Petroleum news

page 5 Survey shows oilfield service companies on the rebound

Vol. 9, No. 27 • www.PetroleumNews.com

North America's source for oil and gas news

Week of July 4, 2004 • $1

KKPL extension pipe heads south

FORREST CRANE

Pipe for Unocal's extension of the Kenai Kachemak Pipeline, brought to Alaska by CN Aquatrain on 34 89-foot flatcars, is loaded at North Star Terminals for trucking by Carlile and Sourdough Transport. The Kenai Kachemak Pipeline began moving gas from the Marathon-Unocal Ninilchik unit in September, and Unocal expects the extension to begin moving gas from its Happy Valley gas discovery in the Deep Creek unit east of Ninilchik this fall. The pipeline will be buried in existing road rights of way for most of its length, primarily along Oilwell Road.

Shell, St. Mary taking hard look at Alaska

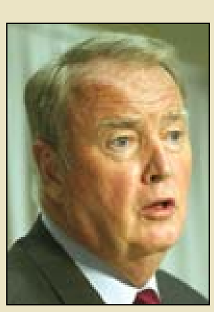
1 2 SERIES

The number of serious inquiries from oil and gas companies coming into the Alaska Division of Oil and Gas has increased in the last seven months, division director Mark Myers told Petroleum News June 30.

"It started with the meetings Gov. (Frank) Murkowski hosted in Juneau late last year," for key Alaska explorers and potential explorers, he said. The purpose of those meetings was to encourage more exploration in the state.

The governor is planning to make a

see **LOOK** *page11*



JUDY PATRICK

FRANK MURKOWSKI

FORREST CRANE

MARK MYERS

● CANADA

Election results troubling to Canada's oil industry

Liberal party needs opposition support to govern; forging alliances could slow progress on major projects, including Mackenzie gas development

By GARY PARK

Petroleum News Calgary Correspondent

In the fallout from Canada's June 28 federal election, the oil patch is in a jittery state, worried about the consequences for a host of big-ticket items — notably the Mackenzie Gas Project, British Columbia offshore, East Coast offshore, Alberta's oil sands and the sale of the government's 19 percent stake in Petro-Canada.

The vote left Canada without a majority government for the ninth time in its 137-year history, as the Liberals under Prime Minister Paul Martin captured only 135 of 308 seats in the House of

see **RESULTS** *page 16*

CANADA LIBRARY OF PARLIAMENT

Canada's House of Commons

● GULF OF MEXICO

Thunder booms over Thunder Hawk prospect

Gulf of Mexico oil discovery uncovers 300 feet net pay in two high-quality zones

By RAY TYSON

Petroleum News Houston Correspondent

Owners of the closely watched Thunder Hawk prospect in the deepwater Gulf of Mexico say additional exploratory drilling has turned up about 300 feet of net oil pay capable of producing upward of 150 million barrels of equivalent.

Thunder Hawk is located in Mississippi Canyon on the northeast fringe of the BP-operated Thunder Horse field complex, the largest discovery in Gulf history at a reported 1.4 billion barrels of recoverable oil.

> *"We are very encouraged by the results of the sidetrack well and are assessing delineation drilling options."*
> **—Duane Radtke, Dominion Exploration CEO**

Thunder Hawk owners Dominion Exploration, Murphy Oil, Spinnaker Exploration and Pioneer Natural Resources went into their drilling venture believing they had a piece of Thunder Horse, 75 percent owned by BP and 25 percent by ExxonMobil.

Operator Dominion hinted at a significant discov-

see **THUNDER HAWK** *page 19*

● ANCHORAGE, ALASKA

B.C. looks to provide good 'golden goose' habitat

By KRISTEN NELSON

Petroleum News Editor-in-Chief

Alaska has been told that it has competition for oil and gas investment — but how often does it get to hear from one of its competitors? In June the Alaska State Chamber of Commerce heard firsthand what British Columbia has done in the last fours years to attract oil and gas investment: investment which more than doubled the number of wells being drilled in the province, from fewer than 650 in 2001 to more than 1,300 this year, and brought royalty revenue to C$2 billion per year.

British Columbia elected a new Liberal government in 2001, and that government wanted the province to be more competitive for oil and gas projects. The province's Division of Oil and Gas got its marching orders — from the

see **HABITAT** *page 18*

FORREST CRANE

Ross Curtis, assistant deputy minister, British Columbia

BREAKING NEWS

Alaska - Mackenzie Rig Report

The Alaska - Mackenzie Rig Report as of July 1, 2004.
Active drilling companies only listed.

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

This rig report was prepared by Wadeen Hepworth

Alaska Rig Status

North Slope - Onshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Doyon Drilling			
Dreco 1250 UE	14 (SCR/TD)	Milne Point, reentry MPJ-25	BP
Sky Top Brewster NE-12	15 (SCR/TD)	Deadhorse yard	Available
Dreco 1000 UE	16 (SCR)	W pad workover W-11	BP
Dreco D2000 UEBD	19 (SCR/TD)	Alpine, drilling CD2-53	ConocoPhillips
OIME 2000	141 (SCR/TD)	Infield Kuparuk, drilling 1E-112 multilateral	ConocoPhillips
Nabors Alaska Drilling			
Trans-ocean rig	CDR-1 (CT)	Stacked, Prudhoe Bay	Available
Dreco 1000 UE	2-ES (SCR)	Prudhoe Bay, C-24A	BP
Mid-Continent U36A	3-S	Prudhoe Bay, 3H-05	ConocoPhillips
Oilwell 700 E	4-ES (SCR)	Prudhoe Bay, J-07A	BP
Dreco 1000 UE	7-ES (SCR/TD)	Prudhoe Bay, A-30	BP
Dreco 1000 UE	9-ES (SCR/TD)	Prudhoe Bay, V-01	BP
Oilwell 2000 Hercules	14-E (SCR)	Stacked, Deadhorse	Available
Oilwell 2000 Hercules	16-E (SCR/TD)	Stacked, Prudhoe Bay	Available
Oilwell 2000	17-E (SCR/TD)	Stacked, Point McIntyre	Available
Emsco Electro-hoist -2	18-E (SCR)	Stacked, Deadhorse	Available
OIME 1000	19-E (SCR)	Stacked, Deadhorse	Available
Emsco Electro-hoist Varco TDS3	22-E (SCR/TD)	Stacked, Milne Point	Available
Emsco Electro-hoist	28-E (SCR)	Stacked, Deadhorse	Available
OIME 2000	245-E	Stacked, Kuparuk	Available
Nordic Calista Services			
Superior 700 UE	1 (SCR/TD)	DS 15-46-L1	BP
Superior 700 UE	2 (SCR)	Endicott, L-2-21A	BP
Ideco 900	3 (SCR/TD)	Meltwater, 1-G-08	ConocoPhillips

North Slope - Offshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Nabors Alaska Drilling			
Oilwell 2000	33-E (SCR/TD)	Stacked, NorthStar	BP
Emsco Electro-hoist Canrig 1050E	27-E (SCR/TD)	Stacked at 12-acre pad	Kerr-McGee

Cook Inlet Basin – Onshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Aurora Well Service			
Franks 300 Srs. Explorer III	AWS 1	Granite Point, drilling Kaloa #2	Aurora Gas
Evergreen Resources Alaska			
Wilson Super 38	96-19	Stacked in Wasilla yard	Evergreen Resources Alaska Corporation
Inlet Drilling Alaska/Cooper Construction			
Kremco 750	CC-1	Stacked, Kenai	Forest Oil
Kuukpik	5	Happy Valley #7	Unocal
Marathon Oil Co. (Inlet Drilling Alaska labor contractor)			
Taylor	Glacier 1	Scheduled maintenance	Marathon
Nabors Alaska Drilling			
Rigmasters 850	129	Kenai, Red #1	Unocal
National 110 UE	160 (SCR)	Stacked, Kenai	Available
Continental Emsco E3000	273	Stacked, Kenai	Available
	51	Steelhead platform, done 12-1-03	Unocal
IDECO 2100 E	429E (SCR)	Stacked, removed from Osprey platform	Available
Water Resources International			
Ideco H-35 KD		Prep to resume operations	Pelican Hill

Cook Inlet Basin – Offshore

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

Mackenzie Rig Status

Mackenzie Delta-Onshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
AKITA Equtak			
Dreco 1250 UE	62 (SCR/TD)	Stacked Tuktoyaktuk, NT	EnCana
Dreco 1250 UE	63 (SCR/TD)	Stacked, Lucas Point, NT	Chevron Canada
National 370	64	Stacked, Inuvik, NT	Available

Central Mackenzie Valley

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
AKITA/SAHTU			
Oilwell 500	51	Stacked in Norman Wells, NT	Available
Nabors Canada			
	62	Racked	Available

Grayling platform COURTESY OFFSHORE DIVERS

Baker Hughes North America rotary rig counts*

	June 25	June 18	Year Ago
US	1,176	1,171	1,074
Canada	334	196	310
Gulf	92	93	101

Highest/Lowest

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

*Issued by Baker Hughes since 1944

Rig start-ups expected in next 6 months

Rig Owner/No.	Rig Location/Activity	Operator
Aurora Gas		
AWS1	Will be moving to Kaloa 3 and then to Long Lake 1 for a re-entry	Aurora Gas
XTO Energy		
A & C	The rig on platform C will be reactivated in July 2004.	XTO

WASHINGTON, D.C.

EPA agrees to break logjam on Gulf of Mexico permits for oil and gas leases

The U.S. Environment Protection Agency apparently has decided to begin renewing water discharge permits for oil and gas leases in the Western and Central Gulf of Mexico, breaking a serious logjam that threatened drilling activities in the region.

Congressman Chris John of Louisiana said he urged Administrator Mike Leavitt last week to immediately renew permits necessary for offshore operators to discharge water produced from drilling activities.

"Energy prices are high, demand continues to grow, and jobs are being lost," John said.

He said the EPA on July 1 posted a notice in the Federal Register related to discharge permits and assured "expedited consideration of these permits so companies may resume business immediately." However, the notice requires a 30-day comment period.

Chris Oynes, Gulf regional director for the U.S. Minerals Management Service, told Petroleum News in early May that EPA's decision to hold up permits while it considered a rule change could severely curtail drilling on both new and existing leases in the U.S. Gulf.

He said MMS vigorously resisted EPA on the issue, asserting that EPA delay in issuing water discharge permits to many operators was "creating a cascading effect" and "affecting more and more leases."

The problem began last November when EPA's general discharge permit for many operators in the U.S. Gulf expired. In addition to existing leases, companies awarded tracts in last March's Central Gulf of Mexico lease sale were unable to drill them because EPA was not issuing discharge permits on new leases.

There are more than 7,000 active leases in the Gulf containing more than 4 billion barrels of proven oil reserves and 24 trillion cubic feet of natural gas.

—RAY TYSON, Petroleum News Houston correspondent

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Petroleum news

North America's source for oil and gas news

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Petroleum News and its supplement, Petroleum Directory, are owned by Petroleum Newspapers of Alaska LLC. The newspaper is published weekly. Several of the individuals listed above work for independent companies that contract services to Petroleum Newspapers of Alaska LLC or are freelance writers.

Petroleum News (ISSN 1544-3612) Week of July 4, 2004
Vol. 9, No. 27
Published weekly. Address: 5441 Old Seward, #3, Anchorage, AK 99518
(Please mail ALL correspondence to:
P.O. Box 231651, Anchorage, AK 99523-1651)
Subscription prices in U.S. — $52.00 for 1 year, $96.00 for 2 years, $140.00 for 3 years. Canada / Mexico — $165.95 for 1 year, $323.95 for 2 years, $465.95 for 3 years.
Overseas (sent air mail) — $200.00 for 1 year, $380.00 for 2 years, $545.95 for 3 years.
"Periodicals postage paid at Anchorage, AK 99502-9986."
POSTMASTER: Send address changes to Petroleum News, P.O. Box 231651 • Anchorage, AK 99523-1651.

MOSCOW, RUSSIA

Russian Tax Service US$3.4 billion bill against Yukos comes into force

A Russian court delivered a hard blow to the Yukos oil giant June 29, upholding a US$3.4 billion tax bill and bringing the beleaguered oil company a big step closer to insolvency.

Yukos, Russia's second-largest oil producer, has three months to pay the bill or it may face bankruptcy proceedings. But despite the major setback, the market reacted calmly, apparently hoping that the Kremlin will intervene in what many allege was a politically motivated assault from the beginning.

The tax case was just one of a myriad of claims against Yukos and its former CEO, Mikhail Khodorkovsky. Analysts see the web of court cases as a Kremlin-directed move to punish Khodorkovsky, Russia's richest man, for his funding of opposition parties and to ensure that such a key firm in Russia's strategically important oil sector is in the hands of someone more loyal.

The Moscow Arbitration Court's decision June 29 gives bailiffs the right to start operations to confiscate Yukos assets from banks as soon as the ruling is published, Yukos lawyer Sergei Pepelyayev said.

"There are illegal decisions and there are blatantly illegal decisions and this is the latter, so we'll recommend that our client appeal," he told The Associated Press.

Lacking the cash to pay the bill upfront and hampered by a court order preventing it from selling its assets, Yukos has also boosted efforts in recent days to seek an out-of-court settlement with the tax agency. But so far, the company says it has received no reply from the government to tentative proposals to stagger its payment over a longer period.

Representatives of the Yukos defense team told the Interfax news agency that the Tax Ministry would receive a writ within one to three days confirming that Yukos does not have sufficient funds to pay the bill — after which court bailiffs could move in. Earlier in June Yukos' chief financial officer Bruce Misamore said that Yukos had only US$1.2 billion to US$1.8 billion of available funds on its balance sheet.

Pepelyayev left open the possibility that an amicable settlement could still be reached. At the same time, Yukos has two months to appeal the ruling to the Federal Arbitration Court of the Moscow Region, and Pepelyayev said that court could decide to suspend any requirements to pay pending a new court decision.

Separately, the Moscow court also decided June 29 to lower the amount of the tax claim by the fractional amount of 32 million rubles (US$1.1 million), Pepelyayev said.

—THE ASSOCIATED PRESS

BRITISH COLUMBIA

B.C. attracts two LNG contenders

A second Calgary-based company has entered the race to build a liquefied natural gas terminal on the British Columbia coast.

Privately owned WestPac Terminals has plans to build the facility near Prince Rupert and import as much as 300 million cubic feet per day.

WestPac President Rob Woronuk told the Financial Post that the terminal will be supplied from Pacific Rim producers, with the gas resold to North American consumers. He would not disclose the projected costs of the venture.

Two months ago, Galveston LNG unveiled plans for an LNG import terminal near Kitimat, about 60 miles south of Prince Rupert.

Preliminary plans call for a C$300 million plant to handle 340 million cubic feet per day, starting in late 2008.

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

CORRECTION

A story in the May 9 issue of Petroleum News about a summary by the Alaska Oil and Gas Conservation Commission of a report on North Slope natural gas sale impacts was misleadingly titled 'Gas sales boost Prudhoe oil output.'

The commission's summary of the Blaskovich Services Inc. report indicated that total hydrocarbon recovery — liquids and natural gas combined — is expected to increase, but that liquids production will decrease with gas sales.

The information on this point in the story was correct.

The story incorrectly stated that in the worst case estimate — a 2010 gas sales start date with nominal off-take of 4.3 billion cubic feet per day from Prudhoe Bay only and no mitigating measures — that field life would not be extended by gas sales. In fact, the study found that all gas sales cases extended field life. The commission's summary said: "The worst case studied for impact on liquid hydrocarbon recovery results from a 2010 gas sales start date, a nominal off-take of 4.3 billion cubic feet per day (pipeline filled by PBU only), no optimization achieved and no extension to field life."

The report found that in comparison to all cases in year 2030, the earliest gas sales case with the highest gas off-take resulted in the lowest liquid recovery. And while in 2030 this earliest gas sales case had the greatest gas recovery, by 2050 total hydrocarbon recovery for all gas sales cases was essentially the same.

The commission's summary incorrectly reported cumulative Prudhoe Bay production as 11.2 billon barrels. The correct number is 10.8 billion barrels (a combination of oil, condensate and natural gas liquids).

● FAIRBANKS, ALASKA

Mining firm making liquid fuel from coal

Silverado pushes its hydrothermal treatment for coal in Asian markets, hopes to build demonstration plant near Fairbanks

By PATRICIA LILES
Mining News Editor

Silverado Gold Mines Ltd., a Vancouver, British Columbia-based gold mining and exploration company, is working to enter a new industrial market with its promotion of a coal treatment process, which produces a liquid fuel capable of being burned in oil-fired power generation plants.

Through its wholly owned subsidiary, Silverado Green Fuel Inc., the company is promoting in Asian markets its hydrothermal treatment process for low-rank or sub-bituminous coal found in huge quantities in Alaska.

According to a June 21 company press release, targeted markets for the coal fuel product are in the Heilongjiang Providence in northern China and the State of Gujarat, on the western side of India. Silverado Green Fuel executive Dr. Warrake Willson, who has previously worked as a University of Alaska researcher on low rank coal water fuels, has been meeting with the potential Asian buyers, according to Silverado's CEO Garry Anselmo.

"Silverado is currently working with a number of organizations to develop funding for a small, 5 to 10 megawatt Silverado Green Fuel-fired power generation plant in the State of Gujarat," the press release said.

Anselmo declined to comment further on developments with the Asian marketing project.

Facility would be shuttered mill

The company also is working to convert its shuttered hard rock gold mill facility, about 10 miles west of Fairbanks on Ester Dome, to a demonstration plant capable of processing low-rank coal into a liquid fuel. "The Grant Mill, situated on the Grant Mine, currently contains much of the necessary equipment and ample space in the building to accommodate the remaining equipment," the press release said.

Anselmo told Mining News on June 25 that estimated costs for that part of the project are about $20 million. About half of that would be required for the additional hydrothermal processing equipment and installation, while the remaining half would be to cover costs to run the project for three years.

"We're pushing to complete a project in the United States," he said. "We've got the drawings, the environmental work finished and are ready to go forward."

He declined to comment further on potential funding sources for that Fairbanks-based project proposal. The company previously sought funding from the U.S. Department of Energy through the Clean Coal Power Initiative, but the project was not selected for research spending.

Editor's note: For more information about this, please look in the July issue of North of 60 Mining News, to be published in the July 11 issue of Petroleum News.

PORTLAND, MAINE

Second of two oil rigs departs Portland

A salute by the Portland, Maine, city fireboat marked the departure of the second of two massive oil exploration rigs, which left Portland Harbor the evening of June 26.

Heavy fog delayed its departure by about two hours, but a small crowd of admirers watched from Portland and South Portland as tugboats moved Pride Portland from its berth. The 12,000-ton rig motored away under its own power shortly after 7 p.m. It was en route to Brazil, where it will drill for oil off the South American coast. Its sister rig, Pride Rio de Janeiro, left in February.

The two-year project was a boon for contractor Cianbro Corp. and the city. Cianbro's $100 million contract created 1,000 jobs, and the city received an additional $2 million in rent.

The rigs were towed to Portland from separate Gulf Coast yards after the companies that were building them sank into bankruptcy.

The massive structures changed the city's skyline and attracted interest from residents accustomed to seeing tankers, warships, tall ships and yachts — but not 319-foot-tall oil rigs — on the waterfront.

"We weren't sure how the city was going to feel about these rigs," said Cianbro spokeswoman Dottie Hutchins.

In the end, people enjoyed watching the progress. Some requested tours.

"One woman e-mailed and said, 'You know, my husband's birthday is next week and the only thing he wants is a tour of the rig,'" Hutchins said. "We took them on a tour."

—**THE ASSOCIATED PRESS**

● HOUSTON, TEXAS

Service companies on the rebound

Survey shows Q2 profits to increase 3.6% from Q1 and over 50% from a year ago

By RAY TYSON

Petroleum News Houston Correspondent

Contract drillers and other oilfield service companies continued their comeback in the 2004 second quarter and are expected to post earnings on average above the prior quarter and well ahead of a year ago.

Profits for the sector should increase about 3.6 percent over this year's first quarter while jumping a hefty 53.5 percent compared to last year's second quarter. Moreover, net income for this year's third quarter is expected to come in about 38 percent higher than the second quarter.

Conclusions were based on a Petroleum News survey of Thompson-First Call analysts' consensus estimates for the 15 leading oilfield service companies.

A consensus estimate represents the average earnings of all analysts polled on a particular company. Individual estimates can be higher or lower than the consensus and tend to change as the reporting season approaches. Estimates generally do not include charges against earnings and other special items.

Contract drillers included in the survey were Transocean, Diamond Offshore, GlobalSantaFe, Rowan, Ensco International, Noble, Parker Drilling and Grey Wolf.

Other oilfield service companies in the survey were Halliburton, Schlumberger, Baker Hughes, Pride International, Smith International, Weatherford International and Varco International.

Only three of 15 in red for quarter

Analysts' estimates for the group indicate that earnings for just three of the 15 companies surveyed, all drillers, fell into the red during the 2004 second quarter.

Analysts' estimates for the group indicate that earnings for just three of the 15 companies surveyed, all drillers, fell into the red during the 2004 second quarter.

Still, those results were an improvement over the first quarter. Moreover, only four of all companies surveyed are expected to post earnings below the first quarter.

Big offshore driller Diamond should show dramatic improvement compared to the prior and year-ago quarters. Net income is expected to be around 1 cent per share in the 2004 second quarter versus a loss of 8 cents per share in the first quarter and a loss of 13 cents per share in last year's second quarter.

Noble could report net income in the recent quarter of about 25 cents per share, up from the prior quarter's 21 cents per share but down from 33 cents per share a year earlier.

Transocean's expected net income of around 10 cents per share for the 2004 second quarter would be below the prior quarter's 15 cents per share but significantly better than last year's second quarter when the company lost 6 cents per share.

Ensco is expected to weigh in with 2004 second-quarter earnings of about 9 cents per share, down from 14 cents per share earned in the prior quarter and down from 18 cents per share in the year-ago period.

GlobalSantaFe's expected profit of 1 cent per share for this year's second quarter would be roughly flat to the 2 cents per share the company earned in the prior quarter. But it would be down considerably from the 19 cents per share the company earned in last year's second quarter.

Parker, Grey Wolf, Rowan expected to show losses

Parker Drilling's financial performance

see **REBOUND** *page 7*

NEWS IN BRIEF

Pan Andean's drilling successful

London-based Pan Andean said in late June that the Vrazel No. 2 well in the Danbury Dome area onshore Texas is capable of producing commercial quantities of natural gas. Pan Andean has a 21 percent interest in the well, which is expected to produce 1.9 million cubic feet of gas per day.

"Drilling confirmed the presence of a number of gas zones. Technical problems greatly delayed the completion process, but now all is in place for commercial production," Pan Andean Chairman John Teeling said.

The Vrazel and nearby Zachry-Korenek No. 1 discovery "bode well for the forthcoming drilling program on our 100 percent owned properties in the Danbury Dome area," he said. Pan Andean expects to make an announcement about the Danbury Dome venture in "coming weeks."

In the next few days Pan Andean will begin drilling offshore in the Gulf of Mexico at its 50 percent owned Hi Island A-68 Block, Teeling said.

—PETROLEUM NEWS

Rivals team up on production information

Four of Canada's biggest energy companies have shifted from competition to cooperation by launching a new computer system for measuring oil and gas production. EnCana, Husky Energy, Talisman Energy and Devon Canada announced June 28 that they will share a single system that is designed to increase the efficiency and improve the quality of information on production. CGI Group will build and maintain the system over the next 10 to 20 years.

Parker Drilling delays rig sales

Parker Drilling said the anticipated sale of its Gulf of Mexico jackup and platform rigs has been postponed due to a delay in the timing of financing for the purchase.

The sale, which excludes jackup rig 25J, was originally scheduled to close June 30, but is now expected to close during the third quarter of this year, the company said.

If financing of the sale is delayed beyond Aug. 1, Parker still would have enough liquidity to pay off a $64.4 million note by drawing on its remaining term loan and using existing cash on hand, the company said.

Canadian drillers post strong first half

Canada reached the midpoint of 2004 with its second highest active rig count on record, but a soggy June trimmed drilling by 10 percent over last year. For the six months, an average 411 rigs were employed by operators, compared with 388 a year earlier. The peak year was 2001 with 434 rigs at work. Utilization of the fleet averaged 59 percent of the 693 available rigs, well behind 1997's 77 percent of 485 available rigs.

To the end of June, Alberta logged 296 active rigs, up 6 percent from 2003 and British Columbia surged 19 percent to 80 rigs.

Seismic plans in motion for Laurentian sub-basin

ConocoPhillips Canada is wasting no time embarking on seismic exploration of the Laurentian sub-basin between Newfoundland and Nova Scotia. So long as it receives regulatory approvals, the company, in partnership with Murphy Oil, will shoot about 3,600 miles of two-dimensional seismic this summer, during the tight exploration season.

But drilling of the basin, which could hold 10 trillion cubic feet of gas and 1 billion barrels of oil, is unlikely before 2007. Two months ago, federal offshore permits issued in the 1970s were converted to modern-day licenses to spur activity

—GARY PARK, KRISTEN NELSON AND RAY TYSON

TULSA, OKLA.

Unit acquires Sauer Drilling

Tulsa, Okla.-based Unit Corp. said June 29 that it has agreed to acquire Casper, Wyo.-based Sauer Drilling Co., a wholly owned subsidiary of Tom Brown, for $34.7 million in cash and an amount equal to Sauer's working capital at close.

The acquisition, expected to close July 30, includes nine drilling rigs, a fleet of trucks and an equipment and repair yard in Casper.

Sauer Drilling and its predecessors have operated in the Rocky Mountains for more than 25 years, Unit said.

"At the close of this acquisition, our rig fleet will total 100 land drilling rigs. Of the 100 rigs, 97 are contracted and the remainder have strong expressions of intent," John Nikkel, chairman and chief executive officer of Unit, said.

finance&economy

WILLOW PARK, TEXAS

Ness increases Barnett Shale acreage, in contract talks with unnamed major independent

Ness Energy International has acquired more acreage in the prolific Barnett Shale gas play of East Texas and currently is in "contract talks" with an unidentified major independent that should result in its quarterly results exceeding previous forecasts, the company said June 24.

Large exploration and production independents currently active in the Barnett Shale include Devon Energy, Anadarko Petroleum and XTO Energy.

Ness said that over the past month it has acquired the rights to explore and drill on about 3,500 acres in the Fort Worth basin. The company already held rights to about 10,000 acres in the region.

"These additional leases … will again supply Ness with an opportunity for additional accelerated growth by directly working with larger independents seeking the vast resources of the Barnett Shale formation," Ness said.

A recent U.S. Geological Survey assessment of the Barnett Shale concluded that the area holds gas reserves of nearly 30 trillion cubic feet. "These figures are expected to increase in the near future as technology continues to advance and drilling continues," Ness said.

—RAY TYSON, Petroleum News Houston correspondent

APPALACHIA

Talisman boosts land holdings

The bullish view of the Appalachian region by Canadian independent Talisman Energy has been reinforced by a US$65 million purchase of 475,000 gross acres of Trenton/Black River rights throughout the region. The Calgary-based company announced June 29 that its U.S. subsidiary, Fortuna Energy, had acquired all of Belden & Blake Corp.'s assets in New York, Ohio and West Virginia. Fortuna currently holds 433,000 acres in the region.

The deal will also give Fortuna about 4-5 million cubic feet per day of production, a volume it expects to double over the next three months.

"The key to this transaction is the highly prospective land position," said Talisman President and Chief Executive Officer Jim Buckee. He said the added production will increase Fortuna's output to 110-120 million cubic feet per day, with the company's latest well testing at 15 million cubic feet per day.

Talisman entered 2004 with plans to spend $60 million in the Eastern United States, drilling 21 wells.

Buckee views Appalachia as a growing core area for the company after paying US$250 million in late 2002 to acquire a foothold in the area.

Although gas has been extracted from the play over many years, deeper drilling is expanding the horizons.

Fortuna has already identified 25 drilling locations in its new properties and expects to add more after a technical review, adding to its current 40 locations.

—GARY PARK, Petroleum News Calgary correspondent

● HOUSTON, TEXAS

Survey: A mixed bag for U.S. independents

Reflects lower profits for 2004 second quarter, increased net income versus a year ago

By RAY TYSON

Petroleum News Houston Correspondent

U.S. exploration and production independents are expected to report lower earnings on average for the 2004 second quarter compared to the previous quarter. But industry analysts also believe the group should see profits climb into double digits vs. last year's second quarter.

Conclusions were based on a Petroleum News survey of Thompson-First Call analysts' consensus estimates for 20 leading U.S. exploration and production independents.

Profits for independents during the 2004 second quarter are expected to slide about 7 percent from the first quarter but increase roughly 17 percent compared to last year's second quarter.

A consensus estimate represents the average earnings of all analysts polled on a particular company. Individual estimates can be higher or lower than the consensus and tend to change as the reporting season approaches. Estimates generally do not include charges against earnings and other special items.

Profits expected to slide from first quarter

Profits for independents during the 2004 second

see SURVEY page 8

● INTERNATIONAL

Norway's labor dispute shows Mideast isn't only vulnerable oil province

International risk factors include bad weather, political unrest, guerrilla attacks, labor disputes, technical problems, maintenance and accidents

By BETH GARDINER

Associated Press Writer

Violence in Saudi Arabia and Iraq have kept oil-importing nations' worries focused on the Middle East, but a recently resolved labor dispute in Norway is a reminder that supplies elsewhere can be vulnerable too.

With OPEC production stretched and the world guzzling ever more oil, analysts say a significant disruption in often-volatile Venezuela or another big exporter could cause a big price spike.

Still, they're mostly optimistic that such a scenario is unlikely, and say it would have to coincide with more Middle Eastern trouble — like a big decline in Saudi or Iraqi production — to cause a real crisis.

An unforeseen supply disruption "is an ever-present threat," said David Fyfe, principle oil supply analyst at the Paris-based International Energy Agency.

Bad weather, political unrest, guerrilla attacks, labor disputes, technical problems, maintenance and accidents are always risk factors, Fyfe said.

"Random events can hold the potential to undermine non-OPEC supplies for a given year by anything up to 300,000 to 400,000 barrels a day," he said. World oil production hovers around 81 million barrels daily.

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REBOUND

reflects nothing but losses. The company is expected to report a loss in the 2004 second-quarter of about 5 cents per share. However, that still would be an improvement over a reported loss of 9 cents per share in this year's first quarter and a loss of 15 cents per share compared to the same period last year.

Land driller Grey Wolf is expected to report a loss of around 1 cent per share for this year's second quarter, also an improvement over a reported loss of 9 cents per share in the previous quarter and a loss of 5 cents per share versus the same quarter last year.

Rowan's earnings also could fall into the red. Analysts' estimates call for the company to lose about 3 cents per share in the 2004 second quarter versus a gain of 11 cents per share in the prior quarter. Still, that would be an improvement from a reported loss of 7 cents per share a year earlier.

Halliburton takes pre-tax charges

None of the remaining seven oilfield service companies surveyed, excluding charges and special items, were expected to fall into the red during the 2004 second quarter. And most were expected to beat or match performances compared to the prior and year-ago quarters. However, nearly $1 billion in pre-tax charges more than likely will radically alter Halliburton's overall financial performance for the 2004 second quarter. The giant oilfield service company recently announced that increasing costs and delays in a large project in Brazil would reduce after-tax earnings by 46 cents per share. Also, costs related to asbestos litigation should further cut into quarterly profits. Excluding the charges, analysts' consensus has Halliburton earning about 33 cents per share in this year's second quarter, up from 29 cents per share in the previous quarter and up from 6 cents per share from the year-ago period.

Most in black

Schlumberger, another giant oilfield service company, is expected to report net income of around 48 cents per share for the 2004 second quarter, roughly flat with the prior quarter's 47 cents per share but up strongly from 38 cents per share earned in the year-ago quarter. Baker Hughes also should report improvements across the board. Analysts expect the company to earn about 31 cents per share for this year's second quarter, up from 29 cents in the previous quarter and up from 24 cents compared to the same period last year. Weatherford's expected profit of 39 cents per share in the 2004 second quarter would be roughly flat with prior quarter net income of 38 cents per share but up from 22 cents per share earned in the year-ago period.

Smith International's expected second-quarter profit of about 44 cents per share also would be flat to the prior quarter's 44 cents per share but up from 30 cents per share versus the same period last year. Pride International is expected to earn about 5 cents per share in the 2004 second quarter, up from 3 cents per share in the previous quarter but down from 9 cents per share in the year-ago period.

Varco International is expected to report net income of around 22 cents per share in this year's second quarter, up from the previous quarter's 18 cents per share and up from 15 cents per share earned a year earlier. ●

continued from page 6

DISPUTE

Norway orders binding arbitration

On June 25, the government of Norway, the world's third-largest oil exporter, ordered an end to an offshore oil workers' labor dispute that had threatened to halt pumping.

Officials said they were ordering binding arbitration because a strike and lockout would have had serious consequences for the nation's economy and reputation as a reliable supplier of petroleum.

Axel Busch, chief correspondent for industry newsletter Energy Intelligence, said Norway can be counted upon to settle oil disputes before they cause real trouble.

Outcomes less certain elsewhere in world

In other parts of the world, the outcomes are less certain.

In Venezuela, where a general strike paralyzed oil exports in late 2002 and early 2003, President Hugo Chavez has consolidated his control of the industry, reducing the chance of another damaging walkout, Fyfe said. But the South American nation, the world's fifth-largest oil exporter and holder of the western hemisphere's biggest reserves, remains unstable, and Chavez faces a planned recall vote in August.

Hints of labor unrest in Ecuador and guerrilla attacks on pipelines in Colombia make those nations potential trouble spots too, Fyfe said.

Ethnic violence in Nigeria's volatile oil delta and the potential for labor trouble are ongoing issues, although they have not had a major impact on the country's production in recent years, Fyfe said.

Busch, the energy newsletter correspondent, said the Caucasus and Caspian Sea are also potential trouble spots, though he predicted political tensions there would ease before interfering with oil production.

Oil prices spiked to record highs earlier this month, under the combined pressure of rising demand from fast-developing nations like China and fears about future production in the Middle East.

Sabotage and general instability are hurting oil production in Iraq. Saudi Arabia, the world's biggest oil producer, is struggling with an upsurge of violence against Westerners and its oil industry.

OPEC pumping close to maximum capacity

With OPEC pumping at close to maximum capacity and other exporting countries already there, simultaneous problems in two or more oil nations could create a price shock, Busch said.

"For instance, if you totally stopped Iraq, no more exports out of Iraq for whatever reason ... and then you also have Venezuela imploding ... then it starts getting close to a crisis point," he said.

"I would foresee the markets going mad and prices would ratchet up, but we wouldn't go cold, the wheels of commerce wouldn't grind to a halt, not for a long time," he added.

Busch said OPEC nations could probably produce about 1.5 million additional barrels a day if they had to, and noted that big oil-consuming countries have large strategic reserves.

Beyond that, he said, "we are up against it," and the world would have to start tapping new oil supplies, perhaps in west or north Africa or Russia.●

continued from page 6

SURVEY

quarter are expected to slide about 7 percent from the first quarter but increase roughly 17 percent compared to last year's second quarter. However, profits for this year's third quarter beginning July 1 also are expected to slide another 5.8 percent from the second quarter.

Despite the anticipated decrease in quarterly profits, independents continue to ride high on robust commodity prices. None of the 20 companies surveyed, unless they report unanticipated charges, was expected to lose money in the recent quarter ending June 30, according to analysts' estimates.

However, only seven of the 20 leading independents surveyed are expected to report 2004 second-quarter earnings exceeding previous quarter. And among the 11 largest independents, only Pioneer Natural Resources, Apache and XTO Energy should see profit increases quarter-over-quarter.

Pioneer, Apache and XTO expected to be up

Pioneer should report earnings of around 70 cents per share, up a healthy 40 percent from prior-quarter earnings of 50 cents per share. Earnings for the second quarter also would be up about 7.6 percent from the year-ago period of 65 cents per share.

Apache's earnings for the 2004 second quarter should increase about 2 cents to around $1.08 per share from $1.06 per share in the prior quarter and increase about 20 cents from 88 cents earned in the year-ago period.

XTO, compared to the prior quarter, also should see a slight increase of 2 cents to 53 cents per share in 2004 second quarter and an increase of 7 cents from 33 cents per share in last year's second quarter.

Most larger independents will be down

Among the larger U.S. independents, Kerr-McGee, Anadarko Petroleum, Devon Energy, Unocal, Chesapeake Energy, EOG Resources, Noble Energy and Burlington Resources were expected to weigh in with lower earnings in the 2004 second quarter vs. the previous quarter.

Kerr-McGee's profit in the recent quarter is expected to drop about 26 percent to $1.09 per share from $1.48 per share in the prior quarter, according to analysts' estimates. Still, the company should do about 2 cents better than the $1.07 per share it earned a year earlier.

Analysts believe Noble's net income for the 2004 second quarter will fall about 20 percent to $1.04 per share from $1.30 per share in this year's first quarter. However, the company is expected to nearly double its profit from last year's 54 cents per share.

Anadarko, which is in the process of restructuring itself following several troubled years, could see its net income fall about 13 percent in the 2004 second quarter to $1.50 per share from $1.72 per share in the previous quarter. However, the company still should do about 30 cents better vs. last year's $1.20 per share.

Devon, the largest U.S.-based exploration and production independent, also could see its profit drop about 7 percent to $1.86 per share in the recent quarter from $2 per share in the prior quarter. Like its large-cap peers, the company is expected to do significantly better than a year ago when it earned $1.56 per share.

Big natural gas producer Burlington is expected to report 2004 second-quarter earnings of about 80 cents per share, down roughly 10 percent from 89 cents in the first quarter but up about nearly 16 percent from 69 cents per share a year earlier.

Chesapeake's net income also is expected to slide to 29 cents per share in the 2004 second quarter from 44 cents per share in the first quarter. That would translate into earnings about 2 cents lower than last year's 31 cents per share.

EOG is expected to post 2004 second-quarter net income of about 95 cents per share, down from the prior quarter's $1.06 per share and roughly flat to 94 cents reported in the year ago period.

Some smaller independents up

Five of the nine smaller independents surveyed — Pogo Producing, Spinnaker Exploration, St. Mary Land & Exploration, Magnum Hunter Resources and Forest Oil — are expected to report 2004 second-quarter net income higher than the previous quarter, according to the consensus.

Newfield Exploration, Tom Brown, Evergreen Resources and Cabot Oil & Gas were expected to check in with lower earnings in the 2004 second quarter vs. the previous quarter

Pogo's net income for the 2004 second quarter could increase around 23 percent to $1.38 per share from $1.12 per share in the previous quarter. Compared to the $1.24 per share earned for the same period last year, company net income could be up about 11 percent.

Forest is looking to net about 51 cents per share for the 2004 second quarter, up about 42 percent from 36 cents earned in the previous quarter and up roughly 6 percent from 48 cents per share in the year-ago period.

Spinnaker's profit is expected to come in around 46 cents per share, an increase of 15 percent from the prior quarter's 40 cents per share and a hefty increase of 53 percent from last year's 30 cents per share.

St. Mary's net income could be about 68 cents for the 2004 second quarter, up marginally from the prior quarter's 66 cents per share but down slightly from last year's 71 cents per share.

Magnum Hunter's profit is expected to be around 29 cents per share, roughly flat to the prior quarter's 28 cents per share but up more than two-fold from the 9 cents per share the company earned during the same period last year.

Newfield, Tom Brown, Evergreen and Cabot down

On the negative side, Newfield should net about $1.24 per share in the 2004 second quarter, down about 17 percent from the previous quarter. However, compared to the $1.03 per share earned for the same period last year, company profit is expected to increase about 20 percent.

Tom Brown, which is being acquired by big Canadian independent EnCana, was expected to report 2004 second-quarter earnings of about 63 cents per share, representing a decrease of around 28 percent from the prior quarter's 88 cents per share. Compared to last year's second quarter net of 53 cents per share, the company's profit for the recent quarter should be up nearly 19 percent.

Evergreen, which is being acquired by Pioneer, should check in with net income of about 41 cents per share, down from 44 cents per share earned in the prior quarter and down from 46 cents in the year-ago period.

Cabot is expected to weigh in with 2004 second-quarter net income of about 55 cents per share, down from the previous quarter's 59 cents per share and roughly flat to last year's 56 cents per share. ●

ANCHORAGE, ALASKA

Total reducing Anchorage staff, Bergeron leaving Alaska

Total E&P USA said July 1 that Jack Bergeron, Alaska manager for Total, will leave Alaska, relocating to Houston by Aug. 1.

The company's Houston-based communications manager, Jenna Wright, told Petroleum News that Total's "Anchorage-based personnel will be reduced to one full-time and one part-time representative as Alaskan operations move from the drilling stage to an evaluation and planning period."

JUDY PATRICK

JACK BERGERON

Remaining staff are George Snodgrass, Total's health, safety and environmental advisor, and Office Manager Lianne Hopper.

Total drilled the Caribou 26-11 No. 1 well in the National Petroleum Reserve-Alaska last winter.

Wright said Total currently "has no plans to conduct drilling this winter. The company is focusing on the evaluation of data gained

see TOTAL page 10

WYOMING

Digital geologic maps available for hole-in-the-wall country

The Wyoming State Geological Survey has released the first two of a planned group of 12 digital quadrangle geologic maps for the southern Bighorn Mountains.

Map author Alan Ver Ploeg, senior geologist and head of the Geologic Mapping Section at the survey, said color geologic maps covering the Hole-in-the-Wall and Poker Butte 1:24,000-scale quadrangles are available as Open File Reports 04-12 and 04-13.

Bentonite is mined from the Frontier formation in the Hole-in-the Wall quadrangle, and terrace deposits — possible local sources for

see MAPS page 10

CANADA

B.C. ends first half with strong land sale of 767,544 acres

British Columbia land sales have dipped slightly, generating almost C$120 million to the end of June on the sale of 767,544 acres, compared with last year's C$134 million for 986,643 acres. The latest sale on June 23 yielded a strong C$30.2 million for 239,400 acres, the best average per acre price this year.

Heading the list was the Cypress-Chowade area northwest of Fort St. John, where Appaloosa Resources picked up two licenses totaling 11,945 acres for C$4.4 million. The largely undrilled area is about 6 miles west of the Cypress gas field.

—GARY PARK, Petroleum News Calgary correspondent

● DENVER, COLO.

St. Mary would bring long history of independence to Alaska's oil patch

Company's market value exceeds $1 billion; production grew by 40% in 2003, to 76.9 bcf natural gas equivalent, with average daily production of 210.7 mcf

By RAY TYSON

Petroleum News Houston Correspondent

Denver-based St. Mary Land & Exploration Co., whose history dates to the turn of the last century, appears destined to remain an exploration and production independent, a remarkable achievement considering successful independents tend to be gobbled up by bigger fish.

For the first time in the company's long history, St. Mary's market value now exceeds $1 billion, placing it in the category of small-to-medium sized independents with a bent for growth.

St. Mary also has big plans for the current year, budgeting $288 million in capital expenditures, a 25 percent increase over last year's $231 million budget. Of the total, $188 million was set aside for exploration and development expenditures and $100 million for property acquisitions.

In 2003, St. Mary grew its production 40 percent from the previous year to 76.9 billion cubic feet of natural gas equivalent, an average daily production rate of 210.7 million cubic feet of equivalent per day.

Net proved reserves at year-end 2003 increased 21 percent over 2002 to 593.7 billion cubic feet of gas equivalent, 89 percent of which were proved developed. That occurred in spite of selling 45.6 billion cubic feet of equivalent of non-core assets. St. Mary's reserve base at the end of 2003 was 52 percent natural gas and 48 percent oil. Last year the company participated in drilling 181 wells with an 86 percent success rate.

$288 million capex budgeted for 2004

St. Mary also has big plans for the current year, budgeting $288 million in capital expenditures, a 25 percent increase over last year's $231 million budget.

see ST. MARY page 10

Mike Richter, a former ARCO Alaska and Phillips Alaska executive and now under contract with St. Mary, was well known for his victory sign following an Alaska discovery. This photo was taken by Judy Patrick in the mid-1990s.

St. Mary brings in Richter to help assess Alaska opportunities

St. Mary Land & Exploration is currently taking a serious look at oil and gas investments on Alaska's North Slope (see related article on page 1 of this issue).

The company has secured the services of North Slope exploration guru Michael Richter, formerly ARCO Alaska and Phillips Alaska's vice president of exploration and land. Richter and his team were credited with more than a billion barrels worth of discoveries on the North Slope, including the first 1990s NPR-A discoveries.

Doug York, St. Mary's executive vice president and chief operating officer, told Petroleum News June 29 that, "Given where we are in our evaluation of potential investment opportunities in Alaska, it would be inappropriate to comment at this time."

Alaska Division of Oil and Gas Director Mark Myers acknowledged the company was

see RICHTER page 10

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ST. MARY

Of the total, $188 million was set aside for exploration and development expenditures and $100 million for property acquisitions.

During the 2004 first quarter, the company reported net income of $21.4 million or 66 cents per diluted share on revenues of $97.4 million.

However, oil and gas was not on the company's mind when it formed under the auspices of Chester Congdon, who is said to have made a small fortune from the development of iron mines in Minnesota and copper mines in Arizona.

St. Mary operates in five U.S. Lower 48 core areas — the Midcontinent, Rocky Mountains, ArkLaTex, Gulf Coast and Permian Basin. In addition to Denver, St. Mary maintains offices in Tulsa, Okla.; Billings, Mont.; Shreveport, La.; and Houston, Texas.

St. Mary was founded in 1908, incorporated in 1915 and became a public company through an initial public offering of common stock in 1992. However, oil and gas was not on the company's mind when it formed under the auspices of Chester Congdon, who is said to have made a small fortune from the development of iron mines in Minnesota and copper mines in Arizona.

Beginning in 1900, Congdon and four associates from the mining industry acquired 17,700 acres of lands on the Gulf Coast of Louisiana for the generous sum of $11,000. The St. Mary's Parish Land Co. was born eight years later. Congdon and an associate purchased 7,200 acres of additional lands under the name of Tidal Wave Land Co. The two companies merged in 1935.

From the start St. Mary investors were largely attracted by the potential of draining the rich marsh lands for agricultural development. Fortunately, they purchased not only the surface rights to these lands but the mineral rights as well.

Company went public in 1992

Non-commercial oil accumulations on Belle Isle, together with the celebrated discovery of oil in 1901 at the Spindletop salt dome on the Texas Gulf Coast, raised hope that oil might be found on the St. Mary lands abutting the Belle Isle salt dome. Several exploration failures followed before the predecessor of Texaco drilled a discovery well on state of Louisiana water bottoms in 1933.

On May 6, 1938, the St. Mary No. 1 was completed at a depth of 9,910 feet for 335 barrels of oil per day, establishing the Horseshoe Bayou field, which would become one of the giant accumulations in the United States. Sun Oil Co., the predecessor of Oryx, discovered gas at Belle Isle in 1941.

In 1966, the company's board of directors recognized the need to build assets to offset depletion of the Louisiana oil and gas reserves. The executive office was moved to Denver and placed under the direction of Tom Congdon, Chester Congdon's grandson and the company's chairman until September 2002. Mark Hellerstein is the current chairman, president and chief executive officer.

Employing a staff of fewer than a half dozen, St. Mary began to explore for new reserves in the Rockies and the Midcontinent by affiliating with experienced partners.

Production and reserves grew rapidly through the 1970s, particularly in the Anadarko basin of Oklahoma.

The decision to become a public company through an initial public offering of common stock in 1992 was taken to raise needed capital and to provide liquidity for family shareholders, according to St. Mary records. ●

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RICHTER

"clearly evaluating Alaska's potential," but was reluctant to say more at this stage.

However, Myers did say that St. Mary was one of the firms the state would like to see invest in Alaska.

St. Mary ranked number 38 in Petroleum News' list of the top capital and exploration spenders in the United States in 2002.

(See Top 70 report under products at www.PetroleumNews.com).

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

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MAPS

sand and gravel — have been mapped in both quadrangles.

The Hole-in-the-Wall is a narrow notch eroded in a nearly continuous, vertical cliff of Triassic Chugwater and runs for almost 25 miles along the east slope of the southern Bighorn Mountains. The Hole-in-the-Wall and the area around it was made famous by various groups of outlaws, rustlers, and army deserters who used this erosional feature as a hidden route in and out of the rugged surrounding area.

The maps can be purchased over the counter of by phone, fax, or e-mail from the Publications Sales Office at the survey in Laramie. The maps are $10 each and are available as a color plotted map, rolled only.

For more information, contact Alan Ver Ploeg at verploeg@uwyo.edu or (307) 766-2286, extension 230.

—**PETROLEUM NEWS**

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TOTAL

from the first well and developing plans for its remaining" Alaska acreage, she said, and most of that work "can be managed from the headquarters office in Houston."

Bergeron will relocate to Houston by Aug. 1, she said. Other Total employees in Alaska "had worked the North Slope project on a temporary basis and were previously re-assigned within the company."

Total acquired its NPR-A acreage in 2002, paying $53 million for 20 tracts.

Total and partner Fortuna Energy Inc., a subsidiary of Calgary-based Talisman Energy, drilled the Caribou 26-11 with Nabors Alaska 14E rig some 80-plus miles from the nearest road, near the vicinity of the old Inigok test well, where there is a 5,000-foot gravel runway.

The well was spud Jan. 29 and work was completed Feb. 25. The Alaska Oil and Gas Conservation Commission said the vertical hole was drilled to 9,362 feet.

continued from page 1

LOOK

visit to Houston in the fall where he plans "a major meeting" with oil and gas companies to stir up more interest in Alaska drilling opportunities, Myers said.

Two of the companies taking a serious look at oil and gas investment opportunities on Alaska's North Slope are Shell, one of the world's largest oil companies, and Denver-based independent St. Mary Land & Exploration Co.

….if Shell and BP swap North Slope assets for, say, mature fields and infrastructure elsewhere, it would restart the depreciation clock for both companies.

A Petroleum News source says Shell and BP are once again talking about swapping assets outside Alaska for North Slope assets, which would give Shell a major production position in the state and Alaska another aggressive explorer. (This information has not been confirmed by either company.)

Why does such a deal make sense?

BP has $5 invested in every barrel of oil it has booked on the North Slope. Outside of Alaska it has $3 per barrel opportunities, so even though there is still a lot of undeveloped and undiscovered oil in Alaska, the state does not compare favorably with BP's exploration opportunities in other parts of the world.

But if Shell and BP swap North Slope assets for, say, mature fields and infrastructure elsewhere, it would restart the depreciation clock for both companies.

If Shell would get all of BP's Alaska assets, the deal would give Shell, among other things, 46.93 percent ownership in the trans-Alaska oil pipeline; the opportunity to take over BP-operated facilities on the North Slope (see map); a major chunk of the ConocoPhillips-operated Kuparuk field; the offshore Liberty prospect, which is likely BP's last development project in Alaska; and BP's stake in the KIC acreage within the 1004 area of the Arctic National Wildlife Refuge.

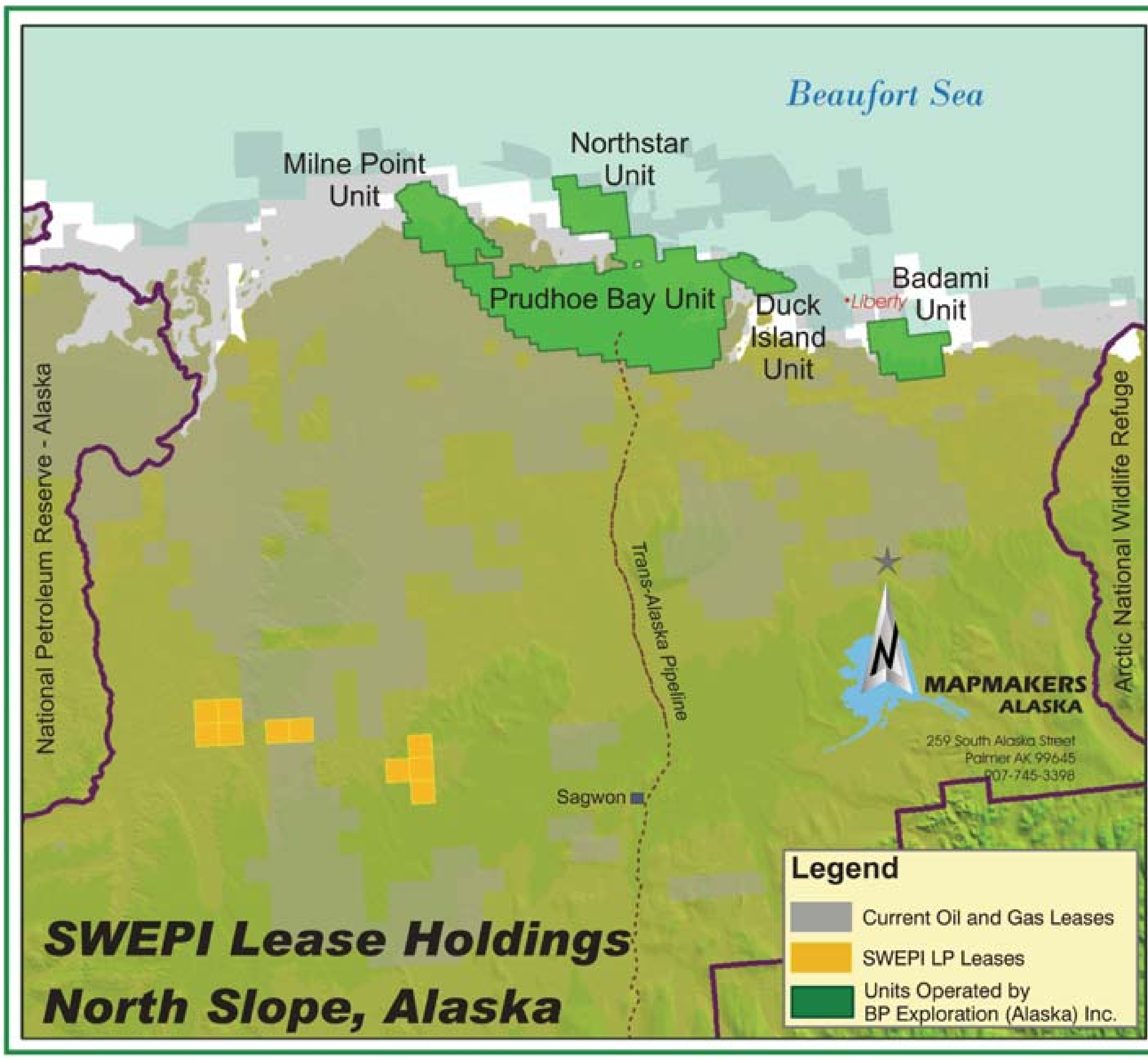
Finally, the deal would also give gas-hungry Shell a stake in the proposed North Slope natural gas pipeline.

In 1997, a Shell spokesman said the main reason the company was pulling out of Alaska after almost 35 years was because, "Shell has such a small position, land holdings, in Alaska. It's not strategic to take a small position a zillion miles from Houston and develop it. You need a critical mass to make it strategic." He explained that traditionally Shell moves into an oil and gas province in a big way or not at all.

So when Shell re-entered Alaska in 2002 with its paltry $2.4 million acquisition of 56,000 acres south of the Kuparuk River unit, Alaskans watched to see what the company would do next.

This June "a small delegation of three people" visited Anchorage "to attend the Alaska Oil and Gas Association's annual lunch and meet with other stakeholders in the industry. Those Shell staff included two people from the company's exploration department and one person from the land department," Shell spokesman for EP Americas, Kelly op de Weegh, told Petroleum News July 1. She said, "even though Shell sold its last producing asset in 1998, Shell has remained an AOGA member."

But those three people included two significant executives – Chandler Wilhelm, the Shell executive in charge of exploration development for new ventures in the Americas, and Gregg Nady, chief, Alaska exploration team.



The Shell group visited several state and federal offices, gathering information on the Bristol Bay basin, as well as the North Slope. Their interest in Bristol Bay, according to one Petroleum News source, was the possibility of exporting liquefied natural gas from the region.

One source said the Shell executives had "really done their homework," asked "very intelligent, informed questions."

John Goll, who heads up the U.S. Minerals Management Service in Alaska, acknowledged the Shell officials had visited him and were briefed on MMS' five year lease sale plan. The plan includes the Chukchi Sea, an area Shell has explored in the past and one that Shell has said it would return to if it could be assured of consistently high oil prices, in the $30 range, and a reasonable tariff for oil pumped down the trans-Alaska oil pipeline.

MMS estimates the Chukchi holds more than 15.5 billion barrels of technically recoverable oil and more than 60 trillion cubic feet of gas.

Shell's official word on Alaska hasn't changed. According to op de Weegh, Shell has "no plans to open an Anchorage office."

She said "Shell is committed to growing globally through exploration, and we believe North America continues to hold promising opportunities. We review and rank all such opportunities on a global basis. Alaska, because of its large resource potential, is one such area that we are investigating. However, the state is also a very high cost area to operate. At this time, we do not have any other details to announce."

(Shell's) interest in Bristol Bay, according to one Petroleum News source, was the possibility of exporting liquefied natural gas from the region.

St. Mary Land & Exploration Co.

St. Mary Land & Exploration is another company that has been taking a hard look at Alaska's North Slope. According to Petroleum News sources, the firm has been looking at both operating its own leases and partnering with other companies, such as North Slope operator ConocoPhillips and independents with undeveloped slope prospects.

St. Mary has secured the services of North Slope exploration guru Michael Richter, formerly ARCO Alaska and Phillips Alaska's vice president of exploration and land.

But St. Mary is not ready to comment on its interest in Alaska.

Doug York, St. Mary's executive vice president and chief operating officer, told Petroleum News June 29 that, "Given where we are in our evaluation of potential investment opportunities in Alaska, it would be inappropriate to comment at this time." (See story and sidebar on St. Mary on page 9 if this issue).

Editor's note: Part 2 of this article will appear in the July 11 edition of Petroleum News.

—KAY CASHMAN, Petroleum News publisher and managing editor

● FAIRBANKS, ALASKA

Resort ready to trade diesel for hot water

Chena Hot Springs applies for grants for geothermal research, hopes to replace diesel generators with renewable power

By PATRICIA LILES

Petroleum News Contributing Writer

Owners of the Chena Hot Springs Resort, about 60 miles northeast of Fairbanks, Alaska, and 30 miles from the Interior's electric grid, want to trade in their diesel-fired generators for geothermal electrical generation.

The resort has applied to state and federal energy agencies for two separate geothermal research grants, according to Gwen Holdmann, vice president of new development at Chena Hot Springs Resort.

One grant application, made to the Alaska Energy Authority, part of the state-run Alaska Industrial Development and Export Authority, is requesting $500,000 to go toward the purchase and installation of a power system that will use the resort's hot springs as its power source. The total cost to install and operate a 400-kilowatt geothermal powered electrical generation system will be $1.7 million, Holdmann told Petroleum News on June 28.

The resort already heats 40 buildings at the facility with its hot water, as well as using the springs for an indoor swimming pool and an outdoor rock pond. Converting to geothermal-powered electricity would allow the resort to shut down its 200 kilowatt diesel-fired generators, which cost about $200,000 to operate in 2003, Holdmann said.

"Now we're paying almost a dollar more per gallon of diesel," she said.

Binary system planned

The resort wants to install a binary generation system, which includes an additional step between extraction of hot water and electric generation, Holdmann said. "Our water isn't hot enough to produce electricity alone."

In a binary system, hot water is used to heat a refrigerant, such as isobutane or ammonia, which creates steam at a much lower temperature than water. The steam drives a turbine, which generates the electricity. Cooled spring water will be reinjected, Holdmann said.

Six wells have already been drilled to test the potential for geothermal-driven electricity, the latest in May 2003, she said. "We haven't decided the specific location, but it will be within fairly close proximity to the wells," Holdmann said. "We're hoping to locate it about one-quarter of a mile away from the resort area."

COURTESY OF CHENA HOT SPRINGS RESORT

Owners of the Chena Hot Spring Resort, about 60 miles northeast of Fairbanks, Alaska, and 30 miles from the Interior's electric grid, want to trade in their diesel-fired generators for geothermal electrical generation.

Previous well testing at Chena Hot Springs indicates the 400-kilowatt steam-driven turbine could be supported with the existing resource. "We've drilled only 300-foot wells, and the hottest water we have is 250 degrees Fahrenheit," Holdmann said. "This initial phase on a small scale will let us see if a large generating capacity is possible, and if so, we'll pursue it later."

Regional assessment project proposed

The second research project Chena Hot Springs is hoping to secure funds for would evaluate that potential larger electric generating source of hot water at Chena Hot Springs, as well as conduct regional reconnaissance for geothermal resources.

The resort has applied to the U.S. Department of Energy for a grant to provide 80 percent of a $3.7 million, three-year geothermal research project, which would evaluate potential electric generation capabilities at six different known hot springs in the Interior.

In addition to drilling a deep well at Chena Hot Springs, down to 4,000 feet, the DOE-funded project would conduct aerial surveys and collect water and chemical samples at five other hot springs locations.

Other proposed test locations include Circle Hot Springs, a resort off of the Steese Highway about 130 miles northeast of Fairbanks and about seven miles from the village of Central, Alaska; and Manley Hot Spring, which is about 90 miles west of Fairbanks at the end of the Elliott Highway. Manley Hot Springs, a small village on a slough of the Tanana River, has a population of about 70.

Three remote locations for proposed geothermal research in the Interior include Big Windy Hot Springs, about 30 miles northeast of Chena Hot Springs; Hutlinana Hot Springs, about 24 miles northeast of Manley Hot Springs and the Tolovana Hot Springs, about 16 miles northeast of the village of Minto.

Workshop planned

AIDEA and the Alaska Energy Authority, state agencies involved with assisting Alaska's electrical utility providers, are helping to coordinate a western regional geothermal workshop at Chena Hot Springs Resort Aug. 10 and 11. Called GeoPowering the West, the workshop will provide information about the emerging renewable energy source, said Bernie Smith, AIDEA's geothermal coordinator.

"Sixteen western states have geothermal potential," he said. "With the price of diesel, people are looking for different types of energy sources that could be competitive."

He and about 25 others either from Alaska or representing Alaska's electrical industry recently completed a trade mission to Nevada, to look at existing geothermal electric production facilities. AIDEA and the Alaska Energy Authority are now coordinating the state's geothermal effort, Smith said, because "... there is potential for a geothermal industry here." ●

● SEWARD, ALASKA

Fuel cell project shuts down after a troubled start

Latest project in Alaska encounters problems in shipping, operation at Seward's Exit Glacier visitor center

By PATRICIA LILES

Petroleum News Contributing Writer

The eighth and latest fuel cell test project in Alaska hasn't mirrored recent successes logged by University of Alaska Fairbanks researchers in the emerging energy industry.

Fired by propane gas, the five-kilowatt solid oxide fuel cell housed at the National Park Service visitor center at Exit Glacier, near Seward, shut down in early June, seven days after its celebratory start-up on May 28. Internal tubes were cracked and had to be replaced, said Dennis Witmer, a leading fuel cell researcher and director of the Arctic Energy Technology Development Laboratory, an organization that manages energy research projects at the University of Alaska funded by the U.S. Department of Energy.

Since then, the Exit Glacier fuel cell was repaired, restarted and shut down again, Witmer said.

"The issue may be related to the increased difficulty in reforming propane (into hydrogen) and it is not clear at this time how successful the company will be in addressing this challenge," he said on June 24.

First unit delivered in September

The propane-fired fuel cell was developed by a Boston-area manufacturer, Acumentrics. The first unit was delivered to the test site at Exit Glacier last September, but it was damaged during shipping, Witmer said. It was shipped back to Boston for repairs last fall.

One possible cause is the unit's fuel source, Witmer said. The propane-fired fuel cell was built based on a similar model that is fired by natural gas. UAF researchers have successfully operated that gas-fired solid oxide fuel cell, also partially funded by DOE, for about 7,000 hours at the offices of Fairbanks Natural Gas.

Other recent fuel cell research by UAF has provided success in the emerging alternative energy arena. This spring, Fairbanks area researchers completed the first phase of testing a methanol-fired fuel cell system, successfully operating a one-kilowatt proton exchange membrane fuel cell. DOE funding was cut for the second year of operation at a remote site, so the unit was shipped back to its supplier in California this spring, Witmer said.

So far, UAF researchers have participated in eight separate fuel cell research projects, and have asked DOE for funding for a ninth, which would involve a diesel-fired solid oxide fuel cell. If approved, the proposed $822,898 fuel cell project will be part of an ongoing $11 million research effort involving a large scale diesel reformer being tested by the U.S. Navy at the Idaho Falls National Engineering and Environmental Laboratory, Witmer said. ●

● ALBERTA

Canada oil sands start-ups fired up

Newcomers on the move with projects; UTS Energy unveils modified plan to revive Fort Hills venture

By GARY PARK
Petroleum News Calgary Correspondent

The pace is quickening for two start-ups in the Alberta oil sands as they press ahead with plans for commercial operations this decade.

UTS Energy, which plans to take 100 percent control of the Fort Hills project, has raised its initial production target but scaled back its overall objective as part of a new strategy for reviving a venture that was shelved early last year.

Meanwhile, Deer Creek Energy, a closely held Calgary-based company, aims to raise as much as C$200 million from an initial public offering to increase its oil sands output in northern Alberta.

UTS said June 25 that it now hopes to produce 50,000 barrels per day of bitumen by mid-2009, up from the earlier first phase plan of 30,000 bpd to come on stream in 2005.

It is also on track to acquire for C$125 million the 78 percent interest it does not already own from TrueNorth Energy, an affiliate of Koch Industries.

UTS has a "high degree of confidence" that it will complete a secondary offering of C$100 million to C$125 million to complete that deal.

Regulators have approved production target

The new production target has been approved by the Alberta Energy Department, subject to UTS completing its purchase of the TrueNorth stake. Other regulatory approvals are already in hand.

Until the TrueNorth deal is concluded, UTS will not release details of how it intends to finance initial construction and subsequent expansion plans.

Beyond arranging the financing, UTS faces the challenge of searching for partners to spread the financial risk and introduce expert staff over the next two years.

The first-phase cost of Fort Hills is now in the C$1.6 billion to C$2 billion range, compared with the original price tag of C$3.3 billion.

UTS estimates that taking over TrueNorth will cost about 8 cents per barrel of reserves for a lease that covers 46,000 acres and has 4.9 billion barrels of bitumen in place, of which 2.8 billion barrels are recoverable over 40 years.

Lease close to other mines

The lease has the added advantage of being alongside the bitumen mines oper-

see **OIL SANDS** page 14

NORTH SLOPE, ALASKA

Anadarko talking with Pioneer about adding adjacent lease to Oooguruk unit

Anadarko Petroleum holds a state of Alaska oil and gas lease which is pretty much in the middle of the Pioneer Natural Resources-Armstrong Oil and Gas Oooguruk unit off Alaska's North Slope. This lease, long past its original expiration date, is still valid because the state has certified a well on the lease, Exxon's 1993 Thetis Island No. 1, as capable of producing in paying quantities.

Anadarko is required to present a plan of development for the lease every year.

The company told the Alaska Division of Oil and Gas June 28 that its plans for the next year of the lease (Aug. 1, 2004, through July 31, 2005) are to continue working on

see **ANADARKO** page 14

CANADA

Asian outlets beckon oil sands producers

The robust economies of Japan, Korea and China could open new doors for Canada's heavy and synthetic crude, according to the Alberta Energy Research Institute. Because synthetic crude yields larger volumes of diesel fuel compared with gasoline, it is a "very attractive option" for Chinese refineries, said Dr Catherine Laureshen, of the institute.

She told a recent conference exploring new markets for oil sands production that the demand for diesel is especially high to support China's agricultural economy.

China, which currently produces 2.8 million barrels per day, is consuming almost 6 million bpd and expected to reach 10 million bpd by 2010.

Korea, with no domestic output, consumes about 2.5 million bpd, while Japan imports 4 million bpd — a level that is expected to decline as it moves to alternative energy sources. Laureshen noted that long-term supply deals between producers and potential consumers are essential to support the capital investment that would be needed to move Alberta oil outside North America.

But she said growing output from the oil sands makes it necessary that "we figure out what to do with it" beyond the heavy reliance on the U.S. Midwest and possibly the Gulf Coast.

However, Bill Henderson, marketing vice president with Terasen, said Canadian crude is more expensive in the Asia-Pacific region than Middle East oil.

He suggested that over the longer term, California might be a better bet than Asia, adding it will take time for the Asian markets to develop.

—GARY PARK, Petroleum News Calgary correspondent

GULF OF MEXICO

Current Deepwater Activity

Operator	Area/ Block	OCS Lease	Rig Name	Prospect Name	Water Depth (ft)
BP Exploration & Production Inc.	WR 724	G17011	OCEAN CONFIDENCE	Das Bump	7,591
Shell Offshore Inc.	MC 657	G08496	R&B FALCON NAUTILUS	Coulomb	7,565
Chevron U.S.A. Inc.	WR 759	G17016	TSF DISCOVERER DEEP SEAS	Jack	6,965
BP Exploration & Production Inc.	GC 743	G15606	TSF DEEPWATER HORIZON	Atlantis(GC)	6,829
BP Exploration & Production Inc.	MC 778	G09868	TSF DISCOVERER ENTERPRISE	Thunder Horse South	6,040
Dominion Exploration & Production, Inc.	MC 734	G21778	TRANSOCEAN CAJUN EXPRESS	Thunderhawk	5,724
Dominion Exploration & Production, Inc.	MC 773	G16647	PRIDE 1503	Devil's Tower	5,610
Marathon Oil Company	AT 488	G18617	NOBLE AMOS RUNNER	Kansas 2	4,725
Spinnaker Exploration Company, L.L.C.	MC 124	G24049	GLOMAR JACK RYAN	Zorin	4,479
BHP Billiton Petroleum (GOM) Inc.	GC 653	G20084	GLOMAR C. R. LUIGS	Shenzi	4,340
Anadarko Petroleum Corporation	GC 608	G18402	NABORS POOL 140	Genghis Khan	4,287
Anadarko Petroleum Corporation	GC 518	G21801	NOBLE PAUL ROMANO	K2 North	4,049
Chevron U.S.A. Inc.	GC 640	G20082	FALCON DEEPWATER MILLENNIU	Tahiti	4,017
Eni Petroleum Co. Inc.	GC 562	G11075	GLOMAR CELTIC SEA	K2	3,933
Kerr-McGee Oil & Gas Corporation	EB 688	G09191	DIAMOND OCEAN STAR	Boomvang (East)	3,786
Shell Offshore Inc.	GC 248	G15565	NOBLE MAX SMITH	Glider	3,440
Eni Petroleum Co. Inc.	GC 254	G08010	DIAMOND OCEAN VALIANT	Allegheny	3,225
Shell Offshore Inc.	VK 956	G06896	H&P 205	Ram-Powell	3,214
Kerr-McGee Oil & Gas Corporation	GB 668	G17408	NABORS MODS RIG 150	Gunnison	3,152
TOTAL E&P USA, INC.	MC 243	G19931	SUNDOWNER XVI	Matterhorn	2,816
Chevron U.S.A. Inc.	GC 205	G05909	NABORS 85 (MAYRONNE 162)	Genesis	2,590
Walter Oil & Gas Corporation	MC 583	G16624	DIAMOND OCEAN LEXINGTON	Killer Bee	2,487
Murphy Exploration & Production Company -	MC 582	G16614	MODS 141	Medusa	2,214
LLOG Exploration & Production Company	GB 378	G24488	DIAMOND OCEAN SARATOGA	GB 378	2,044
Kerr-McGee Oil & Gas Corporation	GB 244	G15860	TRANSOCEAN MARIANAS	Basal Peak	1,946
Chevron U.S.A. Inc.	VK 786	G10944	ENSCO 25	Petronius	1,754
El Paso Production GOM Inc.	EW 1003	G06921	SUNDOWNER XI	Prince	1,483
BP Exploration & Production Inc.	MC 109	G05825	H&P 203	Amberjack	1,030

Total Deep Water Prospects with Drilling/WO Activity 28

DALLAS, TEXAS

Cowboys owner Jones teams with Touchstone to explore Maverick Basin

Pennsylvania's Touchstone Resources has teamed up with Dallas-based Blue Star Operating to explore for oil and gas in the Maverick basin in South Texas, Touchstone said June 28. Blue Star, an exploration and production independent, is controlled by Dallas Cowboys owner Jerry Jones.

Touchstone said it formed a new subsidiary called Maverick Basin Exploration, which entered into an exploration and production agreement with Jones' Blue Star covering 20,000 acres in the Maverick Basin. The companies will share a 50-50 working interest in the acreage and Touchstone will serve as operator.

Touchstone said a number of drilling targets have been identified from 3-D seismic shot over the entire 20,000 acres. Engineering estimates indicate the area could yield more than 180 billion cubic feet of natural gas equivalent, the company said, adding that it plans to drill about 125 wells.

"We anticipate commencing our exploration activities by late July and plan on a very aggressive drilling schedule through year end on this project," Touchstone President Stephen Harrington said.

Touchstone said it would "pursue aggressively" the acquisition of other acreage in the Maverick Basin, which the company noted has seen a significant increase in exploration and development activity over the past 18 months.

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

GULF OF MEXICO

Shell sets world records for deepwater well completions

Shell Exploration & Production Co. has launched natural gas production from its Gulf of Mexico deepwater Coulomb development, which the company said consists of the two deepest well completions in the world in terms of water depth.

The world record-breaking wells are on Mississippi Canyon blocks 657 and 613 and tied back via a 27-mile flowline to the BP-Shell Na Kika floating development system on Mississippi Canyon block 474, Shell said June 29.

Shell said that in early May the C-2 well became the world's deepest water depth completion in 7,565 feet of water and was followed two weeks later with a new record at its C-3 well, completed at a water depth of 7,570 feet of water.

The C-2 is currently producing about 65 million cubic feet of gas per day and continues to ramp up, Shell said, adding that both wells combined are capable of producing around 100 million cubic feet of gas per day.

Shell holds a 100 percent interest in the C-2 well and Petrobras America is a one-third partner in the C-3 well.

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

Gulf platform resumes petroleum production after repair work

Shell Oil Co.'s deepwater Mars platform in the Gulf of Mexico resumed production of oil and natural gas June 28 after about five weeks of repairs, the company said.

Shell closed production on May 22 after workers discovered a pipeline leak that released a few gallons of crude oil into the water.

Shell closed production on May 22 after workers discovered a pipeline leak that released a few gallons of crude oil into the water.

During an inspection, workers found that a natural gas line also showed signs of deterioration, thus forcing a longer delay in starting production, Shell said. The gas pipeline did not leak, the company said.

Shell said it would take two to three days to reach full production of 150,000 gallons of crude oil and 170 million cubic feet of natural gas per day.

The platform is about 130 miles southeast of New Orleans.

—**THE ASSOCIATED PRESS**

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ANADARKO

"regional interpretations and reservoir quality predictions" for the area of the lease, as well data becomes available from the Oooguruk, Ivik and Natchiq wells.

Those were the wells drilled by Pioneer and Armstrong in the winter of 2002-03 on leases that are now part of the Oooguruk unit (Pioneer 70 percent, Armstrong 30 percent), in the shallow waters of Harrison Bay. Oooguruk is northwest of, and adjacent to, the ConocoPhillips Alaska-operated Kuparuk River unit.

Anadarko said it will continue talking with Pioneer "and evaluate participation in any proposed redefined Oooguruk unit" and will identify any owners of seismic over the area who might be interested in a joint reprocessing effort.

In the current plan year (August 2003-July 2004), Anadarko said it upgraded regional interpretations and reservoir quality predictions; continued talking with Pioneer about participation in the Oooguruk unit "as it may be expanded for the development of the Nechelik potential" and participated (with Pioneer) in licensing a three-dimensional seismic survey shot in 2000 over the southeast Colville Delta and Fiord.

Pioneer-Armstrong discovery came in 2003

In April 2003, after Pioneer announced a Jurassic oil discovery at the Ivik, Natchiq and Oooguruk wells in what the company was then calling the Northwest Kuparuk prospect, Alaska Division of Oil and Gas Director Mark Myers told Petroleum News that three Jurassic sandstones are known in the area. Myers said north of Kuparuk and all the way to the Alpine field and into the National Petroleum Reserve-Alaska "there are a series of three upper Jurassic-aged sandstones that are known to contain oil … staggering amounts of oil — the Alpine sand being the youngest, the Nuiqsut and the Nechelik."

In June 2003, when Myers approved Anadarko's 2003-04 plan of development, he noted that Anadarko had declined an invitation from Pioneer to include the lease in the Oooguruk unit.

Myers said in his approval that "development of the lease is likely dependent on negotiations with the working interest owners in the adjacent leases" to form a unit with a plan of development and operating plan acceptable to all the parties.

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

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OIL SANDS

ated by Syncrude Canada and Shell Canada.

The October 2002 regulatory approvals from the Alberta Energy and Utilities Board allow Fort Hills to produce up to 235,000 bpd.

If Deer Creek is successful with its initial public offering which closes in late July, it will aim to produce 10,000 bpd, starting at 600 bpd in 2005, according to the prospectus.

The small company said it will use the IPO's proceeds for facilities that burn natural gas to turn water into steam and inject the steam underground to make it easier to pump the molasses-like oil to the surface.

Deer Creek owns 84 percent of the Joslyn project, with the balance held by Enerplus Resources Fund, a Calgary-based income trust.

Hopes of a strong response to the IPO have been raised by another start-up, OPTI Canada, which generated C$1.8 billion in equity and debt for its share of a joint-venture with Nexen.

When OPTI attracted C$301 million in April, it was the biggest non-income trust IPO in Canada since 1993, according to the Investment Dealers Association of Canada. ●

● FAIRBANKS, ALASKA

Pump Station 9 goes electric

Alyeska signs 20-year contract to purchase electricity from Interior Alaska utility for Delta-area pump station

By PATRICIA LILES

Petroleum News Contributing Writer

Alyeska Pipeline Service Co., operator of the 800-mile trans-Alaska pipeline system, plans to convert one of its pumping stations to electricity, drawing up to 16 megawatts of power from the Interior Alaska electric grid.

Part of Alyeska's $250 million pipeline reconfiguration project is an effort to either electrify or upgrade existing power generation equipment in four pump stations, 1, 3, 4 and 9. Pump Station 9, a few miles south of Delta Junction, will be hooked up to the existing Interior Alaska electric power grid, operated by Fairbanks-based Golden Valley Electric Association.

Currently, diesel-fired generators provide electricity at the pump stations. "A clean, reliable, electric power source provides substantial advantages for Alyeska, including environmental improvements over the current dependence on liquid fuel," said Alyeska president and CEO David Wight, in a June 25 press release announcing the 20-year contract with Golden Valley Electric for electric supply.

"Electricity generated by GVEA will power three new 6,500 horsepower electric motors and pumps that will boost the pressure in the pipeline to move oil from Pump Station 9 to the Valdez Marine Terminal," the release said. "Power for the new station will be available late in 2005 to coincide with construction and start-up of the new equipment."

Alyeska plans to install new, cleaner-burning and more fuel-efficient diesel generators at Pump Stations 3 and 4, said spokesman Curtis Thomas. Alyeska is still considering numerous options for electric power at Pump Station 1 on the North Slope, he added, declining to reveal potential power sources.

"We're looking for the best solution for moving oil, the most cost effective and the best for Alyeska," he said. Options to change the electrical supply at Pump Station 7, which is about 60 miles north of Fairbanks, are also being considered, Thomas said.

Spending to save

Alyeska estimates that the $250 million reconfiguration of pipeline operations will reduce operations costs by roughly 10 percent annually, Thomas said. "We'll eliminate maintenance costs for equipment and facilities that will no longer be required."

The actual dollar savings will fluctuate, depending on what particular maintenance projects are eliminated by the reconfiguration. Average yearly operating cost for the trans-Alaska pipeline is $500 million, he said.

Included in the capital reconfiguration costs is an undisclosed amount for a contract with Golden Valley Electric to pay for a two-mile transmission line to extend power service from Fort Greeley to Pump Station 9. In addition, Alyeska is helping to pay for Static Var Compensation (SVC) equipment, which provides voltage support, in Golden Valley's Jarvis Creek substation. "The SVC was necessary because of Alyeska's large load at the end of the line," Golden Valley spokeswoman Corinne Bradish said.

> *"A clean, reliable, electric power source provides substantial advantages for Alyeska, including environmental improvements over the current dependence on liquid fuel."* **—Alyeska Pipeline Service Co. President and CEO David Wight**

Golden Valley invests in southern line

Golden Valley's electric grid will be upgraded as a result of the Alyeska contract and other new electric demand in the Delta Junction area.

Construction of the Pogo gold mine northeast of Delta Junction is expected to add 13 megawatts of demand to Golden Valley's system, and the National Missile Defense project at Fort Greeley should add another 5 megawatts. Including general growth in the Delta Junction area, Golden Valley plans to add another 35 megawatts of power demand to its system load, Bradish said. Right now, Golden Valley provides about 10 megawatts of power to the Delta Junction area.

To supply this new electric demand, Golden Valley plans to build a new substation in North Pole, adjacent to its existing facilities, and to upgrade its Carney substation near shuttered Pump Station 8, about midway between Fairbanks and Delta Junction.

In addition, the utility plans to build a new 138 kV transmission line from North Pole to the Carney substation, which will increase the utility's capacity to send up to 70 megawatts of electric power south, Bradish said.

Estimated costs for those projects, which are scheduled to begin this winter and be completed in October 2005, are $8 million for the transmission line and $4 million for the two substations.

In addition, Golden Valley plans to build a new gas-fired power plant in North Pole, providing an additional 60 megawatts of power when completed in early 2006. A contract to build that facility is expected to be signed sometime in July, Bradish said. Estimated costs are $75 million.

That new generation plant is due "on line right around the time we'll be needing to serve Alyeska," Bradish said. "They're all tied together."

The electric association will receive "return on the cost of this infrastructure through power sales agreements with Alyeska and eventually Pogo. We signed a 20-year contract with Alyeska and they'll be billed under our industrial rate."

Industrial users are charged $180 per month, plus a demand charge of $11.25 per kilowatt and an energy charge of 5.197 cents per kilowatt hour. Golden Valley and Alyeska both declined to reveal estimated electric costs for powering the pump station. ●

MEXICO

Mexico's crude production up 2.2%

Mexico's crude production rose 74,000 barrels per day in May, a 2.2 percent increase compared with the same period last year, Pemex said.

Mexico's state-owned oil monopoly said it produced 3.39 million barrels of oil a day in May. Pemex, which has been on a drive to boost oil production, said part of the increase was due to higher production of heavy crude, which reached output of 2.46 million barrels a day, a 4.5 percent increase over May of 2003. Total hydrocarbon production, including oil-derived fuels, increased to 3.85 million barrels a day, an increase of 3.2 percent.

Offshore wells accounted for about two-thirds of the Mexico's oil production in May, Pemex said. Mexico's President Vicente Fox has said he wants to open up Mexico's offshore sector to foreign oil companies that can supply the technology that Pemex lacks to do deepwater drilling in the Gulf of Mexico. However, his proposals have stalled amid fierce opposition from political opponents.

Pemex also said it earned more than $8 billion from oil exports from January to May, $1.1 billion more than the same period for the previous year. The increase was due largely to the higher price of crude, which rose by $3.66 to an average price of $28.41 per barrel, compared with the same period in 2001, Pemex said.

—**DEBRA BEACHY,** Petroleum News contributing writer

NORTH AMERICA

Rig counts rebound to total 1,510

The North American rotary rig count, following a week in which the count plummeted by 93, rocketed by 143 to 1,510 rigs for the week ending June 25, according to rig monitor Baker Hughes.

Canada accounted for nearly all of the increase, rising by 138 for a total of 334 rigs versus the previous week. The rig count also was up by 24 rigs compared to the same weekly period last year. The United States gained a net five rigs to end the recent week with 1,176 rigs, an increase of 102 compared to the same period last year. Land rigs, compared to the previous week, increased by eight to total 1,063 rigs. Inland water rigs decreased by two to 18, while offshore rigs slipped by one to total 95.

> *Canada accounted for nearly all of the increase, rising by 138 for a total of 334 rigs versus the previous week.*

Of the total number of rigs operating in the United States during the recent week, 1,005 were drilling for natural gas and 170 for oil, while one rig was being used for miscellaneous purposes. Of the total, 722 were vertical wells, 321 directional wells, and 133 horizontal wells.

Among the leading producing states in the United States, Louisiana gained two rigs in the recent week to total 167 rigs. California picked up one rig to total 24, while Texas gained one rig to total 491. New Mexico's rig count fell by two to 66, while Oklahoma's decreased by two to 165. Alaska lost one rig to total six. Wyoming was unchanged at 80 rigs.

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

SUGAR LAND, TEXAS

Noble buys jackup rig for $29.5M

Noble Corp. said one of its subsidiaries has purchased the Okhi, a 300-foot Levingston 111-S designed independent leg jackup rig, for $29.5 million in cash.

The unit is currently in Wakkanai, Japan, and is being prepared for mobilization to Dalian New Shipyard in Dalian, China, where it will undergo refurbishment and upgrade work, Noble said June 25.

The company said it is marketing the rig for operation in the Middle East, India and Southeast Asia. The unit is being equipped to operate in 230 feet of water.

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

● ALBERTA

Alberta: We're in the money

Oil, gas revenue gusher pumps extra C$3B into province coffers in 2003-04; finance minister hopes to wipe out debt in 2005

By GARY PARK

Petroleum News Calgary Correspondent

An oil and natural gas revenue bonanza gave the Alberta government a C$4 billion surplus for the 2003-04 fiscal year, four times the initial forecast.

The C$3 billion bonus came largely from oil and gas revenues, which tallied C$7.6 billion for the year ended March 31, 61 percent above the budget projection.

Finance Minister Pat Nelson said that if commodity prices remain at their current levels, the province could pay off its remaining C$3.7 billion debt in time for its 100th birthday in 2005.

The highlights released by Nelson June 29 showed that Alberta achieved its 10th consecutive balanced budget; Albertans have the highest personal disposable income per capita in Canada; and created 47,900 jobs, the best performance of any province.

Alberta Heritage Savings Trust Fund recovers

The windfall saw a sharp recovery in the value of the Alberta Heritage Savings Trust Fund, a second-cousin to the Alaska Permanent Fund.

Finance Minister Pat Nelson said that if commodity prices remain at their current levels, the province could pay off its remaining C$3.7 billion debt in time for its 100th birthday in 2005.

The fund's investment portfolio rose by C$2.45 billion, posting an overall return on investment income of 22.5 percent, the largest single rise in the history of the 28-year fund.

It ended the fiscal year with a value of C$12.4 billion, and comes on the heels of a C$1.3 billion decline in 2002-03.

Revenue Minister Greg Melchin was all smiles one year after having to defend the government's strategy of investing heavily in the stock market.

"If we had panicked and changed our investment strategy during the last few years we would have missed this recovery," he said.

Sustainability Fund at C$2.5 billion

More money was added to the government's Sustainability Fund, which now sits at C$2.5 billion and is intended to deal with emergencies from forest fires to droughts, while helping the province ride out volatile swings in oil and gas prices.

For the current fiscal year, Nelson has based projections on oil prices of US$26 per barrel (US$10 below current levels) and C$4.20 per thousand cubic feet for natural gas (C$2.25 short of current prices).

Liberal leader Kevin Taft scolded Nelson for consistently being off-based with her projections. "No financial planner is going to be this far off and still have any credibility," he said.

He accused Premier Ralph Klein's Conservative government of "stumbling, fumbling mismanagement of our resources."

New Democrat spokesman Brian Mason said Alberta's enviable financial position is based solely on rich natural resources, not good management. ●

continued from page 1

RESULTS

Commons, 20 short of the number needed to run the country.

Having ruled out a formal coalition with any of the other political parties, the Liberals can stay alive only by horse-trading with their opposition on an issue-by-issue basis.

Among political observers there is a widespread feeling that Canadians, only 60 percent of whom voted on June 28, have no appetite for an early return to the polls and that the parties have neither the energy nor the finances to wage another battle in the short term.

However, the Liberals still have the challenge of forging alliances to continue governing.

The Conservatives, as the main opposition, have 99 seats, but are the least likely to support Liberal legislation, believing that they have made enough gains to win the next election.

That leaves the Bloc Quebecois with 54 seats, the New Democratic Party, NDP, with 19 and one independent.

Those options are further narrowed because the Bloc Quebecois is committed to an independent Quebec, although it has indicated a willingness to work with the Liberals on issues of importance to Quebec.

New Democratic Party is left-leaning

Thus, the hopes rest with the left-leaning NDP, which promotes a range of issues that raise alarm in the industry and has called for a tax hike of C$45 billion over five years, a full tax on capital gains, higher tax rates for incomes over C$250,000 and higher corporate taxes.

Under leader Jack Layton, the NDP is the most aggressive proponent of the Kyoto climate-change treaty that sets limits on greenhouse gas emissions and the least likely to favor swift regulatory approval of plans to develop the Arctic and frontier offshore regions.

In his opening salvo June 29, Layton threatened to block a deal to sell the federal government's remaining 19 percent stake in Petro-Canada for as much as C$3 billion.

"We have not supported the sale of Petro-Canada, particularly with such a pathetic percentage of the sale revenue going towards renewable energy and energy solutions," he said. "It is not a wisely cast policy, as we see it at the moment."

The NDP campaign platform called, among other things, for the creation of a government-owned corporation to fund and sell renewable energy sources and to build 10,000 wind turbines by 2010.

NDP supports Kyoto Protocol

During the campaign, Layton attacked the Liberals for not having a specific plan to implement the Kyoto Protocol, although the government has pledged to limit emission cuts in the oil and gas sector to 15 percent.

The industry has "probably been put on notice that Kyoto is going to have to be dealt with." **—Roger Soucy, president of the Petroleum Services Alliance of Canada**

"Paul Martin has said he agrees with Kyoto targets, but those are weasel words," he said.

Layton said the NDP wants action to move Canada away from its dependence on fossil fuels and, to that end, would rule out subsidies or tax incentives to help the petroleum industry achieve the Kyoto targets.

Martin had been expected by the industry to stick with Kyoto's broad principles, while setting a timeline and implementation objectives that would be acceptable to industry.

Roger Soucy, president of the Petroleum Services Alliance of Canada, said Kyoto now looms as a larger issue than ever before.

The industry has "probably been put on notice that Kyoto is going to have to be dealt with," he said.

Slower and fewer decisions expected

Even before the voting, Charlie Fischer, chief executive officer of E&P independent Nexen, said the history of minority governments would point to "far slower decisions and far fewer decisions because, in finding compromise, it just takes more effort."

He predicted the "most significant negative effect" would involve the Arctic and frontier regions where the government is "still really trying to define the regulatory structure."

David MacInnis, president of the Canadian Energy Pipeline Association, said "it's safe to say" the industry will have to do business "a little differently" in the changed political environment.

He said the uncertainty "means longer time lines and longer time lines mean higher costs."

The big issues at stake are:

Mackenzie

Mackenzie Gas Project — Applications to build a C$5 billion-plus pipeline from the Mackenzie Delta to Alberta are expected to be filed this summer with regulators. The major producer consortium led by Imperial Oil has repeatedly made the case that serious delays in the regulatory phase pushing the start-up of gas deliveries beyond 2009 could undermine the economics of the project, although the proponents are taking a measured view for now of the shift to minority government.

In keeping with plans for one of Canada's largest pipelines, the regulatory phase, despite moves to conduct a joint environmental review, involves 12 government and aboriginal agencies, most of them with a strong environmental interest.

Given the NDP's claim to have the only "green option" among Canada's four major political parties, the Mackenzie project would be an early opportunity for Layton to assert himself without having an apparent impact on Canada's wider economy or energy security.

In addition, the federal government is already under pressure to resolve the Deh Cho First Nations land claims along the lower one-third of the Mackenzie pipeline route, presenting Layton with a chance to align himself with an aboriginal cause.

British Columbia offshore

British Columbia offshore — The province's hopes of lifting the moratorium on exploration of the region by 2010 could be dealt a serious, if not fatal blow if the Liberals move to the left to appease the NDP. Environment Minister David Anderson, who has insisted on costly environmental impact studies before opening the offshore to exploration and drilling, was re-elected June 28, although there is some speculation he may be dropped from the cabinet.

Regardless of that prospect, the NDP candidate won the riding most directly affected by any offshore development of the Queen Charlotte Basin, with its possible 26 trillion cubic feet of gas reserves and 9.8 billion barrels of oil.

British Columbia Energy Minister Richard Neufeld, who has distanced himself from some of the province's more bullish forecasts that a commercial offshore industry could be up and running this decade, is still holding Martin to his campaign promise to put the British Columbia offshore on the same footing as the East Coast offshore.

"I'm banking on it that his word is true," Neufeld said, while conceding that a balance-of-power position for the NDP is not good news for British Columbia.

East Coast offshore

East Coast offshore — A string of dry holes in the last couple of years and a host of exploration licenses that start to expire this year has the future of the East Coast hanging in the balance, regardless of its fledgling exploration history, with just 200 wells drilled compared with more than 40,000 in the Gulf of Mexico.

The industry, with EnCana in the forefront, has pressured the Canadian and Nova Scotia governments to streamline the regulatory process, which is estimated to take twice as long as rival basins in the Gulf of Mexico and West Africa offshore. That goal produced its own conflict in the federal cabinet before the election, with Energy Minister John Efford favoring removal of "excessive" red tape, while Anderson insisted he was more concerned with protecting marine ecosystems.

Adding the NDP to the mix is not likely to hasten regulatory reform.

Alberta oil sands

Alberta oil sands — The sector is the highest profile target for those who want Kyoto fully implemented, because of its carbon dioxide emissions. If the NDP decides to put the oil sands in its sights, it could spell trouble for the 61 projects currently on the table.

In addition, the industry has been making a case for human resource policies to ease labor shortages that are a major contributor to the crippling cost overruns on projects over recent years. But any changes to labor conditions could be unacceptable to the NDP because of its heavy reliance on organized labor. ●

Companies involved in North America's oil and gas industry

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

Petroleum news

Business Spotlight

By PAULA EASLEY

FORREST CRANE

Dennis Mitchell, international manager

Lynden International

Lynden International began operations in 1977 as a division of Lynden Transport. Lynden International now maintains 50 offices worldwide. The international division provides complete logistics services, including customs brokerage, project services, and air and ocean charters. The Sakhalin office recently expanded to accommodate several new logistics contracts.

Dennis Mitchell's responsibilities also include customs compliance. He joined Lynden nine years ago and has been a licensed customs broker for 20 years; he loves the business, including the worldwide travel. Dennis and his wife Melissa have two grown children, Lydia and Owen. With both in college this fall, Dennis' goal is to survive the next four years of tuition in the black, so all generous contributions will be enthusiastically accepted.

FORREST CRANE

William Dix "Bill" Fowler, president and COO

Northern Air Cargo

Delivering what customers want, when and where they want it is Northern Air Cargo's corporate goal. This longtime Alaska operation has recently added new aircraft to better accommodate customer needs. Operations are in Anchorage, Fairbanks and 19 out-stations. NAC specializes in cost-effective, just-in-time transportation services for its diverse government and private clientele.

Fairly new to the airline business, Bill Fowler brings years of construction management experience to his leadership position at NAC. An Alaskan since 1969, he's quickly learning the industry and its challenges. Bill is married (40 years), has four grown children and three grandchildren. He is a member of AEDC and the UAF College of Fellows.

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premier and from Minister of Energy and Mines Richard Neufeld — and the province changed the way it does business with the oil and gas industry.

"We did things in British Columbia — after undertaking a confidential analysis of all oil and gas jurisdictions in the United States, Norway, Saudi Arabia and Australia. And we built a regulatory regime that works for British Columbia," Ross Curtis, assistant deputy minister in the British Columbia Ministry of Energy and Mines, told the state chamber's summer energy seminar June 22 in Anchorage.

Regulation wasn't the only change: oil and gas taxation and permitting were also overhauled.

Part of the comparative risk analysis that British Columbia did, Curtis said, was a "quite comprehensive economic analysis," looking at how much money the oil and gas companies would make and how much royalty the government would get.

Creating favorable geese habitat

Curtis characterized what the province has done over the last four years as creating favorable goose habitat for the oil company "geese" that lay all of those golden eggs.

Geology is what attracts them, he said, but "… if you want them to stay, they have to have a happy home and you have to treat them well." And it isn't just government that benefits, he said: By creating a good habitat for geese, and increasing egg production, "the service sector gets a share and the government gets a share and the company gets a share."

British Columbia annually produces 1.1 trillion cubic feet of natural gas a year and 14 million barrels of oil, he said, but only one of its seven basins is in production.

"The total revenue for oil and gas last year was $2 billion — that's just royalty revenue," Curtis said.

To get that level of royalties, the British Columbia government intervened in "all of the processes: We changed royalties. We changed taxes. We changed property taxes. We changed the regulatory regime. We changed how we work with companies. We changed how we work with communities. We changed how we work with First Nations."

The result, he said, is that oil and gas is now the single largest source of resource revenue for British Columbia.

Since these golden geese are attracted to geologic potential, Curtis said, government needs to advertise its geologic potential. But once the geese are attracted, Curtis said: "They have to have infrastructure" if they're going to stay. This includes roads, power and a service industry "that can provide competitive services in a timely fashion."

They also need certainty in taxation and regulation. On the regulatory side, companies need to know how quickly they can get permits; on the fiscal side, the royalty and tax regime "doesn't necessarily have to be simple — often it can be quite complicated — the key is providing certainty."

Golden geese 'high maintenance'

If the habitat is right, he said, oil and gas companies will spend huge sums of money, but it's important that these geese get to keep a share of the eggs, he said, "because otherwise there won't be any reinvestment in their company" and the shareholders won't tolerate that.

But, he warned, these geese are "high maintenance. They're really high maintenance." They need fast response from government so they can respond to supply and demand, and government needs to keep up with technology.

Curtis said he got a call from a company president in Houston last year, complaining that his company wanted to do a $50 million seismic program, but the province's oil and gas commission wouldn't accept the application.

When he flew up to Fort St. John to the British Columbia Oil and Gas Commission to find out what the matter was, Curtis said what he discovered was that while the province's regulations required terrestrial mapping for seismic, the company had submitted a three-dimensional geologic image based on satellite imagery enhanced with results from an infrared tachometer flown over the area.

"You could actually identify individual animals … Our guys simply had no idea what to do with it."

For government to be responsive to the industry, it has to keep up with the technology, he said.

Geese can fly

"Now the other thing you have to remember about these geese is you don't ever want to piss them off, because you know what? They fly away. And when they fly away, it's really hard to get them back, because somebody else has them. And they're going to be nice to them," Curtis said.

And trying to choke an extra egg out of the goose with more taxation (he showed a cartoon of four hands around the neck of a goose) may work for a time, he said, "but the second those hands slip off, that guy's out of here, and you won't attract any more geese."

The government is the farmer, he said, and its job is to nurture the goose, and to attract more geese, and "to help the goose increase production."

The government's job is "to develop and operate and keep the farms clean and open." And it's an important job, he said, because it isn't just geese on the farm: "there's the service sector, there's the rest of industry: they all have to survive."

The job of the goose is "to produce more eggs and to be an exemplary steward on its part of the farm," Curtis said.

What did British Columbia do?

The direction from his government was to make British Columbia more competitive for oil and gas investment.

"I can't change the geology," Curtis said, but "I can compensate for it" with royalty reductions and with a "single-window" oil and gas commission for permits.

Royalty reductions were something the provincial government was willing to do to attract investment.

On the permitting side, the British Columbia Oil and Gas Commission, "in part modeled on the state of Alaska's" commission, was created to provide "single-window" permitting for everything from the camp toilet to putting pipe in the ground to drilling wells. The commission, he said, is "fully funded by the oil and gas industry" through fees and a levy on production. The commission now averages 18 days to get a permit out, and the target for next year is 14 days, and for the following year, 10 days.

British Columbia is also moving to electronic permitting.

And it is working with stakeholder groups and industry to change regulations to performance based.

And the province has developed what Curtis called a "shared vision" with the Canadian Association of Petroleum Producers.

"This isn't all about making money for oil and gas companies — it's about having a strong and viable service sector…," he said, and about community involvement and about working with the First Nations.

Competitive changes

Only one of seven basins in the province was under production, so the ministry went out and talked to industry, to the communities, to First Nations and to environmentalists.

"And what we came up with was what we call the oil and gas development strategy," Curtis said, focused on infrastructure, royalties, the service sector and regulation.

Infrastructure was crucial, because "British Columbia operates on what we called 100 days of hell — which is about 100 days of the year where it's frozen so you've got better access to the ground," much of which is muskeg. The short season not only limited the number of wells that could be drilled, it meant the local service sector had a hard time being competitive because all its costs had to be recovered in that 100 days, he said.

A better road system was crucial to extending the drilling season, he said. In the past, companies were forced to build expensive roads which might have no other use, he said — millions of dollars spent to move 10 drilling rigs.

The government decided, he said, that "if we owned the resource, then we should be sharing the risk of developing it" if economic viability was an issue. The government has contributed $30 million in royalty road credits each in 2003, 2004 and 2005, and an additional $10 million is budgeted for 2006.

The province put $30 million into one such road four years ago, Curtis said. "That road has already paid off more than $400 million in royalty returns to the province." Technically, he said, he is the manager of that road, but in fact, "all I simply do is collect money off the companies, provide them a royalty credit and the companies have a road usage group" that has contracted with a local firm for roadwork. "It's kind of a public-private partnership. It seems to be working extremely well," he said.

The province has two criteria for a road to receive credits: two companies must use the road, and the road must be an arterial for somebody — a forest, or forest fire access or a logging community, Curtis said.

The province has also gotten somewhat more pragmatic about road use. The province's department of highways closes roads for heavy loads when it thaws. But road damage is now being balanced against drilling.

"If I can drill one more average gas well, one more well in a year, that has a net credit value of $2 million" to the province, so instead of having the highway closed because moving a rig could do $25,000 worth of damage, Curtis said, "forget it: I'll pay (the highway department) the $25,000 and take my $2 million."

Royalty credits are also available for pipelines and telecommunications and power equipment.

Targeted royalties

British Columbia's royalty system is not simple, but reflects the willingness of British Columbia to make production economic by sharing the risks.

Curtis said he discovered that the province had 5,000 shut-in wells, shut-in because at existing royalty rates the wells weren't economic. A royalty change put "500 of those wells back in production within 30 days."

"We have the ability to put in a royalty program for anything a company comes in the door with … anything to do with high-risk" drilling, Curtis said.

The province will share the risk with companies on unconventional gas — coalbed and tight shale — as well as on re-entry drilling, deep wells, directional and horizontal wells, and on summer drilling.

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THUNDER HAWK

ery at Thunder Hawk in early May, reporting at least 100 feet of hydrocarbon bearing section in multiple thin sands of the middle Miocene horizon. It apparently took a sidetrack off the main well bore to establish the prospect's true potential.

Both Thunder Hawk and Thunder Horse, in the Boarshead basin, are overlain by so-called "allocthonous" salt bodies, which tend to distort seismic readings and make imaging difficult.

Sidetrack results encouraging

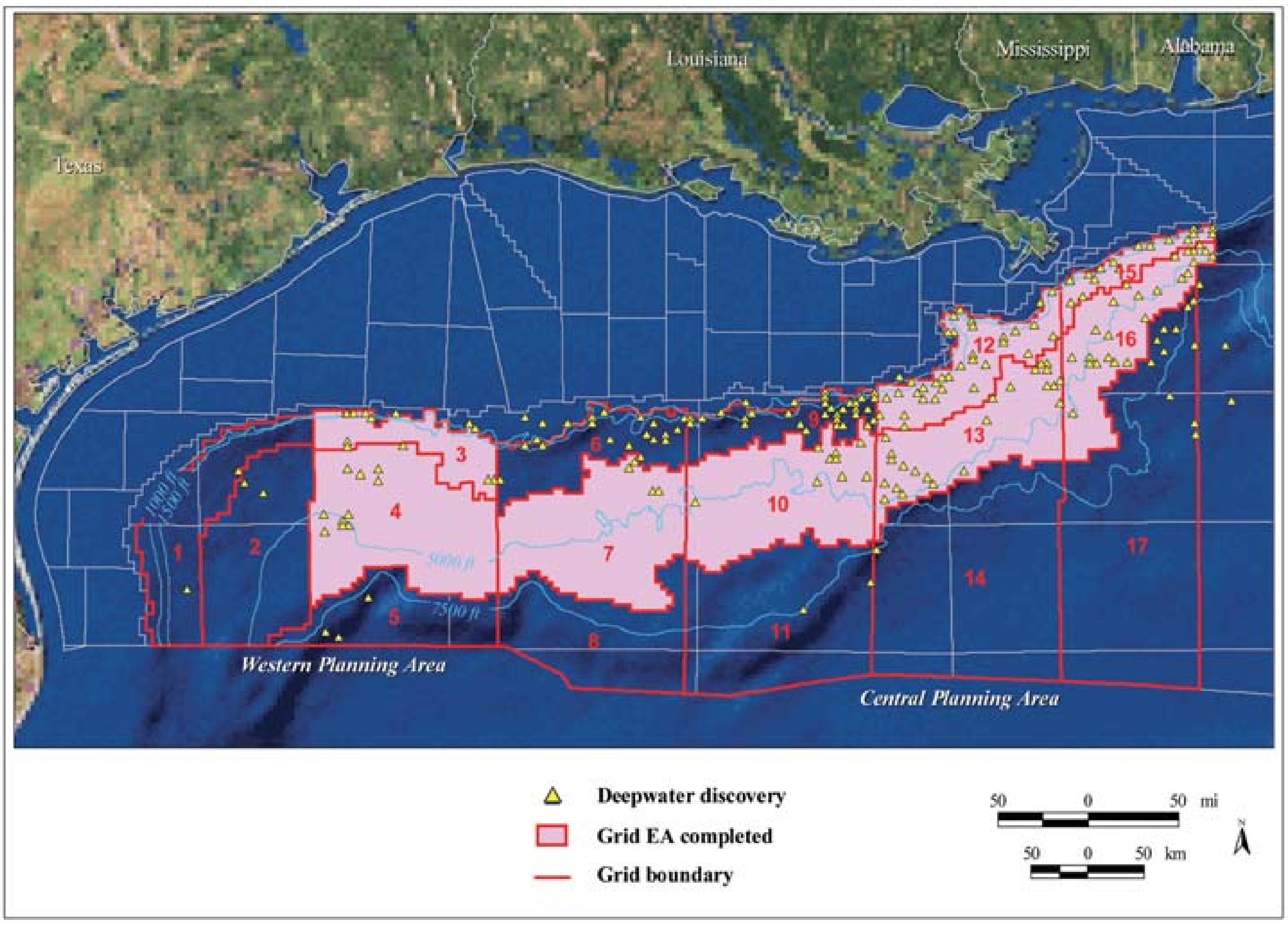
"We are very encouraged by the results of the sidetrack well and are assessing delineation drilling options," Duane Radtke, Dominion's chief executive officer, said June 28.

The sidetrack well, on Mississippi Canyon block 734, was drilled 150 miles southeast of New Orleans, La., in a water depth of 5,724 feet. The well reached a total measured depth of 24,831 feet and a true vertical depth of 23,101 feet. Dominion said the well would be temporarily abandoned.

The approximately 300 feet of net oil pay encountered by the sidetrack was situated "in two high-quality reservoir zones," the company said.

"Our current estimate of reserves based on the two penetrations is from 50 to 150 million barrels of oil equivalent," Radtke said.

Dominion holds a 25 percent working interest in Thunder Hawk. Murphy has 37.5 percent stake, followed by Spinnaker with a 25 percent interest and Pioneer with a 12.5 percent position.



Thunder Hawk is in block 16 between 5500 and 6000 feet of water. Thunder Horse is in the same block, at 6000 feet.

Both fields in Boarshead basin

Both Thunder Hawk and Thunder Horse, in the Boarshead basin, are overlain by so-called "allocthonous" salt bodies, which tend to distort seismic readings and make imaging difficult. The eight-block Thunder Horse complex is scheduled to launch first production next year at 250,000 barrels of oil per day and 200 million cubic feet of natural gas per day.

However, because of the region's complex geology and reservoir imaging challenges, no one is certain of Thunder Horse's true potential.

Some analysts believe the play could hold upward of 7 billion barrels of recoverable reserves, although 3 billion barrels is often cited as the likely mean.

Most of the federal leases within a 15-mile radius of Thunder Horse have been scooped up by various companies over the past five years, demonstrating the region's strong attraction to explorers. Other players in the area include Shell, ChevronTexaco, ConocoPhillips, Marathon Oil and Anadarko Petroleum.

However, the Thunder Hawk partners were able to acquire their prospect in the 2000 Central Gulf of Lease Sale 175 for an uncontested $2.1 million. Ironically, Thunder Horse partners ExxonMobil and BP chose not to bid on the block. ●

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Summer drilling

In addition to a royalty credit for summer drilling, more roads expand the drilling season, as does the use of mats for drilling pads.

The result? In 2001, Curtis said, there were no summer wells drilled. In 2002 there were 150 summer wells, in 2003 there were 300 and this year there are expected to be 500 summer wells.

In addition to helping increase the number of wells drilled, expanding the seasons helps make the service sector more competitive. For the drilling company, it means the crew isn't working at minus 50, and they stay around longer, and safety numbers have improved.

In addition to longer contracts for drillers, the service sector got longer contracts, and "because they're not in that 100-day box any more they can lengthen out their capital costs."

Both industry revenues and provincial revenues, Curtis said, were increased by the summer drilling program.

"Often in the United States," he said, "what I seem to notice is that people underestimate the power that government can have" if that power is "used properly" to build "a sustainable, competitive habitat — what government can do to nurture the goose." ●

Editor's note: See information about the British Columbia oil and gas program at: www.em.gov.bc.ca/ogds