Petroleum news

page 5 Knowles backs SB 21; believes oil tax change needs time to work

page 5

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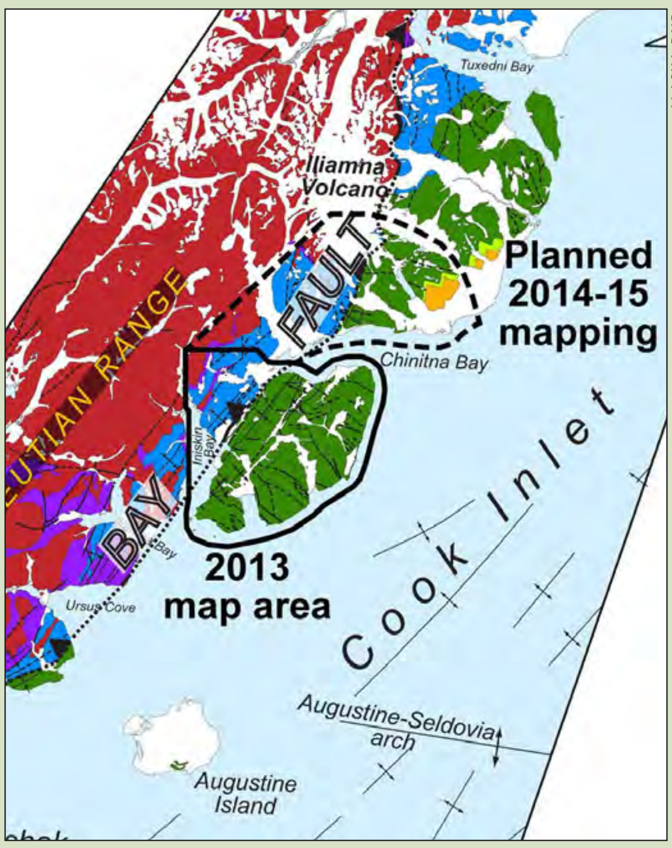
What are the odds?



The Iniskin Peninsula on the west side of Alaska's Cook Inlet has oil potential but has thus far eluded a significant hydrocarbon discovery. See story on page 12.

Buccaneer proposes reorganization; would repay unsecured creditors

Buccaneer Energy Ltd. has proposed a reorganization plan.

The bankrupt Australian independent and its eight subsidiaries have put forth a plan in the U. S. Bankruptcy Court for the Southern District of Texas for paying creditors.

For the plan to go ahead, it must first satisfy a long list of requirements set by the court, and it must also pass muster with certain classes of creditors, as determined by a vote.

Implementation of the plan would follow a proposed auction of the oil and gas assets held by Buccaneer and its eight subsidiaries. The companies, which have asked the court to consolidate their estates, are looking to hold the auction in early August. The plan would establish a liquidation trust to disperse assets collected during the auction.

Currently, creditors have until Sept. 29 to file claims, except for governmental entities, which have until Nov. 27 to file claims,

see **BUCCANEER PLAN** *page 17*

Point Thomson progress continues as ExxonMobil seeks air permit

On the tundra, and in offices, progress continues toward an elusive goal — first production from Point Thomson.

The latest indication is a preliminary decision by the Alaska Department of Environmental Conservation to approve an "air quality control construction permit" for ExxonMobil Corp., operator of the remote Point Thomson field.

It takes a lot to bring a new oil and gas field into production, and ExxonMobil now appears to be entering the home stretch in its effort to add Point Thomson to the ranks of producing units on Alaska's prolific North Slope.

Point Thomson is located on state leases about 60 miles east of Prudhoe Bay, next to the Arctic National Wildlife Refuge. The field was discovered in 1977.

ExxonMobil is aiming to start producing 10,000 barrels per day of natural gas condensate from Point Thomson beginning in 2016. Condensate is a form of light crude oil.

see **THOMSON PROGRESS** *page 17*

GOVERNMENT

Natives win ruling

Canada's Supreme Court: Consent mandatory between governments, First Nations

By GARY PARK

For Petroleum News

The Supreme Court of Canada has sent a tsunami wave through oil and natural gas, mining and forestry industries in a ruling that gives First Nations effective control over vast tracts of territory beyond the confines of their defined traditional lands.

The 80-page decision applies specifically to drawn-out litigation affecting about 660 square miles in British Columbia's central interior occupied by six communities within the Tsilhqot'in Nation, but has the potential to reshape resource development across Canada.

> *Chief Justice Beverley McLachlin wrote that the rights "conferred by aboriginal title means that governments and others seeking to use the land must obtain the consent of the aboriginal titleholders."*

The unanimous judgment represents a major victory for aboriginal groups, expanding their rights to claim possession of ancestral lands as a result of a semi-nomadic lifestyle and to control those lands permanently.

Chief Justice Beverley McLachlin wrote that

see **COURT RULING** *page 19*

EXPLORATION & PRODUCTION

Many new opportunities

Recent seismic data identifies more drilling targets in the aging Kuparuk field

By ALAN BAILEY

Petroleum News

Recent 3-D seismic surveys in the Kuparuk River field on Alaska's North Slope are enabling the identification of new drilling leads in the field, according to field operator ConocoPhillips' latest Kuparuk plan of development that the company has submitted to the Alaska Department of Natural Resources. A survey conducted in 2005 has enabled the discovery of a number of drilling opportunities, including sidetrack wells using coiled tubing drilling, sidetracks using conventional rotary drilling, and the drilling of new wells, the plan says.

> *In addition to maximizing oil recovery within the traditional reservoirs of the Kuparuk field, ConocoPhillips sees potential for exploration and appraisal leads identified from seismic surveys within the Kuparuk River unit, the plan says.*

The results of another survey, conducted over 220 square miles of the western part of the Kuparuk River unit in 2011, are still being inter-

see **KUPARUK TARGETS** *page 18*

EXPLORATION & PRODUCTION

Fifth well on horizon

Furie obtains Kitchen Lights no. 5 permit as gas field development proceeds

By ALAN BAILEY

Petroleum News

Furie Operating Alaska has obtained a permit to drill a fifth well in the Kitchen Lights unit, in the northern part of the Cook Inlet.

In the latter part of the 2013 drilling season the company used its Spartan 151 jack-up drilling rig to start the drilling of the Kitchen Lights unit no. 4 well. Furie's President Damon Kade has told Petroleum News that his company's plans for the drilling of both the no. 4 and the no. 5 wells are confidential. However, both wells are clearly exploration wells and, given the timing of the permit application for the no. 5 well, Furie would appear to be planning to at least start the drilling of that well during the current drilling season.

> *Furie is currently engaged in the development of a gas field, based around the Kitchen Lights unit no. 3 well in the Corsair block.*

The Kitchen Lights unit is divided into four exploration blocks. In the southern part of the unit, immediately north of the East Foreland region of the Kenai Peninsula, lie the southwest and central blocks. In the middle lies the Corsair block, with the fourth block, the northern block, in the unit's northeastern sector.

Furie is currently engaged in the development of a gas field, based around the Kitchen Lights unit no. 3 well in the Corsair block. The development involves the installation of a new offshore gas production plat-

see **FIFTH FURIE WELL** *page 16*

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ON THE COVER

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PIPELINES & DOWNSTREAM

Alaska - Mackenzie Rig Report

The Alaska - Mackenzie Rig Report as of July 2, 2014.
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 Marti Reeve

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)	Prudhoe Bay DS 05-13B, workover	BP
Dreco 1000 UE	16 (SCR/TD)	Prudhoe Bay F-23, workover	BP
Dreco D2000 Uebd	19 (SCR/TD)	Alpine CD4-96	ConocoPhillips
AC Mobile	25	Prudhoe Bay Y-39	BP
OIME 2000	141 (SCR/TD)	Kuparuk 2.E-0	ConocoPhillips
Kuukpik	5	Stacked out 100% Pad Deadhorse, Royale Energy Well AK #1, AK #2, Winter 2014-2015	
Nabors Alaska Drilling			
AC Coil Hybrid	CDR-2	Kuparuk 2F-18	ConocoPhillips
Dreco 1000 UE	2-ES (SCR-TD)	Prudhoe Bay	Available
Mid-Continental U36A	3-S	Prudhoe Bay	Available
Oilwell 700 E	4-ES (SCR)	Prudhoe Bay	Available
Dreco 1000 UE	7-ES (SCR/TD)	Kuparuk	ConocoPhillips
Dreco 1000 UE	9-ES (SCR/TD)	Kuparuk	ConocoPhillips
Oilwell 2000 Hercules	14-E (SCR)	Prudhoe Bay	Available
Oilwell 2000 Hercules	16-E (SCR/TD)	Prudhoe Bay	Available
Emsco Electro-hoist-2	18-E (SCR)	Prudhoe Bay	Stacked
Emsco Electro-hoist Varco TDS3	22-E (SCR/TD)	Prudhoe Bay	Stacked
Emsco Electro-hoist Canrig 1050E	27-E (SCR-TD)	Deadhorse, under contract to ExxonMobil for 2015	
Emsco Electro-hoist	28-E (SCR)	Prudhoe Bay	Stacked
Oilwell 2000	33-E	Prudhoe Bay	Available
Academy AC Electric CANRIG	99AC (AC-TD)	Deadhorse	Availablel
OIME 2000	245-E (SCR-ACTD)	Oliktok Point	ENI
Academy AC electric CANRIG	105AC (AC-TD)	Deadhorse	Available
Academy AC electric Heli-Rig	106-E (AC-TD)	Deadhorse	Available
Nordic Calista Services			
Superior 700 UE	1 (SCR/CTD)	Prudhoe Bay Drill Site 2-07	BP
Superior 700 UE	2 (SCR/CTD)	Prudhoe Bay Well Drill Site E-36	BP
Ideco 900	3 (SCR/TD)	Kuparuk Well 1Y-34	ConocoPhillips
Parker Drilling Arctic Operating Inc.			
NOV ADS-10SD	272	Prudhoe Bay DS 18	BP
NOV ADS-10SD	273	Prudhoe Bay DS W-59	BP

North Slope - Offshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
BP			
Top Drive, supersized	Liberty rig	Inactive	BP
Doyon Drilling			
Sky top Brewster NE-12	15 (SCR/TD)	Spy Island SP12-SE3	ENI
Nabors Alaska Drilling			
OIME 1000	19AC (AC-TD)	Oooguruk ODSN-02	Pioneer Natural Resources

Cook Inlet Basin – Onshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Kenai Land Ventures LLC (All American Oilfield Associates, labor Contract)			
Taylor	Glacier 1	Kenai Loop Drilling Pad #1	Buccaneer Energy Ltd.
All American Oilfield Associates			
IDECO H-37	AAO 111	Kenai Yard	Available
Aurora Well Services			
Franks 300 Srs. Explorer III	AWS 1	Stacked out at Sterling	Available
Doyon Drilling			
TSM 7000	Arctic Fox #1	Beluga BRU 242-04	ConocoPhillips
Nabors Alaska Drilling			
Continental Emsco E3000	273E	Kenai	Available
Franks	26	Kenai	Stacked
IDECO 2100 E	429E (SCR)	Kenai	Stacked
Rigmaster 850	129	Kenai	Available
Saxon			
TSM-850	147	Ninilchik Unit, Bartolowits pad drilling Frances #1	Hilcorp Alaska
TSM-850	169	Swanson River	Hilcorp Alaska

Cook Inlet Basin – Offshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
XTO Energy			
National 110	C (TD)	Idle	XTO
Spartan Drilling			
Baker Marine ILC-Skidoff, jack-up		Spartan 151 Upper Cook Inlet KLU#1	Furie
Cook Inlet Energy			
National 1320	35	Osprey Platform RU-1, workover	Cook Inlet Energy
Hilcorp Alaska LLC (Kuukpik Drilling, management contract)			
		Anna Platform, Demobilized Hilcorp Rig 428 to shore	Hilcorp Alaska LLC
		Steelhead Platform, Well M-34 Grassroots, Drilling	Hilcorp Alaska LLC
Patterson UTI Drilling Co LLC			
	191	West McArthur River Unit #8	Cook Inlet Energy
Kenai Offshore Ventures			
LeTourneau Class 116-C, jack-up	Endeavor	Port Graham	Buccaneer Energy Ltd.

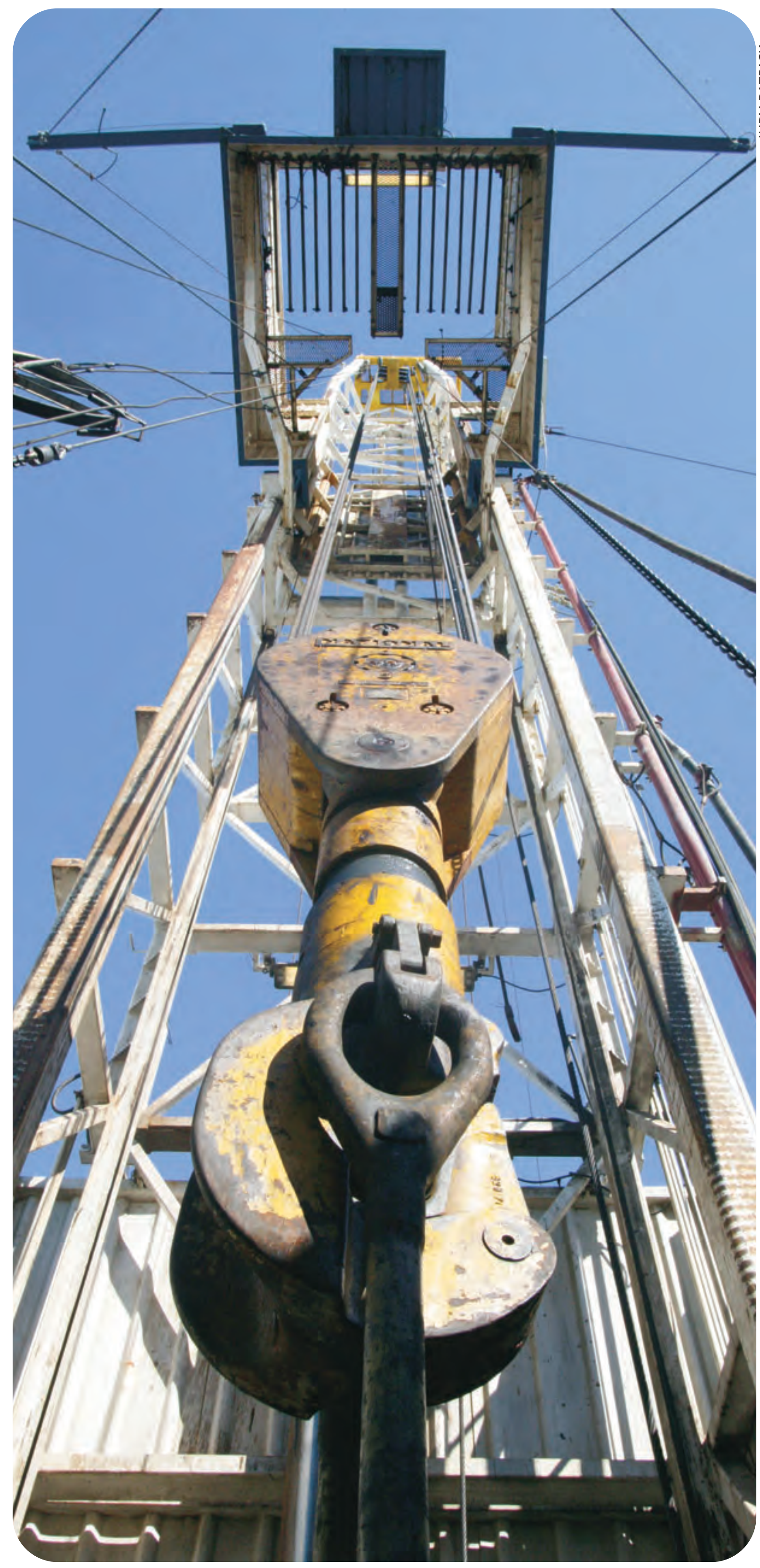
Mackenzie Rig Status

Canadian Beaufort Sea

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
SDC Drilling Inc.			
SSDC CANMAR Island Rig #2	SDC	Set down at Roland Bay	Available

Central Mackenzie Valley

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Akita			
TSM-7000	37	Racked in Norman Well, NT	Available



JUDY PATRICK

Baker Hughes North America rotary rig counts*

	June 27	June 20	Year Ago
US	1,873	1, 858	1,748
Canada	236	265	206
Gulf	54	57	54

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

The Alaska - Mackenzie Rig Report is sponsored by:

● EXPLORATION & PRODUCTION

Summer maintenance drops ANS production

North Slope averages 500,525 bpd in June, down 7.5% from May; includes first full pipeline shutdown of season; Cook Inlet also down

By KRISTEN NELSON
Petroleum News

Alaska North Slope crude oil production averaged 500,525 barrels per day in June, down 7.48 percent from a May average of 541,001 bpd, driven by the first scheduled summer maintenance shutdown of the trans-Alaska pipeline oil pipeline.

Alyeska Pipeline Service Co., operator of the trans-Alaska pipeline, had the line shut down for 24 hours of major maintenance June 20-21. Shorter shutdowns are scheduled over the summer and one additional long-duration shutdown Aug. 29-30.

North Slope producers take advantage of the Alyeska shutdown and summer weather for scheduled maintenance.

May production for Cook Inlet fields, as reported by AOGCC, averaged 16,073 bpd, down 1.22 percent from an April average of 16.271 bpd.

The largest month-to-month production drop was at the BP Exploration (Alaska)-operated Lisburne field, part of greater Prudhoe Bay, down 68.26 percent from May. That drop occurred because Lisburne was totally shutdown for almost two weeks, June 14-27.

BP spokeswoman Dawn Patience told Petroleum News in an email that "the Lisburne work is part of the summer turnaround schedule."

Lisburne averaged 8,806 bpd in June, down 18,938 bpd from a May average of 27,744 bpd. Crude oil from Point McIntyre and Niakuk is processed through the Lisburne facility.

June production information is from the Alaska Department of Revenue's Tax Division which reports North Slope oil production consolidated by major production centers and provides daily production and monthly averages. More detailed data, including Cook Inlet and individual North Slope fields and pools, is reported by the Alaska Oil and Gas Conservation Commission on a month-delay basis.

All North Slope producing areas down

All North Slope producing areas as reported by the Department of Revenue had month-over-month declines, showing daily production drops on either side of the Alyeska June 20-21 shutdown.

The ConocoPhillips Alaska-operated Kuparuk River unit averaged 135,538 bpd in June, down 9.09 percent from a May average of 149,092 bpd.

ConocoPhillips Alaska spokeswoman Natalie Loman told Petroleum News in an email that turnarounds included a shutdown at Kuparuk Central Processing Facility 3 scheduled to coincide with the June 20-21 trans-Alaska oil pipeline shutdown; a CPF 2 shutdown which began June 15 and will run through early August for inspection and modification work; and an annual turnaround at Alpine which will begin in late August and is estimated to take several days.

Kuparuk production includes satellites at Meltwater, Tabasco, Tarn and West Sak, as well as production from the Eni-operated Nikaitchuq field and the Caelus Alaska-operated Oooguruk field.

AOGCC data for May show that Nikaitchuq averaged 21,813 bpd, up 3.53 percent from an April average of 21,069 bpd, and Oooguruk averaged 13,012 bpd in May, down 16.52 percent from an April average of 15,587 bpd.

Endicott, Prudhoe down

The BP-operated Endicott field averaged 9,183 bpd in June, down 2.8 percent from a May average of 9,488 bpd. Endicott includes production from the Savant Alaska-operated Badami field, which AOGCC data show averaged 1,124 bpd in May, up 3.28 percent from an April average of 1,089 bpd.

The BP-operated Prudhoe Bay field averaged 294,537 bpd in June, down 1.93 percent from a May average of 300,330 bpd.

In addition to Lisburne, BP's Patience said BP also has three primary turnarounds planned at Prudhoe Bay — at the Central Gas Facility, Gathering Center 2 and Flow Station 3. She said the work "is focused on facility maintenance, vessel repairs and other improvement projects." The turnarounds are part of the company's "commitment to safe, reliable and efficient operations" and take advantage of other facility or pipeline shutdowns to allow "workers to safely work around pipes, flares and other equipment," she said.

Prudhoe production includes satellites at Aurora, Borealis, Midnight Sun, Orion and Polaris, as well as production from the BP-operated Milne Point and Northstar fields.

Cook Inlet down 1.2%

May production for Cook Inlet fields, as reported by AOGCC, averaged 16,073 bpd, down 1.22 percent from an April average of 16.271 bpd.

The largest percent increases were at two of the inlet's smaller fields, the Cook Inlet Energy-operated West McArthur field, which averaged 1,294 bpd in May, up 56.11 percent from an April average of 829 bpd, and the Hilcorp Alaska-operated Beaver Creek field, which averaged 130 bpd in May up 24.76 percent from an April average of 104 bpd.

Production also increased at the Hilcorp-operated McArthur River field, the inlet's largest, which averaged 4,082 bpd in May, up 0.62 percent from an April average of 4,057 bpd.

All other Cook Inlet fields had month-over-month declines, led by two Hilcorp-operated fields, Trading Bay, which averaged 2,567 bpd in May, down 12.28 percent from an April average of 2,926 bpd, and Swanson River, which averaged 2,002 bpd in May, down 11.99 percent from an April average of 2,275 bpd.

Cook Inlet Energy's Redoubt Shoal averaged 1,239 bpd in May, down 5.03 percent from an April average of 1,305 bpd; Hilcorp-operated Granite Point averaged 2,725 bpd, down 0.5 percent from an April average of 2,739 bpd; and XTO-operated Middle Ground Shoal averaged 2,033 bpd in May, down 0.14 percent from an April average of 2,036 bpd.

ANS crude oil production peaked in 1988 at 2.1 million bpd; Cook Inlet crude oil production peaked in 1970 at more than 227,000 bpd. ●

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● GOVERNMENT

Knowles backs continuation of SB 21

Believes tax change needs time to work; concerned about state taking 25% equity share in LNG project because of amount of money

By STEVE QUINN
For Petroleum News

Former Gov. Tony Knowles says he believes it's time to leave the new gas tax alone. Knowles, an Anchorage Democrat, left office in 2002, after a two-term stint as the state's seventh governor, and has remained actively interested oil and natural gas issues driving Alaska's economy.

While voters hit the polls in August to decide whether to repeal Gov. Sean Parnell's tax plan, Senate Bill 21, Knowles has backed those fighting the repeal.

He faces pushback from those pushing the repeal who alleged a cozy relationship and being a paid shill by with the oil industry.


GOV. TONY KNOWLES

Knowles said he was never paid and had never received any money from the industry since the 1960s when he worked in the Cook Inlet and North Slope oil patch.

He received an apology and has held strong on his position: SB 21 needs to be given time to work; any changes need to be small and necessary, but not wholesale.

Knowles spoke to Petroleum News about his position on oil taxes and the prospects of Alaska marketing North Slope gas.

Petroleum News: There have been different oil tax versions backed by different Legislatures. Do you think this has hurt the state or are we just trying to find a balance?

Knowles: Well, let me maybe try to explain what I think is the overarching policy that should govern various tools — and taxes are certainly an important part of that. While oil taxes in detail are quite complicated in detail, our policy is quite simple in what should drive it.

Alaska is in a unique position to benefit the general public because it owns the resources. In owning the resource, which is unique among any of the 50 states in America, we are able to develop it as an owner and we also, as a sovereign state, will be able to benefit from taxation.

We want to make sure those policies are in alignment. We negotiated with a competitive bid that brought the state a lot of money for oil companies to develop the resources. We not only got the money from the competitive bidding, but we also retain in general about 12.5 percent of the oil for our ownership share.

In having that, it of course is the basis of the $40 billion permanent fund that we have as well as a significant source of revenue to the state. The other role that we have is that we have a regulatory role to make sure the fields are developed safely and most efficiently, then we have the sovereignty role in terms of taxes. There is the production tax, as well as the corporate tax and the property tax.

How we should develop the policies that make this of the optimal value to Alaska shouldn't be determined by political slogans. Like you are being "anti-business" or you are "selling out" to the oil companies or this tax is a "giveaway." We have to look at the economics. The most important issue facing Alaskans today regarding the future oil and gas development has to do with ensuring that we get more oil production. We have to work with the tax policy because that's really the only tool that we have to effect the additional production of oil to make sure that while it maximizes the current value, that it also gives the right kind of incentives industry to develop more oil.

Petroleum News: So what drove your support for change?

Knowles: I saw we clearly needed a change in our tax policy because for the last six years with the production dropping at about 5 to 6 percent a year, we were clearly going to the edge of a fiscal cliff that would be a disaster to the Alaska economy unless we were able to reverse and lessen the reduced oil production.

Given that, we also recognized that Alaska, with the 12.5 percent of the oil, we are the fourth largest producer of the North Slope. We don't take any risk as a state. We are the only producer that I know of that has never drilled a dry hole. We don't provide money for maintenance and upkeep or development of infrastructure. Yet we belly up to the ATM machine every time a barrel of oil gets produced. We are in the cat bird seat in that sense as a producer because we pay no expenses and we collect all the benefits. We look to the oil companies for taking the risk and making the investments.

That's where it's a careful balance. The current issue over what tax regime that we have and what signals it sends has to be judged as a balance. If you look at the tax structures over the years, there have been changes. I would call them marginal changes that came with time depending on factors that the state has determined would be in the best interest of the public but also continuing to encourage the investment. There has to be an upside for the oil companies to make those investments. The most dramatic change was the ACES bill, which placed Alaska in terms of the marginal taxation of new oil the highest in the nation. We were ranked by any number of entities in terms of competitiveness and with other areas not only in the United States but internationally we were the least competitive. That's what we were faced with. That's what I think people need to judge today in terms of what is the best policy that we have given the limited tools that we have that will get us to the single most important goal and that is oil production.

We should also make sure in our analysis that we take a look at the other factors other than state revenues for the health of our economy. The other factor people need to judge is what tax regime is going to promote jobs for Alaskans and this is on a promote sustainable basis. What tax regime is going to promote the greatest stability for our state budget which affects the economy but certainly affects the critical services that we have: education; public safety; transportation, etc.

That's the basis I think people should look at this referendum: a change from a tax passed to make Alaska more competitive back to a tax system that clearly had put a chill or put the brakes on additional investment, and was leading us astray, even though it was disguised by high oil prices and more jobs disguised by the increased maintenance, but those are not long-term sustainable, the kind of jobs that would increase our exploration and production.

Q AND A

Petroleum News: The prevailing argument right now on television and the Web seems to be this measure is about jobs. During the debate in the Legislature, it was about increasing production. Has the focus really changed?

Knowles: It's clearly both. We are talking about the long-term sustainable jobs and also the connection of the health of the oil patch in terms of how it will affect the development of a gas line. Oil and gas fit together in the vision of the future. It's jobs but it has to be jobs oriented to producing more oil. We know we have the resource. I don't think anyone disagrees with that. What we have to have is the investment. As I say, Alaska doesn't invest it. That's not our position. Nor should it be. That has to come from the oil industry. We look at the 50-plus years of history our state has had, and we've had a balance, I think, whether there has been incentives for the development of oil and gas. At the same time, the people of Alaska have greatly benefited not only from the royalty but also the production tax. That's changed over the years and it will continually be changed at the margin. But it always has to be looked at with the oversight in that we have to be competitive in terms of getting investment dollars to produce more oil.

Petroleum News: So why do you support SB 21? Is there anything there that stands out that will help advance the state's interest and not just the treasury?

Knowles: it clearly did away with the extreme progressivity in ACES, which taxed at the margin with the high price of oil 75 percent. We clearly saw it put a chill in exploration and future production. What SB 21 does is it increased the minimum based tax of the next profits to 35 percent; ACES was 25 percent. That's reflective of the fact that while we provide incentives on the upside by decreasing the progressivity, we traded it for if the price of oil drops, then we have a higher base minimum tax. My own personal experience, the price of oil can drop. When I was governor it went

see **KNOWLES Q&A** *page 15*

● EXPLORATION & PRODUCTION

Oil sands ride out storms

Northern Alberta resource buffeted by multiple challenges; foreign investors take brunt; energy regulator busy with new proposals

By GARY PARK
For Petroleum News

No matter how much the Alberta oil sands get pilloried in the public arena and buried under a landslide of negatives the sector shows no signs of wilting.

The operating environment in the northern Alberta resource has seldom, if ever, been so unfriendly, with capital costs on the rise again, takeaway capacity in short supply, aboriginal communities and environmental organizations blocking projects on multiple fronts, regulatory processes increasingly erratic and foreign investors forced into retreat by Canadian government rules.

There is also talk that Asian investors who have set up shop in the oil sands are deeply troubled by their returns, with China Investment Corp., CIC, a US$575 billion sovereign wealth fund, coming under fire in June from China's National Audit Office for mismanagement of its offshore investments, with managers accused of dereliction of duty and substandard due diligence.

Although the audit office did not name the specific cases, CIC's stakes in Sunshine Oilsands (as well as Athabasca Oil Corp. and Penn West Petroleum), along with a formidable lineup of Chinese and Hong Kong stakeholders, have crumbled in value this year.

Sunshine has been unable to raise the financing it needs to restart work on its 80 percent complete West Ells thermal-recovery project, or even think about developing its other oil sands leases, while facing a stack of legal actions by creditors.

Rules blamed for decline

The rules imposed by Canada that prevent outright takeovers of oil sands producers by foreign state-owned companies have been blamed for a sharp decline over the past 18 months in oil sands shares, which are 20 percent below what would otherwise have been expected, with junior companies taking a 30 percent hit, according to a study by the University of Calgary's School of Public Policy.

The study authors said they found that the "federal government's policy change has resulted in the material destruction of shareholder wealth."

The small oil sands producers rely on outside investment to develop their holdings, much of it coming from joint ventures, which are still allowed under the Canadian's government's rules, but are facing a sharp investment drop off.

Eugene Beaulieu, director of the school's international economics program, said the lack of clarity in the government rules is scaring off investors at a time when the sector expects to need about C$100 billion over the next five years.

But Natural Resources Minister Greg Rickford brushed off those who argue that investors no longer believe Canada is open to investment.

He told The Canadian Press that the government's objective is to draw a distinction between free market private investment and entities that are controlled or influenced by foreign governments by ensuring that "foreign investment transactions are reviewed on their merits based on the long-term interests of the Canadian economy."

Forward-looking activity

While that debate ebbs and flows and the issues confronting oil sands companies become more tangled, there has been a flurry of forward-looking activity, with the Alberta Energy Regulator being authorized by the provincial government to approve two projects by privately owned companies, while receiving an application to expand an existing operation.

Koch Oil Sands Operating, a Canadian unit of Koch Industries, is one of the companies to receive a green light from the government for a 10,000 barrels-per-day project on its Muskwa lease, while it pursues initial regulatory work on a possible 60,000 bpd steam-driven operation which has been labeled as the Dunkirk In Situ Project.

The other operator on the verge of approval is Cavalier Energy, a wholly owned subsidiary of Paramount Resources which was created to take responsibility for developing Paramount's oil sands leases.

In a terms-of-reference document for Dunkirk, Koch plans to proceed in two stages of 30,000 bpd each, which points to a capital cost in the mid range of C$2.4 billion.

The filing said Koch hopes to obtain approvals to allow a construction start in 2016, with first production scheduled for 2018.

The decision to move ahead with Dunkirk came after Koch was unable to find buyers in 2012 for all of its six properties covering 220,000 net acres.

The company is well advanced in talks with the Fort McKay First Nation, which has business ties with other oil sands operators, but has shown some unease over the level of activity on or near its lands.

Cavalier Energy

The other operator on the verge of approval is Cavalier Energy, a wholly owned subsidiary of Paramount Resources which was created to take responsibility for developing Paramount's oil sands leases.

It holds more than 200,000 net acres where 760 million barrels of estimated contingent resources have been identified in the Grand Rapids formation on the Hoole property.

Cavalier said it believes the Hoole resources are capable of producing in excess of 80,000 bpd by 2022, starting with a 10,000 bpd commercial demonstration project, with full production from its initial phase expected by the end of 2017.

The company also owns 23,000 net acres on the Eagles Nest lease, which has an estimated 178 million barrels of prospective recoverable resources from 2 billion barrels of original bitumen in place and has interests in a number of carbonate assets.

Pengrowth Energy's filing is designed to add 17,500 bpd to its Lindberg steam-recovery project in the Cold Lake area of northeastern Alberta.

To date Lindberg production has totaled 1.2 million barrels and approvals were received a year ago to accelerate the first commercial phase to 12,500 bpd, with first production targeted for the open quarter of 2015.

Pengrowth believes it has the potential to reach 50,000 bpd by late 2018 that will generate C$600 million of free cash flow a year based on West Texas Intermediate prices of US$90 a barrel.

The company said it has the ability to ship across North America by rail and refine its heavy oil without needing to ship overseas.

Pengrowth said in June that GLJ Petroleum Consultants has increased Lindbergh's proved plus probable reserves by 61 percent to 230 million barrels, raising the value to C$2.2 billion. ●

Contact Gary Park through publisher@petroleumnews.com

Oil sands march on

The Alberta Energy Regulator, AER, reported that raw crude bitumen produced from the oil sands reached 2.1 million barrels per day last year, up 8 percent from 2012, while the province's crude production posted a 5 percent gain to 582,000 bpd.

The government regulatory agency predicted crude bitumen will almost double to 4.1 million bpd by 2023.

It said Alberta has produced 9.63 billion barrels of bitumen from the oil sands since 1967 and 16.9 billion barrels of crude since 1914.

The regulator estimated remaining crude bitumen and crude oil reserves at 169 billion barrels, of which crude accounts for only 1.8 billion barrels.

Remaining established marketable conventional gas reserves dropped 2 percent to 32 trillion cubic feet, but natural gas liquids rose 2 percent to 1.6 billion barrels.

The demand for more takeaway capacity from the oil sands is reflected in an application by TransCanada, in partnership with a PetroChina subsidiary, now being heard by the AER to bring another 900,000 bpd into the Edmonton area.

The C$3 billion Grand Rapid project, which includes a second line to carry diluents to blend with bitumen and three large-storage tank farms, is needed to handle production growth that is expected to reach markets as early as 2015, the company said.

However, TransCanada project manager Greg Bridgewater said shippers have yet to determine what will happen to the bitumen beyond Edmonton.

There is no plan to connect Grand Rapids to TransCanada's planned Energy East system to Ontario, Quebec and possibly Atlantic Canada, the company said.

—GARY PARK

● FINANCE & ECONOMY

Alberta farming, forestry outstrip energy

Independent study shows energy rates third for human footprint in vast oil sands of northern Alberta; bitumen mines greatest impact

By GARY PARK
For Petroleum News

Agriculture and forestry are responsible for a larger human footprint than the energy industry across Alberta's three recognized oil sands units, putting a dent in the claims of those who blame the resource for laying waste to the province's northern region.

The findings emerge in a study by the Alberta Biodiversity Monitoring Institute, an independent, not-for-profit scientific organization which reports on the status and trends of the province's species, habitat and human footprint to help shape natural resource and land-use decision-making.

The ABMI board of directors includes representatives from the Alberta government, environmental non-government organizations, the forest, energy and agriculture sectors and the research community.

The ABMI, run by the University of Alberta and the University of Calgary, said it is guided by a "core set of principles — we are independent, objective, credible, accessible, transparent and relevant."

Its study of the oil sands region covered the Athabasca, Cold Lake and Peace River units, which cover 21 percent of Alberta's land area, and is comparable in size to the State of New York.

The ABMI has set up 350 permanent monitoring sites in the region and from 2003 to 2012 it conducted field surveys at 186 of the sites.

Human footprint 13.8%

As of 2012, the total human footprint in the oil sands study area was 13.8 percent, with agriculture accounting for 7.4 percent, forestry 2.9 percent and energy 2.2 percent.

The total human footprint area increased to 13.8 percent from 11.3 percent from 1999 to 2012, more than half driven by the creation of the forestry footprint, while energy grew to 2.3 percent from 1.6 percent, with agriculture virtually unchanged.

Overall, the ABMI said 86 percent of the oil sands region has no direct human footprint, while 6.2 percent of the region is managed as protected areas.

The status of 425 species was assessed — data was collected on more than 2,000 species — with biodiversity found to be intact for an average 88 percent, but active oil sands mining operations, which represent a "small portion" of the region, showed "biodiversity intactness values near 0 percent."

The report said that "managing the cumulative effects of all land-use activities is a key management challenge" in the oil sands, noting that the Alberta government recently initiated an integrated resource management system "to understand and manage the cumulative effects of economic growth."

"Under this approach, targeted outcomes must be defined and achieved for environmental as well as social and economic values.

'Early warning signal'

However, Simon Dyer, regional director for Alberta and the North at the Pembina Institute, described the findings as an "early warning signal" for the government about the state of some fragile species" that showed a decline of 20 percent among bird species.

He said that should put pressure on the government to hasten the completion of regulations promised in 2013 to reduce the loss of wildlife and habitat.

Dyer said the government can order remedial action when companies fail to comply with the legally binding benchmarks contained in regional land-use plans for acceptable losses of wildlife and landscapes.

He said the report concluded that reclamation efforts in the oil sands are lagging behind the disturbances caused by expanding mines and in situ pipelines, as well as forestry operations.

A spokesman for the ABMI said he was surprised by agriculture's large impact in a region where oil sands activities tend to shoulder most of the blame for habitat and wildlife loss.

Separately, government and industry reports point to a reduction of 26 percent in carbon emissions from the oil sands over the 1990-2011 period, while the government has indicated it is poised to increase the carbon tax it charges on greenhouse gas emissions from the oil sands, to lower the carbon intensity by 40 percent. ●

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PIPELINES & DOWNSTREAM

RCA considering Badami transfer

State regulators are considering a request to transfer a controlling interest in two pipelines associated with the Badami unit as part of an acquisition at the eastern North Slope field.

Savant Alaska LLC is looking to transfer its 67.5 percent interest in Nutaaq Pipeline LLC to Miller Energy Resources Inc., which is acquiring the small North Slope independent.

The ASRC Exploration LLC subsidiary Badami Pipeline Holding Company LLC holds the remaining 32.5 percent interest. ASRC Exploration is a subsidiary of Arctic Slope Regional Corp., which is the Alaska Native corporation covering the North Slope region.

Nutaaq Pipeline is the certificated operator of the Badami Oil Pipeline and the Badami Gas and Products Pipeline. The Badami Oil Pipeline, also known as the Badami Sales Pipeline, connects the unit to the Endicott Pipeline. The Badami Gas and Products Pipeline is also known as the Badami Utility Pipeline and runs from Endicott to Badami.

No changes in day-to-day operation

After operating an exploration program nearby, Savant joined the Badami unit in 2008, under a farm-out agreement with then-operator BP Exploration (Alaska) Inc. Savant undertook a multiyear development program at the unit and became operator in 2012.

Under the proposed acquisition, Miller subsidiary Miller Energy Colorado 2014-1 LLC would merge into Savant and Savant would remain as the surviving

see **BADAMI TRANSFER** page 9

● EXPLORATION & PRODUCTION

Cook Inlet Energy gets boost for Sword

Alaska regulators allow commingling of oil production from multiple zones in well; parent company discloses new loan, tax credits

By WESLEY LOY

For Petroleum News

Cook Inlet Energy LLC has won approval from Alaska regulators to commingle production from multiple zones in the company's Sword No. 1 well.

The company first brought Sword online in November 2013.

The exploratory well was drilled on land from a site near the company's West McArthur River oil field on the inlet's west side. The well angles out to a bottomhole location beneath the inlet.

On May 1, Cook Inlet Energy asked the Alaska Oil and Gas Conservation Commission to allow downhole commingling of production from three oil zones: the Hemlock, the Lower Tyonek G and the Lower Tyonek G Upper.

Miller and Cook Inlet Energy launched as an Alaska operator in late 2009. Since then, they have pursued an aggressive program of drilling and asset acquisition.

The commission approved the commingling with a June 26 conservation order.

"Commingling production from the three zones will increase the flow rate from the well and thus improve the economics for the well, which will prevent waste and lead to increased ultimate recovery from the well as compared to producing the zones separately," the order said.

Aggressive program

Cook Inlet Energy, based in Anchorage, is a subsidiary of publicly traded, Tennessee-based Miller Energy Resources Inc.

Miller, in an investor presentation posted on its website on June 24, said the Sword No. 1 well had produced about 116,000 barrels of oil.

Miller and Cook Inlet Energy

see **SWORD BOOST** page 10

ENVIRONMENT & SAFETY

Board faults key device in BP oil spill

US Chemical Safety Board report blames bad management, operations for faulty wiring, dead battery, bent pipe in blowout preventer

By SETH BORENSTEIN

Associated Press Science Writer

A federal board investigation into the 2010 BP oil spill concludes that a last-ditch safety device on the underwater well had multiple failures, wasn't tested properly and still poses a risk for many rigs drilling today.

The report issued June 5 by the U.S. Chemical Safety Board (available on the board's website at www.csb.gov/) zeroes in on what went wrong with the blowout preventer and blames bad management and operations. They found faulty wiring in two places, a dead battery and a bent pipe in the hulking device. And that, they said, led to the dumping of 172 million gallons of oil into the Gulf of Mexico and the nation's worst offshore oil disaster.

Investigators have long known that the device failed. But "The problems with this blowout preventer were worse than we understood," safety board managing director Daniel Horowitz said in an interview. "And there are still hazards out there that need to be improved if we are to prevent this from happening again."

The massive spill followed an explosion that killed 11 workers at the Deepwater Horizon drilling rig, about 50 miles off the Louisiana coast.

Old vs. new

Massive blowout preventers are anchored to the top of underwater wells. In an emergency, the devices use multiple mechanisms — including clamps and shears — to try to choke off the oil flowing up from a pipe and disconnect the rig from the well. They can operate automatically when pressure or electricity is cut off or manually.

The 9-year-old one that failed was nearly 57 feet tall and weighed about 400 tons.

Robert Bea, a professor of engineering and expert in oil pipelines at the University of California Berkeley, praised the report and said blowout preventers are like cruise ship lifeboats, used only in last resort but crucial. In this case the blowout preventers "are deeply flawed, they've got holes," said Bea, who was not involved in the new study.

Kevin Ewing, a Washington attorney who represents many oil drilling interests, said well operators have improved their techniques. He cautioned against broad indictments on the safety of currently operating blowout preventers.

Various investigations have found that the cause of the initial explosion involved multiple screw-ups with cement, drilling mud, fluid pressure, botched tests, management problems and poor decisions. The blowout preventer sealed the well temporarily, but then it failed and that caused the massive spill, the new 166-page report found.

Failure in testing

The report faulted the rig operators. The problem, said safety board investigator Mary Beth Mulcahy, was that well owner BP and rig operator Transocean didn't test the blowout preventer's individual safety systems. They just tested the device as a whole. It turned out there were two sets of faulty wiring that caused problems and a dead battery.

Mulcahy said individual tests were suggested by the preventer's manufacturer but the companies instead followed a standard set by the industry.

The safety board also found that the drill pipe bent far earlier in the accident and from a different cause than determined by a presidential oil spill commission. That failure is also connected to a problem with the blowout preventers, investigators said.

The board said the same device design is being used on at least 30 rigs worldwide and some general problems with operations and testing could affect other types of preventers.

Donald Boesch, a University of Maryland professor who was on the presidential oil spill commission, agreed with the latest investigation. He said the chemical safety board was able to do what his board didn't do, a hands-on testing of the device.

The two companies involved in rig operations blamed each other. BP spokesman Geoff Morrell said all of the evidence "demonstrates that Transocean owned the rig's blowout preventer and was responsible for its maintenance."

Transocean spokesman Brian Kennedy noted that BP pleaded guilty to 12 felony counts from the accident while Transocean did to only one misdemeanor violation of the Clean Water Act. He also said the blowout preventer "had been tested successfully in accordance with regulatory requirements and activated as intended at the time of the incident, but was unable to seal the well because immense pressure buckled the drill pipe." ●

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BADAMI TRANSFER

entity, giving Miller an indirect interest in the unit and its associated infrastructure, such as the pipelines.

The proposed transfer makes no changes to the day-to-day operation and management of the pipelines, or to the "dismantlement, removal and restoration" obligations BP Transportation (Alaska) Inc. continues to hold for the entire Badami Pipeline System.

While crucial for the operation of the Badami unit, the two Badami pipelines are also a link to future development of the eastern North Slope, including the Point Thomson unit.

The Regulatory Commission of Alaska is currently considering the requests. The companies have asked the regulators to issue an expedited ruling by Oct. 24.

—ERIC LIDJI

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GOVERNMENT

Cook Inlet RCAC wants new lease on life

The Cook Inlet Regional Citizens Advisory Council is seeking recertification for another year.

The council, based in Kenai, is a congressionally mandated organization that monitors oil industry activity including tanker traffic in Cook Inlet.

Council members represent a broad range of interests: local governments, tourism and recreation, commercial fishing and aquaculture, environmental groups, and Alaska Native organizations.

The council's work includes providing advice and recommendations on terminal and tanker operations, and reviewing the adequacy of oil spill prevention and cleanup plans.

The organization receives funding from Cook Inlet oil and gas producers, refiners and transportation companies.

The U.S. Coast Guard handles council recertification.

The council's current certification will expire Aug. 31.

A Coast Guard notice published June 13 said the council has applied for recertification for Sept. 1 through Aug. 31, 2015. The Coast Guard is taking public comments through July 16 on the application. Comments may be submitted at www.regulations.gov using docket number USCG-2014-0414.

The Coast Guard said it can deny council recertification if it finds the organization "is not broadly representative of the interests and communities in the area or is not adequately fostering the goals and purposes" of the Oil Pollution Act of 1990.

—WESLEY LOY

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SWORD BOOST

launched as an Alaska operator in late 2009. Since then, they have pursued an aggressive program of drilling and asset acquisition. Their producing properties in the Cook Inlet region include the offshore Redoubt unit, the West McArthur River oil field and the North Fork natural gas field.

The company is aiming to close a deal by November for a controlling stake in the small Badami oil field on Alaska's North Slope.

Nearly all of Miller's oil and gas production comes from the Cook Inlet region, where gross production was 3,000 barrels of oil equivalent per day at the end of April, the investor presentation said.

In a June 30 filing with the U.S. Securities and Exchange Commission, Miller said it had taken out a $10 million loan, bringing its total borrowing to $30 million under a KeyBank credit facility.

The filing added: "On June 24, 2014, we received from the State of Alaska the proceeds of tax credits totaling approximately $21.8 million." ●

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● EXPLORATION & PRODUCTION

Iniskin exploration: what are the odds?

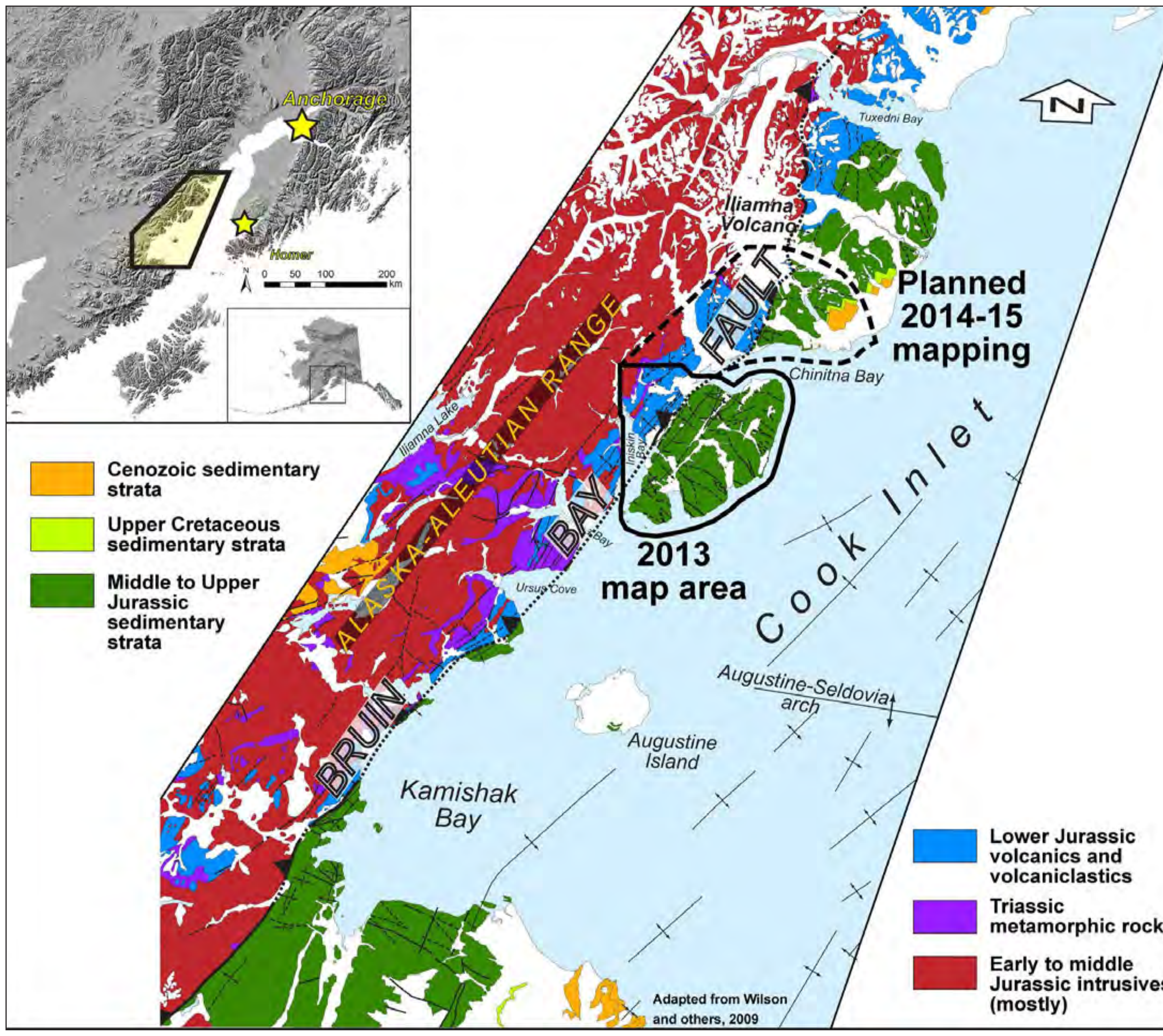
The peninsula on the west side of Alaska's Cook Inlet has oil potential but has thus far eluded a significant hydrocarbon discovery

By ALAN BAILEY
Petroleum News

A clearly observable large anticline in sedimentary strata, coupled with the existence of several surface oil seeps, will excite any worthwhile oil explorer. And, with both of those oil-suggesting features known about for many years, the Iniskin Peninsula on the west side of Alaska's Cook Inlet, almost opposite the town of Homer, has long intrigued those interested in finding new sources of oil and gas.

New proposals for state exploration licenses encompassing the peninsula indicate renewed interest in the area. The state's Division of Oil and Gas has received two competing proposals, has decided that exploration of the peninsula would be in the state's interests and has invited competitive bids for a license. The state has not divulged the identities of those who have made the proposals. In the summer of 2013 Hilcorp Alaska conducted a mostly onshore 2-D seismic survey in the area.

But what are the odds of finding commercial quantities of oil or gas?



ALASKA DEPARTMENT OF NATURAL RESOURCES, DIVISION OF GEOLOGICAL AND GEOPHYSICAL SERVICES

The Iniskin Peninsula is on the west side of the Cook Inlet, within the area outlined as "2013 map area."

Early attention

The peninsula and its oil seeps attracted companies during early Alaska oil exploration. The Alaska Petroleum Co. drilled a couple of wells near Oil Bay on the southern end of the peninsula in 1902 and 1903. The first of these wells reached a total depth of 305 meters, encountering natural gas below 58 meters and a "considerable" oil flow at a depth of 213 meters, according to unofficial reports. A water influx cut off the oil flow. The second well encountered oil shows but had to be abandoned at a depth of 137 meters. The company subsequently drilled two further wells in the same general area, with one of these wells encountering some oil and gas.

Also in 1902 and 1903, the Alaska Oil Co. tried drilling a couple of wells near an oil seep north of Dry Bay, on the southeast side of the peninsula. These wells were abandoned at shallow depths without encountering oil.

The major anticline that straddles the peninsula is called the Fitz Creek anticline. Between 1936 and 1939 the Iniskin Bay Association drilled a well to a depth of 2.7 kilometers into the anticline, encountering oil and gas shows. During the 1950s other investors drilled two further wells: the Beal No. 1 and the Antonio Zappa No. 1, with both of these wells encountering oil shows and the Beal well flowing gas at 4,000 cubic feet per day.

No further wells have been drilled on the peninsula since that time.

Different geology

Although the peninsula lies directly opposite gas fields on the Kenai Peninsula, on the east side of the Cook Inlet, the geology at Iniskin is quite distinct from that of the producing oil and gas fields of the Cook Inlet basin. Essentially, while the producing fields have reservoirs in a sequence of Tertiary strata, the rocks around the Iniskin Peninsula are from an older rock sequence, Mesozoic in age, that lie underneath the Tertiary rocks in the region of the developed fields. And, while the sediments that formed the Tertiary sequence were laid down on land from a system of rivers, the Mesozoic sediments are predominantly marine, laid down in an ancient sea.

But the source of oil in the Cook Inlet oil fields is known to lie within the Tuxedni group, a sequence of rocks of Jurassic age, within the Mesozoic. Rocks from the Tuxedni group are observed at the surface on the Iniskin Peninsula. And with younger Jurassic rocks, including large thicknesses of sandstones, overlying the Tuxedni on the peninsula, a known oil and gas source that would account for the observed oil seeps lies in proximity to other rocks that could perhaps host oil pools.

DGGS research

A team of geoscientists led by Alaska's Division of Geological and Geophysical Surveys has been conducting research into the geology of the Cook Inlet basin and recently reported the results of some geological mapping on the Iniskin Peninsula. Among its results the team described a 6,000-foot section of sandstone and siltstone of the upper Jurassic Chinitna and Naknek formations.

Although geologists view the Naknek as a possible oil reservoir rock in the Cook Inlet region, there is considerable regional variation in the composition of the formation, with the formation having quite low porosity and permeability in the area of the Iniskin Peninsula. But, while

see INISKIN POTENTIAL page 16

Oil Patch Bits

Maritime Helicopters announces new service locations

COURTESY MARITIME HELICOPTERS

Maritime Helicopters Inc., an Alaska-owned business headquartered in Homer, has recently expanded its operations, adding seven new aircraft, including Bell 407s, Bell 206L4s and Eurocopter BO-105 twin engine helicopters. In support of this expansion, Maritime has recruited 15 new pilots and 15 new mechanics along with additional office staff statewide.

Celebrating 41 years in the Alaska aviation industry, Maritime Helicopters was founded in 1973 with a single Bell 47 helicopter. The company has since grown to its current 16 aircraft, an 86-foot helideck-equipped research vessel, more than 30 pilots, 20 mechanics and a versatile support staff, with main operating facilities in Homer and Fairbanks, providing logistical advantages to Southcentral Alaska, the Interior and the North Slope.

Starting June 1, Maritime began providing helicopter support services to Alyeska Pipeline Service Co. at five locations along the Trans-Alaska Pipeline System. This major long-term contract facilitated Maritime's expansion of air operations from the North Slope to Valdez. Additionally, Maritime increased its presence in the Aleutians this spring supporting the Aleutians East Borough with ferry service between Akutan and Akun Islands.

In addition to being a Bell Helicopter Customer Service Center and a jet fuel provider for the cities of Homer, Fairbanks, Valdez and Kodiak, Maritime now has aircraft permanently based in these cities as well as in Akutan and Kenai.

For more information contact Maritime Helicopters at 907-235-7771, info@maritimehelicopters.com or www.maritimehelicopters.com

Nabors announces agreement with C&J Energy Services

Nabors Industries Ltd. announced that the company has signed a definitive agreement to combine its completion and production services businesses in the U.S. and Canada with C&J Energy Services Inc., an independent oilfield services and manufacturing company.

Following the completion of this transaction, Nabors will own approximately 53 percent of the combined company, which will be incorporated in Bermuda and listed on the NYSE as C&J Energy Services Ltd. In addition to the 62.54 million shares of the combined company, Nabors will also receive approximately $937 million cash, to be paid from proceeds of a

see OIL PATCH BITS page 16

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

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

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KNOWLES Q&A

from $20 a barrel to $9 a barrel. Now that may be distant memory or history for most people. The one thing we know is oil can have dramatic changes up or down. The state's many interest as a passive owner, since we do not take the risks and invest money, is to play it on the safe side and protect the stability of our revenues with a higher minimum base tax.

Petroleum News: The debate over oil taxes doesn't seem like it will ever end. What do you make of that?

Knowles: In the SB 21/ACES debate there are a couple of issues that have been settled. One, there is no $2 billion give-away. Scott Goldsmith from ISER at UAA has clearly shown that the giveaway to the oil companies touted by the referendum supporters does not exist. In today's market condition there is little difference in state revenues from either tax regime. Two, experts agree that the most likely near-term movement of transportation and production costs growing at a faster rate that oil prices will mean that SB 21 will probably raise modestly more state revenues than ACES. However this is not the most significant reason why we should retain SB 21. The real issue is the current and long term jobs and economy for Alaska, which depends on the ability of SB 21 to increase the exploration and production investment which will increase the total production of oil. We know the effect of ACES after six years of dramatic decline in production. SB 21 appears to have changed that direction. Oil company investments are up, jobs are up, and history shows that will result in more oil production. It deserves a chance to prove that point.

Petroleum News: This report gained a lot of pushback, in part for lacking a peer review. Why do you back Goldsmith's work?

Knowles: There is no economist in Alaska that can come close to matching Scott Goldsmith's credentials and publications on the wide spectrum of the economics of Alaska and public policies. At the University of Alaska Anchorage and its Institute of Economic and Social Research he has authored over 350 research academic papers on these subjects over three and a half decades. While I was governor, Scott authored and provided invaluable public research materials on the topic of constructing a long-range sustainable fiscal plan for Alaska. He is universally regarded as a brilliant economist who provides independent well-researched documents on the economic analysis of public policy. I have known him personally for many years and highly respect his integrity and the quality of his work.

Petroleum News: There are some, even in the majority caucuses who believed change was needed but SB 21 went too far. Is that possible?

Knowles: There are different opinions on it and I think what we have to do is work with this new law. I know it's disputed but there is evidence being given that it's encouraged more investment. Conoco has doubled its investments in the last year and a half; BP likewise; ExxonMobil with all the commitments at Point Thomson. That should be closely monitored by the administration and the Legislature to see if there needs to be any changes. But they would be minor changes with a certain amount of stability the industry can see. The industry needs stability because it takes up to 10 years for a project to be envisioned, put in place and actually get more oil. They are looking at a horizon much further than just next year's budget.

If there are things that need to be changed with SB 21, I know there is confusion over what new oil is that gets credit for being new oil. That's going to have to be ironed out. It can be done through regulation if necessary through statute without overhauling the whole mechanism and going back to a system we know didn't work. Even the proponents of going back admit that ACES didn't work. What we should do to promote that sense of stability that is necessary to get the billions of dollars and investment that need to be done, we should look at what we have now, see where problems come up and make adjustments accordingly.

What we need is not political sloganeering, but a strategy to have the best business relationship. We know the oil companies, they have business goals and we want to try to bring them in alignment and that's what I think is the most important relationship. As we look back in history, that's where it's worked.

Petroleum News: On to natural gas and a pipeline. Your administration created the Stranded Gas Development Act. Since then there have been plans that failed at various junctures. What do you think is holding this back? Is it the market? Is it politics? Is it a bad blend of both?

Knowles: What drives natural gas is the market. When I was governor, gas was about $2 an mcf. Then it spiked and it went up to $8 and $10 an mcf and that generated a huge interest in developing a gas line, but that gas line, it was felt, had to go from Alaska to the Lower 48 because that was the market. The foreign market was hesitant to look at natural gas, certainly in the volume and long-term commitment that is necessary to finance a multi, multi-billion dollar contract. You couldn't use a small amount to finance a large-diameter pipeline. If Tokyo Electric wanted 750 mcf a day, well, OK, where are you going to sell the other 3.5 bcf a day? That's why the foreign market didn't seem feasible. Fast forward to where we are today. The spike in the Lower 48 gas prices has collapsed with the renaissance of the shale gas. We are now looking at exporting LNG where a few years ago everybody was predicting that we would be relying on imported natural gas just as we did with oil. The foreign market remains very high in Japan and the Far East, somewhere around $14 to $18 an mcf, and if there can be worked out a long-term marketing system, that's what's going to make it work.

I applaud the work being done on it by the state and the producers. I think it probably will happen and should happen, but the market is what's going to drive it.

Petroleum News: So is the state on the right track?

Knowles: With one caveat. I think something that I share what has been expressed by a lot of people, is real reservations on the 25 percent ownership being put on the line. I don't think there is enough information about that. It's a huge amount of money. We know the risk that is in a project of that size, with that much gas and that long period of time. The profit margins for natural gas are so much smaller than they are with oil. I don't think there is nearly enough understanding of real risks for a large state ownership in that project. It certainly is in complete reversal from day one for all of the state's policies in oil. There are reasons why it would be a lot more attractive to oil than natural gas. There is a cautionary note.

If we have a stake in the project, we certainly need to be a strong advocate. In terms of sitting down and writing a check for $15 billion, that's a whole different story. I don't have any philosophical opposition to it. I look at the traditional roles of private sector risk in investment and the state's traditional role as an owner having a royalty share of it, just like we do with the oil, but in terms of going out and negotiating a contract, drilling the wells, building a pipeline, taking the risk in a market collapse, that's a whole different story.

People ought to think about this. The development of a gas line and the raw economics of project depend on the competitive price of natural gas, which is dependent on using the infrastructure of the oil development, because when you discover oil, you discover gas. You build infrastructure in terms of the development of it, which will in effect be a zero cost for the gas up to the point where it enters the pipeline. If we don't have a robust oil patch, if we have a declining oil patch which is in a going-out-of-business-sale type approach, then there will be very little encouragement for the industry to put up the necessary money to build the gas line and develop that project. ●

Contact Steve Quinn at squinnwrite@gmail.com

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OIL PATCH BITS

public debt placement by the combined company. The new C&J Energy Services Ltd. will be managed by the current C&J Energy Services management team, supplemented by Nabors' completion and production services workforce. The transaction will roughly triple the C&J stimulation fleet, which should then rank as the fifth largest fleet in North America. The combined company will also operate the largest fluids management fleet and the second largest workover and well-servicing fleet in North America. In addition, prospects for international expansion should be enhanced through a global alliance agreement with Nabors.

The transaction has been approved by the boards of directors of both companies and is subject to approval by C&J shareholders and the satisfaction of customary closing conditions and regulatory approvals. It is anticipated shares in C&J Energy Services Ltd. will be publicly traded under the symbol CJES, pending approval from regulatory authorities. Goldman, Sachs & Co. and Lazard Ltd. advised Nabors on the transaction. Citigroup and Tudor, Pickering, Holt, & Co. represented C&J Energy Services.

Anderson joins URS as local development specialist

URS Corp. said that Tim Anderson recently joined its team as a local development specialist. Anderson has more than a decade of service within the Chugach Region focusing on developing projects to help the communities and their members. He has human resources, computer, financial and budgetary, research, curriculum development and management experience. Anderson's functions include project controls and procurement activities, stakeholder engagement support and local content development. He also provides oversight and mentorship of three interns.

TIM ANDERSON

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FIFTH FURIE WELL

form, laying of gas-gathering pipelines from the platform to shore, and the construction of an onshore facility. The platform has been fabricated and is currently being shipped from Texas to the Cook Inlet. The Kitchen Lights no. 1 and no. 2 wells are also located in the Corsair block.

The Kitchen Lights no. 4 well is located in the Northern block. And, based on location information included with the new drilling permit, the no. 5 well location would appear to be towards the western side of the central block, about halfway down the block.

The sequence of drilling appears consistent with requirements in Furie's Kitchen Lights exploration plan, stating that the company must drill wells in several exploration blocks within the Kitchen Lights unit.

Exploration blocks

The locations of the exploration blocks, and the exploration prospects that each block encapsulates, relate to the subsurface geologic structures that characterize the Cook Inlet basin. Essentially, the strata that typically host the Cook Inlet oil and gas fields have been deformed into a series of north-north-east trending folds, with hydrocarbon resources tending to become trapped in the crests of the folds. Each fold forms an elongated dome-like structure, generally bounded by geologic faults. The folds form sets, with the folds within a set lined up end-to-end along a north-north-east trend line.

The Corsair block, in which Furie is developing its new gas field, contains a structure on a fold trend that lines up with the North Cook Inlet gas field to the north and the Kenai and Cannery Loop gas fields to the south. Shell, Phillips and ARCO, between them, drilled five wells in the prospect between 1962 and 1993. The wells all had gas show, with some also testing small quantities of oil.

None of the other prospects within the Northern Lights unit have seen previous drilling.

The northern block corresponds to what used to be called the Northern Lights prospect and lies on the same structural trend as the Corsair block. The Northern Lights prospect has in the past been viewed as an oil opportunity related to a known oil pool under the North Cook Inlet field.

The central block corresponds approximately to what used to be called the East Kitchen Lights prospect, a prospect lying on that same structural trend as Corsair and the northern block.

The southwestern block corresponds to what was called the Kitchen prospect, a structure on the east side of the fold structure that holds the Middle Ground Shoal oil field. ●

—A copyrighted oil and gas lease map from Mapmakers Alaska was a research tool used in preparing this story.

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INISKIN POTENTIAL

the Mesozoic rocks of the peninsula may not in themselves be particularly ideal as oil reservoirs, there are faults and fractures in the rocks that could provide conduits within which hydrocarbons could flow.

Oil-stained rocks

One of the discoveries made by the DGGS team was an exposure of oil-stained rocks within the Tuxedni group, on the southeast side of the Fitz Creek anticline. The oil staining occurs around a fault, exposed at the surface, supporting the concept that fractures and faults control the flow of oil in the subsurface, and suggesting the possibility of unconventional oil reservoirs in the Mesozoic of the peninsula area, the team reported.

Research conducted by the U.S. Geological Survey in the 1960s suggested that known oil seeps, and oil shows encountered in wells, are controlled by rock fractures and fault zones, the team reported.

However, in another new discovery, the team found oil-stained sandstone at the surface in the Chinitna formation. The lack of fracturing in the rocks at this location suggests that at least some of the Jurassic rocks on the Iniskin Peninsula hold enough permeability to support oil migration, thus raising further questions over the petroleum system that has led to those long-known oil seeps.

With exploration licenses in the offing, new oil exploration may shed further light on this enigmatic region. ●

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EXPLORATION & PRODUCTION

US drilling rig count rose 15 to 1,873

Oilfield services company Baker Hughes Inc. says the number of rigs drilling for oil and natural gas in the U.S. rose by 15 the week ending June 27 to 1,873.

The Houston firm said in its weekly report that 1,558 rigs were drilling for oil and 314 for gas. One was listed as miscellaneous. A year ago there were 1,748 active rigs.

Of the major oil- and gas-producing states, Oklahoma gained eight rigs, Pennsylvania gained two and Alaska, California, Colorado, North Dakota and Ohio each gained one.

Kansas lost three rigs while Louisiana lost two.

Arkansas, New Mexico, Texas, Utah, West Virginia and Wyoming were unchanged.

The U.S. rig count peaked at 4,530 in 1981 and bottomed at 488 in 1999.

—ASSOCIATED PRESS

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THOMSON PROGRESS

ExxonMobil already has drilled a pair of wells at Point Thomson, and is well along on pad construction. A new 22-mile pipeline link to the existing North Slope oil transportation network is done. In coming months, hulking process modules will arrive from South Korea.

In sum, it really does appear the Point Thomson field is headed toward first production, something state officials have long pushed ExxonMobil and its partners to achieve.

The initial production rate is modest, but the hope is it will set the table for much greater oil and gas production from Point Thomson, where the main prize is an estimated 8 trillion cubic feet of gas — a world-class volume.

The air quality permit is among the scores of permits necessary for a new field. It sets limits on pollution that can come from the Point Thomson production facility, the development and operation of which involves equipment such as a drilling rig, engines, turbines, generators, pumps, heaters, incinerators and gas flares.

The requested air permit would actually be a revision of a permit DEC issued previously for Point Thomson.

The requested air permit would actually be a revision of a permit DEC issued previously for Point Thomson.

In a recent public notice, DEC said it is taking public comments until July 24 on its preliminary decision to approve the new air permit for ExxonMobil. The department said it will decide whether to issue or deny the permit once the public comment period closes.

More information on the permit, including a technical analysis report, is available from DEC at http://tinyurl.com/llwyolq.

ExxonMobil's partners in the Point Thomson field include BP and ConocoPhillips.

—WESLEY LOY

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BUCCANEER PLAN

according to filings. After eliminating liabilities held among the nine companies, Buccaneer and its subsidiaries currently owe nearly $30.8 million in outstanding liabilities to a long list of unsecured creditors.

AIX to be stalking horse

The largest secured creditor, AIX Energy LLC, has agreed to be the stalking-horse bidder for the auction, committing to bid some $58 million for "substantially all" of Buccaneer's assets, should such an auction take place. The unpaid balance on an AIX Energy revolving credit facility is also about $58 million. The facility matured June 30.

The court-appointed official committee of unsecured creditors is composed of five companies: Kenai Offshore Ventures LLC, Archer Drilling LLC, Teras Oilfield Support Ltd., Frank's International LLC and AIMM Technologies Inc.

The sale advisor Global Hunter Securities LLC said it has drawn up a list of more than 25 "potential financial and strategic partners" that might be interested in buying the assets.

Buccaneer is also looking to sell less valuable assets.

The company and its subsidiaries said they have received offers to purchase assets including "office equipment and supplies, drilling supplies and equipment, iron ore, and other miscellaneous property." These "de minimis" assets are all worth less than $3,000 each and worth between $100,000 and $200,000 combined, according to Buccaneer.

The largest secured creditor, AIX Energy LLC, has agreed to be the stalking-horse bidder for the auction, committing to bid some $58 million for "substantially all" of Buccaneer's assets, should such an auction take place.

The court will consider the request at a July 22 hearing.

The bankruptcy case continues to play out in other ways.

While the nine Buccaneer companies asked the court for permission to continue paying their remaining employees, some of whom are working at the producing Kenai Loop gas field, the companies have asked the court to reject contracts with Spartan Offshore Drilling LLC and All American Oilfield Associates LLC, which have been operating the Endeavour jack-up rig and the onshore Glacier No. 1 rig, respectively, for Buccaneer.

The claims to reject the rig contracts, as well as similar claims for unexpired leases, are estimated to be worth more than $100 million, according to the bankruptcy filings.

—ERIC LIDJI

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KUPARUK TARGETS

preted, with the results being integrated into work programs and the identification of further drilling opportunities. And in 2013 ConocoPhillips merged this survey with another survey in the southwestern part of the unit, to allow complete coverage of the area of the Shark Tooth prospect that the company is currently working on, the plan says.

Coiled tubing drilling, a key drilling technique in the Kuparuk field, involves the use of a continuous length of small-diameter, flexible drill pipe, with a motor-driven drill bit. The flexible drill pipe is drilled out from the side of an existing well bore, to form a sidetrack well that can snake its way through packages of oil-bearing reservoir sands.

The large portfolio of potential coiled tubing wells has resulted in the commissioning and contracting of a state-of-the-art specialized coiled tubing Arctic drilling rig that has been in continuous use since May 2009, the plan says.

A huge field

As one of the largest producing oil fields in North America, the Kuparuk River field has been delivering oil since the early 1980s. But, as the amount of oil remaining in the ground declines, ConocoPhillips is having to use high-tech drilling and oil recovery techniques to extract further oil from the field's challenging, compartmentalized reservoir rocks. In May Trond-Erik Johansen, the company's Alaska president, told the Anchorage Chamber of Commerce that 3.75 billion barrels of conventional oil remain in the field, and that there are a further 15 billion barrels of heavy oil in the Kuparuk River unit.

ConocoPhillips anticipates 13 to 17 coiled tubing sidetrack projects and eight new conventional rotary wells in 2014, the plan says.

In 2013 field production averaged 85,700 barrels of oil per day, the plan of development says. During that year ConocoPhillips completed a 14-well coiled-tubing-drilling program that generated a peak rate of 4,520 barrels per day of incremental oil. The company also completed one conventional well, the plan says.

In 2013 the field had 466 production wells and 351 injection wells in 44 drill sites.

ConocoPhillips anticipates 13 to 17 coiled tubing sidetrack projects and eight new conventional rotary wells in 2014, the plan says.

Enhanced oil recovery

Maximizing oil recovery from the aging field involves the effective management of various techniques for enhanced oil recovery, as well as delineating areas of the field with oil accumulations that can viably be developed and then drilling appropriate development wells.

At the core of the oil recovery strategy comes waterflood, the injection of seawater and produced water into the field reservoir to sweep oil from the reservoir rock. But the alternation of waterflood with the injection of a material known as miscible injectant, a mixture of natural gas and natural gas liquids, has become the procedure of choice for enhanced oil recovery. Essentially, the miscible injectant acts as a solvent, leaching the oil from the rock pores, while the water sweeps the oil towards production wells.

The technique, referred to as water-alternating-gas, or WAG, can involve the use of either miscible injectant or immiscible dry gas. And, as the field has evolved, some drill sites have stopped using miscible injectant, and some have been converted to water injection only, the plan says. ConocoPhillips has been piloting the use of injected dry gas to retrieve from the reservoir some of the natural gas liquids that were previously injected as miscible injectant.

ConocoPhillips is also evaluating the potential use of a technique called alkali surfactant polymer, or ASP, for mobilizing oil in one of the Kuparuk sands, the plan says.

Artificial lift

One benefit of using miscible injectant for enhanced oil recovery is the manner in which the injectant flowing towards production wells assists in "artificial lift," a procedure whereby oil is driven up a production well by some artificial means, rather than just being forced to the surface by the reservoir pressure. Gas lift, a technique that involves flowing gas into a production well, is the most common artificial lift technique used in the Kuparuk field, the plan says. But the gas lift system cannot by itself drive oil all the way to the surface in many wells, given limitations on gas pressure and the fact that some wells are now producing fluids containing as much as 95 percent water, the plan says.

Gas needs

Natural gas is clearly a key material for use in oil production at Kuparuk, and is also used as a fuel for the field facilities. In the past, gas production from the field has exceeded fuel requirements, thus enabling the use of surplus gas for WAG operations, the plan says. With insufficient natural gas liquids to meet miscible injectant demand, Kuparuk has for several years been importing natural gas liquids from the neighboring Prudhoe Bay field through a pipeline called the Oliktok pipeline.

But gas production at Kuparuk is declining. So, with fuel gas being critical to field operations, ConocoPhillips has been moving ahead with a plan to convert the Oliktok pipeline for shipping gas rather than natural gas liquids from the Prudhoe Bay field. The import of natural gas liquids from Prudhoe Bay is expected to end in 2014, the plan says. As a consequence, the plan assumes that large-scale WAG with miscible injectant will also stop before the end of 2014. After that time, miscible gas injection will continue at just four drill sites, using natural gas liquids produced from the Kuparuk field, the plan says.

Because the gas from Prudhoe Bay contains 10 to 12 percent carbon dioxide and could, therefore, cause corrosion in the Kuparuk production system, this gas will simply be used as fuel gas, and will not be injected into the Kuparuk field reservoir, the plan says. Then, with indigenous Kuparuk gas that would otherwise have been used as fuel becoming available, ConocoPhillips plans to commence a full-field "lean gas chase," using injected dry gas to recover some of the natural gas liquids trapped in the reservoir rocks, and to enhance the artificial lift in wells that produce high volumes of water.

Other opportunities

In addition to maximizing oil recovery within the traditional reservoirs of the Kuparuk field, ConocoPhillips sees potential for exploration and appraisal leads identified from seismic surveys within the Kuparuk River unit, the plan says. The company has been moving forward with one of these opportunities, the Shark Tooth prospect, having drilled a well in the prospect in January 2012. Production results are also being evaluated, following a perforation and hydraulic fracturing pilot test in the Cretaceous Moraine interval, an oil reservoir in the Brookian rock sequence above the reservoir rocks of the Kuparuk field, the plan says. ●

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COURT RULING

the rights "conferred by aboriginal title means that governments and others seeking to use the land must obtain the consent of the aboriginal titleholders."

The landmark ruling also provides a roadmap for all unresolved land claims across Canada by First Nations seeking to negotiate modern treaties, or to contest their land rights in court.

"Aboriginal title confers the right to use and control the land and to reap the benefits flowing from it," McLachlin wrote for all eight justices, while noting that aboriginal title is not absolute.

However, the ruling also made clear that, even if there is no consent, economic development should be able to proceed if governments can establish that projects have a "compelling and substantial" public interest.

Response mixed

Aboriginal leaders immediately and enthusiastically greeted the ruling as marking an epic shift in Canada-First Nations relations and a signal to Prime Minister Stephen Harper and provincial premiers to take treaty negotiations more seriously.

"This will be a game-changer in terms of the landscape of British Columbia and throughout the rest of the country where there is unextinguished aboriginal title," said Jody Wilson-Raybould, British Columbia chief of Canada's Assembly of First Nations.

"This has to be a wakeup call for governments, both provincial and federal, and we look to Mr. Harper to actually see this as the fundamental impetus to sit down at the table ... and meaningfully move towards reconciliation," she said.

"We now have the opportunity to settle, once and for all, the so-called 'Indian land question' in British Columbia and Canada where aboriginal title exists through good-faith negotiations."

Canada's Natural Resources Minister Greg Rickford offered only a sketchy view of the ruling, saying his government "believes the best way to resolve outstanding aboriginal rights and title claims is through negotiated treaty settlements." He would not be drawn into commenting on how the decision might affect Enbridge's Northern Gateway project.

End of 'business-as-usual'

Bill Gallagher, a former Canadian government regulator, oil and gas lawyer and treaty negotiator, told the Globe and Mail that "the climax of Native empowerment has arrived. It's not going to be business-as-usual for (energy) projects."

Grand Chief Stewart Phillip, president of the Union of B.C. Indian Chiefs, said resource projects infringing on traditional aboriginal territories will now require "consent" as well as "consultation" before they can proceed.

"We are in an entirely different ball game," he told a news conference, suggesting that Enbridge and Kinder Morgan (through its plans to expand the Trans Mountain system) are "probably back on their heels."

Bernie Mack, one of six Tsilhqot'in chiefs, left no doubt that proponents and governments will have to demonstrate a "substantial and compelling public purpose" to gain the consent of First Nations.

"The days of easy infringement (on aboriginal land) are gone," he said, predicting that a "lot of our leaders" will now become involved in oil and gas and mining companies, taking a place in corporate board rooms.

Joe Alphonse, also a Tsilhqot'in chief, said his community did not engage in a decade-long fight "to separate from Canada. We fought it to be treated as equals."

> *Other legal and regulatory observers said the ruling has implications not just for future projects but for those to have been approved or are under construction.*

"This case is about us regaining our independence ... to be able to govern our own Nation and relay on the natural resources of our land. We are ready to move forward in this new relationship with government and industry," he said.

John Bennett, executive director of the Sierra Club in Canada, offered one concise assessment of what now lies ahead.

He suggested Enbridge will have to restart the regulatory hearing process if it hopes to gain approval for Northern Gateway.

Enbridge didn't offer anything conclusive beyond a spokesman's comments that it will "continue to act pro-actively on our responsibility to consult and build relationships with aboriginal communities near our proposed projects. This decision will not change that commitment."

CAPP: ruling adds clarity

Alex Ferguson, vice president of policy for the Canadian Association of Petroleum Producers, told the Calgary Herald that, like Enbridge, his organization needed time to examine the 80-page court decision.

He said CAPP's early view is that the ruling adds clarity to the "long-standing evolution of these issues."

But Ferguson said it was too early to say what the implications would be for Northern Gateway and the Trans Mountain expansion, both of which could face a tough legal test if any First Nations in Alberta or British Columbia file a land claim along the pipeline rights of way.

Steven Paget, an analyst with FirstEnergy Capital, said in a note that more Native communities will now be able to claim standing to oppose pipelines, helping clarify for proponents which communities they must negotiate with.

However, he pointed out that the ruling neither helps nor hinders the pipeline companies because many First Nations that oppose the projects are able to establish long-term continuous settlement of their lands and thus have automatic standing in any legal challenges.

Retroactive cancellations?

Other legal and regulatory observers said the ruling has implications not just for future projects but for those to have been approved or are under construction.

They noted that one paragraph in the judgment might force governments to retroactively cancel approval of a project if it was given the go-ahead before aboriginal title was established, while legislation enacted before title was established might also be "rendered inapplicable."

Jean Crowder, aboriginal affairs spokeswoman for the federal New Democratic Party, said the ruling shows the Canadian government should set up a "protocol" for First Nations consultation on future resource development projects that would take place from the initiation of a project. ●

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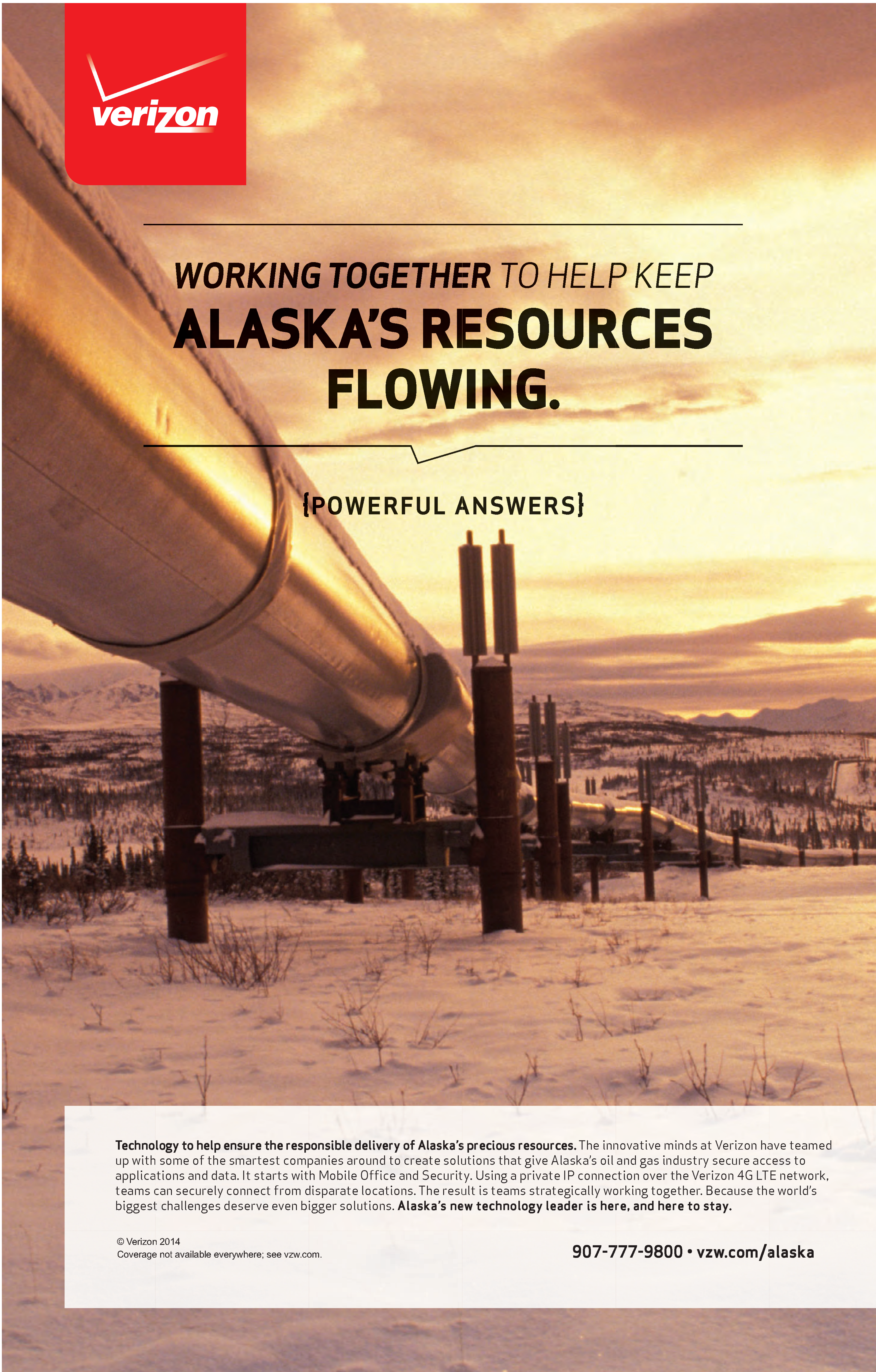
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