Petroleum news

Vol. 10, No. 31 • www.PetroleumNews.com | A weekly oil & gas newspaper based in Anchorage, Alaska | Week of July 31, 2005 • $1.50

page 8 Aurora successful with new natural gas wells

21st century transportation

COURTESY PEAK OILFIELD SERVICES

Peak Oilfield Service all-terrain vehicle (see story page 9.)

FERC approves LNG terminal-chemical plant combination

The Federal Energy Regulatory Commission has approved a novel LNG terminal and related facilities proposed by subsidiaries of Occidental Petroleum Corp. The design couples the terminal with a chemical plant, providing energy savings for both.

Ingleside Energy Center would be built on Corpus Christi Bay near Ingleside, Texas, next to an existing Occidental Chemical Corp. plant. FERC gave its approval on July 21.

The liquefied natural gas terminal will have the capacity to send out up to a billion cubic feet of gas daily, with the energy for regasifying the LNG coming from the waste heat of the chemical plant. That will save 16 million cubic feet of gas that would otherwise be burned in standard regasification.

The chemical plant, meanwhile, can use 'waste cold' from

see **TERMINAL** page 15

Alaska contracts for gas campaign; Mac deals look good so far

WITH CONTRACT TALKS PROCEEDING between the state of Alaska and the North Slope producers for fiscal terms for a natural gas pipeline, preparations are beginning for the task of explaining that contract to the state's residents.

The contract and a best interest finding will be issued, and the governor's office is looking for a firm to handle the education campaign. Letters of interest are due July 29.

A July 25 public notice said the state is looking for "firms interested in providing a short-term, immediate educational public awareness statewide campaign to educate Alaska residents on the terms and conditions of the North Slope natural gas contract, with the campaign "estimat-

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5 Energy policy clears Congress: Bill a smorgasbord including many Alaska provisions; ANWR put off for budget reconciliation

7 Alaska Peninsula lease sale set: North Slope, Beaufort sales deferred to February; first areawide in Bristol Bay set for Oct. 26

● GULF OF MEXICO

More Gulf hubs

Kerr-McGee unveils more 'hub-and-spoke' prospects, estimates 140M-850M bbls

By RAY TYSON

Petroleum News Houston Correspondent

Big exploration and production independent Kerr-McGee has disclosed the names, locations and reserve estimates for three large Gulf of Mexico prospects, any one of which the company believes holds the potential to serve as the center of another Kerr-McGee "hub-and-spoke" development in the U.S. Gulf.

David Hager, Kerr-McGee CEO

Kerr-McGee also unveiled for industry analysts in its July 27 conference call on 2005 second-quarter earnings other smaller targets in the U.S. Gulf that could provide the company with immediate proved reserves to book.

The larger prospects with hub potential were identified as Claymore, Mission Deep and Norman.

Together, the three prospects are said to hold possible reserves ranging widely from 140 million to 850 million barrels of oil equivalent. Kerr-McGee holds a 50 percent interest in each of the sub-salt plays.

A hub typically produces from one major field and later from any satellite discoveries in the area. Development is arranged in a hub-and-spoke pattern, with the largest field as the anchor. Kerr-McGee has developed a number of these production hubs in the U.S. Gulf, including the Nansen-Boomvang complex at East Breaks.

One well expected by year-end

"We are in the final stages of working out some

see **HUBS** page 15

● NORTH SLOPE

Cutting exploration costs

Truckable rig will enable drilling of multiple wells in a single North Slope season

By ALAN BAILEY

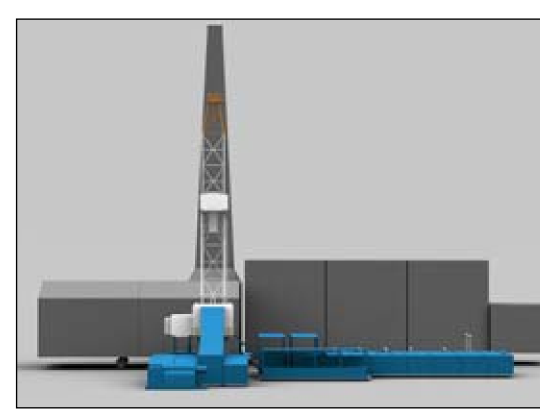
Petroleum News Staff Writer

Ken Sheffield, president of Pioneer Natural Resources Alaska, told Petroleum News in July that the new Arctic Fox No. 1 rig under construction for his company's use will employ proven technology to cut exploration drilling costs on Alaska's North Slope.

"This rig is very, very similar to rigs that are used in the Canadian Arctic for exploration," Sheffield said. "The rig design is proven. It's just a new application for the North Slope.

"What we're trying to do is drill more wells per season and spend time drilling wells and less time moving and building ice."

A joint venture between Doyon Drilling Inc. and Akita Drilling Ltd. is building the rig in Nisku, Alberta, for use in next winter's exploration season. A team of Pioneer, Doyon and Akita personnel specified the rig design.



COURTESY PIONEER NATURAL RESOURCES

The Arctic Fox No. 1 drilling rig being built for use by Pioneer Natural Resources will have an in-line layout that breaks down into 35 truckable loads.

"They tried to draw on the experience of all of

see **RIG** page 15

● ALBERTA

Gold in them thar coals

CBM underpins Alberta's long-term gas hopes; environmental issues tackled

By GARY PARK

Petroleum News Canadian Correspondent

If you'll pardon the mangled metaphor, there's a gold mine of natural gas trapped in the coal seams of Alberta — maybe as much as 500 trillion cubic feet of gas in place.

Enough to attract growing attention from some of the largest E&P companies, with EnCana showing the way and now Nexen ready to open up a new prospect.

Having spent C$100 million and drilled 80 wells over the past four years, Nexen (with a 40 percent working interest), Red Willow Production (a unit of the Southern Ute tribe of Colorado) and Trident Exploration (founded by three men from the U.S. Rocky Mountain states), as operator, are ready to move to the commercial phase of devel-

> ***In preliminary findings issued in mid-July, the committee surprised some by recommending lower provincial royalties for up to five years on coalbed methane wells drilled in the Mannville formation to promote development of the resource.***

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Petroleum News *A weekly oil & gas newspaper based in Anchorage, Alaska*

GULF OF MEXICO

COURTESY BP

Thunder Horse, the largest oil discovery in the Gulf of Mexico, will miss its original late 2005 startup because of damage to the Thunder Horse production platform

Thunder Horse damage delays field startup

Thunder Horse, the largest oil discovery in the Gulf of Mexico, will miss its original late 2005 startup because of damage to the Thunder Horse production platform, BP spokesman Ronnie Chappell confirmed July 27.

The BP-operated platform was found listing 20 to 30 degrees in the wake of Hurricane Dennis, which swept into the U.S. Gulf in early July. However, the U.S. Minerals Management Service has all but dismissed Dennis and its high winds as the cause of the listing. The platform has since been righted.

"There is no apparent damage to the hull or deck box," Chappell said, adding that damage assessment was still ongoing. "However, some equipment was soaked when the platform listed."

He said cause of the mishap was still under investigation and that BP would be in a better position later on in this year's third quarter to discuss cause, costs and a revised project schedule.

The $1 billion Thunder Horse production platform, not yet connected to sub-sea wells, is on Mississippi Canyon block 778 about 150 miles southeast of New Orleans, La. The platform was scheduled to come on line by the end of the year, producing at peak rates of 250,000 barrels of oil per day and 200 million cubic feet of natural gas per day.

Nearly 50 contractors and sub-contractors provided assistance during recovery operations. Government regulators, including MMS and the U.S. Coast Guard, also are contributing to the effort.

The platform is anchored in 6,050 feet of water and is designed to produce from some of the deepest wells in the world. The Thunder Horse field holds an estimated 1 billion barrels of oil equivalent. The field and facilities are owned 75 percent by BP and 25 percent by ExxonMobil.

—RAY TYSON

● NORTH AMERICA

Heads up U.S.: The trusts are coming

Analysts project more Canadian trusts will move south as Enerplus pays C$509M for Lyco, following one buyout last year

By GARY PARK

Petroleum News Canadian Correspondent

The long-expected move into the United States by Canada's income trusts may be under way.

Faced with slim pickings in the Western Canada Sedimentary basin to bolster their reserve base and meet their imperative of at least holding the line on production, it has, in the view of many analysts, been just a matter of time before trusts extended their reach south of the 49th parallel.

But other than last year's C$190 million takeover of Los Angeles-based BreitBurn Energy by Provident Energy Trust the waiting game continued until July 19 when Enerplus Resources Fund snapped up closely held Lyco Energy for C$509 million.

"Here we go," was the response from Leslie Lundquist, manager of the Calgary-based Bissett Income Fund.

Accustomed to intense bidding for assets in Canada, the trusts, with their pockets bulging, are seen as formidable rivals for U.S. properties.

The Enerplus deal involves 31 million barrels of oil equivalent of proved plus probable reserves, representing a reserve life of 12.1 years, in the Williston basin of North Dakota and Montana, with production from the Sleeping Giant reservoir at 7,000 boe per day, 92 percent light oil and 8 percent natural gas.

Enerplus said Sleeping Giant has an estimated 300 million barrels of gross original oil in place on developed Lyco lands, offering potential for improved recovery through additional infill drilling, waterflooding and possibly carbon dioxide flooding.

The trust said an independent engineering evaluation assumes the recovery of about 20 percent of the original oil in place with two wells for every 640 acres. Enerplus believes further technological advances could increase the recovery factor.

Accustomed to intense bidding for assets in Canada, the trusts, with their pockets bulging, are seen as formidable rivals for U.S. properties.

Vermilion may be next

Those looking for the next trust to set up operations in the United States should include Vermilion Energy Trust on their list.

It has already demonstrated an adventurous streak by acquiring 16,300 boe per day of production over the last year in Australia, the Netherlands and France.

Provident has underscored its intention to grow in the United States and other countries by allowing the BreitBurn unit to spend C$95.8 million in February to take over Nautilus Resources, with production concentrated in Montana.

Chief Executive Officer Tom Buchanan told unit holders in May that acquisition and development costs in Canada could climb above US$20 per barrel, compared with US$6 in California, while per barrel netbacks will average US$23 in Canada and US$30 in the United States

The cost of acquiring BreitBurn was more attractive than Canadian prices, heightening Provident's anticipation of more growth in Southern California.

Grant Hofer, an analyst with Scotia Capital, fully expects that politically stable international regions will be the next logical step to sustain trusts. ●

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● WASHINGTON, D.C.

National energy policy clears Congress

Alaska senator played key role in crafting bipartisan legislation; sweeping measure offers something to everybody

By ROSE RAGSDALE
Petroleum News Contributing Writer

As a new energy bill emerged from conference July 26, Congressional leaders predicted Congress would send a sweeping national energy policy to President Bush for his signature by Aug. 1, meeting a self-imposed deadline.

H.R. 6, the first such energy legislation in 13 years, literally covers the waterfront, offering something for everyone from climate change to oil and gas leasing.

Hailed by proponents as legislation filled with conservation and efficiency measures that reflect the will of the bipartisan, bicameral majority of Congress, the energy bill was expected to win the approval of the House on July 28 and head to the Senate for a final vote July 29.


Sen. Lisa Murkowski, R-Alaska

In praising H.R. 6, Sen. Pete Domenici, R-N.M., who chairs the Senate Energy and Natural Resources Committee, said provisions of the energy bill would shave 10-40 percent off the anticipated growth of energy demand by 2015, according to the Alliance to Save Energy. He also cited the American Council for an Energy Efficient Economy's estimate that conservation measures that survived the conference committee debate will save 50,000 megawatts of peak electricity demand by 2020. That's the equivalent of 170 300-megawatt power plants, Domenici said in a statement July 26.

Sen. Lisa Murkowski, R-Alaska, also a member of the conference committee, called the legislation "balanced."

Murkowski said the bill's climate change title is the first ever crafted by Congress. She was an original co-sponsor, with Sen. Chuck Hagel, R-Neb., of several bills that were included in the final energy bill to address climate change.

The bill creates an Interagency Coordinating Committee on Climate Change Technology to create technology to help capture greenhouse gases and keep them out of the atmosphere. It also works to prevent developing nations from adding to greenhouse gas emissions by reducing trade barriers for the U.S. to export new technology to reduce gas emissions, and by authorizing overseas technology demonstration projects.

But critics say the bill does little to corral high oil prices and stops short of ensuring real and immediate reductions in the production of ozone-eating greenhouse gases.


U.S. Rep. Don Young, R-Alaska

At one point during the Senate debate, Sen. Joseph Lieberman, D-Conn., described the Hagel amendment as "fiddling while the earth warms."

ANWR not in energy bill

Most of the provisions introduced by the Alaska delegation made the final cut and remained in the energy bill. However, a much-criticized provision to open the coastal plain of the Arctic National Wildlife Refuge to oil and gas exploration in the House bill was dropped in conference after failing to make it into the Senate version. Republican leaders wanted to avoid a threatened filibuster by Senate Democrats if ANWR drilling was included. The ANWR provision, meanwhile, is included in a budget reconciliation package that Congress expected to consider in September after its August recess.

"It would appear that Alaska is getting what we wanted and expected out of the energy bill," said Mike Chambers, a spokesman for Gov. Frank Murkowski. "When it finally goes through, (the bill) is going to get a warm reception in Alaska," he said July 27.

In addition to previously reported provisions (See July 17 and July 24 stories in Petroleum News), the bill should provide a major boost to construction of a modern, less expensive power system in Alaska and further a variety of energy projects that could greatly aid the state's economy and employment in the future, Murkowski said.

U.S. Rep. Don Young, R-Alaska, who also served on the conference committee, joined Murkowski in protecting most all of the Alaska provisions placed in the bill by the House and Senate earlier in the year — provisions highlighted by authorization of a $550 million rural energy development program.

During the final day of the conference, they also succeeded in reauthorizing the Oil Spill Recovery Institute, which conducts research on ways to combat and prevent oil spills in northern climates. The OSRI was made permanent to conduct long-term research on spill impacts as long as oil development occurs in the state.

Murkowski also sponsored a measure that extends an agreement between Israel and the United States to cooperate on energy research and development activities.

Alternate energy funded

The conference bill's roughly $11.5 billion tax title includes a tax production credit for wind turbines, geothermal energy and biomass that may make such projects more viable in Alaska. The bill also includes a $400 million tax credit to help refineries afford the cost of producing ultra-clean diesel fuels in the future.

Other tax breaks will encourage ethanol production, renewable energy sources, and capture of carbon dioxide, hydrogen-fueled vehicles, and new energy efficiency standards for appliances, buildings, buses and trains. They also will help to reduce fuel consumption by planes; set up a national bicycle program; improve insulation in homes and double funding to $5.1 billion for the Low-Income Home Weatherization Program.

Other previously reported Alaska specifics of the bill include: Indian energy assistance; rural energy assistance; and coal production assistance. The bill includes $200 million per year in aid for projects to utilize the nation's coal resources, with the aid especially intended (70 percent) to help construction of clean coal gasification combined cycle plants. The State of Alaska has two such projects under potential development, one intending to use Beluga coal — the Silverado Green Fuels — project to make boiler fuel for export to the Pacific Rim, and a second project that intends to use Healy coal to make aviation and diesel fuels for use in the Alaska market.

The bill also includes the Power Cost Equalization program, National Petroleum Reserve Alaska oil and gas leasing changes, Alaska offshore royalty suspension, gas hydrate research and development assistance, Cook Inlet carbon dioxide oil enhancement program, Healy Clean Coal loan, renewable energy provisions, Alaska Natural Gas Pipeline provision, Alaska Hydropower bill, Arctic Engineering Research Center and the Barrow Geophysical Research Facility. ●

WASHINGTON, D.C.

Greenspan calls for more oil infrastructure

Federal Reserve Chairman Alan Greenspan said July 21 that it's "perfectly credible" that crude-oil prices could fall in the short run, but he warned that prices in the long-term may remain high without increased investment in oil infrastructure.

"We have had a very significant run-up (in crude oil prices) and it's perfectly credible that it could go down for a while," Greenspan told the Senate Banking Committee. "But ... unless we address the issue of getting adequate investment to convert the proved reserves into productive oil capacity, we're going to have trouble meeting long-term demand for oil."

Crude oil prices have more than doubled to about $60 a barrel since early 2004 and are expected to shave as much as three-quarters of a percentage point off U.S. economic growth this year. Greenspan said earlier July 21 that a further increase in oil prices "could cut materially into private spending and damp the rate of economic expansion." Greenspan has said the supply of oil hasn't been able to keep up with demand recently partly because of constraints on investment in some major Middle Eastern oil producers.

—THE ASSOCIATED PRESS

NORTH AMERICA

Canada's rig count up by 28; U.S gains 6

The number of rotary drilling rigs operating in the United States and Canada during the week ending July 22 totaled 1,931, a net increase of 34 rigs compared to the previous week and a net increase of 335 rigs compared to the same period last year, according to rig monitor Baker Hughes.

The Canadian rig count alone during the recent week was 521, up 28 rigs from the previous week and up 141 rigs from the year-ago period.

The number of rigs operating in the United States during the recent week totaled 1,410, an increase of six rigs compared to the previous week and an increase of 194 rigs versus the same period last year. Compared to the previous week alone, offshore rigs increased by six to 104, while land rigs increased by one to total 1,282 rigs. Inland water rigs decreased by one to total 24 rigs.

Of the total number of rigs operating in the United States during the recent week, 1,228 were drilling for natural gas and 181 for oil, while one rig was being used for miscellaneous purposes. Of the total, 882 were vertical wells, 335 directional wells and 173 horizontal wells.

Among the leading U.S. producing states during the recent week, Louisiana picked up eight rigs for a total of 202 rigs, while California picked up four rigs for a total of 27 rigs, Colorado gained one rig for a total of 69 rigs and Wyoming gained one rig for a total 78 rigs. Texas lost three rigs during the recent week for a total of 616 rigs. Oklahoma lost three rigs for a total of 148 rigs. New Mexico lost two rigs for a total of 88 rigs and Alaska's rig count dipped by two to total eight rigs.

—RAY TYSON

ALASKA

Trans-Alaska oil pipeline restarted after second Alyeska summer shutdown

Alyeska Pipeline Service Co. said July 25 that it had safely restarted the trans-Alaska pipeline at approximately 2:30 p.m. July 24 after completing a variety of projects. The shutdown, planned to last approximately 36-hours, began July 23 at 6 a.m. and allowed crews to work on projects from Prudhoe Bay to the Valdez Marine Terminal.

Alyeska said the primary scope of the work included: infrastructure installation at Pump Station 9 for new electric driven pumps for strategic reconfiguration; installation of a 48-inch straight-run mainline pipe at Pump Station 12; and maintenance on selected valves.

This is the second summer project and maintenance shutdown of the line.

The Joint Pipeline Office, which said it would be monitoring the activities, said prior to the shutdown that it is reviewing strategic reconfiguration packages for Pump Stations 3 and 9 general contract for new facilities and notices to proceed on existing facilities at those pump stations, as well as changes to the power systems scheme at the four electrified pump stations: 1, 3, 4 and 9.

—PETROLEUM NEWS

WASHINGTON, D.C.

Oil futures up on oil demand projection

Crude futures gained July 28 after the U.S. Department of Energy gave a mixed picture of U.S. petroleum stocks but suggested that it may raise its 2005 projection for oil demand.

Analysts said that tightening crude supplies in the United States, the world's largest oil consumer, heighten supply-related fears and could push prices to new highs.

Light, sweet crude for September delivery was up 30 cents to $59.41 a barrel on the New York Mercantile Exchange.

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● CANADA

'Security' bill no threat to energy deals

Canadian government lacks ability to review transactions; says focus of legislation on defense technology, military hardware

By GARY PARK
Petroleum News Canadian Correspondent

At the same time U.S. lawmakers are grappling with the strategic and security worries of China's drive to lock up scarce global oil supplies, the Canadian government has tabled legislation that would require a probe of any foreign investment seen as potentially "injurious to national security."

In the midst of a firestorm over the threatened purchase of Unocal by the Chinese National Overseas Oil Co., CNOOC, the Liberal government of Prime Minister Paul Martin quietly introduced a bill giving itself explicit authority to review and block foreign transactions.

But Industry Minister David Emerson said the proposed amendment to investment review law was not a signal that foreign investments in the "natural resources sector" were unwelcome.

He said Bill C-59 was not an attempt to shut off major Canadian companies from foreigners.

The emphasis, Emerson said, was a concern about the transfer of sensitive defense technology and military hardware in the wake of 9/11.

Canada lacks review ability

Although a 2004 bid by state-owned China Minmetals to take over mining giant Noranda eventually fell through, it did alert the federal government that Canada — unlike other Group of Eight countries — did not have the ability to review a transaction.

But he would not go into greater detail on what might constitute an investment "injurious to national security."

Until this year, the greatest anxiety over foreign incursions into Canada's petroleum industry have focused on U.S.-based companies, which have at times controlled more than 60 percent of Canada's production, prompting the Canadian government in the 1970s to impose stringent reviews of takeovers.

Having apparently been thwarted in its bidding war with Chevron for Unocal, CNOOC is now rumored to have its eye on Talisman Energy, even though the Canadian independent does not have any interests in the oil sands, where the Chinese apparently think future value lies.

Those restrictions no longer exist and over recent years U.S. companies have pulled back from most of the assets they acquired at premium prices in the 1990s.

The only turnaround occurred in the second week of July when Texas-based Pogo Producing forked over US$1.8 billion for the Canadian holdings of Unocal — the first acquisition of a Canadian oil and gas producer in the four years since Devon Energy took over Anderson Exploration.

Concern over China's investments

Now that concerns about excessive U.S. influence on the Canadian industry have evaporated, attention has shifted to the arrival of the Chinese, with CNOOC and Sinopec both taking stakes in start-up oil sands producers and PetroChina hoping to become the anchor tenant on Enbridge's proposed Gateway oil sands pipelines.

But there could be much larger issues looming.

Having apparently been thwarted in its bidding war with Chevron for Unocal, CNOOC is now rumored to have its eye on Talisman Energy, even though the Canadian independent does not have any interests in the oil sands, where the Chinese apparently think future value lies.

A move on Talisman would probably stir the same anxieties that had U.S. political leaders demanding that the Chinese government should allow takeovers of its state-controlled energy industry before it could gain a foothold in the U.S. ●

● ALASKA

Alaska Peninsula lease sale set for Oct. 26

State postpones North Slope and Beaufort Sea areawide sales until February; some 5.8 million acres offered in peninsula sale

By KRISTEN NELSON

Petroleum News Editor-in-Chief

The first Alaska Peninsula areawide oil and gas lease sale will be held Oct. 26, and it will be the only areawide sale the state holds in October: it has rescheduled the North Slope and Beaufort Sea sales to February.

The Alaska Department of Natural Resources Division of Oil and Gas said July 25 that it wants to focus industry attention on the Alaska Peninsula sale and to spread the work of both participants and staff more evenly. "The Department of Natural Resources has worked hard to evaluate and organize AP 2005, and this sale deserves our full attention this October," the department said in a sale notice.

The division said hydrocarbon potential for the northern coastal plain between Becharof Lake and a narrow strip of coastline opposite Cold Bay is expected to be "moderate to locally high for gas, and low to moderate for oil." The division said this represents its "general assessment of the oil and gas potential of the area …

In a July 26 press release Alaska Gov. Frank Murkowski noted that the lease sale will be the first in the area in two decades and comes in response to requests made by local leaders and organizations who urged the governor to support new oil and gas efforts in the area.

"The state is very optimistic about the oil and gas potential in the lease sale area," the governor said. "This sale presents a significant opportunity for the Alaska Peninsula and Bristol Bay regions to diversify their economy and foster new economic development for their communities."

Department of Natural Resources Commissioner Tom Irwin said DNR "worked closely with local governments and organizations to ensure that oil and gas exploration and development in the region will be conducted in a manner compatible with commercial and subsistence fishing, which will remain a cornerstone of the local economy."

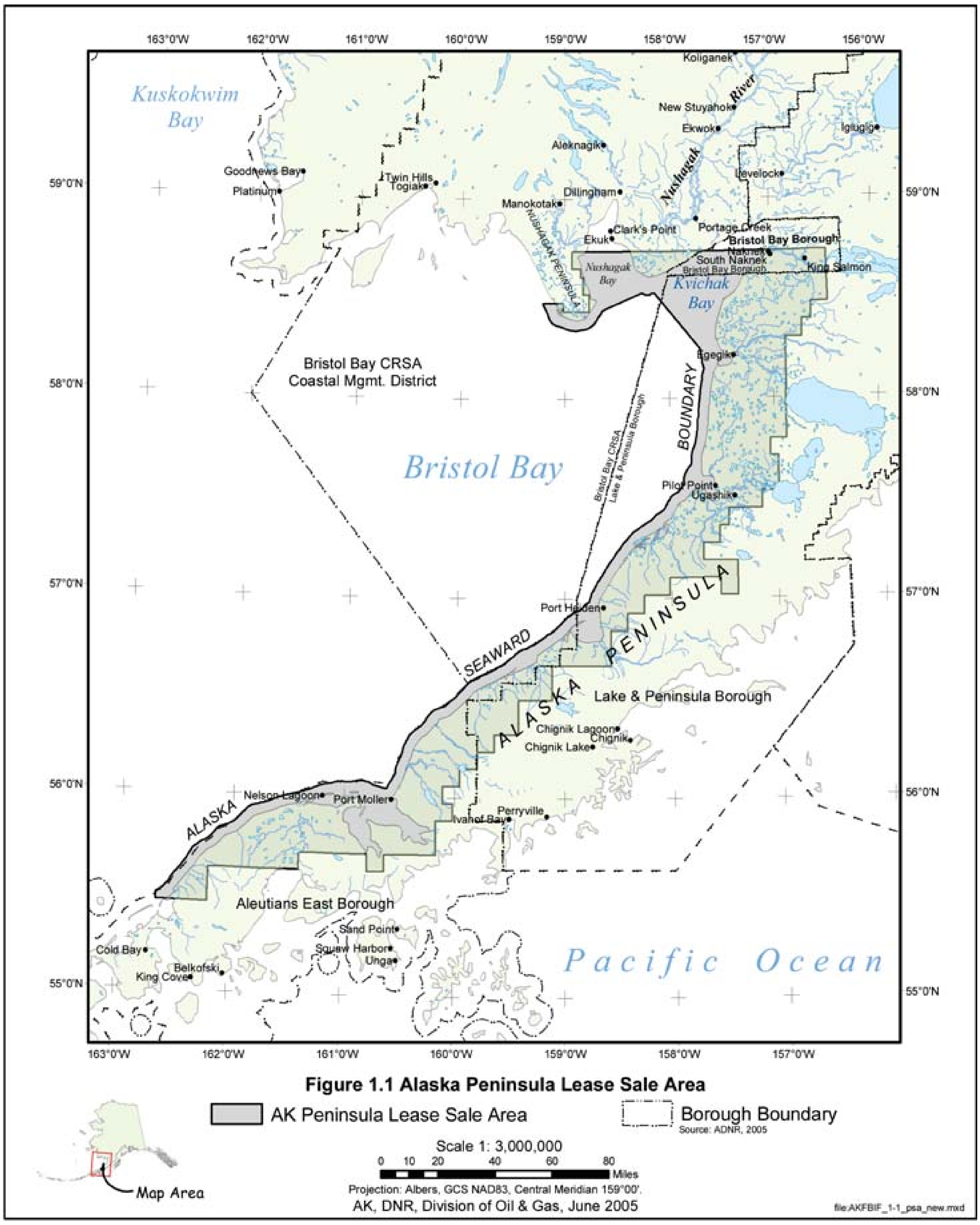


Figure 1.1 Alaska Peninsula Lease Sale Area

Sale covers 5.8 million acres

The department released the final best interest finding and the Alaska Coastal Management Program determination for the Alaska Peninsula areawide sale July 25. The 5.8 million acre sale area is divided into 1,047 tracts ranging in size from 1,280 acres to 5,760 acres, and includes onshore and offshore acreage from the Nushagak Peninsula in the north, down the north side of the Alaska Peninsula to just north of Cold Bay. Approximately 1.75 million acres are offshore.

While tracts in state waters are included in the sale, mitigation measures in the final best interest finding specify: "Drilling in offshore tracts will only be conducted directionally from onshore locations."

Bids will be opened at 8:30 a.m. Oct. 26 at the Loussac Public Library in Anchorage. A minimum bid of $5 an acre is required; leases will have a fixed royalty rate of 12.5 percent; and the leases will have 10-year terms. Annual rental begins at $1 per acre, increasing to $1.50 per acre in the second year, $2 per acre in the third year, $2.50 per acre in the fourth year and $3 per acre for the fifth and following years.

Detailed information is posted on the division's Web page at: http://www.dog.dnr.state.ak.us/oil/.

Exploration activity

There was an oil well drilled near Puale Bay in 1902, the division said in the final finding. That well was not successful, however, and by 1906 the effort was abandoned.

Twenty-six wells have been drilled since 1903, the latest the Amoco Becharof No. 1 in 1985. One offshore stratigraphic test, the ARCO North Aleutian COST well No. 1, was drilled in 1983.

The division said hydrocarbon potential for the northern coastal plain between Becharof Lake and a narrow strip of coastline opposite Cold Bay is expected to be "moderate to locally high for gas, and low to moderate for oil." The division said this represents its "general assessment of the oil and gas potential of the area and is based on its resource evaluation," including geology, seismic data, exploration history and proximity to known hydrocarbon accumulations.

"Conditions are expected to be very good for both structural and stratigraphic traps," the division said, noting that there are several oil and gas seeps along the southeastern flank of the peninsula, "such of which occur along the crests of large anticlines." ●

● COOK INLET

Aurora bringing successful wells online

West side Cook Inlet drilling includes Three Mile Creek discovery testing 5 million cf/d; Lone Creek at 16.4 million cf/d

COURTESY AURORA GAS

Ed Jones, Aurora Gas vice president of operations and engineering, on location during testing of Lone Creek No. 3 well. Aurora said it believes the well, which tested at 16.4 million cubic feet per day, will be its best producer to date.

By KRISTEN NELSON

Petroleum News Editor-in-Chief

Aurora Gas is in the middle of a busy drilling season on the west side of Cook Inlet.

The company said in a July 26 statement that it has completed testing an apparent discovery at Three Mile Creek and drilled successful development wells at Moquawkie and Lone Creek. Gathering lines and production facilities are nearly complete at Three Mile Creek, and that field should be ready to go into production in early August, the company's vice president of operations and engineering, Ed Jones, told Petroleum News.

The company has four onshore gas fields developed on the west side of Cook Inlet — Nikolai Creek, Kaloa, Moquawkie and Lone Creek — but only three in production. Jones said the company has about 6 million cubic feet a day of production currently, but would have about 12 million if it could move gas from Nikolai Creek which is physically connected to CIGGS, the Cook Inlet Gas Gathering System.

Aurora President Scott Pfoff said the company has permission from the Regulatory Commission of Alaska to use CIGGS on an interim basis, but still needs "a commercial deal with one of the two owners, Unocal or Marathon, and right now we don't have one with either one of them. We're trying to get one and so the field is shut in," he said.

There has been a settlement in principle on CIGGS, but the final settlement won't be submitted until late August.

An agreement needs to be in place by Nov. 1, said Dave Boelens, Aurora's vice president of Alaska operations, if Aurora is going to be able "to sell gas to Agrium, because they're relying on that pool of gas that they've assembled from all these different companies …" to keep the plant operating.

Pfoff said the company's other fields are tied to the Beluga pipeline, with gas flowing north to a connection with Enstar at Beluga. But Aurora wants to put gas into CIGGS from other fields as well as Nikolai, and that would require that the Beluga line, which now moves gas north, flow bi-directionally. Marathon built the Beluga line in the early 1990s to move its gas north from CIGGS to Beluga, but now, Pfoff said, there is interest in having that line also move gas south to CIGGS and then across the inlet to Agrium and the liquefied natural gas plant. That would require some mechanical changes to the Beluga line, mainly added compression, so that the gas in the Beluga line is under high enough pressure to move into the CIGGS line, Boelens said.

"Gas doesn't really care which way it flows," he said, and with added compression gas could flow from either end of the Beluga line at the same time, moving both north to Beluga and south to CIGGS.

Success with the drill bit

While Aurora still can't move all of its gas to market, it is having good results finding gas.

In January, Jones said, the company completed the Three Mile Creek No. 1 well. As the first part of its rig program this spring, Aurora "added more perforations" and has the well ready to go. The company used a recently acquired well testing module at Three Mile Creek, and tested several Beluga sand intervals for a combined flow rate of approximately 5 million cf/d. Aurora owns a 70 percent working interest in Three Mile Creek and is the operator; Forest Oil owns the remaining 30 percent.

The five-mile gathering line connecting to an existing gathering line from the Lone Creek field to the Beluga pipeline and facilities should be completed in early August, Jones said.

Aurora said it is evaluating the possibility of "extending the gathering system to the south where the gas could be delivered directly to CIGGS."

From Three Mile Creek Aurora moved the rig to the Moquawkie field, Jones said, "and drilled an offset to our old re-entry No. 1 well." The Moquawkie No. 3 was drilled to a depth of 2,560 feet and completed in the Tyonek and Beluga sands, with combined flow rates of 5.5 million cf/d. This well is on the same pad as the earlier well, and will be on production by Aug. 1, the company said.

Best well to date

Aurora then moved the rig to the Lone Creek field and on July 3 spudded the Lone Creek No. 3, an offset to the Lone Creek No. 1. The well was drilled to 3,025 feet. The company described the well as its best to date: it flowed at 16.4 million cf/d "from several upper Tyonek sands, with several apparently productive sands yet untested."

"We're real pleased with what we've got there," Jones said. (See photo this page.)

Aurora said the well would be tied in with a short gathering line to the central production facility at the Lone Creek No. 1 well pad.

The rig will next move to Aurora's Aspen prospect. Jones said there were some oil wells drilled in the area, east of Moquawkie, but this is an exploratory gas well. The well will be drilled from a new pad, and should spud by Aug. 1 he said, with an expected depth of some 4,000 feet. "It's based on seismic plus some old wells that were drilled in the late '60s, early '70s," Jones said.

From Aspen, the rig will go on to drill development wells, either at Kaloa or Three Mile Creek, where there are two development prospects.

Aurora expects to drill six wells this season, Jones said.

There are multiple reservoirs in almost every well. They typically drill through eight Beluga sands and six Upper Tyonek sands, he said, and this improves the chances of finding gas. The Three Mile Creek wells, he said, had Upper Tyonek targets. Those were wet, "but we found a number of nice Beluga sands that we've completed in and I think we're in seven individual stringers of Beluga there."

Kenai oil prospect

Aurora is also working an oil prospect on the lower Kenai Peninsula, Jones said.

see **AURORA** *page 14*

● NORTH SLOPE

North Slope transportation in the 21st century

Peak Oilfield Service's new all-terrain vehicles carry large loads across the tundra to sites far from infrastructure

By ALAN BAILEY

Petroleum News Staff Writer

To support operations in ever more remote places on Alaska's North Slope, Peak Oilfield Service Co. has added two new all-terrain vehicles to the company's fleet. The company has designed and built these vehicles to handle loads of up to 125,000 pounds and has tested the vehicles with loads up to 110,000 pounds, Patrick Walsh, vice president of Peak Oilfield Service, told Petroleum News.

"We had two all-terrain vehicles … designed and built in an attempt to look out into the future," Walsh said. "We're seeing exploration going further and further away from infrastructure. We need some ways of supporting our remote sites."

The new vehicles can carry heavy equipment or move supplies such as fuel and drilling mud for remote drilling operations.

Like "ships of the tundra" these behemoths carry their huge loads across roadless terrain without marking the ground. With gigantic tires in the form of airbags the vehicles only exert a pressure of two to three pounds per square inch on the ground. Friction drive through rollers on the airbags ensures that the wheels will not spin on the ground. Independent suspension, all-wheel drive and lockable differentials enable the vehicles to negotiate rough terrain.

Increasing the loads

The main innovation in Peak's new vehicles is an ability to carry substantially heavier loads than earlier designs.

COURTESY PEAK OILFIELD SERVICES

One of Peak Oilfield Service's new all-terrain vehicles crosses snow covered tundra

"They've got 10 bags under the tractor and six bags under the trailer," Walsh said. Older models have fewer airbags — the extra airbags in the new design distribute the load across a larger ground area, he explained.

Using techniques such as finite element analysis designers came up with a fifth wheel-style tractor-trailer configuration for the new vehicles. The tractor uses articulated steering and the trailer deck is 50 feet long. An engine on the tractor and another on the trailer deliver power to all of the wheels through a system of drive shafts and differentials.

New Caterpillar engines meet environmental regulations and are tuned to deliver about 425 horsepower.

"We've put the new Cat C-15 motors in them so we're compliant with the tier two air quality permits which are coming out," Walsh said.

Approved for tundra travel

The Alaska Department of Natural Resources has approved the new vehicles for summer tundra travel.

"There's only a couple of different types of vehicle that are approved," Walsh said. "One is the all-terrain vehicle with a bag and drive roller on top of it and then the other is a Tucker (with tundra pattern tracks)."

Approval for summer tundra travel means that the vehicles can operate on state land on the North Slope after July 15 each year, long before the opening of the winter tundra travel season.

Unlike the state, BLM does not allow summer tundra travel on federal land. However, the all-terrain vehicles still enable off-road transportation on federal land during the winter season.

Proactive transportation

The ability to travel on the tundra in the summer can enable Peak to start constructing ice roads on state land several weeks before the winter tundra travel season opens. This early start provides a tremendous benefit, given the short winter travel season, Walsh said.

"That's a proactive measure as far as the contractor's concerned to assist in lengthening the drill season," he said.

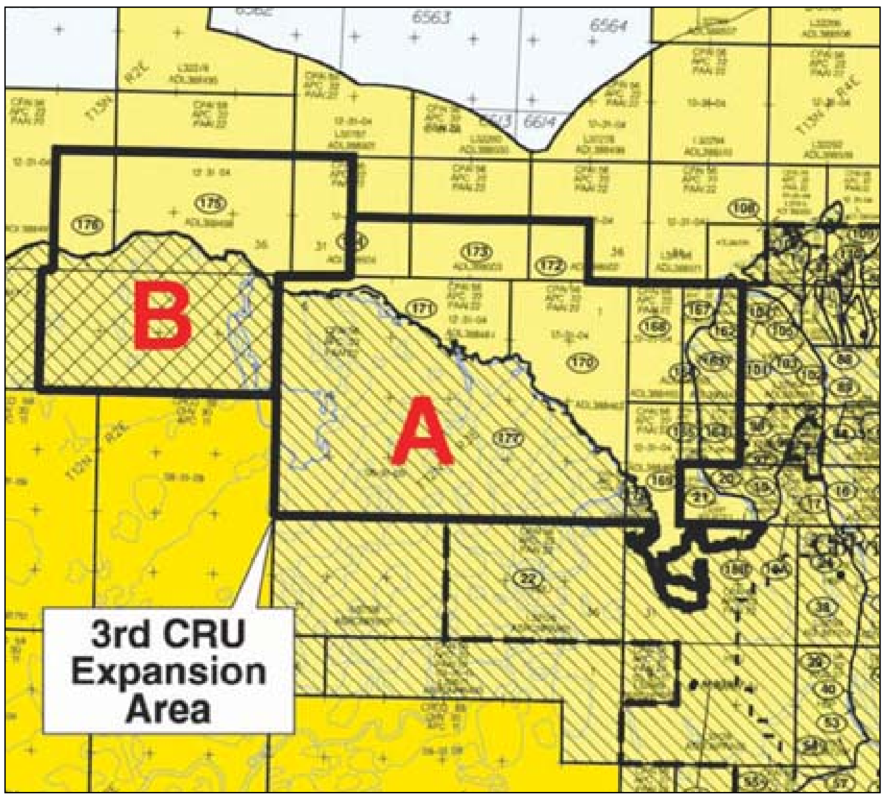
If, for example, there's a substantial snowfall in October, the all-terrain vehicles can pack down a trail. The packing of the snow reduces the insulation provided by the snow cover and causes the underlying ground to freeze faster along an ice road route.

State officials will then test the freezing conditions to determine whether conventional vehicles can move in to start ice road construction.

"Usually you'll get a special permit

see ALL-TERRAIN page 10

NORTH SLOPE



COURTESY CONOCOPHILLIPS

A portion of the Colville River Unit

Conoco won't drill 2nd Iapetus well

Colville River unit operator ConocoPhillips Alaska has told the state it won't drill a second well at the Iapetus prospect at the northwest corner of the unit.

ConocoPhillips applied to expand the unit to the west last year to extend leases with Jan. 31, 2004, expiration dates. The company wanted to drill a prospect, Iapetus, on the western edge of state acreage on Alaska's North Slope.

The state requested that the proposed expansion area, some 34,176 acres (16,578 belonging to Arctic Slope Regional Corp., 15,681 acres to the state and 1,920 acres jointly held by ASRC and the state) be divided into two areas, "A" being the portion adjacent to the existing Colville River unit and "B" the portion farther to the west; a well was required in each area, the first in 2005 and the second in 2006.

> *The state requested that the proposed expansion area, some 34,176 acres (16,578 belonging to Arctic Slope Regional Corp., 15,681 acres to the state and 1,920 acres jointly held by ASRC and the state) be divided into two areas, "A" being the portion adjacent to the existing Colville River unit and "B" the portion farther to the west; a well was required in each area, the first in 2005 and the second in 2006.*

Rick Mott, ConocoPhillips Alaska vice president exploration and land, told Petroleum News in January that Iapetus is on state and Native lands due west of the Fiord development and could "be a new discovery out there, or an extension of Fiord." He said Iapetus would be drilled from an ice pad at the shoreline, "but the prospect straddles the onshore and offshore."

First Iapetus well drilled

The first well was drilled this winter in area "A."

State records show the well was drilled from a surface in section 8, township 12 north, range 4 east, Umiat Meridian, to a bottomhole in section 7, township 12 north, range 4 east, UM. This well, drilled into the "B" segment farther west, was plugged and abandoned March 28. It reached a measured depth of 9,300 feet and a true vertical depth of 7,986 feet.

No further information is available on the well, but ConocoPhillips must not have liked what it saw, because it opted to drop the acreage to the west, rather than committing to drill the second well in area "B" next year.

In late May ConocoPhillips informed the state that the working interested owners had elected not to drill in area B; area B contracted out of the Colville River unit effective June 1 and the leases expired.

In addition to the drilling requirement, the expansion area lands must be in an approved participating area within five years of the expansion approval (April 22, 2004) or they will be dropped from the unit.

—KRISTEN NELSON

● DENVER

Whiting Petroleum buys Celero properties

Firm to spend $802M in cash and stock to buy Celero properties in Texas, Oklahoma; deal nearly doubles Whiting's reserves

By RAY TYSON
Petroleum News Houston Correspondent

Denver-based exploration and production independent Whiting Petroleum is accumulating U.S. oil and gas properties faster than a hungry squirrel collects nuts for the winter.

In 2004 alone, Whiting completed six property transactions and a merger with Equity Oil, ending that year with proved reserves of 865.4 billion cubic feet of gas equivalent, a hefty 97 percent increase over its year-end 2003 reserves of 438.8 bcfe.

The company then proceeded to gobble up another $95 million worth of U.S. properties in 2005, not including a rather large $802-million cash and stock deal announced July 26. That pushed Whiting's total proved reserves to about 1.6 trillion cubic feet of gas equivalent, an 85 percent increase over 2004 year-end reserves.

"The purchase fits our plan to grow our asset base through acquisition and subsequent development of producing oil and gas properties," Whiting chief executive James Volker declared in announcing the deal that actually included two separate transactions with the same company.

Celero properties in Oklahoma, Texas

Whiting said this time it was buying of oil and gas properties in the Oklahoma Panhandle and the Permian basin of West Texas from Celero Energy, LP, owned by Quantum Energy Partners of Midland, Texas. The transactions specifically include Celero's interests in the Postle field in Oklahoma and the North Ward Estes field in West Texas. Combined proved reserves for the two fields were estimated at 734 bcfe, 94 per cent of which is oil and 43 percent of which is developed, according to Whiting.

Under terms of its latest deal, Whiting has pledged to pay Celero $343 million in cash at an August closing and $442 million in cash at an October closing, as well as issue 441,500 Whiting shares to Celero at the October closing. Based on recent trading, the stock has a value of around $17 million.

Whiting will operate 95%

Upon the closings, Whiting said it will operate about 95 percent of the Celero properties, which the company said produced at an average net rate of 7,510 barrels of oil per day and 2.8 million cubic feet of natural gas per day.

Substantially all of the properties to be acquired from Celero have the potential for enhanced recovery and CO2 injection, as well as reserve growth associated with development and exploratory drilling, Whiting said.

Whiting said that through 2006 it intends to invest about $197 million to further develop the Postle and North Ward Estes fields.

Meanwhile, Whiting reported a 2005 second-quarter profit of $24.2 million or 82 cents per share on revenues of $111.1 million, a substantial increase over 2004 second-quarter net income of $13.5 million or 72 cents per share on revenues of $54.7 million.

Second-quarter 2005 production also climbed to 180 million cubic feet of natural gas equivalent per day, representing a 75 percent increase over the 103 million cubic feet of equivalent average in 2004's second quarter. The increase was primarily due to the producing property acquisitions that Whiting closed in the second half of 2004, Whiting said. ●

continued from page 9

ALL-TERRAIN

just on your road route to start constructing an ice road," Walsh said.

Walsh also said that his company is being proactive in preparing for possible exploration to the east of Prudhoe Bay. There's less water available to the east for ice road construction, he said. In this type of situation Walsh sees a need for all-terrain vehicles to shuttle loads for ice pad and airstrip construction. And drilling operations many miles from any form of road will require continuous transportation services.

"I think that you're going to have to come up with multiple modes of transportation," he said. "You have to have (transportation) options — these (vehicles) are an option and I think it's a good option."

In fact Walsh views his company's investment in the research and development of new vehicle designs as a commitment to the future transportation needs of the Alaska oil and gas industry.

"I look at it as a commitment because I think there's a tremendous future (in Alaska)," Walsh said. "We are exploring for resources further away from the infrastructure, but to me that's smart business — you don't run your car out of gas and then look for a gas station." ●

● ALBERTA

Standalone upgrader gets regulatory nod

BA Energy plant in Edmonton refinery area will be first independent of producers; North West Upgrading also has plant in works

By GARY PARK

Petroleum News Canadian Correspondent

A private company is one large step closer to launching a possible C$1.8 billion heavy oil upgrader plant — the first of its kind to operate independently of producers.

BA Energy, a unit of Value Creation, did not have to go through a public hearing to obtain approval from the Alberta Energy and Utilities Board to proceed with its 75,500 barrel per day first phase costing C$720 million.

The regulator approved three phases of the project with ultimate capacity of 226,000 bpd.

The company now aims to raise about C$360 million in equity and use debt to cover the balance of construction, targeting a late 2007 start-up.

BA and Value include former Shell Canada and Syncrude Canada oil sands managers in their leadership teams.

BA President Ray Cej was a Shell executive and Value's Chief Executive Officer Columba Yeung, who designed an upgrader for Shell's 60 percent owned Athabasca project, is credited with proprietary technology that is aimed at lowering operating costs at BA's Heartland plant.

The upgrader will be located in the Edmonton refinery area, close to a planned Terasen Pipelines heavy oil terminal.

Cej said in a statement that BA is now talking with "various" heavy oil producers to arrange supplies and, with more than 300,000 bpd flowing into the Edmonton area, it does not expect any problems securing 50,000 bpd.

More flexible processing system a priority

One of the priorities for Heartland is to lower the impact of downtime for upgraders by introducing a more flexible processing system that will allow it to handle as little as 20,000 bpd without affecting the economics.

Among the innovations, BA intends to generate its own gas to soften one of the most challenging cost factors in bitumen upgrading.

It will produce light-medium, semi-sour crudes that are low in residues and contaminants, giving it access to a greater range of North American refineries.

Another side benefit of the technology is the reduction it will achieve in greenhouse gases.

The next ambitious goal for Value is the possible development of its own oil sands leases, which hold an estimated 26 billion barrels in place, but that is on hold until the upgrader technology is commercialized.

Hot on the heels of BA in the standalone upgrader field is another privately owned company, North West Upgrading, which has just raised C$38 million from a private placement to develop its plans for a C$1.2 billion upgrader to handle 50,000 bpd.

North West hopes to come on stream near Edmonton in early 2010 and plans three additional phases as market demand grows.

It expects to file a regulatory application late this year and start construction towards the end of 2007. ●

OIL COMPANY EARNINGS

Earnings from Top 35 North American E&P Capex Spenders

Earnings second quarter 2005 • Change from second quarter 2004
Liquids production second quarter 2005 • Change from second quarter 2004
Natural gas production second quarter 2005 • Change from second quarter 2004

Company	symbol	earnings	%	liquids	%	gas	%
BP	BP	$4,981	+29	2,619,000	+4	8,661	+3
RD/Shell	RD	$5,236	+34	2,168,000	–3	7,875	+1
EnCana	ECA	$839	+248	157,108	-8	3,212	+7
ExxonMobil	XOM	$7,640	+32	2,466,000	–4	8,686	-4
Can. Natural	CNQ.TO						
ConocoPhillips	COP						
El Paso	EP						
Chevron	CVX						
Anadarko	APC						
Devon	DVN						
Dominion	D						
Burlington	BR						
Occidental	OXY	$1,536	+164	416,000	-5	681	+6
Husky	HSE.TO	C$394	+72	194,000	-9	689	+1
Newfield	NFX	$104	+55	25,500	+64	593	+12
Petro-Canada	PCZ	C$345	-12	284,300	-8	815	-6
Unocal	UCL						
Kerr-McGee	KMG	$370	+234	175,000	+25	1,118	+51
EOG	EOG	$248	+74	28,500	+7	1,182	+21
Nexen	NXY.TO						
Imperial	IMO	C$539	+7	267,000	+6	576	+8
Talisman	TLM	C$340	+76	228,977	(0)	1,292	+4
Pioneer	PXD						
Apache	APA	$587	+54	253,510	+8	1,297	+4
Marathon	MRO	$673	+91	219,100	+23	893	-7
Suncor	SU.TO	C$112	-45	128,200	-43	175	-16
Merit	Private company does not report results						
Williams	WMB						
Chesapeake	CHK						
Pogo	PPP	$103	+59	30,450	-22	255	+2
Penn West	PWT.TO						
XTO	XTO	$220	+122	47,327	+88	1,019	+27
Spinnaker	SKE						
Forest	FST						
BHP Billiton	BHP	Does not report quarterly figures					

** Does not include share of Lukoil production*
Liquids production in barrels per day. Natural gas production in millions of cubic feet per day.
NOTE: Top 35 is based on Petroleum News research

CANADA

Carbon tax could hit Canadians

The Canadian government is being accused of sliding a costly carbon tax through the back door by treating carbon dioxide as a toxic substance Kyoto Protocol measures published earlier in July in the official newspaper of Parliament.

Without any public announcement, the Canadian Environmental Protection Act required large industrial companies to reduce their emissions of greenhouse gases by 45 million metric tons, or 16 percent of Canada's total output.

Failure to comply will result in fines amounting to C$200 million per million metric tons.

By including the rules in the official newspaper of Parliament, the Liberal government of Prime Minister Paul Martin does not have to obtain approval from the House of Commons.

That has enraged the major opposition party, the Conservatives.

Bob Mills, environment spokesman for the Conservatives, said the Liberals should have had the courage to introduce legislation and allow a full debate on rules that could have a severe impact on the Canadian economy.

Industry-specific agreements recognized

However, the regulations specify that industry-specific agreements reached with the Canadian government will still be recognized.

For the petroleum industry that means a 15 percent increase in carbon output from 1990 negotiated with the previous administration of Prime Minister Jean Chrétien will still apply.

There is also a promise to consult with private-sector stakeholders over the new rules. The measures suggest that companies unable to meet their emission targets will buy so-called credits from domestic or overseas sources to meet the targets or contribute to a government green-technology fund.

But indications that the government has bought into the concept of a carbon tax, despite assurances to the contrary from federal officials earlier this year, points to higher gasoline and electricity prices for consumers, said John Williamson, a director of the Canadian Taxpayers Federation.

—GARY PARK

ALASKA PENINSULA

DGGS releases data on Alaska Peninsula

The Alaska Department of Natural Resources' Division of Geological & Geophysical Surveys released new information on the geology of the Alaska Peninsula and Bristol Bay area, Preliminary Interpretive Report 2005-4, on July 21.

Division Deputy Director Bob Swenson said the data contained in the report will be useful for companies evaluating prospects for the upcoming Alaska Peninsula areawide lease sale, scheduled for Oct. 26.

"This report provides the best source yet of public information about the geologic history, detailed stratigraphic analysis and hydrocarbon potential of this region," Swenson said in a media release July 22.

The division said the report draws on data from existing wells, seismic surveys and field mapping performed by geologists from DNR, the U.S. Geological Survey, the university and industry.

The report includes information about the region's geology, organic geochemistry, sedimentology and characterizations of significant rock formations. It also includes preliminary subsurface interpretations based on publicly available seismic data.

Copies of the preliminary interpretive report are available on the division's Web site at http://www.dggs.dnr.state.ak.us/

—PETROLEUM NEWS

CANADA

'Long live the new king!' as trusts grow

Income trusts are still searching for the upper limits in Canada, despite warnings of an impending reversal.

Dominated by the energy trusts, 203 trusts now trade on the Toronto Stock Exchange, an increase of 28 in just six months, carrying a market capitalization of C$153 billion, up C$32 billion from the end of 2004.

At that pace it may be only a matter of time before the trust grouping challenges the exchange's other powerhouse sectors — financial at C$380 billion and energy at C$314 billion.

Dominated by the energy trusts, 203 trusts now trade on the Toronto Stock Exchange, an increase of 28 in just six months, carrying a market capitalization of C$153 billion, up C$32 billion from the end of 2004.

It's enough for BMO Nesbitt Burns strategist Ben Joyce to predict in a research note that the influence of trusts will prevail well into 2006.

New issues by trusts reached C$5 billion in the March-June quarter, matching what would once have been normal for common equities, while common shares on Canada's major exchange are into decline for the first time in 42 years.

Joyce said the spectacular transformation results largely from the favorable tax treatment for trusts compared with common stocks.

In his words: "The king is dead, long live the new king!"

Percentage of payout expected to drop

Awash in the spoils of high oil and natural gas prices, the trusts are expected to sharply lower the percentage of cash flow they distribute to unit holders this year.

Brian Ector, a Scotia Capital analyst, said in a research note that he expects a record low percentage payout to be reported in this year's second quarter.

The ratios will likely fall to 68 percent from 74 percent in the first three months and 78 percent in the second quarter of 2004.

Ector estimates cash flow will rise by an average 20 percent on a year-over-year basis, led by Acclaim Energy Trust with a 57 percent gain, followed by Paramount Energy Trust at 39 percent and NAL Oil & Gas Trust and Petrofund Energy Trust, both at 38 percent.

He noted that the trusts posting the largest hikes in cash flow are those that have completed acquisitions in the past 12 months that have increased their size by one-third or more.

—GARY PARK

● WASHINGTON, D.C.

Unocal was ready to OK higher CNOOC offer

Company says board was close to endorsing Chinese company's takeover plan before Chevron raised its offer to $63 per share

By BRAD FOSS

Associated Press Business Writer

Unocal Corp. says it was prepared to drop its support for a takeover agreement with Chevron Corp. and accept an acquisition by CNOOC Ltd. had the Chinese state-owned oil company raised its bid sufficiently enough to offset regulatory and financial risks.

Instead, Chevron upped its offer for the El Segundo, Calif.-based company, thwarting the "substantially completed" draft merger agreement between Unocal and CNOOC, according to a proxy statement Unocal filed July 25 with the Securities and Exchange Commission.

Unocal first agreed to be acquired by Chevron in April for $16.6 billion in cash and stock. Two months later, China's third-largest oil producer offered $18.5 billion in cash, or $67 a share, for Unocal, touching off weeks of negotiations between the companies, as well as a backlash in Congress, where many legislators feared the proposed deal presented risks to America's economic and national security.

While the Chevron proposal had cleared all regulatory hurdles by mid-July, the CNOOC bid was likely to face months of intense scrutiny in Washington.

Unocal wanted the right price

But even though the political backlash complicated the sweetened bid by CNOOC, Unocal says it was ready — for the right price — to try to make it work.

"Unocal's advisors conveyed to CNOOC's advisors their expectation that the Unocal board would be willing to accept the considerably greater degree of transaction risk associated with the CNOOC proposal, as compared with the Chevron transaction, if the board were presented with a CNOOC proposal at a price that could be viewed as sufficient to compensate Unocal's stockholders for the additional risks," the proxy said.

On July 15, Unocal Chief Executive Charles Williamson conveyed the message directly to CNOOC Chief Executive Fu Chengyu, urging Fu to make his best offer.

CNOOC wanted Unocal to lobby

CNOOC, which had been authorized by its board to raise its all-cash offer to $69 a share, said the next day it would not put any more money on the table unless Unocal agreed to pay the $500 million cost of terminating the Chevron deal and lobby for the deal in Congress.

Unocal demurred.

Nevertheless, "by July 17, Unocal's and CNOOC's advisors had substantially completed negotiation of the key documentation relating to the potential CNOOC transaction," the proxy said. That same day, Williamson called Chevron Chief Executive David O'Reilly to notify him of "the likelihood that, absent an improvement in the terms of the Chevron merger, the board would be inclined to change its recommendation."

But that never happened.

On July 19, Chevron raised its cash-and-stock offer to about $63 a share from around $60.50, and the next day, Unocal's board accepted the higher offer and recommended shareholders approve it.

Unocal shareholders are scheduled to vote on the offer Aug. 10. ●

KENAI, ALASKA

Gov says little interest in bullet gas line

Alaska Gov. Frank Murkowski told a gathering in Kenai, Alaska, that keeping large consumers of natural gas in the Cook Inlet basin improves the chances of building a pipeline to deliver North Slope gas to the region.

But when the governor was asked why a pipeline from the North Slope to Cook Inlet was not "already halfway finished," he said there is nobody interested in building it.

"The state is not in the business of competing with the private sector," Murkowski said July 21 at the Kenai Visitors and Cultural Center.

Southcentral Alaska faces gas shortages as early as 2009.

Murkowski was in Kenai to talk about Agrium's North Kenai fertilizer plant and sign three bills. Agrium announced July 14 it postponed the plant's closure for one year because it negotiated a one-year supply of natural gas. The plant needs more gas to stay open.

ANGDA would build as fallback

The Alaska Natural Gas Development Authority, a state corporation, has focused its energy on building a spur pipeline that branches off of a main line to the Midwest. ANGDA has said it would be interested in building a North Slope to Cook Inlet "bullet" line as a fallback position.

The time frame for building a spur line depends on how soon a main pipeline can be built. Harold Heinz, chief executive officer for the ANGDA, said a bullet line could be built in five to seven years.

Murkowski spokesperson Becky Hultberg said Murkowski believes a spur line is a good option because there already would be an infrastructure in place if a main line to the Midwest is built. A bullet line would cost more because there are higher capital costs, she said.

A spur or bullet pipeline would bring up to 1 billion cubic feet per day of natural gas to the region. Right now, a little less than half that amount is consumed in the region on a daily basis.

"We're going to do everything we can to maintain an adequate supply (of gas) out of Cook Inlet," Murkowski said. "There's still plenty of gas to be found."

—THE ASSOCIATED PRESS

Companies involved in Alaska and western and northern Canada's oil and gas industry

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Business Spotlight

By PAULA EASLEY


FORREST CRANE

Lance Leibole, Senior Project Manager

Nabors Drilling USA

Nabors Drilling is known worldwide for its first-class drilling and workover rigs that are designed to fit specific needs of the harsh environments in which they operate. The company's talented, energetic employees live up to the challenge of delivering safer, more cost-effective operations with each well drilled.

If you've been missing Lance Leibole, who's worked for Nabors Alaska for more than 17 years, he flew the coop and is now a Senior Project Manager for Nabors in Houston. Lance and his wife Laurie lived in Alaska 40 years. He wanted to give a fond farewell to his Alaska friends and coworkers and let them know they'll be missed. You can reach him by phone at 281-775-4923.


FORREST CRANE

Charles Lovelace,
Operations Manager

Alaska Rubber & Supply Inc.

Alaska Rubber supplies in state companies with industrial and hydraulic hose and fittings. It specializes in 24-7 customer service and support. Customers range from the airline industry to local banks and everyone in between. Solving what frequently can be "pretty bizarre problems" keeps the operations people on their toes.

Charlie Lovelace joined Alaska Rubber & Supply 17 years ago — the year before the Exxon Valdez oil spill. He learned about the industry very quickly. Charlie's a single dad with two wonderful daughters, Courtney 13 and Coralaine 11. Snowmachining, boating, biking and hiking are favorite activities the family shares. His goal is for the girls to enjoy a safe, secure life.

ALASKA

NPR-A south scoping meetings postponed

The Bureau of Land Management's Alaska State Office has postponed scoping meetings for the southern portion of the National Petroleum Reserve-Alaska.

BLM's Alaska State Director Henri Bisson said in a July 22 statement that attendance at scoping meetings held so far has been light because of subsistence gathering in Alaska. The meetings had been scheduled in July and early August, with the scoping period scheduled to end Aug. 26.

The scoping timeframe will be adjusted to accommodate the delay in the meetings; new meeting dates will be announced later.

The southern portion of NPR-A has 9.2 million acres of public land. The scoping meetings are for a plan to guide management of resources and programs in the planning area.

CANADA

Albertans have been drillin' in the rain

All-time record rainfalls in parts of Alberta during June were not enough to wash away a strong first-half drilling performance.

And what ground was lost is being rapidly recovered this month, with a record 568 rigs at work in mid-July, or three-quarters of the available fleet, an unprecedented showing for the height of summer.

However, the Canadian Association of Oilwell Drilling Contractors has been forced to revise its 2005 prediction to 24,099 wells — still a record — from its target of 24,205 set in October 2004.

To the year's midpoint, operators completed 10,158 wells, just 2 percent behind the benchmark 10,349 in the same period last year, with June's tally off sharply at 1,276 finished wells from 1,883 a year earlier.

But the intentions were signaled in the 2,476 well permits approved in June, edging ahead of the 2,363 issued in June 2004.

Alberta logged 7,932 completions for the six months, only 1 percent short of the 2004 mark, but June tumbled by one-third to 981.

Saskatchewan also suffered from soggy conditions, lowering its first-half count to 1,257 from last year's 1,369 and British Columbia backed off slightly at 871 well from 881. Member companies of the drilling contractors' association reported 19,783 operating days in the second quarter, 16 percent ahead of 2004, but typically less than half the peak winter quarter's tally of 40,359.

Leading the contractors were Precision Drilling, which worked on 3,164 wells in the January-June period, trailed by Ensign Drilling at 2,210.

EnCana led the pack of 412 operators, posting 2,105 completions or one-fifth of the industry total, reporting a pace-setting 320 exploratory gas finds.

Next were Canadian Natural Resources at 739 wells and Husky Energy at 598.

The busiest explorers were EnCana, which racked up 1.53 million feet of hole, trailed by Burlington Resources Canada with 788,000 feet, Devon Canada with 628,000 feet, Canadian Natural with 606,000 feet, Apache Canada with 545,000 feet and Husky with 487,000 feet.

—GARY PARK

● VALDEZ, ALASKA

Error puts two tankers in Valdez Narrows

THE ASSOCIATED PRESS

A procedural error moved two tankers loaded with crude oil from the North Slope into a navigational bottleneck known as the Valdez Narrows, violating federal regulations that say only one ship at a time should sail through the waterway.

A U.S. Coast Guard commander said the ships, one trailing the other, never came dangerously close to one another.

The primary purpose of the regulations is to make the Narrows essentially a one-way street — with no chance of an empty, inbound tanker crowding or running head-on into a loaded tanker heading out of Valdez.

But the regulation also bars two tankers traveling in the same direction from entering the Narrows together, Gardiner said.

The Narrows is a particularly dangerous place for mariners, as maneuvering room is tight and the tankers need lots of water to turn or to stop in case of an emergency. At its most narrow point, the waterway is less than a mile wide.

The miscue on July 10, raises a red flag with a Valdez-based oil industry watchdog organization, which worries about how tanker traffic is managed in Prince William Sound.

"The fact that the system slipped up is what makes us nervous," said Stan Jones, spokesman for the Prince William Sound Regional Citizens' Advisory Council. The council was formed by congressional mandate after the 1989 Exxon Valdez oil spill.

Second clearance was in error

According to the Coast Guard the tanker SeaRiver Baytown — which carries oil for Exxon Mobil — received permission from the Coast Guard's Vessel Traffic Center in Valdez to depart from the dock.

A second ship, the Polar Adventure owned by Conoco Phillips, received the same permission 25 minutes later.

The two ships, each escorted by powerful tugboats, sailed west through the Port of Valdez toward the Narrows, a rock-studded four-mile channel leading to Prince William Sound.

Each ship required a second clearance from the Coast Guard to enter the Narrows. The regulations specify that only one large ship is allowed to travel through the channel at a time.

The Coast Guard gave the first ship, the Baytown, permission to go through. A watch supervisor in the Vessel Traffic Center focused his radar on commercial

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FUTURES

In London, the September contract for Brent crude on the International Petroleum Exchange gained 19 cents to $58.20 a barrel.

Oil prices are about 40 percent higher than a year ago. The U.S. weekly inventory data, released July 27, showed a decline in domestic inventories of crude oil last week but an increase in the supply of distillate fuel, which includes heating oil and diesel. But the weekly report showed a somewhat larger-than-expected drop in the nation's commercial supply of gasoline.

The Department of Energy's statistical office, the Energy Information Administration, said it revised upward its total demand figures for last year and said it could do the same for this year as well.

"Revisions are the norm," the EIA said, adding that "higher final 2005 numbers are likely." That seems to run counter to recent projections by the Paris-based International Energy Agency and the Organization of Petroleum Exporting Countries, which have cut forecasts for world oil demand growth, citing weaker-than-expected consumption in China that sent prices downward.

"The 2004 revision comes at a time when demand growth appears (to some) to be unchecked by higher oil prices," the EIA said in its report. "Because this seems counterintuitive to some analysts, there may be some tendency to view revised 2004 data-based comparisons as signaling a demand slowdown, partially attributable to high oil prices."

The midweek data snapshot showed crude oil stocks fell by 2.3 million barrels to 317.8 million barrels, or 7 percent above year-ago levels.

—THE ASSOCIATED PRESS

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AURORA

"It's an onshore offset to the Cosmopolitan play … and we're going to use an existing pad," he said.

Jones said Aurora is looking for a partner on the Kenai. "No deals yet," he said, "but we expect that we will probably drill an oil well there within the next year for sure, maybe within the next six months."

Pfoff said Aurora is "trying to bring up an industry partner … somebody that's probably not a current player in Alaska," as a partner on the Kenai oil prospect.

It's 70 miles to the Tesoro refinery, Jones said, noting this is the same problem ConocoPhillips faces at Cosmopolitan.

"We are just south (of Cosmopolitan) right at Anchor Point," he said, "… If we should make a discovery that would certainly make a pipeline look more feasible to ConocoPhillips."

Aurora hasn't given up on the peninsula, Jones said, but has "plenty to do" across Cook Inlet on the west side. "Right now we can get things on stream almost immediately there, so it makes a lot more sense to develop what we're doing there."

Aurora has also picked up acreage a little further north on the west side.

"We're looking at that area as well," Jones said. "We're interested in whatever's on that side … Again, trying to position ourselves so that every year we'll have work to do." Work on newer leases to the north, he said, would be "several years away yet."

West side advantages

In the west side area the company is working now, "we're within six miles of infrastructure most of the time," Boelens said. By staying close to its own infrastructure the company can get new production hooked up quickly.

There are also a lot of existing roads on the west side, he said, put in originally for oil exploration and later for logging. If a pipeline can be laid out along a road, he said, it goes pretty fast: you lay the pipe out on the road and weld it up.

The trick, Jones said, is to avoid wetlands. "… construction is easier if you avoid the wetlands, so we'll lay 10-20 percent extra pipe to avoid some wetlands, because it makes sense to do that."

The west side season runs from about April to November.

If you go into December, Jones said, "then on the west side of the inlet you have the ice in the inlet," and you can't always get barges in and out. "And we rely on barging to get in and out." The other issue is that the rig isn't "winterized for zero-type temperatures."

Boelens said they can work in freezing temperatures, "but we don't want to do 10 below." You can get a lot of work done, he said, starting in April and running into November or December. You avoid the coldest weather in winter, Boelens said, "then you start back up in the spring and plan your work and get your program lined up … and just go from one to the other. And that is what we're doing."

The logistics of west side work require some planning to get equipment barged in, Jones said, and makes costs 20-25 percent higher than they would be on the Kenai Peninsula. They barge in primarily from Nikiski, sometimes from Homer or Anchorage. ●

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HUBS

potential arrangements to get some large new field wildcats on the schedule," said David Hager, Kerr-McGee's chief operating officer. He said that at least one of them likely would be spud before year-end.

Reserve estimates for Claymore, on Atwater Valley block 96, range from 40 million to 300 million barrels of oil equivalent, Hager said, adding that the play is similar to Tahiti in nearby Green Canyon, among the larger oil discoveries in deepwater U.S. Gulf.

Mission Deep, on Green Canyon block 955, is said to hold estimated reserves ranging from 80 million to 250 million barrels of oil equivalent. Norman, with reserve estimates of 120 million to 300 million barrels of oil equivalent, is on Garden Banks block 435.

"Those will not be the primary reserve booking opportunities, but they are the large new field wildcat opportunities that can be new hubs in the future," Hager said.

Some reserve bookings this year

He said Kerr-McGee has several "moderate size" prospects in the U.S. Gulf that could provide additional reserve bookings as soon as this year, including Nansen Northwest, Castleton, Covington, Doubloon and Conquest. Kerr-McGee recently spud an appraisal well at the Conquest discovery, located in Kerr-McGee's Constitution corridor at Green Canyon Block 767.

"Some of those (such as) Covington are a little bit on the larger size, on the order of 80 to 200 million barrels," Hager said. "The others are more moderate size and will be our primary booking opportunities."

Meanwhile, Kerr-McGee reported net income for the 2005 second quarter of $370.8 million or $2.60 per share, a more than three-fold increase over $110.6 million or $1.01 per share the company earned in the 2004 second quarter.

The increase in profit was attributed largely to higher oil and natural gas prices during this year's second quarter and higher production and increased profits from its chemical unit. The higher oil and gas sales volumes were attributed primarily to the acquisition of Westport Resources and production start ups in China's Bohai Bay and at the Red Hawk field in deepwater U.S. Gulf.

Kerr-McGee's oil production in the 2005 second quarter rose 25 percent to average 175,000 barrels per day, compared with 140,500 barrels per day for the same period last year. Natural gas sales averaged 1.118 billion cubic feet per day, up 51 percent from the 2004 second quarter. ●

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ERROR

fishing vessels to see that they cleared out of the tanker's path.

Subsequently, the supervisor realized he'd made a mistake by giving the trailing tanker, the Polar Adventure, permission to enter the Narrows before the Baytown had exited.

As it turned out, both ships sailed on through the Narrows without incident, never coming closer to one another than about two miles, said Cmdr. Michael Gardiner, who heads the Coast Guard's Marine Safety Office in Valdez. Tankers have seen trouble in the Narrows before. In July 2001, escort tugs had to haul an oil tanker to a stop to avert a possible collision with a salmon seiner that was in the way. ●

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RIG

the personnel in those three companies to design this rig," Sheffield said. "… It is a fit-for-purpose rig, designed to drill exploration wells on the North Slope of Alaska."

Lightweight design

The rig's lightweight design involves a 400,000-pound rated double mast that reduces the derrick height to about two-thirds that of a typical triple-mast North Slope rig; the double mast derrick handles two joints of drill pipe rather than the three joints of a triple mast derrick. The double-mast configuration is suitable for exploration drilling where long lateral well are not required, Sheffield said.

"It's very common onshore … to drill with a double," Sheffield said.

Using 4-inch or 4.5-inch drill pipe, the new rig will drill routinely to 10,000 feet and could drill to 12,000 feet, depending on the casing and well bore designs, he said.

In fact the rig's design team considered several pipe diameter options for the type of exploration work that Pioneer anticipates — the team determined that relatively small diameter piping would achieve an effective balance between rig size and well depth.

"Five inch was for a long time the standard across the slope," Vance Hazzard, Pioneer's Alaska drilling superintendent, said. "(4 inch) works out great for the hole sizes that we're looking at."

Truckable modules

The rig can break down into many small modules for easy portability — an in-line layout design coupled with a telescoping mast helps allow the rig to split into 35 individual loads, each of which will fit onto a conventional truck. The rig is highway transportable and could be moved to places in Alaska with road access during the summer, Sheffield said. Even on the slope the new rig will prove much more mobile than the large development-oriented rigs that have characterized North Slope drilling, he said.

"This rig will move in loads of approximately 100,000 pounds which is considerably lighter than the existing rigs on the slope," Sheffield said. "(The existing rigs), they're quite mobile if they're on a gravel pad moving a short distance to drill the next well. But if you try to take one of those rigs and move a long distance they're quite heavy and relatively time consuming to move."

Less ice road construction

A reduction in the need for heavy-duty ice roads should also prove to be a big pay off in the use of the new rig.

"We are confident that this lighter rig will require considerably less ice construction because of the much lighter loads," Sheffield said. "… Considerably less ice is required to support 100,000 pounds than is required to support 1.5 million pounds (for a development rig)."

Also the rig will not require the same road width as a conventional North Slope rig.

"The other thing is that the North Slope rigs are all much wider — they're set up for 30 to 35-foot wide roads and in general we can get by with as little as 16 to 20-foot road," Hazzard said.

What's more, the trucks carrying the rig modules will be able to cross the tundra on snow roads, Hazzard said. Snow roads don't need water to make ice and are quicker and cheaper to build than ice roads.

We're working through a snow road concept that uses densified, processed snow, Hazzard said. Using a truck "the densified snow has enough strength to keep you off the tundra," he said.

Even over water, where ice roads will still be necessary, the loads will not require the same thickness of ice that a conventional rig needs. A typical development rig would require 7 or 8 feet of ice to go over a flowing river or over sea ice — for our load we would be looking at 4 feet, Hazzard said.

"And we have much more flexibility with the road layout than you do with the large rigs," he said. A development rig needs a very wide road without much slope but a truck can handle bigger grades and go round sharper curves, he said.

Multiple wells per season

Simplified road construction and the ability to move the rig quickly will enable Pioneer to drill multiple wells in a single winter season. And, given the fixed costs inherent in mobilizing a rig for a drilling season, drilling multiple wells will translate directly into less cost per well.

"We're hopeful that we'll be able to move this rig in three or four days from location to location," Sheffield said. "… We feel fairly confident that we can drill four wells in a season and once we get our legs and our operations under way we're hopeful that we'll be able to drill five wells per season.

"We need to get the rig up here and shake it out and get some experience under our belt and prove what we can do."

But, although this purpose-built exploration rig can't drill the deep development wells or long horizontal wells of the more conventional North Slope rigs, Sheffield thinks that the cost reductions that rig will achieve will more than compensate for any limitations.

"There aren't any easy wins out there from a cost reduction standpoint so you have to find a number of different ways to save money to make it add up to a significant issue," he said. ●

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TERMINAL

the LNG to save 2 million gallons of water now used each day in the cooling system.

In addition, a recovery unit for natural gas liquids will be included in the complex, so the chemical plant will be able to get some of its feedstock from the LNG.

That helps two ways. If the high-BTU liquids aren't pulled out of the natural gas stream, it can be too potent for normal utility lines, and so nitrogen or another diluting gas has to be added.

As part of the proposal, San Patricio Pipeline will build and operate a 26-inch gas line that will run 26 miles to connect to major interstate trunk lines.

Occidental already owns the site where the terminal will be built. The total project is expected to cost about $450 million.

—ALLEN BAKER

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INSIDER

ed" to begin in August and "expected to conclude within four months."

The governor's office is looking for an Alaska firm and the project would require a full-time staff including a senior level account supervisor, media relations specialist, copywriter, art director, media buyer and scheduler.

The firm must have the ability to sign a confidentiality agreement and "may not have a current relationship with a company in negotiations with the state on the gas pipeline or with a company who is seeking to acquire North Slope gas," the state said.

Experience in statewide multi-media public policy campaigns is required.

The firm selected must be able to begin work in August to develop an education/awareness campaign and will design and produce all communication tools — including print, radio and TV ads; brochures; electronic presentations; media relations plan; and a statewide speakers bureau.

There will be hearings on a proposed contract and public comments will be taken. Based on those comments, the state may renegotiate.

A final contract will go to the Alaska Legislature for an up or down vote, expected in a special session later this year.

So far, so good for Mackenzie deals

IT'S ONE THING TO TALK OF A NEW HIGHWATER MARK for the Mackenzie Gas Project and another to wait for the backwash.

For decades the dream of exploiting Canada's Arctic natural gas has been a litany of hopes raised, hopes dashed.

But the latest chance for optimists to be — well, optimistic — is holding firm.

The response to a flurry of pivotal developments in mid-July has largely been low-key, which is exactly what the proponents might have hoped for.

Governments, community groups and aboriginal leaders have, with few exceptions, accepted the deals that saw the Deh Cho First Nations drop their lawsuits and the Canadian government offer C$500 million over 10 years to the Northwest Territories government and aboriginals along the pipeline route.

How well those pacts hold together is key to keeping the project on track for a start of regulatory hearings this year and possibly achieving a 2010 start-up of operations.

Publicly declared opposition to the federal allocation to meet social and economic needs stemming from the pipeline has been confined to some social groups.

Barbara Saunders, executive director of the NWT Status of Women Council, said she could not accept that the money would be allocated in return for support of the pipeline — a condition she did "not want to believe is true."

Other social organizations are less than enthused about the linkage of socio-economic handouts and the pipeline, arguing the money was needed regardless of the C$7 billion project because of rising drug and alcohol problems, education and health needs.

A spokesman for federal Deputy Prime Minister Anne McLellan agreed that the problems exist regardless of the pipeline, but the government is concerned to prepare now for any negative impacts from the pipeline.

He said Ottawa wants to strike a balance between what is needed now and what will be needed once the pipeline is operating. ●

Editor's note: Oil Patch Insider is written by Gary Park and Kay Cashman. News tips can be emailed to publisher@PetroleumNews.com.

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CBM

oping the Mannville formation, which stretches across central Alberta and is rated as the largest coalbed methane play in North America at an estimated 300 tcf.

The partnership expects to invest C$400 million in the next 18 months exploiting potential recoverable resources of 412 billion cubic feet, part of a greater area holding 4 tcf, of which 1 tcf is rated as economically recoverable.

Nexen is targeting 150 million cubic feet per day of coalbed methane production by 2011, matching Canada's current total output.

Formation more difficult than U.S. coal seams

But getting to this point has not been easy because the Mannville formation is described by Trident President Jon Baker as more difficult than the U.S. coal seams, of which only 10 percent are considered economic.

Baker downplays suggestions that once Mannville is into commercial production it will be easier for other companies, arguing that the Horseshoe Canyon formation, which extends from central Alberta down the middle of the province and into Belly River play in the southeast corner and has reserves of about 70 tcf, is still a better bet.

The industry apparently shares that view, according to Alberta Energy and Utilities Board data showing that 90 percent of Alberta's coalbed methane wells have been drilled in Horseshoe Canyon and Belly River and only 7 percent in Mannville.

While Alberta tries to close a 20-year gap in coalbed methane production enjoyed by the U.S. and scientists work to crack the code of complex geology, the Alberta government has high hopes for coalbed methane.

CBM could extend gas production

Energy Minister Greg Melchin told the Financial Post that coalbed methane could extend the province's gas production into the next century.

He said Alberta is "clearly on the cusp of something large."

The National Energy Board has projected coalbed methane production of 500 million cubic feet a day by the end of 2005 to 3 billion cubic feet per day (one-fifth of current volumes) within two decades.

The sector is already on the path to that goal, with coalbed methane drilling accounting for 15 percent of Western Canada's wells, up from virtually nothing three years ago.

Based on current commodity prices of US$7.50 per thousand cubic feet and the gas-strapped outlook for North America, the economics are also promising, with FirstEnergy Capital, the Calgary-based investment dealer, calculating that gas prices of only US$4.25 can yield a return on coalbed methane of 10 percent.

Water from formation a concern

But coalbed methane poses a worry. Although the Horseshoe Canyon coals are relatively dry, the Mannville zone involves producing large volumes of water to the concern of environmentalists, land owners and farmers.

The Alberta government answered those concerns in late 2003 by naming a multi-stakeholder advisory committee to gather information and hold public hearings on whether and how coalbed methane development should proceed.

Working groups from the committee delved into water, surface, air, royalties and tenure issues, with water emerging as clearly the key issue for Albertans.

In preliminary findings issued in mid-July, the committee surprised some by recommending lower provincial royalties for up to five years on coalbed methane wells drilled in the Mannville formation to promote development of the resource.

It urged the government to "increase the opportunity for education and public awareness of the possible effects of coalbed methane development, calling on the Alberta Energy and Utilities Board and Alberta Environment to make a joint effort to consolidate coalbed methane data.

Recommendations to protect environment

But the committee also recommended action on several fronts to protect the environment, including:

- Standard procedures for sampling, analyzing and monitoring saline and non-saline water quality and quantity for coalbed methane wells and for potentially affected non-saline water wells.
- Review drilling and completion practices for new and re-completed water wells and "energy" wells, to ensure regulations are appropriate for the purpose of the well concerned.
- Consultations with coalbed methane operators and drilling contractors about current and future requirements to protect non-saline aquifers.
- Investigations to determine whether coalbed methane drilling and completion practices may affect aquifers and review regulations to decide whether changes are needed.
- A review of existing requirements for the deep-well disposal of non-saline produced water and to consider appropriate alternatives.
- Establish criteria for the beneficial use of non-saline produced water.
- Review the regulatory process for new ways to support minimal surface disturbance and reduced cumulative impact associated with coalbed methane development.

The Pembina Institute for Appropriate Development flatly opposed any lowering of royalties, arguing that industry "should bear the full cost of development, since any form of subsidy distorts the playing field with respect to renewable energy," said Mary Griffiths, the institute representative on the government-appointed committee.

She noted that industry has already embarked on pilot projects in the Mannville formation "without royalty reductions."

Kim Chow, chairman of the Canadian Society for Unconventional Gas, argued that the preliminary findings reflect a "good balance" of viewpoints.

Chow's predecessor, Michael Gatens, chairman and chief executive officer of coalbed methane producer MGV Energy, insisted the industry was not looking for a handout, but he noted that Mannville is a much more difficult formation than Horseshoe Canyon and might need incentives before companies will take the risk and spend more money to develop the resource. ●