a very general statement of principle, if you will, and both sides were arguing that they had met that."

With large amounts of money involved, and trying to project out into the future, "I don't think you can ever do a perfect job of it," Dickinson said, but he also said the goal is to winnow down the amount of conflict you have so that it's in the $10 million to $30 million range, not in the $100 million to billion-dollar range issues the state faced over oil.

Oil pipeline tariff issues

The long-standing dispute over the oil pipeline tariff also got a review.

Nan Thompson, out-going commissioner at the Regulatory Commission of Alaska, told legislators that beginning during pipeline construction there "was a lot of dispute about what rates would be charged for shipment" on the trans-Alaska pipeline. There was fact-finding before the Alaska Public Utilities Commission (the predecessor of the Regulatory Commission of Alaska) and there was some 10 years of litigation.

Then the parties settled, and the settlement was presented to the commission, which accepted it, but without reviewing it. The commission did say that if there was ever a protest it would revisit the settlement.

One of the shippers protested in 1997, and in 2002, after lengthy hearings, the commission ruled that the rates were too high.

The difficulty in the case, Thompson said, "was that when the original settlement was approved, they never had clear pegs for some of the numbers." The commission "had not made a finding that, for example, the amount of depreciation … was just and reasonable. Nobody knew."

The parties to the settlement agreed on the numbers, she said, "but the agency hadn't done what it was supposed to do under statute and made a just and reasonable finding."

The commission did a finding on just and reasonable numbers beginning in 1997, she said, with the biggest adjustment in the rate of depreciation. She noted that the commission's decision is under appeal.

Don't go there again

Thompson said she thought the lesson learned from evaluating 20-year old rates, "and I think probably even the carriers would agree, (is) that going through that process is something they would want to avoid a second time."

Information was stale by the time the commission looked at the issue beginning in the late 1990s, she said, noting that when the settlement was accepted, the commission was "under enormous pressure at the time from folks who had been litigating for 10 years and said look, we agree it's all over, don't look at this."

That, she said, created a problem which took twice as long to wind up.

What the commission found when the rates were appealed, she said, was that when cost-based rates were compared to the settlement rates, "the cost basis was significantly lower."

When the commission heard the rate appeal, they didn't find that numbers presented by the pipeline owners were supported, and the numbers didn't provide the basis for the "just and reasonable" rates required under state statute for shipment of the oil that is moved within Alaska, she said.

Thompson said that in hindsight, had she been a commissioner when the settlement was presented, she "would have argued that the commission should have looked at that under those same standards of just and reasonable at the time," and not just accepted it "because everybody agreed."

Transparency, she said, is important in rates, and that wasn't available in the settlement.

So is rate adjustment over time. In a normal utility or pipeline setting, "you come in and adjust your rates every four or five years," she said, and not try to guess what rates should be 20 years in the future.

Brena: ownership the problem

Robin Brena, a partner in Brena Bell & Clarkson, and the attorney who appealed the oil tariff on behalf of Tesoro Petroleum, had a somewhat different take on what should have been done when the parties, including the state of Alaska, agreed to the settlement in the 1980s.

Brena said the fact that pipeline shippers owned the trans-Alaska oil pipeline was the problem: "If you have an alignment of ownership between production and transportation so that people are paying themselves the tariff rate, then they will charge the highest possible tariff rate they can, because they save a quarter in royalty and severance taxes on every dollar they overcharge themselves," he said.

High rates are also a benefit to the owners because they profit from non-pipeline owners "that need to use this monopoly infrastructure."

Brena said alignment of production and ownership is "the game that's afoot" and he said it is "the game that we haven't figured out yet well enough."

On the other hand, "if the rates are just and reasonable, if regulation works, ownership doesn't matter," because then the return the owners get will be fair," he said. "It only matters who owns it if there's an opportunity for excessive return."

State should have litigated

The state should have litigated, Brena told the legislators. It had already spent $35 million when it settled, he said, and it should have litigated the tariff, not agreed to the settlement.

He also noted that there was no re-opener in the settlement, no opportunity to go back in "if any of the assumptions in the settlement proved wrong."

So how should the state get rates right in the future?

The state needs to make sure there is "a transparent and informed process among all financially impacted participants," he said. Rates should be cost-based, just and reasonable, he said, and need to be predictable, "in link with the actual costs."

He noted that independents were recently asked if they wouldn't prefer certainty over predictability. To a company, he said, the independents active in Alaska said "no, we want predictability. We know how to run our models. We know what the costs of providing service are. We do this all over the United States.

"We don't want the certainty of a bad deal; we want the predictability of cost-based rates." ●

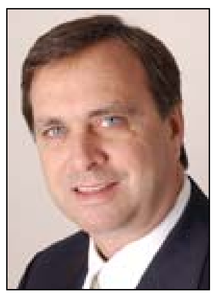
finance&economy

EL SEGUNDO, CALIF.

Unocal names Joseph Bryant President, COO

Unocal Corp. said July 21 that Joseph Bryant has been named as Unocal's president and chief operating officer effective Sept. 1.

Bryant, 48, has been president of BP Angola since 2000, and previously was president of BP Canada and an Amoco joint venture in Canada. He also held leadership roles for Amoco business units in The Netherlands and the Gulf of Mexico. He holds a Bachelor of Science degree in mechanical engineering from the University of Nebraska.



Joseph Bryant Unocal's new president and COO

"Joe comes to Unocal with more than 27 years experience in the industry in both the domestic and international arenas," said Charles Williamson, Unocal chairman, chief executive officer and president. "He is a proven business leader and brings broad experience in exploration, production and operations around the world, including management of deepwater developments."

Bryant will be responsible for the company's domestic and international E&P units, as well as Unocal's reservoir and production engineering, exploration technology, drilling procurement and logistics, engineering and construction, and corporate information groups.

Unocal's president and COO post became vacant earlier this year when Timothy Ling died unexpectedly. Williams has held the president post temporarily since that time.

—PETROLEUM NEWS

CANADA

Penn West on verge of showing hand on new organization

The liveliest guessing game in the Canadian oil patch — whether senior producer Penn West Petroleum will end months of speculation and convert itself into one of the largest energy trusts — could soon be resolved.

With institutional investors clamoring for the change and analysts counting on a decision as early as this month, the Calgary-based E&P independent is believed to be close to wrapping up a year-long study of its future.

In late March, when Penn West cancelled its May annual meeting, President William Andrew said three options were on the table: Converting to a trust, selling or merging the company, or remaining an independent.

He suggested the company would have a clearer picture of its future plans by the time of its scheduled annual meeting. Four weeks later the meeting was postponed because of what Andrew described as a "tight timeline" and has now been set for Aug. 20.

Among analysts such as Gordon Zive, of RBC Energy Fund, that was all clear proof "something is happening ... they wouldn't delay

see **PENN WEST** *page 8*

● HOUSTON, TEXAS

Noble, Ensco profits fall

Despite second quarter dip, contract drillers see improving market conditions in Gulf of Mexico, but North Sea remains drag on earnings

By RAY TYSON

Petroleum News Houston Correspondent

International rig markets in the 2004 second quarter continued to improve along with the Gulf of Mexico, but the North Sea remained a drag on earnings for contract drillers Noble Corp. and Ensco International.

"While we are generally more encouraged about the improvement in several markets, it is still too early to conclude we have turned the corner in terms of a clear worldwide acceleration in activity," James Day, Noble's chief executive officer, told industry analysts in a July 20 conference call.

Noble's profit in the 2004 second quarter, with the help of a stronger rig market in West Africa, increased 22 percent from the previous quarter to $34.4 million or 26 cents per share. But the company's second-quarter net was down 21 percent from the $43.7 million versus the same period a year earlier.

Despite the decline in profit, operating revenues for the 2004 second quarter were $253-mil compared to $247.9 million for the same period last year.

"Worldwide activity over the last two quarters continued to improve, certainly not dramatically, but in a very measured fashion," Day said. "I'm constantly amazed that people struggle in this market to achieve good returns."

Earnings up 5 cents per share

Noble's overall earnings were 5 cents per share higher in the 2004 second quarter versus the year-ago period. However, 2004 second-quarter profits in the North Sea alone were 3 cents per share lower than the previous quarter and 9 cents per share below a year earlier, Noble said.

Noble's rig utilization in the North Sea decreased to 81 percent in the second quarter of 2004 from 95 percent in the second quarter of 2003, the company said, adding that the average day rate in the region decreased nearly $10,000 from $60,150 in the second quarter of 2003 to $50,247 in the recent quarter.

Market conditions in the Gulf of Mexico are improving but not by much, Day said, adding that "the only thing that looks somewhat promising is some of the deeper water projects that may be coming up."

COURTESY PIONEER RESOURCES

Noble's Homer Farrington, Gulf of Mexico

The average rig day rate on the company's deepwater assets in the U.S. Gulf capable of drilling in 6,000 feet or greater decreased 30 percent to $96,727 in the second quarter of 2004 compared to the second quarter of 2003, while utilization increased to 99 percent from 71 percent.

He said rig day rates in some areas of the U.S. Gulf are currently averaging between $40,000 and $50,000 but that Noble "would like to see them" in the range of $70,000.

"We believe we'll be able to march toward that range over the next 18 months, as activity in deeper water starts improving," Day said.

However, overall rig bidding activity year-to-date in the U.S. Gulf is down compared to the same period last year but is up internationally, he said.

"In general, the Gulf of Mexico is improving but only slightly," he said. "It's really nothing in our opinion to get excited about. But hope springs

see **PROFITS** *page 8*

SUGAR LAND, TEXAS

Noble buys jackup from A.P. Moeller

Noble Corp. has exercised its option to purchase the premium jackup drilling rig, the Maersk Viking, from a subsidiary of A.P. Moeller for $32.9 million, the company said July 16.

A year ago Noble paid an option fee of $15 million to the seller for the right to acquire the Maersk Viking.

The Maersk Viking is currently in the territorial waters of the United Arab Emirates being assimilated into Noble's Middle East fleet which is now comprised of 12 units. The unit is scheduled to commence an 880-day contract in Qatar in mid-September 2004 after an upgrade program. The unit has been renamed the Noble Cees van Diemen.

—RAY TYSON, Petroleum News Houston correspondent

FRISCO, TEXAS

New company formed to explore Gulf

Comstock Resources said it contributed about 300 billion cubic feet of natural gas equivalent reserves to help form a new company called Bois d'Arc Energy LLC, a limited partnership which intends to focus on exploring, developing and producing in the Gulf of Mexico.

The new independent also will assume about $102.7 million in Comstock debt, Comstock said July 19, adding that for its contribution it will receive a 59.9 percent equity interest in Bois d'Arc Energy.

Bois d' Arc Resources Ltd. and its two principals owners, Wayne Laufer and Gary Blackie, also contributed to Bois d'Arc interests in their Gulf of Mexico properties and certain related debt, together with their interests in Bois d'Arc Offshore Ltd.

Other undisclosed parties with working interests in the same properties also are expected to contribute their interests to the new company, Comstock said.

In addition, Comstock said it made available to Bois d'Arc a $200-million revolving line of credit, $152 million of which is expected to be outstanding after all parties have contributed their interests. Also, the existing exploration venture between Comstock and Bois d'Arc Offshore has been terminated.

Comstock's partnership with Bois d'Arc Offshore dates back to 1997. "We expect the new venture will be even more successful in exploring for oil and natural gas reserves in the Gulf of Mexico," said M. Jay Allison, Comstock's chief executive officer.

However, Comstock said that if the new company does not complete a financing transaction which generates sufficient proceeds to repay all of the amounts outstanding under the Comstock credit facility by Dec. 1 of this year, it would be dissolved and liquidated "in a manner to put the contributors in a position as near as possible to the same economic position that they would have been in if they had never formed Bois d'Arc."

—RAY TYSON, Petroleum News Houston correspondent

● I N T E R N A T I O N A L

OPEC cancels planned meeting

Cartel agrees to make automatic increase in oil output ceiling

By BRUCE STANLEY

Associated Press Business Writer

With the price of oil stuck above US$40 a barrel, OPEC agreed July 15 to raise its daily production target by 500,000 barrels, or 2 percent, in an effort to keep crude prices from lurching even higher.

The Organization of Petroleum Exporting Countries made the increase automatically, by mutual agreement, and canceled a formal meeting it had planned for its members on July 21 at its headquarters in Vienna, Austria, said an official for the group, speaking from Vienna on condition of anonymity. The increase will take effect Aug. 1.

Although oil-exporting countries are happy to maximize profits, OPEC and its de facto leader Saudi Arabia worry that global economic growth and the long-term demand for crude could suffer if prices spike to punishing heights.

However, few analysts expect the increase in OPEC's target to do much to reduce prices from current levels. Most of the group's members are already pumping flat out to satisfy strong demand, and oil markets had already factored the increase into prices.

Two-step increase agreed to in June

OPEC, which pumps more than a third of the world's oil, agreed in June to make a two-step increase in its output ceiling, to try to calm concerns about disruptions in oil supplies from Iraq and a possible terror attack on export facilities in Saudi Arabia. The group decided first to raise its ceiling by 2 million barrels on July 1, and agreed to follow up with a second increase of 500,000 barrels on Aug. 1 if market conditions warranted.

"The market conditions these days actually call for the implementation of the second part of the agreement. There is a consensus that the extra 500,000 barrels should be implemented August 1," the OPEC official said.

A meeting of OPEC representatives to discuss the matter in person would be "a waste of time," the official added.

OPEC's production target is now 25.5 million barrels a day.

Increase approved; meeting cancelled

A senior adviser to one OPEC oil minister confirmed that the June 21 meeting had been canceled and said that the minister would not be traveling to Vienna as originally planned. The adviser, speaking on condition of anonymity, said the minister told OPEC "just to go ahead with the increase."

Still, the hike will probably have little effect on crude prices. OPEC's production of actual barrels already far exceeds its new official target. The International Energy Agency, a watchdog for major oil-importing nations, estimates that OPEC produced an average of 26.9 million barrels a day in June — or 3.4 million barrels more than its target at the time.

"It's almost academic. They're already producing way over quota," said John Waterlow of Wood Mackenzie Consultants in Edinburgh, Scotland.

Also, markets had anticipated the 2 percent rise ever since OPEC approved it in principle on June 3 in Beirut, Lebanon.

"The increase itself has been telegraphed in the same fashion that dropping a brick on someone's toe gives a hint. Whatever impact this is going to have has been already digested in the market for a month and a half," said Jan Stuart, head of energy research at New York brokerage FIMAT USA.

Contracts of U.S. light crude for August delivery were at US$40.80, down 17 cents, in midday trading July 15 on the New York Mercantile Exchange.●

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PENN WEST

unless they were trying to iron out last details."

Beneficial to shareholders

While the waiting continues, Peters & Co. analysts Brian Prokop and Jeff Martin said the Penn West review will likely conclude a trust conversion is beneficial to shareholders, given their own assumption that if most assets are moved to a trust, share values, which have jumped about 50 percent in the past year, could make another surge.

Prokop believes the trust portion could be worth C$62.80 a unit, while any exploration and other properties kept out of the trust might be valued at C$11.20 — for a C$74 total, compared with recent trading in the C$66 range.

The current betting favors a trust conversion, but if a sale occurs the focus is on Canadian Natural Resources, where Penn West Chairman Murray Edwards is a key shareholder and member of the board of directors.

Penn West currently produces about 55,000 barrels per day of oil and 336 million cubic feet per day of gas, while controlling 5.3 million net acres of undeveloped land. It has targeted capital spending this year of C$600 million-$700 million.

—GARY PARK, Petroleum News Calgary correspondent

continued from page 7

PROFITS

eternal."

Rig acquisition program provides biggest lift

While improving market conditions West Africa not doubt helped in the 2004 second quarter, it was Noble's rig acquisition program that proved the biggest lift, adding 5 cents per share in net income during the quarter.

The company added two premium jackups to its fleet and plans to add a third in November. "These recent acquisitions will also be accretive to earnings in the second half of the year," said Mark Jackson, Noble's chief financial officer.

He noted that the company's recent rig acquisitions were paid from cash flow. In addition, Noble generated enough cash during the first six months of this year to finance its capital projects and to repurchase 1.1 million shares of its stock without having to resort to credit.

Ensco continues Gulf upgrade

Meanwhile, Ensco International said that after having lagged other markets, the U.S. Gulf and the North Sea are now showing signs of improvement. "We continue our upgrade program in the Gulf of Mexico," said Carl Thorne, the company's chief executive officer.

Still, Ensco's 2004 second-quarter net income of $17.5 million or 12 cents per share was down nearly 44 percent compared to the same period last year. Revenues were $181.4 million versus $194.3 million.

The company's rig day rate for its operating jackup rig fleet was $51,200 for the second quarter of 2004 compared to $47,500 in the prior year quarter. But utilization of the company's jackup fleet decreased to 83 percent in the most recent quarter from 88 percent in the second quarter of 2003.

"Consistent with our expectations, the demand for premium jackups is strengthening with activity in the second half of the year expected to be stronger than in the first half," Thorne said, adding that activity currently remains strong in the Pacific Rim, Middle East and India.●

● HOUSTON, TEXAS

Newfield buys Denbury's offshore Gulf assets

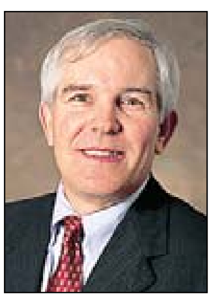
Independent raises '04 production estimate; $187 million sale of Denbury Offshore will allow firm to focus on tertiary operations

By RAY TYSON

Petroleum News Houston Correspondent

Independent producer Newfield Exploration, a major natural gas player on the Gulf of Mexico's outer continental self, has acquired Denbury Resources' Gulf assets for an adjusted $187 million, causing Newfield to raise its overall production guidance for this year by 7 to 11 percent.

"The Denbury Gulf of Mexico assets are an excellent fit with our offshore operations and this will lead to substantial operating cost savings," David Trice, Newfield's chief executive officer, said July 20.



"The Denbury Gulf of Mexico assets are an excellent fit with our offshore operations and this will lead to substantial operating cost savings." —David Trice, Newfield Exploration CEO

Newfield said it specifically acquired the outstanding stock of Denbury Offshore, a subsidiary of Dallas-based Denbury Resources, giving Newfield additional daily production of more than 50 million cubic feet of gas equivalent, 97 percent of which is classified as natural gas.

Consequently, Newfield said it increased its overall 2004 production estimate to 235-245 billion cubic feet of gas equivalent over 2003 production of 220.6 billion cubic feet of equivalent.

Thirty-eight Gulf blocks

The deal included 38 Gulf blocks, 32 percent of which are company operated, and 16 fields. Ninety percent of the reserves and 95 percent of the production come from seven fields. Eighty percent of the wells and 95 percent are company operated. Average working interest in the properties is 75 percent.

Trice said the expected cost savings coupled with the price hedging of natural gas production from Denbury's properties at a weighted average price of $6.26 per thousand cubic feet "will ensure a quick payout and a superior rate of return on this acquisition."

He said Newfield would conduct detailed field studies to identify additional exploitation and exploration opportunities on the Denbury properties. The company said it would pay for the properties using a combination of cash on hand and credit.

Denbury said its offshore subsidiary had total proven reserves of 96.2 billion cubic feet of gas equivalent, including $82 million of future development and plugging and abandonment costs as of year-end 2003. The company said average daily production in the 2004 second quarter averaged 50 to 55 million cubic feet of equivalent.

Proceeds from the sale will be used to retire bank debt and reduce its total debt to $225 million, Denbury said. The company said it expects to receive an additional $2.8 million during 2004 from the sale of other offshore assets in separate transactions.

Denbury estimated that the sale to Newfield would generate between $70 million and $75 million of excess cash after repayment of its bank debt, estimated income taxes and other fees and expenses of the sale.

Denbury focus will be on tertiary operations

Gareth Roberts, Denbury's chief executive officer, said that with completion of the property sale, Denbury intends to focus its energy and investment on its tertiary operations "where we have lower risk, greater predictability, virtually no competition and higher profitability."

He said the company plans to accelerate development of its CO2 reserves and production, accelerate Phase II of its tertiary operations, and invest additional funds in its East Texas Barnett Shale acreage and other areas of operations.

"With our focus on the tertiary operations, we expect to show steady, predictable organic growth in 2005 and for multiple years thereafter," Roberts said.

As a result of the proceeds generated by the sale, Denbury said it increased its 2004 development and exploration budget from $185 million to $205 million.

However, the company said it expects its daily production during the third quarter of this year to be about 27,500 barrels of oil equivalent, reflecting the absence of production from its offshore properties. Production for the fourth quarter was estimated at between 28,000 and 28,500 barrels of equivalent per day. ●

CANADA

EnCana raises $894 million from sales; more to come after Tom Brown takeover

EnCana has now locked up US$894 million in asset sales on its way over the next year to as much as US$1.5 billion.

It added Harvest Energy Trust to its list of buyers July 15 as the expansion-minded trust forked over US$395 billion for 19,000 barrels of oil equivalent per day, the bulk of it coming from medium and heavy crude in east central Alberta.

On July 20, it completed another US$219 million agreement, selling conventional natural gas assets producing 7,250 boe per day after royalties to a Calgary-based producer it did not identify.

On July 20, it completed another US$219 million agreement, selling conventional natural gas assets producing 7,250 boe per day after royalties to a Calgary-based producer it did not identify.

The transaction covers gas properties in northeastern Alberta with proved reserves estimated at 66 billion cubic feet.

Paramount Energy Trust followed that release by announcing it was buying 8,000 boe per day from EnCana for C$208 million (US$158 million), replacing output it has lost through an Alberta Energy and Utilities Board gas shut-in in northeastern Alberta.

For EnCana, this week's transactions came on top of two earlier sales that saw Magnum Hunter pay US$243 million for 3,900 boe per day of New Mexico production and a US$37 million sale of Sauer Drilling to Unit Corp.

Deals followed Tom Brown takeover

All of the deals have occurred since EnCana's US$2.35 billion takeover of Tom Brown in April. Prior to that EnCana had divested another US$500 million in conventional, non-core properties in the first quarter of 2004.

With up to 60 prospective buyers attracted to EnCana's offerings, the Canadian independent hopes to unload another 15,000 to 35,000 boe per day in the next year, to both reduce its borrowings and tighten its focus on longer-life gas properties.

From its round of acquisitions and divestitures, EnCana hopes to achieve production this year of 725,000-765,000 boe per day. At the midpoint between those two numbers of 745,000 boe per day it would post a 15 percent gain over 2003.

Harvest has been reaping its own gains this year, buying all the shares of Strom Energy in June for C$189 million, raising output by 27 percent to 19,000 boe per day from reserves of 47 million boe. EnCana's volumes should boost those volumes to about 38,000 boe per day.

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

KANSAS

Petrol signs deal to sell Kansas gas

Petrol Oil and Gas Inc. has signed a long-term contract to sell natural gas from its Coal Creek project in southeastern Kansas, the company said July 20, with shipments to start within 30 days. Buyer is Big Creek Gas Field Services LLC.

Petrol, based in Las Vegas, has drilled six pilot wells so far on the prospect in Coffey County, and plans to hook them up to the Big Creek sales line shortly. The deal with Big Creek is a multi-year contract, according to Petrol, which didn't specify the term.

The company has rights to 165,000 acres in southeastern Kansas and southwestern Missouri, and says the area could support 1,700 producing wells.

Petrol, which just got its POIG trading symbol on the OTC Bulletin Board in March, is hoping to start generating some cash flow from its investments in coalbed methane wells.

—**ALLEN BAKER,** Petroleum News contributing writer

● LOUISIANA

Capturing offshore winds for energy

Company targets former oil platforms off Louisiana coast for 230-foot turbines; wind farms would have 25 turbines each


HERMAN J. SCHELLSTEDE & ASSOCIATES

Offshore wind power is attractive, because wind stations on land are far from population areas and power is more expensive to ship.

By HENRI LEJEUNE
The Daily Iberian

A New Iberia, La., company wants to take the winds blowing offshore and turn them into power for Louisiana homes.

Grand Vent Wind Energy Systems Technologies LLC hopes to take oil platforms no longer in use and place 230-foot-tall turbines on top of them.

Company president Herman Schellstede envisions a wind farm with 25 turbines each. The initial plans have turbines on top of three former oil platforms and the other 22 turbines on top of specially made smaller platforms. The first farm would produce 50 megawatts total. One turbine could supply power for 3,200 households and all 25 could provide power to 40,000, he said.

Grand Vent is looking at three locations to start the first farm. One is off the coast of Port Fouchon, another east of Marsh Island and the third near Freshwater Bayou.

"By the end of this year, they'll have the planning design and approval," Schellstede said. By 2005, he hopes to have the first 50-megawatt unit running.

Schellstede said Harold Schoeffler, of Lafayette, gave him the idea to pursue the project. Schellstede has worked in the oil industry for years and designed oil platforms, but had never thought to use abandoned platforms for that purpose.

State of Louisiana interested

Louisiana Public Service Commissioner James Field said Schellstede's company gave the commission a project presentation. He said the state is interested and that the commission encouraged the company to go ahead with its experiment.

Fields felt the turbines would be welcomed by the oil industry because companies would not have to spend the millions it takes to dismantle the old platforms.

In addition to working with state regulators, Schellstede has been working with the U.S. Mineral Management Service, the U.S. Army Corps of Engineers and others to build the farms.

Christopher Namovicz, wind expert for the federal Energy Information Administration, said there is little federal regulation of offshore wind generation stations.

Companies are planning wind farms off the coast of Cape Cod in Massachusetts and Long Island, N.Y., Namovicz said, but none have been built offshore yet. Namovicz said part of the problem with getting wind power up and going is that no federal process has been set up: "They're kind of making up the process as they go along," he said.

Platforms within 12 miles of shore of interest

Wind power has already taken off in Europe and could take off in the United States soon, Namovicz said. Offshore wind power is attractive, because wind stations on land are far from population areas and power is more expensive to ship. Stations off the coast could be a cheap alternative.

Gregory Stone, director of coastline studies at Louisiana State University in Baton Rouge who took part in the data collection for Schellstede's offshore wind study, said he would like to see more study of Louisiana coastal wind potential.

The state has adequate wind for the generators, but the data he supplied Schellstede was for one year's worth of study. He said he'd also like to place wind meters higher on towers to obtain more accurate data.

"I think the concept is a good one," Stone said. "We don't have a lot of data in the Gulf of Mexico, but with the data I have, it shows it's worth investigating."

Schellstede said there are about 5,200 oil and gas platforms off the coast of Louisiana. He said he is hoping to use 1,017 platforms that are within 12 miles of the Louisiana shoreline. The farms should cost $50 million to install.

The generators would be bought from General Electric, and the smaller platforms would be built locally. All 25 stations would be tied together, and one of the three platforms would be used as the energy gathering and electrical switch gear station. The power lines would be run down an abandoned pipeline and connected to the grid on land.

Schellstede said he wants the headquarters and wind platform generation yards to be at the Port of Iberia. ●

exploration&production

ALASKA

Alaska governor committed to drilling offshore ANWR strat well

Alaska Gov. Frank Murkowski has decided to continue to pursue drilling a stratigraphic test well offshore the Arctic National Wildlife Refuge.

"We're still evaluating the project (and) …. looking for ways to move it forward," Becky Hultberg, the governor's press secretary, told Petroleum News July 20 when she was asked about the July 9 deadline set by the state for commitments from oil and gas companies to join an ANWR strat well drilling consortium. Hultberg said the project was important to the governor.


JUDY PATRICK

Gov. Frank Murkowski

She had no comment when asked how many companies had committed by July 9 to participating in the project.

She did say that no decision had been made on whether to continue permitting the project, which would be essential if the well were to be drilled during the upcoming Beaufort Sea winter drilling season.

Hultberg said the state Division of Oil and Gas needed "to sit down with ASRC Energy Services E&P Technology," the contractor in charge of permitting the ANWR strat well, and discuss the project.

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

NORTH AMERICA

Rig count down by 68 to 1,452

The number of rotary drilling rigs operating in North America during the week ending July 16 fell by 68 vs. the previous week to 1,452, according to rig monitor Baker Hughes. The recent week also was down by 49 rigs compared to the same period a year earlier.

Canada accounted for most of the overall decrease, falling by 72 rigs to 241 compared to the previous week and plummeting by 171 compared to the year-ago period.

The number of rigs operating in the United States in the recent week rose by four to 1,211 vs. the previous week and was up by 122 compared to the same weekly period a year ago. Land rigs alone increased by two to 1,094 compared to the previous week, while offshore rigs increased by one to 97 and inland water rigs increased by one to 20. Of the total number of rigs operating in the United States during the recent week, 1,041 were drilling for natural gas and 168 for oil, while two rigs were being used for miscellaneous purposes. Of the total, 735 were vertical wells, 341 directional wells, and 135 horizontal wells.

Among the leading producing states in the United States, Texas gained seven rigs vs. the previous week to total 502. Alaska gained one rig for a total of 11. New Mexico's rig count declined by three to total 65 and California lost one rig for a total of 27. Louisiana lost one rig to total 166. Oklahoma lost one rig to total 169 and the number of rigs operating in Wyoming slipped by two to total 83.

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

● GULF OF MEXICO

Marco Polo, Red Hawk on stream in deepwater Gulf

Fields latest addition to Anadarko, Kerr-McGee's growing positions

By RAY TYSON

Petroleum News Houston Correspondent

First production has been launched from two fields in the deepwater Gulf of Mexico, with Marco Polo eventually adding 50,000 barrels per day of oil equivalent to total U.S. Gulf output and Red Hawk 120 million cubic feet of natural gas per day.

Marco Polo, Anadarko Petroleum's first deepwater discovery in the U.S. Gulf, is currently producing at a rate of 15,300 barrels of equivalent per day from three wells, Anadarko said July 19. The field is expected to reach a peak of 50,000 bpd after an additional three wells are brought on stream by early next year.

Houston-based independent Anadarko discovered Marco Polo at Green Canyon block 608 in April 2000. It will serve as a production hub for nearby Anadarko discoveries, including the K2 and K2 North fields, discovered in September 2002 and November 2003.


COURTESY GULFTERRA ENERGY PARTNERS

Marco Polo, Anadarko Petroleum's first deepwater discovery in the U.S. Gulf, is currently producing at a rate of 15,300 barrels of equivalent per day from three wells

see **MARCO POLO** *page 15*

● CANADA

CAPP: Oil sands will drive 40% hike in crude output

By GARY PARK

Petroleum News Calgary Correspondent

The case for Alberta's oil sands becoming a vital component of the global supply picture got another strong endorsement from the Canadian Association of Petroleum Producers.

In its 2004 Canadian crude oil production and supply forecast, the lobby group said July 15 that oil sands output will raise Canada's volumes by 40 percent, or 9.6 percent annually, over the next 10 years to 3.62 million barrels per day from 2.48 million bpd.

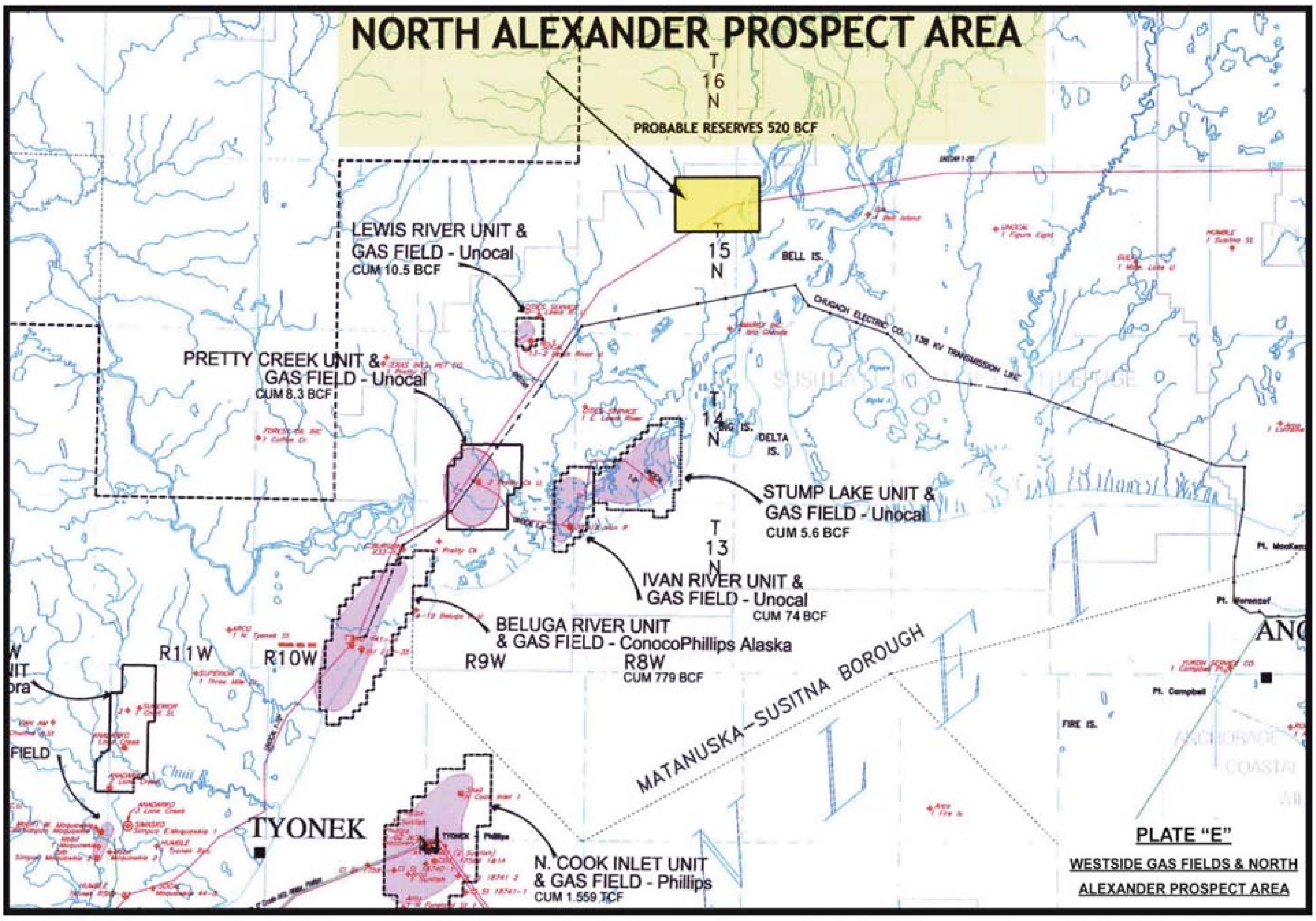
At that level, the oil sands would account for 71 percent of Canada's total volumes, compared with just under 35 percent in 2003, with 1.75 million bpd coming from mining operations and 851,000 bpd from the deeper in-situ projects.

Further reinforcing the importance of the 175 billion-barrel resource in northern Alberta, the association said conventional light and heavy production over that same period will shrink to


COURTESY OF SUNCOR ENERGY

Oil sands coking towers

see **OIL SANDS** *page 15*



COURTESY OF ESCOPETA

● UPPER COOK INLET ALASKA

Escopeta, Altus to drill North Alexander prospect

By KAY CASHMAN

Petroleum News Publisher & Managing Editor

Houston-based Escopeta Oil & Gas has attracted a new player to Alaska's upper Cook Inlet basin. Altus Explorations (OTCBB: ATUX), an independent oil and gas company headquartered in Olive Branch, Miss., has acquired 100 percent working interest in Escopeta's North Alexander prospect and is moving forward with plans to drill a natural gas well in January or February, company officials told Petroleum News in mid-July.

Escopeta President Danny Davis and Altus Explorations President Milton Cox said Anchorage-based Fairweather will handle permitting and drilling operations.

As of July 17 no rig had been selected for the North Alexander project, but permit applications were expected to be filed starting in August.

The 22,882-acre prospect lies onshore on the northwestern edge of the Cook Inlet basin along the western margin of the Susitna River drainage, just southeast of the Castle Mountain Fault. The prospect is six to 10 miles north of the Stump Lake gas field; and six to nine miles east of the Lewis River gas field, both of which have established gas production.

The well will target the Beluga and Tyonek formations, which Altus said are made up of sandstones, siltstones and pebble conglomerates. A secondary objective is the shallower Sterling sandstones.

Almost 400 billion cubic feet of gas

The three objectives represent the major gas producing zones in the Cook Inlet basin and nearby gas fields, the companies said.

Estimated recoverable natural gas reserves from the first two objectives are expected to total 398.5 billion cubic feet.

Escopeta acquired three seismic lines over the prospective area, which were reprocessed and interpreted, a procedure that included Energy Absorption Analysis, Davis said. Structural interpretations on horizons within the Beluga and Tyonek formations were constructed.

In an informational statement about the prospect Altus said "three distinct structural closures were identified. Two closures separated by the north-south trending Alexander fault represent the major prospect or North Alexander. This prospect is a northwest-southeast faulted anticlinal structure plunging to the southeast and faulted by the Alexander fault. The third closure, East Alexander (see map on page 14), is also a northwest-southeast treading anticline, exhibiting four-way closure and lying to the northeast of the East Alexander fault."

The North Alexander prospect consists of three leases totaling 17,122 acres that were acquired by Escopeta

see NORTH ALEXANDER page 14

continued from page 13

NORTH ALEXANDER

in state of Alaska lease sales in 1999 and 2000.

After completing its analysis, Escopeta picked up the third closure encompassing 5,760 acres (see smaller block to east on map on this page).

The three closures are "inter-related," Davis told Petroleum News July 21. "You prove one, you prove the other. It looks like it could be a pretty long structure."

The company refers to all three closures as the North Alexander prospect, Davis said.

Altus looking at other prospects

Although it is not an operator, Altus has working interests in oil and gas leases in Texas, Kansas and Oklahoma, and has recently partnered with Escopeta in two other Lower 48 oil and gas ventures.

Cox said Altus was looking at investing in other Cook Inlet prospects.

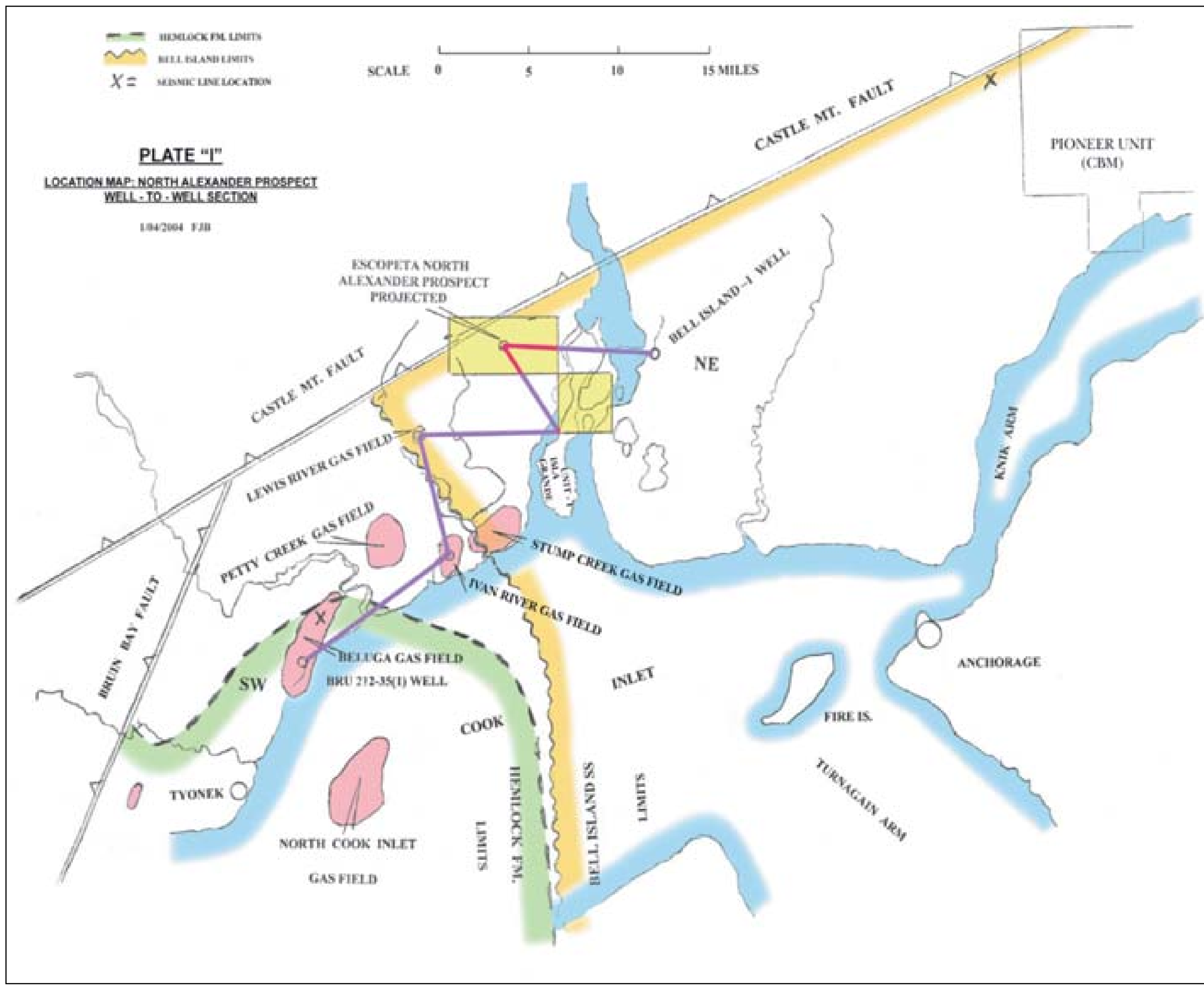
"In its recent report on Cook Inlet, DOE (U.S. Department of Energy) estimated there are 17 tcf of undiscovered natural gas in the Cook Inlet basin. Undiscovered gas. DOE said as of Jan. 1, 2004, the remaining discovered reserves were at 1.8 tcf of gas. Those reserves will last, will meet demand, until 2012. That's if Agrium shuts down its fertilizer plant in 2005 because of inadequate supplies and the Kenai LNG plant stops exporting in 2009 when its export license expires. Otherwise, DOE predicted shortages could occur as early as 2009," Davis said.

What Davis likes about Cook Inlet today is that a new gas field like Unocal's Happy Valley project "can be connected to the market with a six-mile pipeline and get $4.84 for gas. The old contracts were at $1.50. The price of natural gas has changed the economics of drilling gas wells in the Cook Inlet," he said.

"Cook Inlet, with a lot of infrastructure in place, is a bargain, compared to the Gulf of Mexico, where companies are drilling in 6,000 feet of water and risking a lot more money to find smaller reserves than they would be in the inlet."

The same can be said about the North Slope, Davis said, where the "cost of doing business is significantly higher" than in the Cook Inlet basin. ●

NOTE: In 2002 Escopeta transferred 100 percent of its working interest in its Cook Inlet leases to BBI Inc., a holding company owned equally by Escopeta Oil & Gas President Danny Davis and Lawrence Berry of Berry Contracting Inc. of Texas. At that time, BBI was the third-largest leaseholder in the inlet with 120,000 acres. It has since added to its acreage base. An Escopeta team under the direction of Davis handles the geological, geophysical and marketing work for the holding company's Cook Inlet acreage.



COURTESY OF ESCOPETA

● CANADA

Oil sands project on time and on budget

Nexen, OPTI Canada joint-venture confident they can avoid cost overrun pitfalls of other oil sands peers

By GARY PARK

Petroleum News Calgary Correspondent

Nexen and OPTI Canada are delivering a bold promise to their shareholders — they are on schedule and on budget with their C$3.4 billion Long Lake oil sands project in Alberta.

By maintaining tough controls over all aspects of the project and employing a new construction approach they hope to end a succession of cost overruns that have hammered all of their bigger oil sands rivals — Syncrude Canada, Suncor Energy and Shell Canada.

A key shift in strategy has seen the joint venture partners assemble the component parts in modules at Edmonton plants rather than on location in the Fort McMurray area, and then transport the pieces over almost 300 miles by giant trucks.

Nexen and OPTI also broke with the tradition of awarding project management to engineering contractors, by putting their own employees into supervisory roles within the engineering firms working on Long Lake.

Currently 500 people are employed on the project and those numbers will grow over the rest of 2004.

The C$3.4 billion front-end cost estimate is unchanged after orders have been placed for about 80 percent of the equipment for the bitumen production system and 50 percent of the upgrader plant.

More money may be needed for drilling

Nexen Chief Financial Officer Marvin Romanow told a conference call with analysts that more money may be needed to drill the wells needed to achieve the bitumen output target of 72,000 barrels per day by the mid-2007 start-up date. (The raw bitumen will be converted into 58,500 bpd of premium sweet synthetic crude and other products.)

But he said that should not result in a significant overrun because the wells account for only 7 percent of the project's total cost.

Module fabrication is scheduled to start late this year, followed by aboveground mechanical construction in the first half of 2005, while commercial drilling will start this fall and continue through 2005.

COURTESY OF NEXEN

Long Lake is budgeted to hold operating costs to C$6 per barrel, about half the prevailing cost at other oil sands operations.

Using a new process that eliminates the need for natural gas to upgrade raw bitumen into refinery-ready crude, Long Lake is budgeted to hold operating costs to C$6 per barrel, about half the prevailing cost at other oil sands operations.

Once Long Lake is in full production, Nexen, the Calgary-based independent, will decide whether to retain its 7.23 percent stake in Syncrude Canada, the world's biggest producer of synthetic crude.

Chief Executive Officer Charlie Fischer told a conference call July 15 that as the Long Lake partners gain experience from using their proprietary technology and build on their opportunities "we have some choices when we look at Syncrude."

For now, he said, the Syncrude consortium is a "very valuable asset," providing Nexen with extensive knowledge relating to the production and marketing of synthetic crudes and the production of bitumen. ●

continued from page 11

MARCO POLO

K2 and K2 North, on Green Canyon blocks 562 and 518, will be tied back to the Marco Polo platform and are expected to begin production in 2005. Anadarko holds a 52.5 percent working interest in the K2 field and 100 percent working interest in the K2 North field, as well as a 100 percent interest in the Marco Polo field.

Anadarko also operates the Marco Polo tension leg platform, which has a production capacity of 120,000 barrels of oil per day and 300 million cubic feet of gas per day. It is about 160 miles south of New Orleans in 4,300 feet of water and was installed in January 2004.

GulfTerra Energy Partners and marine construction company Cal Dive International actually own the Marco Polo platform. In addition to its 50 percent ownership in the Marco Polo platform, GulfTerra owns 100 percent of the export pipelines that gather the production processed on the platform and transports it to the downstream markets.

Kerr-McGee has Red Hawk on production

Meanwhile, Oklahoma-based independent Kerr-McGee announced that the Red Hawk field in the deepwater Gulf of Mexico achieved first production on schedule using the world's first cell spar facility.

Red Hawk, Kerr-McGee's deepest development to date in 5,300 feet of water on Garden Banks 877, started production from the first of its two subsea wells just two months after sanctioning.

Production from Red Hawk, with an estimated resource base of about 250 billion cubic feet of natural gas, is expected to ramp up to a peak of 120 million cubic feet of natural gas per day in early August after the second well is placed on production, said Kerr-McGee, which operates Red Hawk with a 50 percent interest. Independent Devon Energy holds the remaining 50 percent interest.

The cell spar, a floating production facility, is the third generation of the spar systems, all of which were pioneered by Kerr-McGee. The technology was designed to further reduce the reserve threshold for economical development of deepwater fields.

Measuring 64 feet in diameter and 560 feet in length, the facility, named the Kerr-McGee Global Producer IX, can be expanded to handle 300 million cubic feet of natural gas production per day. ●

continued from page 11

OIL SANDS

600,000 bpd from 1.12 million bpd, meaning the oil sands will climb to 2.6 million bpd from today's 1 million bpd.

The report projects that production of conventional light will drop to 334,000 bpd in 2015 from 622,000 bpd in 2003, while conventional heavy will decline to 266,000 bpd from 497,000 bpd.

"The growing production will serve Canada's strong domestic market and our important export markets in the U.S.," said association analyst Paul Unruh.

Underpinning the oil sands growth, the association report said investment spending will exceed C$30 billion over the next decade as new projects or expansions come on stream.

Analyst says high prices make sands attractive investment

Brian Prokop, an analyst with Peters & Co., told the Globe and Mail that the oil sands, despite their higher operating costs, are an attractive investment opportunity because of current high crude prices and expectations that longer-term prices will be even higher.

He said that unless producers are involved in the oil sands, now recognized as the second largest oil reserve outside of Saudi Arabia, they "won't be involved in the growth portion" of the industry.

The findings are based on a survey of association member companies who generally believe that long-term oil prices will be in the range of US$25 per barrel of West Texas Intermediate.

In a higher-growth case, which the association thinks is less likely, production could exceed 4.1 million bpd, including a lower decline rate for conventional crude to 826,000 bpd by 2015.

But the more moderate case will be an important guide in helping assess the need for new pipeline capacity from Western Canada to various markets, including the need for blending light synthetic crude with bitumen into a synthetic-bitumen mix that can be carried by pipeline.

For all of Canada, the association has forecast that 3.34 million bpd of the 3.62 million bpd target will come from Western Canada, with most of the remainder produced in the Eastern Canadian offshore. ●

CANADA

Husky launches oil sands project

Husky Energy is taking the plunge into the oil sands world by giving the green light to its C$500 million Tucker project that should be commissioned in the third quarter of 2006. The Canadian integrated company said July 19 that approval from the Alberta Energy and Utilities Board will allow construction to start next year on its 1.27 billion-barrel lease about 16 miles northwest of Cold Lake, Alberta.

Husky expects production to start within three to six months of commissioning, to peak at 30,000-35,000 barrels per day and to recover 350 million barrels over a 35-year project life, employing steam-assisted gravity drainage technology to recover the raw bitumen.

"Tucker is an important undertaking by Husky as it is our milestone oil sands project," said John Lau, president and chief executive officer.

He said Tucker is one of several oil sands leases held by Husky covering 425,000 acres and holding an estimated 3 billion barrels of possible reserves.

Lau said the oil sands will "play a significant role in the company's medium- and long-term growth strategies."

Husky already producing heavy oil

Husky has already gained some experience in the region by operating three heavy-oil recovery projects and producing more than 100,000 bpd in Western Canada.

It can process Tucker bitumen into synthetic crude at its Lloydminster upgrader, which is scheduled to achieve capacity of 82,000 bpd this year, or deliver a bitumen blend directly to market through terminals at Hardisty, Alberta.

Next on the horizon for Husky is a possible 200,000 bpd oil sands project, which could come on stream in 2008 at 50,000 bpd and quadruple in size over the 2010-2014 period, exploiting a 2.25 billion barrel lease over 40 years.

Husky released the Sunrise project plan earlier this year for public comment after three years of drilling delineation wells and testing its steam-assisted gravity drainage technology.

—GARY PARK, Petroleum News Calgary correspondent

KETCHIKAN, ALASKA

State of Alaska cites Greenpeace ship for environmental violations

Alaska state environmental officials say the Greenpeace ship Arctic Sunrise broke Alaska law by not filing an oil spill response plan or having a certificate of financial responsibility.

The ship was ordered to anchor until both requirements are met, Department of Environmental Conservation spokeswoman Lynda Giguere said.

An investigation is being conducted to decide whether a fine will be levied, she said. The Arctic Sunrise is carrying Greenpeace activists through Southeast Alaska to protest logging in the Tongass National Forest. It docked in Ketchikan earlier this week.

The DEC filed its notice of violations July 14.

Under state regulations, a non-tank vessel larger than 400 gross tons needs to file an oil spill response plan application five days prior to entering state waters.

State law also requires a ship the Arctic Sunrise's size to provide 15 days before entering Alaska waters insurance information and an application for a certificate of financial responsibility in case of an oil spill.

Arctic Sunrise Capt. Arne Sorensen said he didn't know until the ship was under way that it was missing a response plan and financial responsibility certificate.

"I was told everything was in order and proceeded to get under way and then I was told the paperwork was not in order," he said.

The DEC and Sorensen were working to file the correct paperwork, at which the boat could resume its trip up the Inside Passage. That was expected to happen as early the evening of July 15, Giguere said.

"The state has these rules for a good reason and I think that's fine," Sorensen said. "We simply overlooked something and we'll comply with it."

—THE ASSOCIATED PRESS

● SANTA FE, N.M.

Commission adopts new drilling rules

THE ASSOCIATED PRESS

The New Mexico Oil Conservation Commission has adopted new rules that will make it tougher to drill for oil and natural gas on Otero Mesa and other Chihuahua Desert areas in New Mexico.

The rules, approved July 15, are designed to protect ecologically important areas in southern New Mexico's Otero and Sierra counties.

The rules ban the use of pits for storing drilling fluids and water produced in the drilling process as well as set stricter requirements for injection wells used to put brackish water back underground.

"The governor has determined this is a very important area that needs protection," said Mark Fesmire, commission chairman and director of the state Oil Conservation Division.

The three-member commission unanimously approved the rules July 15 after considering testimony from a public hearing in June.

Means less tax revenue for poor part of state

Commissioner Jami Bailey of the state Land Office said the new rules will mean less tax revenue for the state.

"I believe it's a shame the schoolchildren of New Mexico will be denied about $40 million and the economic development of a poor part of the state will not occur," she said.

Environmentalists applauded the decision while industry representatives said it will not better protect the environment.

"There's very little scientific data that demonstrates that these extreme precautions are necessary," said Mark Mathis, spokesman for the Independent Petroleum Association of New Mexico. "They're going to discourage exploration and development of oil and natural gas on Otero Mesa."

The Bureau of Land Management announced in May that it proposes placing only 35,000 acres of the 2 million-acre mesa off-limits to oil and gas development.

Gov. Bill Richardson has appealed the BLM plan, saying it fails to consider the impacts on groundwater and grassland. He has said the state will consider legal action against the federal government if necessary. ●

ALBERTA

Alberta poised to be debt-free

Alberta Premier Ralph Klein set the stage for a fall election by declaring that the province has the needed cash to wipe out its remaining C$3.7 billion debt.

"Today, I am very proud to announce Alberta has slain its debt," the premier told 2,000 guests at his annual Calgary Stampede breakfast July 14.

The goal was accomplished by setting aside another C$3 billion from Alberta's 2004-05 budget surplus, on top the C$700 million already earmarked for the purpose.

But the debt will actually remain on the province's books for at least two years as the government pays off portions as they become due to avoid paying penalties.

During his 12 years as premier, Klein has reduced the debt from C$22.7 billion, accelerating the paydown in recent years as sky-high oil and gas royalties have poured into the treasury. With Alberta entering its centennial year in 2005, Klein has mused about seeking one more term. The debt elimination is seen by many observers as his best chance to go to the polls, but the premier remained coy about the prospects.

—GARY PARK, PETROLEUM NEWS CALGARY CORRESPONDENT

COLORADO

Energy sector boom sets production records

Coal, natural gas, oil and minerals production in Colorado increased 49 percent last year and is expected to grow again this year.

The energy sector set a record value in 2003 of $6.05 billion, with two-thirds attributed to natural gas, according to a recent Colorado Geological Survey report. Preliminary midyear reports indicated the sector could do even better this year.

The boom has been credited to higher prices for oil, natural gas and gold, which boosted production to record levels for natural gas and coal, said James Cappa, chief of the survey's mineral resources section. Natural gas production totaled $4.01 billion in 2003, which was about two-thirds of the total value, the survey reported.

The Colorado Oil and Gas Conservation Commission said 2.5 billion cubic feet of gas per day was produced last year, an increase of 6 percent from 2002. Production could hit 3 billion cubic feet per day this year, the commission forecast.

About 6,000 cubic feet of gas is the equivalent of one barrel of oil.

Colorado ranked seventh in the nation in coal production, which hit a record 35.9 million tons valued at $682 million.

Oil production was valued at $599 million in 2003, and is forecast to be about 21.9 million barrels in 2004, which would be up 2.8 percent, the state commission estimated. Minerals such as gold, gypsum and molybdenum totaled $702 million in 2003, up 11.6 percent from 2002. Colorado's only active gold mine, which is owned by the Cripple Creek & Victor Gold Mining Co. in Teller County, produced 281,588 troy ounces in 2003, and plans to produce 348,000 ounces this year.

Also, Colorado produced 22.2 million pounds of molybdenum and 590,000 tons of gypsum in 2003.

—THE ASSOCIATED PRESS

natural gas

COLORADO

BP America clamping down on natural gas well 'flaring'

Energy giant BP America is experimenting with a drilling technique that eliminates the raw flame that burns off methane and helps get natural gas flowing.

Officials with the company in Illinois, which is responsible for some 1,100 coal-bed methane wells in southern Colorado's La Plata County, say the technique would cut down on the amount of greenhouse gases released into the atmosphere.

BP spokesman Dan Larson said the company began using a well completion technique in Wyoming four years ago that cut flaring in half. He said the company estimates that in a year, the new technique saves the equivalent amount of carbon dioxide from entering the atmosphere as would result from taking all the cars in Wyoming off the road for a year and a half.

BP spokesman Dan Larson said the company began using a well completion technique in Wyoming four years ago that cut flaring in half. He said the company estimates that in a year, the new technique saves the equivalent amount of carbon dioxide from entering the atmosphere as would result from taking all the cars in Wyoming off the road for a year and a half.

"The company recognizes our main products, oil and gas, cause problems," Larson told the Durango Herald. "But without energy, the economy stops."

Flaring helps flow

Flaring helps get methane flowing from a coalbed well. BP engineer Phil Loftin said coal beds where methane is trapped 1,800 feet to 3,200 feet below the surface are not very permeable, so they are fractured, or "frac'ed," to get the gas flowing.

Loftin said frac'ing a coal formation 200 feet to 300 feet on either side of a well bore helps the trapped gas flow upward. But fluid and sand used as part of the process must be cleaned out and when that happens, gas becomes mixed in. That's the amount that must be burned off for safety reasons.

For the flareless alternative, workers pump gas instead of air down the well bore. Gas is not flammable until it is mixed with air.

"It's actually safer to pump down natural gas instead of air," Loftin said.

In the flareless wells, gas returning to the surface with fluids and sand is separated with new equipment and cycled back through the well bore or sent off in a pipeline to be sold.

"The oil and gas industry has shown itself to be very inventive and technologically savvy," said Dan Randolph of the San Juan Citizens Alliance. BP completed three flareless wells last year in a pilot program in La Plata County, and has completed eight more this year. Larson said BP is drilling about 50 new coalbed methane wells each year in the county.

—THE ASSOCIATED PRESS

● CANADA

Gas producers notch big win in high court ruling

Supreme Court of Canada rules in favor of companies, against landowners involved in decades-old dispute; lawyer says millions of dollars at stake

By GARY PARK
Petroleum News Calgary Correspondent

Natural gas producers have won a decades-long legal fight in Canada that carries a multi-million dollar prize.

The Supreme Court of Canada issued a unanimous ruling July 16 that the producers can keep a share of the gas extracted from land once owned by the Canadian Pacific Railway.

In upholding an earlier decision by the Alberta Court of Appeal, Canada's top court rejected 21 test cases by 85 individual landowners who had sought royalties from liquefied gas on their properties, covering 7,000 leased acres.

Lenard Sali, a Calgary lawyer who represented BP's Canada division, said the case involved some of the most important legal issues to the energy industry to come before the court in the last decade.

He said the verdict, which represents "hundreds of millions of dollars" of royalties, could have repercussions for the development of coalbed methane in Canada.

The dispute had its origins in 1912 when the Canadian government gave the Canadian Pacific Railway land as payment for building a rail link from British Columbia to the rest of Canada.

Gases belonged to landowners

The railway made agreements with settlers on those lands under which petroleum liquids belonged to the energy companies that leased the rights from Canadian Pacific and the gases belonged to the landowners.

The case focused on whether natural gas that is in

see RULING page 18

● MIDDLE EAST

ExxonMobil signs $7B GTL deal

Company to pay entire capital cost of Qatar plant to produce 154,000 bpd

By ALLEN BAKER
Petroleum News Contributing Writer

Exxon Mobil Corp. has moved a step closer to building a large-scale plant to turn Qatar's immense deposits of natural gas into a liquid fuel starting in 2011.

Once it's completed, it will be the world's largest single, fully integrated GTL project, putting out 154,000 barrels of high-quality liquids each day, half of it diesel fuel. The facility would be built at the Ras Laffan Industrial City in Qatar.

ExxonMobil spent $600 million developing its gas-to-liquids process over the course of two decades, and earned a long string of patents, but commercial development was shelved for years as oil prices remained too low for it to be worthwhile.

Talks with Qatar on a GTL project began years ago, and a letter of intent was signed three years ago.

ExxonMobil plans to drill an appraisal well this year and kick into higher gear its engineering and design work, which is already well along.

The Heads of Agreement signed July 14 represents a major step forward for the technology, which dates back to German processes developed before World War II.

With high world demand for energy, and oil prices remaining above $35 a barrel, the GTL process may get increasing attention as a way to cash in on remote reserves of natural gas.

High oil price vital

In an analysis of the commercial potential prepared by the U.S. Department of Energy in the late 1990s,

see GTL page 18

MOSCOW, RUSSIA

Russian bailiffs say shares in Yukos daughter company to be sold off

Russian bailiffs intend to turn seized shares in one of the Yukos oil giant's daughter companies over to authorities for sale to meet part of the company's huge back taxes bill, the ITAR-Tass news agency reported July 20.

The report, citing the Prime-Tass financial news service, said the shares in Yugansknefetgaz would be turned over to "a specialized organization." That could mean the Federal Property Fund, the agency that is the nominal owner of Russia's state assets.

The report reduced waning hopes for a compromise in the case, in which Yukos has been ordered to pay 99.4 billion rubles (US$3.3 billion) in back taxes for the year 2000. The company has said it does not have enough ready cash to pay the bill, and is prevented by court order from selling assets to raise cash.

It also appeared to support wide analyst speculation that authorities do not intend to drive Russia's largest oil producer into disintegration but aim to put its shares into more Kremlin-friendly hands.

The tax case against Yukos is one part of a complex web of legal actions against the company and its former CEO Mikhail Khodorkovsky that is widely seen as a Kremlin-directed drive to punish Khodorkovsky for funding opposition parties and to stifle his presumed political ambitions.

News reports July 20 also cited bailiffs as saying 5.25 billion rubles (US$175 million) had been recovered from Yukos. It was not immediately clear if that amount was the presumed value of the daughter company's shares.

Yukos shares fell some 9 percent in trading in Moscow after the report.

Khodorkovsky, meanwhile, faces charges of tax evasion, fraud and forgery. His trial resumed July 20, with prosecutors beginning the reading of the lengthy charges.

—THE ASSOCIATED PRESS

continued from page 17

GTL

the conclusion was that GTL development, with its high capital costs, wouldn't be viable unless oil prices were above $30 a barrel, which was far above their level at the time. But the study also assumed that remote gas could be purchased for something in the range of 50 cents (U.S.) per thousand cubic feet.

But liquefaction, the competing technology for moving natural gas long distances, has been refined substantially in recent years, especially with sharp reductions in the cost of LNG tankers.

As supply issues arose in the North American gas market, driving up prices, LNG rose to the forefront. BP and its partners developed the huge plant in Trinidad that now ships large quantities of LNG to the United States. ExxonMobil also forged deals with Qatar for two LNG projects to export gas from the giant North Field there.

Other Qatar projects

But now interest in GTL appears to be reviving, and ExxonMobil isn't the only game in town for Qatar. The Middle Eastern country is already working on GTL projects with South Africa's Sasol, which refined the technology when South Africa was under an embargo over its racial policies, and ChevronTexaco. Other Qatar GTL agreements have been signed with ConocoPhillips and Shell.

The ExxonMobil agreement calls for the company to design, build and operate the plant, as well as providing all the capital. ExxonMobil will have the rights to develop and produce natural gas, associated liquids, and other hydrocarbons to meet the plant's capacity. ExxonMobil plans to drill an appraisal well this year and kick into higher gear its engineering and design work, which is already well along.

Low-sulfur products

One advantage of the GTL process is that the liquids produced are essentially free of sulfur, which means a premium prices for the diesel that will comprise half of the new plant's output. The complex will produce about 20 percent lube stocks, with the remainder in naphtha and other products.

Next step in the ExxonMobil-Qatar GTL negotiations is a Development and Production Sharing Agreement. The term of that agreement will be 25 years from the start of production.

ExxonMobil has a long history in Qatar, dating back to 1935, and bills itself as the leading foreign investor in the country. ●

● CHINA

Kerr-McGee starts flow at Bohai Bay wells

Company isn't thinking small: Facilities can handle daily production of 80,000 barrels of oil, 350,000 gallons of gross liquids

By ALLEN BAKER

Petroleum News Contributing Writer

Independent Kerr-McGee Corp. started producing oil from four wells in its Bohai Bay field off China on July 18, the company announced, saying start-up was ahead of schedule.

The company expects to have 10 wells on line by the end of this month in the CFD 11-1 and CFD 11-2 fields on block 04/36. Production of 15,000 to 20,000 barrels per day is expected from the group.

Kerr-McGee is operator, with a 40 percent interest in the development. CNOOC Ltd., the Chinese national oil company, has 51 percent and Sino American Energy Corp., a unit of Ultra Petroleum, has the remaining 9 percent.

By the middle of next year, geologists expect peak production from the two fields of 40,000 to 45,000 bpd. Kerr-McGee China Petroleum Ltd., a wholly owned subsidiary of the Oklahoma City-based company, is the formal operator.

Kerr-McGee isn't thinking small on this development. Its floating production, storage and loading facility there can handle 80,000 barrels of oil and 350,000 gallons of gross liquids, with storage for a million barrels of oil for offloading to shuttle tankers. The first phase of the development includes one 48-slot wellhead gathering platform and one 24-slot wellhead platform.

"Consistent with our hub-and-spoke strategy of developing core areas in proven petroleum basins, this infrastructure will allow for the cost-effective development of additional discoveries in this new core area for Kerr-McGee," said Dave Hager, the Kerr-McGee senior vice president responsible for oil and gas exploration and development.

"With five more discoveries to date, additional identified prospects and interests in approximately 1.7 million gross undeveloped acres, we plan to leverage our expertise to build on our success in Bohai Bay." ●

COURTESY OF KERR-MCGEE

This wellhead gathering platform (WGP-A) is part of Kerr-McGee's new core operating area in Bohai Bay, China, which includes two platforms and one large throughput floating production, storage and offloading facility.

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RULING

liquid form deep below the surface should be defined as petroleum.

The Supreme Court ruled that the term petroleum included all hydrocarbons in liquid form, including liquefied natural gas.

It further concluded that the gas was in liquid state at the time of the land sale and therefore did not belong to the landowners.

Norm Machida, an attorney for the plaintiffs in the 21 lawsuits, said his clients have received no royalties on the gas and, based on the court ruling, it is now clear that they are not entitled to any.

Companies listed in the lawsuits include BP Amoco, Petro-Canada, Gulf Canada (now ConocoPhillips Canada), Imperial Oil, Suncor Energy and Mobil Oil Canada (now ExxonMobil Canada). ●

● BRITISH COLUMBIA

B.C. on coalbed methane collision course with Montana

By GARY PARK

Petroleum News Calgary Correspondent

The British Columbia government has shrugged off concerns from neighboring Montana and invited bids for coalbed methane rights in its southeastern corner.

An auction which will close Aug. 25 will grant five-year exploration permits to successful bidders, who will also have the right to development permits once they propose formal plans for methane fields.

Montana officials had asked for an environmental, social and economic study to examine potential effects of the project.

Todd O'Hair, natural resource adviser to Montana Gov. Judy Martz, said the state wants to be kept informed throughout the auction process.

"This government's position is not to stop you at all costs," O'Hair told Canadian officials. "Our concern has been understanding potential impacts to the state."

British Columbia Energy and Mines Minister Richard Neufeld said coalbed methane development would have a "huge economic benefit" for his province, while posing no downstream threat to the water quality, wildlife and environment in the Flathead River system of Montana, despite the salty and acidic water produced by coalbed methane wells.

But the Kalispell Chamber of Commerce and the Flathead Basin Commission have called for an international environmental assessment before any coalbed methane development proceeds. They have a British Columbia ally in the City of Fernie, which objects to the province launching a new industry without a formal set of rules for coalbed methane.

Fernie city councilman David Thomas said coalbed methane is unlike traditional oil and gas drilling "yet we have no rules to enforce it. And the government doesn't want to study the impacts or gather the baseline data before they begin drilling. That's very troubling."

An earlier proposal to strip mine coal in British Columbia about six miles from the northern border of Montana's Glacier National Park was scuttled this spring amid opposition from both Canada and the United States.

—The Associated Press contributed to this story

ALASKA

Potential Alaska, federal oil gas lease sales

Agency	Sale and Area	Proposed Date
DNR	North Slope Areawide	October 2004
DNR	Beaufort Sea Areawide	October 2004
MMS	Sale 195 Beaufort Sea	March 2005
DNR	Cook Inlet Areawide	May 2005
DNR	Foothills Areawide	May 2005
BLM	NE NPR-A	June 2005
DNR	North Slope Areawide	October 2005
DNR	Beaufort Sea Areawide	October 2005
DNR	Alaska Peninsula Areawide	October 2005
MMS	Sale 199 Cook Inlet	2006
MMS	Sale 202 Beaufort Sea	2007
MMS	Chukchi Sea/Hope Basin	interest based
MMS	Norton Basin	interest based

Agency key: BLM, U.S. Department of the Interior's Bureau of Land Management, manages leasing in the National Petroleum Reserve-Alaska; DNR, Alaska Department of Natural Resources, Division of Oil and Gas, manages state oil and gas lease sales onshore and in state waters; MHT, Alaska Mental Health Trust Land Office, manages sales on trust lands; MMS, U.S. Department of the Interior's Minerals Management Service, Alaska region outer continental shelf office, manages sales in federal waters offshore Alaska.

U.S. ROCKY MOUNTAINS

Berry adds to Uinta Basin acreage

Berry Petroleum Co. has signed an agreement with the Ute Indian Tribe to explore and develop about 125,000 acres in the Uinta basin of Utah, the company announced July 19. The deal also involves another industry partner that Berry did not name.

Berry, based in Bakersfield, Calif., has also agreed to buy an interest in 46,000 acres of fee lands near or adjacent to the tribal parcel, giving it a block of 171,000 acres immediately west of Berry's Brundage Canyon field. Berry's production from that field is about 4,500 barrels of oil equivalent daily. The development plan for the block calls for Berry to act as operator and have an interest of up to 75 percent down to 6,500 feet, and up to a 25 percent in the deeper zones. The tribe will hold a 25 percent working interest throughout.

—ALLEN BAKER, Petroleum News contributing writer

● ROSS RIVER, YUKON TERRITORY

Freegold Ventures acquires Yukon property

Junior exploration company signs option on Grew Creek Gold Project, plans August drilling

By PATRICIA LILES

Petroleum News Contributing Writer

Freegold Ventures announced July 14 that it has signed an option agreement to earn a 100 percent interest in the Grew Creek gold property, 35 kilometers (21.7 miles) west of the historical mining town of Ross River in the southeastern part of the Yukon Territory.

The Vancouver, British Columbia-based junior exploration company plans to begin diamond core drilling on the 7,500 acre property in August, starting with a 10-hole program, the company said.

About 2,000 meters (6,561 feet) will be completed during the first phase of work on the property, according to Peter Dasler, a spokesman for Freegold. Drilling will target known mineralization previously drilled, as well as other new zones called Rat Creek and Tarn.

Past work has identified a mineral resource of 773,012 tonnes, with an average grade of 8.9 grams of gold per ton and 33.6 grams of silver per ton.

The Grew Creek property, one kilometer off the Robert Campbell Highway, which links Carmacks with Ross River and Watson Lake in a southeasterly route following the Pelly River, is also near the Whitehorse power grid.

"The property covers a sequence of Eocene volcanic and sedimentary rocks preserved within a graven formed by the Tintina Fault System," Freegold said. "Gold and silver mineralization at Grew Creek is hosted by highly permeable felsic pyroclastic tuff."

Research done on property in late 1990s

Freegold said the property consists of 192 mining claims within the Tintina fault, which stretches in an arc from southeastern Yukon Territory across the U.S.-Canadian border and through Interior Alaska.

PATRICIA LILES

"Unlike the gold occurrences of Interior Alaska, Grew Creek is thought to be an epithermal deposit… These types of occurrences can be extremely high grade and that is a big plus in this part of the world." —Curt Freeman, geological consultant for Freegold

"Unlike the gold occurrences of Interior Alaska, Grew Creek is thought to be an epithermal deposit, meaning it formed at lower temperature, nearer surface and normally something that deposited gold when the fluids rose into a lower pressure zone and boiled, dropping the gold and silver as minerals from solutions," said Curt Freeman, Freegold's geological consultant based in Fairbanks, Alaska. "These types of occurrences can be extremely high grade and that is a big plus in this part of the world."

His company, Avalon Development, conducted research on the property in the late 1990s, although work slowed when market prices for gold dropped. The property currently has a small gold resource calculated, Freeman said. "The real key at Grew is to look for the higher-grade new resources."

Freegold Ventures has several active gold exploration projects in Interior Alaska and has a joint venture agreement with Lonmin for its platinum property in Southeast Alaska, called Union Bay. ●

Editor's note: For more details about this story, see the Aug. 8 issue of North of 60 Mining News.

● HEALY, ALASKA

CHRIS AREND

Usibelli Coal Mine has landed a contract to provide test product for a northern Chile power plant.

Usibelli sends coal test shipment to Chile

Alaska's only commercial coal producer will send shipment to northern Chile power plant through agreement with Glencore

By PATRICIA LILES

North of 60 Mining News Editor

Usibelli Coal Mine Inc., Alaska's only commercial coal producer, landed a contract announced July 20 to provide test product for a northern Chile power plant, opening the door to a potential new market for Healy coal.

CHRIS AREND

Steve Denton, Usibelli VP of business development

The contract was signed with Glencore Ltd., a leader in the international coal trade business, the company said in a July 20 press release.

The initial shipment of 45,000 metric tons of Usibelli's coal will be transported by ship, scheduled to arrive for loading in Seward in the last half of August, the company said in its press release.

If the coal in the first shipment proves to be compatible with the customer's boilers, there is an option for a second shipment of the same size in November, the company said.

"This is a very significant event for our company," said Joe Usibelli Jr., president of Usibelli Coal Mine. "Not only is this our first shipment to South America, it is also a great opportunity to establish a relationship with Glencore."

Usibelli currently exports about 400,000 tons of Healy coal to power plant consumers in South Korea. In the past, the company has sent test shipments of coal to Taiwan and Russia, ranging in size from 20,000 to 70,000 tons, according to Steve Denton, vice president of business development at Usibelli. This will be the company's first test shipment of its ultra-low sulfur coal to a customer on the eastern Pacific Rim.

"The price of coal in the Pacific Rim has dramatically increased during the last year. That's creating an interest in looking for new coal sources," he told Petroleum News July 21. "We've been getting inquiries from a lot of potential customers."

Usibelli's workforce of about 85 produces 1.2 million tons of coal annually. About 800,000 tons provides fuel for power generation and heat throughout Interior Alaska. ●

Editor's note: For more details about this story, please see the Aug. 8 issue of North of 60 Mining News.

Companies involved in North America's oil and gas industry

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

Petroleum news

Business Spotlight

By **PAULA EASLEY**

FORREST CRANE

David Shaw, office manager

Cooper Cameron

Anchorage-based Cooper Cameron supplies gate valve, actuator, chokes and wellhead components to the oil industry, from the North Slope to Cook Inlet operations. Cameron leads the industry in total vendor management (TVM) tailored to individual needs while supplying major brands of equipment, including Cameron, Ingram Cactus, WKM, Demco, McEvoy, Willis, Thornhill Craver and Foster.

David Shaw joined the company as a service representative in 1983. Since then, he worked his way through the ranks to his present position. David finds his work very challenging and diversified; he cherishes the many business and personal friendships developed during the last 20 years. His church activities involve doing mission work in rural Alaska villages. David and his wife Colleen have three daughters — Courtney 17, Lindsey 15, and Lacey 11.

FORREST CRANE

Larry Larson, superintendent

STEELFAB

From a small job shop with a handful of employees in 1988, STEELFAB has become Alaska's largest steel fabrication facility. It holds certificates and endorsements from entities such as AWS, ASME, AISC, DOT and UL, which allow the company to engage in all aspects of steel fabrication. It can build a pickup truck bumper or a 400,000-pound fracture-critical D1.5 bridge.

After attending WI Technical Institute, Larry Larson spent 12 years as a lead fabricator or shop foreman and 15 years as superintendent for STEELFAB. He's looking forward to a September trip to Australia and celebrating his and Barbara's 25th wedding anniversary. Two of their three daughters attend college, and one is in the Navy. Ask Larry why his thrill-seeking agenda no longer includes sky diving.

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DETAILS

which can have "some real dour consequences."

Different regulatory regime

The regulatory regimes are different for oil and gas pipelines, Loeffler said. For oil, the FERC shares regulatory authority with the Regulatory Commission of Alaska, which sets rates for shipments within Alaska, while the FERC sets rates for shipments that go outside of Alaska.

"That does not happen with gas pipelines. The FERC sets the rates for the gas … outside of Alaska and for any gas that's taken off in Alaska, as far as that gas travels on the main pipeline."

There is a second big difference between oil and gas, he said. You don't need permission from FERC to go into the oil pipeline business or to exit the business, but for gas pipelines you do. For gas pipelines FERC "regulates the size, pressure, whether it serves the public interest — and there is a huge environmental impact process."

Gas pipeline regulation is the FERC's bread and butter, Loeffler said, while a FERC staffer once described oil regulation "as the crazy aunt in the attic."

Gas pipeline regulation is the FERC's bread and butter, Loeffler said, while a FERC staffer once described oil regulation "as the crazy aunt in the attic." For every hundred gas pipeline cases at the FERC, he said, you'd probably only find one or two oil cases, which holds true for the rate area as well as the regulatory area.

"You've got to remember this framework when you think about fighting the last war which was the Taps war and fighting the wars that are to come on the gas," he said.

Original cost

The FERC has used different methodologies over the years, Loeffler said, but original cost remains the basis. "That's not true for oil pipelines. Sometimes it's original cost, sometimes it's indexing, sometimes it's this trended original cost."

But, he said, gas pipeline ratemaking is different.

"The objective is to strike a balance between rates that protect consumers from excessive rates and that reward investors for the risks of investing in a pipeline," Loeffler said.

The pipeline will put out proposed rates in the open season and file proposed rates with FERC, which will review them.

Gas pipeline rates are a "cost-plus system," he said: "The rates are designed to recover the operating costs, depreciation, taxes and a return on capital investment."

Most of the effort in ratemaking is spent on three things, Loeffler said: profit, depreciation and rate design.

Profit is the rate of return the pipeline will be allowed to earn, and the commission is concerned about determining the cost of capital. There are two large steps, he said: how much investment is debt and how much is equity; and what is the cost of each.

Debt is what is borrowed and the market rate on that debt.

Equity, and the return on equity, is determined by looking at "what other pipelines in the industry are earning." What determines how high the return is on equity is how risky the pipeline is. Pipelines will

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HUNT

final status.

Of the record 10,258 wells that were rig released in the first six months — 3 percent ahead of the previous high of 9,996 in 2001 — gas targets accounted for 68 percent.

Total well depths in western and northern Canada were 36.57 million feet, an increase of 15 percent over last year's 31.88 million feet and ahead of the 2001 record of 34.67 million feet.

In Alberta, operators rig released 7,987 wells, beating last year's tally by 19 percent, while British Columbia posted 886 completions, up 37 percent from 2003.

To the end of June, regulators issued 13,294 well licenses, strongly ahead of the 12,271 permits awarded in the same period last year, with Alberta racking up 10,556 of the permits.

For Alberta, Saskatchewan and British Columbia, operators licensed 9,809 gas-targeted wells vs. 2,562 oil wells, compared with 8,116 and 2,986, respectively, in 2003.

EnCana, the gas-weighted independent, easily led the operators with 3,035 well permits, trailed by Husky Energy at 936, Canadian Natural Resources 864 and Apache Canada 811.

Consultant projects strong gas prices

But the struggle by E&P companies throughout North America to survive in an era of smaller pool discoveries is reflected in a report by Cambridge Energy Research Associates.

The Massachusetts-based consultant said July 12 that gas prices will stay strong over the next four years and could rise even faster if there is any delay in completing new liquefied natural gas facilities in the United States.

The study forecasts average prices of US$5.83 per million British thermal units this year, $6.02 in 2005, $6.40 in 2006 and $6.62 in 2007 and could continue an "upward trajectory" beyond 2007 if LNG imports are stalled.

The consultant said U.S. lawmakers and regulators must be flexible in allowing drilling in restricted areas, while streamlining permitting in areas already open for drilling and to accelerate construction and expansion of LNG receiving terminals.

"Land access will continue to be a key issue for natural gas production, especially in the Rockies, on many federal land areas and in many sensitive offshore areas," the study said.

"Since the gas market is expected to remain very tightly balanced over the next five years, efforts should be focused on actions that boost supply or reduce demand over that period," Cambridge said.

Drilling not the solution

The consultant does not believe more North American drilling can solve the supply problem, noting that in summer 2001 the United States boosted the number of rigs at work to more than 1,000 from 700 a year earlier, but productive capacity edged up to only 56.8 billion cubic feet per day from 54.9 billion in 1999.

Cambridge said the current gas shortage stems from a decade-old inability to increase output in the United States due to basin maturity, the shift from strong Canadian growth that boosted exports by 80 percent over 15 years to a flat production profile in recent years and an absence of large discoveries despite surging expenditures.

The study predicts North American demand will grow by 1.7 percent a year on average through 2010, assuming gas prices in the $5-$7 range, easing to $4-$6 when LNG imports grow.

It suggests measures may be needed to reduce the dependence on gas, which currently meets 23 percent of U.S. energy needs, including a temporary relaxation of clean-air standards to allow greater use of residual fuels, distillate fuel and coal.

Others have echoed the grim near-term outlook, with Stephen Thumb, with Virginia-based Energy Ventures Analysis, warning there is no supply relief in sight at a time when the most optimistic hope is for flat production.

Tom Driscoll, with Lehman Brothers, said new pools are harder and more expensive to find and, despite new technologies, average wells flow for only two or three years compared with five years or more a decade ago. ●

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SQUEEZE

Independent producers Apache, Devon Energy, Anadarko Petroleum, WT, Arena, McMoRan, as well as Australia's BHP Billiton, also have deep-shelf plans on the table, Rowan said, adding that BHP is currently talking to the company about drilling a 32,000-foot well.

Rowan has drilled about two-thirds of ultra-deep wells

Rowan has drilled about two-thirds of all the wells thus far in the U.S. Gulf in excess of 18,000 feet.

"There is a lot of discussion going on with operators right now about these ultra-deep wells," said Danny McNease, Rowan's chief executive officer.

However, the biggest challenge facing deep-shelf operators now appears to be securing the specialized drilling equipment and steel pipe necessary to withstand the extreme pressures and temperatures in the ultra-deep zone.

"Exxon wouldn't have gone out six months ahead of time and contracted a rig if they weren't concerned about getting the right rig to do the job," McNease said of the Blackbeard prospect. "Rigs that are available that can actually drill these type wells play a big role in when they actually do start."

ExxonMobil and partners BP and Petrobras will be shelling out between $28 million and $35 million to secure a Rowan rig capable of drilling to untested depths of nearly 40,000 feet at Blackbeard in the Treasure Island area. The rig is contracted for a practically unheard of 350 days with drilling to commence by year-end or in the first quarter of 2005.

"As people drill deeper and deeper wells, it takes longer and longer to drill those wells. So those rigs are going to be tied up longer," McNease said.

Noble holds off on major capital projects

However, based on the lack of success so far among the few operators who actually have ventured into the ultra-deep, Noble Corp. is one contract driller that is less than thrilled about joining the party.

"Early results are underwhelming," said James Day, Noble's chief executive officer. "Results have not been very good. But I hope it works for obvious reasons. It pulls rigs out of the marketplace."

He said that Noble does not like to invest in major capital projects on plays that have not been proven, favoring instead to chase a "sweet spot of proven geology" in such places as West Africa and the deepwater U.S. Gulf.

But if the geology on the shelf proves itself, he added, Noble could upgrade existing rigs with larger pumps and other equipment required to drill in to deeper zones on the shelf.

"We're going to be quick to change if there is a string of successes on the deep shelf," Day said. "We'll pull the jackups in and it will take a lot of time and effort. And it will take a little money to put in big pumps and stiffen up the derrick. Those are all expensive undertakings."

Steel pipe for ultra-deep wells an issue

Rowan said it expects another 11 to 16 drilling rigs to depart the U.S. Gulf, unless day rates improve. There are 92 rigs of various classes currently available in the Gulf, down 10 from a year ago, according to rig monitor Baker Hughes.

McNease said that because of extreme depths and other unknowns, deep-shelf operators also are being caught flat-footed when it comes to the type of steel pipe required to do the job.

"People really didn't know what kind of casing they were going to need for these wells," he added.

Despite predictions that more drilling rigs will leave the U.S. Gulf in search of better day rates, oil and gas prices are expected to remain strong through 2005, as well as capital spending, McNease said.

"Our Gulf of Mexico customers continue to post record cash flows," he said. "Gulf of Mexico budgets appear to be holding firm with a projected 10 to 15 percent increase." ●

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SPOTLIGHT

9,955 feet, and is 50 miles south of Norman Wells, where Imperial Oil made a 1920 discovery of 660 million barrels.

But that discovery is slowing, with an 520-mile Enbridge pipeline to northern Alberta now averaging about 23,000 barrels per day, down from a 30,000 bpd peak, although Imperial expects oil to continue flowing for another 15 to 20 years. Currently, the field has 176 producing wells.

Interest has been growing lately in the region's oil prospect, despite the intense focus on natural gas in the Northwest Territories.

Devlan Exploration plans an exploratory well this summer, provided it gets a regulatory green light within a month, and Husky has indicated oil exploration in the central Mackenzie is on its agenda.

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

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XTO

acquisitions this year.

But a few plums came along that XTO just couldn't pass up: $1.1 billion worth of ChevronTexaco oil and gas properties spread across seven states, including Texas and New Mexico, and $340 million worth of ExxonMobil onshore assets.

XTO chief executive Bob Simpson said it was "the best set of properties" he had seen in a decade.

"But we do have to digest these large acquisitions," he said in a July 20 conference call with industry analysts. "We are behind on hiring people. And I think I need to be careful in terms of being too aggressive. If you did too much this year you get the base so large that our growth rate might be impaired a little bit."

For now, XTO intends to buy properties at an annual pace of $600 million to $800 million, Simpson said. But the company hasn't entirely ruled out another large acquisition this year.

"I just don't think it's likely that we do another big acquisition this year," he added. "But I tell you that if it's the correct asset at the right price, we would buy it."

Properties today pricey

Still, properties today are pricey because of the surge in oil and gas prices, Simpson noted, adding that the $1.8 billion in acquisitions XTO has done this year averaged just $25 per barrel of oil and $4 per thousand cubic feet of natural gas.

"So the market appears to be trending to somewhat overheated in my estimation," he said. "That means people are starting to pay for (today's) commodity price. I think what we'll do now is worry about the year after next. We always try to stay a year or two ahead."

As for "cleaning up" ChevronTexaco acquisition, XTO's largest deal ever, Simpson said the company may sell about 5 percent of the properties and trade another 20 to 25 percent in areas not operated by XTO.

"So I would say two-thirds of the acquisition are already known to be strategic long-term, really a great asset to own and those are secure in the position," he said. "The other third would be sold or traded perhaps."

Production to record levels

Excluding benefits from the ChevronTexaco acquisition, which is expected to close Aug. 16, XTO's oil and gas production climbed to record levels during the 2004 second quarter versus the year-ago period. Natural gas output increased 27 percent to 803 million cubic feet per day, while oil jumped 38 percent to 17,682 barrels per day and natural gas liquids increased 17 percent to 12,847 barrels per day.

Earnings for the 2004 second quarter were $99.1 million or 41 cents per share, up a hefty 73 percent compared with second quarter 2003 earnings of $57.3 million, or 25 cents per share.

Second quarter 2004 earnings included the effects of a liberal employee stock-based incentive compensation program amounting to $37.7 million, $30.6 million of which was non-cash, and a one-time bonus of $11.7 million relating to the $1.4 billion acquisitions from ChevronTexaco and ExxonMobil.

Excluding those items, the company's earnings were $134.6 million or 55 cents per share, compared to second quarter 2003 adjusted earnings of $74.4 million or 33 cents per share.

Operating cash flow during the 2004 second quarter was a record $285.6 million, up 59 percent from 2003 second quarter comparable operating cash flow of $179.6 million.

Total revenues for the second quarter were $444.7 million, 58 percent above second quarter 2003 revenues of $282.2 million. Operating income for the quarter was $187.8 million, a 65 percent increase from second quarter 2003 operating income of $113.9 million.

To reflect future production gains from the ChevronTexaco deal, XTO revised its production forecast for the remainder of this year. In the third quarter, the company said it expects to produce 860-865 million cubic feet of natural gas per day and 26,500-27,000 barrels of oil per day. In the fourth quarter, natural gas output is expected to jump to 925-930 million cubic feet per day and oil to 33,000-33,500 barrels of oil per day.

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

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DETAILS

argue, "I'm not an average pipeline, I'm more risky than anyone else, so I deserve more. And of course the shippers on the pipeline argue, they're not risky at all…"

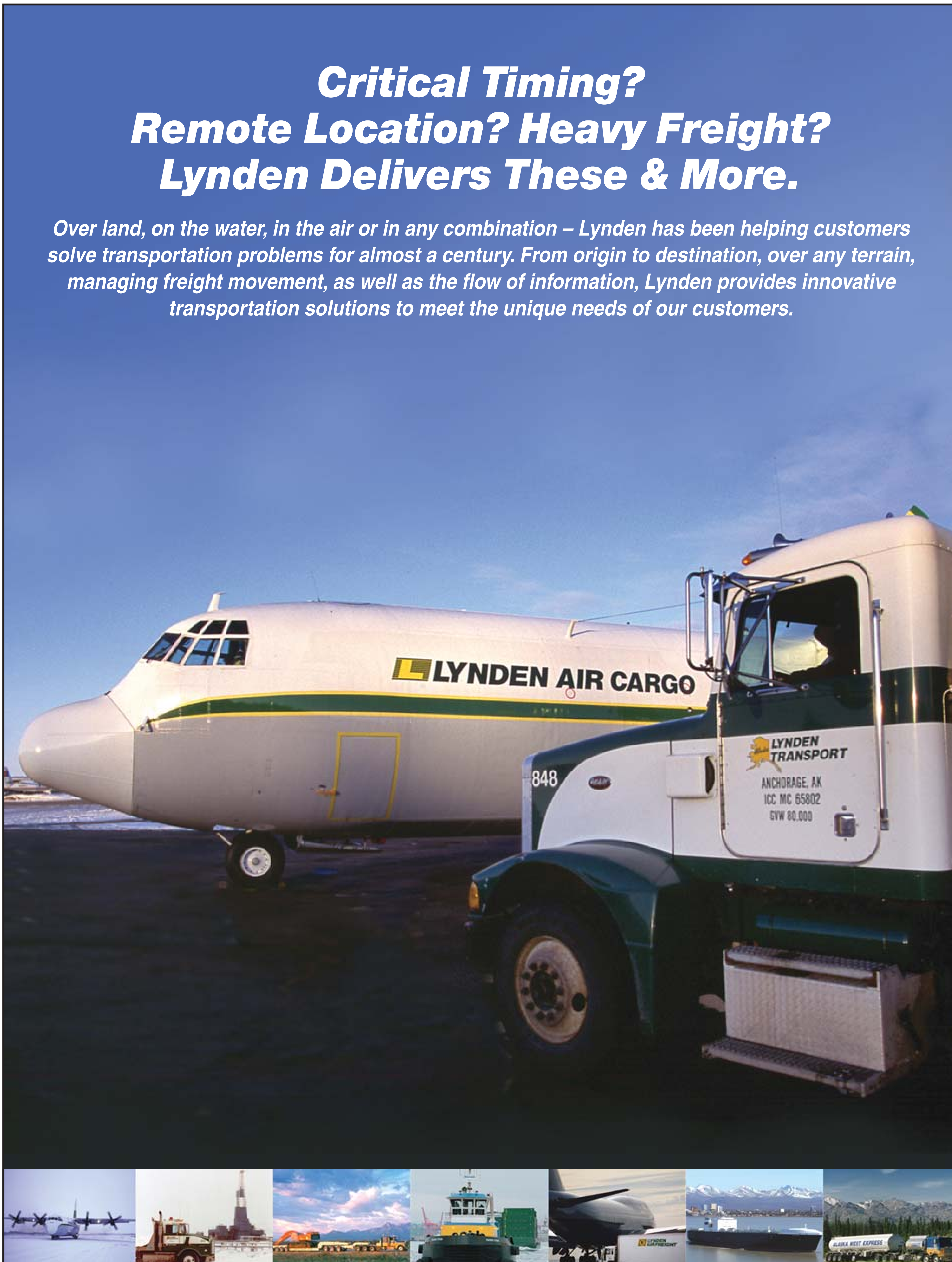
Loeffler said in closing that, while the FERC has established ways of looking at gas pipelines, "Alaska is the biggest thing that will go through the commission and it will set its own rules."

Rates can be levelized

One difference in how rates are set comes from how depreciation is handled. Myers said one of the biggest differences between recourse rates, set by FERC, and negotiated rates is that under negotiated rates, the rate can be levelized.

FERC-set recourse rates, typical cost-of-service rates, reflect depreciation: the line is worth more at the beginning of its life and hence the tariff is higher. As the line is depreciated, it is worth less, and the tariff drops.

In negotiated rates, however, the tariff could be levelized and would be the same throughout: It will be lower in the beginning than a FERC-set recourse rate, but higher at the end. And, because the FERC is only asked for new recourse rates periodically, Myers said, the recourse rate tends to stair-step down and to be "somewhat sticky in adjustments downward," so "the shippers are going to pay more, generally, under the recourse rate than they would" under a negotiated rate. ●



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