Petroleum news

page 4 Alaska House minority leader tackles oil taxes, in-state gas line in Q&A

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Petroleum news BAKKEN

page 6 Q&A: Senate majority leader weighs in on North Dakota oil, gas legislation

Vol. 1, No. 21 • www.PetroleumNewsBakken.com | A semi-monthly newspaper for industry and government | February 17, 2013

Crude on rails in for long haul

VERN WHITTEN PHOTOGRAPHY

Plains All American's Manitou crude oil and NGL rail facility near Ross, west of Stanley in Mountrail County, North Dakota. Photo taken this winter by Vern Whitten. See rail story below.

Rail will survive pipeline additions

The need for rail to move crude from Midcontinent fields will likely persist, even if plans for expanding pipeline links from the Bakken to the Gulf Coast go ahead, EOG Resources Chief Executive Officer Mark Papa told a Colorado conference.

He said rail will still be used five years from now to deliver Bakken crude to all three Lower 48 coasts — the Gulf, East and West — but expects the current advantage of Louisiana Light Sweet, LLS, crude prices in the Houston market will probably change within 18

MARK PAPA

see RAIL SURVIVAL page 24

Bakken threatens Alberta upgrader

The Bakken might be about to register a friendly-fire victim — a C$11.6 billion Suncor Energy upgrader to convert oil sands bitumen into synthetic crude for refining into fuels.

Suncor, with France's Total as a 49 percent partner, expects to decide no later than March 31 on the immediate fate of its Voyageur project, which has been in a holding pattern for the last four years, putting an end to its original startup date of 2016.

Since taking control of the oil sands giant nine months ago, Suncor Chief Executive Officer Steve Williams has increasingly hinted that economic challenges could be the undoing of Voyageur.

His explanation has been delivered in clear-cut terms.

see ALBERTA UPGRADER page 24

Helms slams U.S. Fish & Wildlife

Two new slides have appeared in Lynn Helms' presentation packet — slides with information that he thinks indicate an attempt by the U.S. Fish & Wildlife Service to take over oil and gas permitting in North Dakota.

SERIES

One is a map backing up his agency's recent analysis that shows 83 percent of North Dakota's oil and gas spacing units have some federal land ownership, surface and/or minerals.

LYNN HELMS

Helms, director of the North Dakota Industrial Commission's Department of Minerals, Oil and Gas Division, told North Dakota lawmakers in January, "It was really sur-

see PERMITTING page 10

COMPANY UPDATE

WLL gets bum rap

James. T. Brown: Whiting Petroleum is not running out of drilling inventory

By RAY TYSON

Petroleum News Bakken

Denver-based E&P independent Whiting Petroleum Corp. is finding it difficult convincing investors that the company is not running out of suitable places to drill.

"The knock against Whiting is that you guys don't have any inventory and in three years you're going to be done," James T. Brown, Whiting's president and chief operating officer, told industry analysts Feb. 6 at the Credit Suisse 2013 Energy Summit in Vail, Colo.

The lack-of-inventory perception seems to be particularly acute when it comes to finding new targets in Whiting's flagship Sanish field in North Dakota's Williston Basin, which accounts for around 30,000 barrels per day, or nearly 40 percent of the company's roughly 80,000 barrels per day of production.

JAMES T. BROWN

By the end of 2012, a total of about 300 production wells had been drilled in the Sanish field, with at least another 200 to be drilled and completed.

"It seems that when we get to the end of every year, we have two-and-half to three years of drilling

see WHITING INVENTORY page 18

LAND & LEASING

Riverbed draws top bids

QEP Energy high bidder on 22 Missouri River leases; shore zone included

By MIKE ELLERD

For Petroleum News Bakken

A total of 27,370 acres were leased in 306 tracts in nine western North Dakota counties in the Feb. 5 North Dakota Department of Trust Lands oil and gas lease auction bringing in a total of $24,609,206 at an average price of $899 per acre. The auction was dominated by tracts between the former high water marks on the two banks of the Missouri River under Lake Sakakawea in Dunn County.

LANCE GAEBE

DREW COMBS

Of the 27,370 acres leased, slightly less than one-third or 9,900 acres were in 106 Missouri riverbed tracts in Dunn County and those tracts brought in a total $21,227,455, a sum that accounted for more than 86 percent of the gross auction proceeds.

The Dunn County lease activity was, in turn, dominated by 22 Missouri riverbed tracts totaling 1,465 acres that fetched a total of $16,536,197 at an average price of $11,291 per acre, all purchased by Denver-based QEP Energy Co.

see ND LEASE AUCTION page 21

ASSOCIATIONS

Galt: MPA ever vigilant

Montana Petroleum Association chief keeps tabs on several bills during session

By MIKE ELLERD

For Petroleum News Bakken

Numerous oil and gas-related bills have been introduced thus far in the 63rd session of the Montana legislature currently in session in Helena, and while Montana Petroleum Association Executive Director Dave Galt follows all of them closely, he recently spoke with Petroleum News Bakken and discussed those that he thinks are most important to his membership.

DAVE GALT

The key bills Galt identified fall into a variety of categories. Some deal with compensation for landowner surface damage, eminent domain and forced pooling, all of which Galt lumps together into what he considers to be "property rights" legislation. Other bills that Galt considers key deal with taxation, temporary leasing of water rights, financial relief to oil and gas-impacted communities, and carbon sequestration and enhanced oil recovery using carbon dioxide.

Property rights: surface damage compensation

House Bill 431, introduced by Rep. Austin Knudsen of Culbertson, is a surface damage compensation bill that would add to the existing oil and gas surface damage and disruption compensation statue the definition of "lost land value" as "the value

see ENERGY LEGISLATION page 22

Exxon signs deal to possibly make Rosneft a Point Thomson partner

Are the Russians coming to Alaska's North Slope?

Could be.

On Feb. 13, ExxonMobil and Rosneft announced out of Moscow that they had agreed to expand their 2011 "strategic cooperation agreement" to include an additional 150 million exploration acres in the Russian Arctic and "potential participation by Rosneft (or its affiliate) in the Point Thomson project in Alaska."

ExxonMobil further said the companies had agreed to conduct a joint study on a potential liquefied natural gas, or LNG, project in the Russian Far East.

ExxonMobil is operator of the Point Thomson field, situ-

see EXXON DEAL page 19

LNG warning flags; Canada's First Nations ponder legal fight

The National Energy Board has granted Canada's third LNG export permit, this one for Shell-operated LNG Canada to process the equivalent of 3.23 billion cubic feet per day over 25 years.

Combined with the other two licenses, for Chevron's Kitimat LNG and the BC LNG Export Co-operative's Douglas Channel project, that raises British Columbia's commitment to produce to 4.8 billion cubic feet per day, almost 25 percent more than the province's total current out.

It represents another bold step toward the grand dream of British Columbia Premier Christy Clark, who wants LNG in her province to match the oil sands in Alberta as a source of jobs and government revenues.

But, if Clark is keeping an eye on her rear-view mirror, she

see WARNING FLAGS page 19

EXPLORATION & PRODUCTION

Shell to move rigs

Will dry tow Kulluk and Noble Discoverer to Asian shipyards for repair

By ALAN BAILEY

Petroleum News

Following weeks of speculation over the eventual fate of the Kulluk, Shell's floating drilling platform that ran aground en route from the Aleutians to the U.S. West Coast, and with the drillship Noble Discoverer stuck in the Alaska port of Seward with propulsion problems, Shell has shed some light on how it proposes dealing with its two Arctic drilling units. The two vessels had been transiting south, following the end of the 2012 drilling season in the Beaufort and Chukchi seas.

Move to Asia

Shell is going to move the Kulluk to an Asian harbor with a suitable dry dock for repair, company spokesman Curtis Smith said in a Feb. 11 email. The Kulluk has been anchored in Kiliuda Bay on the south side of Kodiak Island since Jan. 7, having been refloated after running aground in a severe storm on the evening of Dec. 31. The vessel had been sched-

Det Norske Veritas, the engineering firm commissioned to assess the condition of the Kulluk, has validated that the vessel has the necessary structural integrity and stability to be towed, and has issued appropriate certification for the vessel.

see RIG MOVE page 18

FINANCE & ECONOMY

Alaska's ELF war

Oil companies continue to fight a controversial 2005 tax change that cost them big

By WESLEY LOY

For Petroleum News

Back in 2005, then-Gov. Frank Murkowski rankled the Alaska oil industry with an announcement that several satellite oil fields would be "aggregated" with the main Prudhoe Bay field for purposes of production taxes.

The effect was to greatly increase the taxes paid on oil produced from the satellites.

The decision by Alaska's Department of Revenue drew serious industry grumbling and political heat for Murkowski. But he stood firm and the unhappy oil producers got over it.

Right?

Not exactly. Turns out a quiet battle over the tax hike has been simmering ever since. And it's far from over.

During a Feb. 7 legislative hearing, a top oil and gas lawyer for the state offered a status report on the conflict, saying several hundred million dollars in tax revenue is at stake.

Recently, he said, an administrative law judge rendered a favorable decision for the Department of Revenue.

Now the oil companies are appealing that decision in state Superior Court.

The companies involved

The companies challenging the 2005 tax hike include Chevron, ConocoPhillips, ExxonMobil and

see ELF WAR page 18

FINANCE & ECONOMY

The takeover completes

Hilcorp's acquisition of all of Marathon's Cook Inlet assets finally concludes

By ALAN BAILEY

Petroleum News

Hilcorp Alaska has completed its takeover of Marathon Oil Co.'s Cook Inlet oil and gas assets, Hilcorp spokeswoman Lori Nelson confirmed to Petroleum News in a Feb. 12 email. The purchase transaction completed on Jan. 31, Nelson said.

The assets that Hilcorp has purchased include 10 fields in the Cook Inlet basin, three gas storage facilities, two gas pipelines and the remaining interests in two other gas pipeline systems. In total Hilcorp has acquired 157 Marathon wells, 75 of which are actively producing, Nelson said. Marathon was primarily a gas producer in the basin.

That consent decree puts a price cap on Hilcorp gas sold for local Southcentral Alaska use over the next five years and prohibits Hilcorp from selling gas for export as liquefied natural gas unless all local gas supply needs are met.

April agreement

Hilcorp originally announced its agreement with Marathon over the purchase of Marathon's assets in April 2012, but an investigation by the Federal Trade Commission and the State of Alaska

see TAKEOVER page 17

contents

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Alaska - Mackenzie Rig Report

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status

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-07-34	BP
Dreco 1000 UE	16 (SCR/TD)	Milne Point MPG-19	BP
Dreco D2000 UEBD	19 (SCR/TD)	Alpine CD3-127	ConocoPhillips
AC Mobile	25	Prudhoe Bay Z-61	BP
OIME 2000	141 (SCR/TD)	Kuparuk 3K-105	ConocoPhillips
Kuukpik	5	Mobilizing to Umiat	Linc Energy Operations Inc.
Nabors Alaska Drilling			
Trans-ocean rig	CDR-1 (CT)	Prudhoe Bay	Stacked
AC Coil Hybrid	CDR-2	Kuparuk 1H-19	ConocoPhillips
Dreco 1000 UE	2-ES	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)	Mobilizing to Colville River	Repsol
Dreco 1000 UE	9-ES (SCR/TD)	Prudhoe Bay	Available
Oilwell 2000 Hercules	14-E (SCR)	Prudhoe Bay	Available
Oilwell 2000 Hercules	16-E (SCR/TD)	Prudhoe Bay	Available
Oilwell 2000	17-E (SCR/TD)	Prudhoe Bay	Stacked
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	28-E (SCR)	Prudhoe Bay	Stacked
Emsco Electro-hoist Canrig 1050E	27-E (SCR-TD)	Kuparuk NDST-2	Pioneer Natural Resources
Oilwell 2000	33-E	Prudhoe Bay	Available
Academy AC electric Canrig	105-E (SCR-TD)	Colville River Q1	Repsol
Nordic Calista Services			
Superior 700 UE	1 (SCR/CTD)	Prudhoe Bay Drill Site 5-35AL1	BP
Superior 700 UE	2 (SCR/CTD)	Prudhoe Bay Well Drill Site 6-24B	BP
Ideco 900	3 (SCR/TD)	Kuparuk Well 2N-304	ConocoPhillips
Parker Drilling Arctic Operating Inc.			
NOV ADS-10SD	272	Prudhoe Bay Acceptance meeting scheduled for Feb. 11, 2013	BP
NOV ADS-10SD	273	Prudhoe Bay DS 02-12D	BP

North Slope - Offshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
BP			
Top drive, supersized	Liberty rig	Inactive	BP
Nabors Alaska Drilling			
Commander 1500 HP	19-E (AC)	Ooguruk ODSN-24	Pioneer Natural Resources
OIME 2000	245-E	Oliktok Point	ENI
Doyon Drilling			
Sky Top Brewster NE-12	15	Spy Island SP22-FN1	ENI

Cook Inlet Basin – Onshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Kenai Land Ventures LLC (All American Consultants, labor Contract)			
Taylor	Glacier 1	Kenai Loop Drilling Pad #1	Buccaneer Energy Ltd
Aurora Well Service			
Franks 300 Srs. Explorer III	AWS 1	In winter maintantance mode through February	Hilcorp Alaska
Cook Inlet Energy			
Atlas Copco RD20	37	Beluga I-78	MGM Energy
Doyon Drilling			
TSM 7000	Arctic Fox #1	Swanson River SRU 13-27	Hilcorp Alaska LLC
Nabors Alaska Drilling			
Academy AC Electric CANRIG	99AC	Mobilizing to Colville River	Repsol
Continental Emsco E3000	273E	Kenai	Available
Franks	26	Kenai	Stacked
IDECO 2100 E	429E (SCR)	Stacked in Kenai	Available
Rigmaster 850	129	Kenai	Available
Academy AC electric Heli-Rig	106-E (SCR/TD)	Tiger Eye 1	NordAq

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, labor contract)		Steelhead Platform Well M-31B redrill, KD management contract	Hilcorp Alaska LLC

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

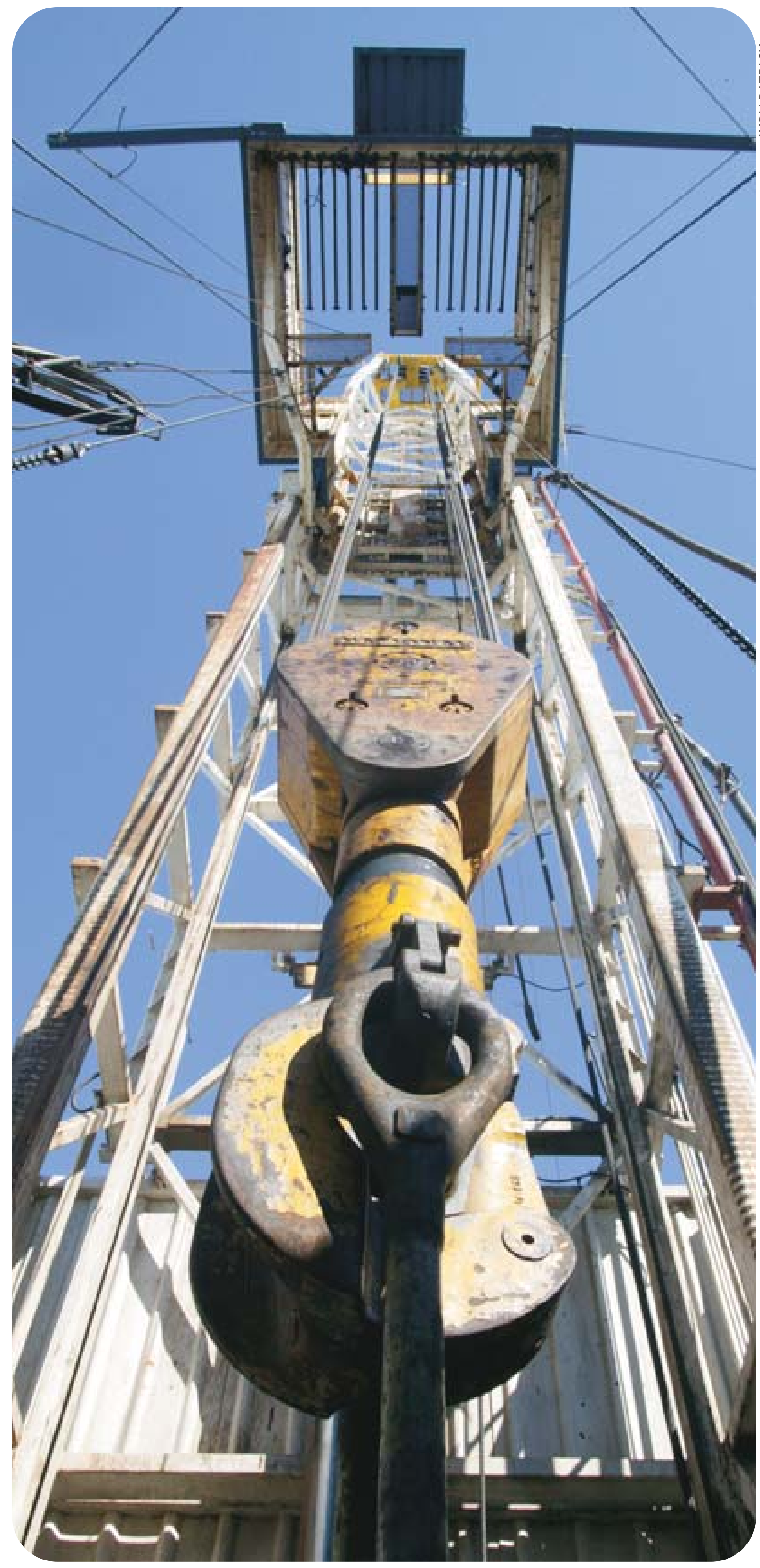
Central Mackenzie Valley

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Akita/SAHTU			
Oilwell 500	51	Still out of the NWT, but is again available	Available
TSM 7000	34	On the move to East Mackay I-78 in the Sahtu	MGM Energy Corp.

The Alaska - Mackenzie Rig Report as of February 14, 2013. 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



JUDY PATRICK

Baker Hughes North America rotary rig counts*

	Feb. 8	Feb. 1	Year Ago
US	1,759	1, 764	1,989
Canada	631	625	709
Gulf	53	51	40

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

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● GOVERNMENT

Kerttula on oil taxes, in-state gas line

Juneau Democrat, House minority leader brings long-term perspective to tax change, Alaska Gasline Development Corp. legislation

By STEVE QUINN
For Petroleum News

Just as Gov. Sean Parnell's oil tax bill hit parallel tracks in the Legislature, another oil tax bill emerges — this one from Democratic leaders in the House and Senate.

Right now Senate Bill 21 and House Bill 72 are being heard in respective House and Senate Resources committees.

But House and Senate Democrats say they have an alternative designed to create competition and achieve the goal all lawmakers on both sides of the oil tax argument agree upon: increasing throughput in the trans-Alaska oil pipeline.

BETH KERTTULA

On the House side, Minority Leader Beth Kerttula, a Juneau Democrat, is leading the efforts behind HB 111, the Democrat's oil tax bill.

Kerttula does not sit on any resource committee but she has been on the front lines of oil tax debates since the Petroleum Profits Tax was approved in 2006.

She was also there when the Legislature replaced PPT with the current system known as ACES slightly more than one year later.

Q AND A

At the time, she successfully spearheaded efforts to secure a standardized deductions provision, which has since expired.

Before entering public office, she served as an attorney for the Attorney General's office in the oil, gas and mining division.

Kerttula is among the longest serving House members and has begun her eighth term this year.

She sat down with Petroleum News to discuss her views on oil taxes and on advancing a natural gas pipeline project, as HB 4's in-state line efforts are also being debated in the House Resources Committee.

Petroleum News: What would you say is the thesis of HB 111?

Kerttula: The thesis of the argument is that we want more production in the pipeline. To try to do that, there are three ways. First, get some new guys in the game. Get innovation. It's what we know as the natural progression towards the smaller, scrappier companies. It means the tax breaks and credits. It also includes some things that have become more obvious after time. Get them access to the facilities. Get them that leg up that they have to have. We particularly have to have it in Alaska. We have a grip in the market from the big companies. We want oil and gas. We want to work with the big companies. But just classic economics tells you that you have to have competition.

That's the second thing: Get competition going. Be sure that we've got some. Something that can progress the way most states have and that Alaska needs to.

Finally, try to incentivize, I guess what I would call the old oil. Get the older folks producing more oil and get heavy oil, those things going, too. So it's a broad look at how to get production. For that we get reduced taxes. Alaskans have got to benefit along with the companies, especially on the high side. Now I'm hearing there will be a 0.1 progressivity. That's laughable. That's just laughable. That's ridiculous.

Petroleum News: By offering an alternative, is this a statement that ACES is broken? Does it change your position on ACES?

Kerttula: It doesn't. I think there could be things that could be tweaked. We had standard deductions that I would have liked to have seen kept for good, but they sunsetted. So there are obviously things that could be changed with any tax law. This is an effort to make changes that we think will help for a long time. ACES isn't broken. ACES gave us in the enviable position that the state is in and it obviously hasn't hurt the companies. Exploration is up; profits are high. It obviously isn't broken.

Petroleum News: Why didn't you offer one last year?

Kerttula: At that point the state was moving along and there was no real necessity for us to do that. Certainly there is the difference in the Legislature itself with the Senate having changed leadership, so we have to keep trying a little harder this year.

Right now there is such a huge push on the governor's bill, and we need to be very clear on things that could help versus things they are doing.

Petroleum News: Do you think there is a chance that this can work its way to the floor?

I'm always an optimist that people will take good ideas and consider them. Then again, I watched what happened with the cruise ship bill in House Resources. That was a very poor process. I just don't know. I'm hopeful any good idea gets discussed and we can see good ideas get into legislation, however it happens.

Petroleum News: So why not these bills that the House and the Senate are reviewing now? What problems do you have with the bill currently discussed in each resource committee?

Kerttula: For one thing, it gives away Alaskans benefit on the high side. What happens when oil goes to $250 a barrel? That's just wrong. The second thing I really have a hard time with, why when companies are in the development stage, do we start messing with the credits then? We are trying to get them there, then all of the sudden the governor's bill pulls the rug out from under them.

Petroleum News: Let's switch to natural gas. What are your thoughts on the

see KERTTULA Q&A page 17

FINANCE & ECONOMY

EIA forecasts dropping crude oil prices

US crude oil production expected to continue to grow over next 2 years, from 6.4 million bpd last year to 7.8 million bpd in 2014

By KRISTEN NELSON

Petroleum News

The U.S. Energy Information Administration expects the Brent crude oil spot price to drop both this year and next. From an average of $112 per barrel last year, EIA said in its Feb. 11 Short-Term Energy Outlook, it expects Brent to average $109 per barrel this year and $101 per barrel in 2014. Brent rose to $119 per barrel in early February, the agency said.

The projected discount of West Texas Intermediate to Brent, which averaged $18 per barrel last year, is expected to drop to $9 per barrel in 2014, EIA said, as completion of planned new pipeline capacity lowers the cost of moving Midcontinent crude oil to the Gulf Coast.

EIA said the expected drop in the Brent crude oil spot price reflects an increasing supply of liquid fuels from non-Organization of the Petroleum Exporting Countries, OPEC.

WTC averaged $94 per barrel last year and is projected to average $93 per barrel this year and $92 per barrel in 2014, EIA said.

US production grows

The estimated crude oil production in the U.S. last year was 6.4 million barrels per day, EIA said, an increase of 800,000 bpd from 2011.

Domestic crude oil production is projected to increase to 7.3 million bpd this year and to 7.8 million bpd in 2014, EIA said.

"Central to this projected growth will be continuing development of onshore basins," EIA said, with drilling in tight oil plays in the Williston, Western Gulf and Permian basins expected to account for the bulk of the forecast production growth.

EIA noted a seasonal low in Alaska crude oil production of 400,000 bpd in August, during summer maintenance, with recovery to 530,000 bpd in October for an annual average of 530,000 bpd. Alaska crude oil production is projected to average 500,000 bpd this year and 470,000 bpd in 2014.

U.S. federal Gulf of Mexico production averaged an estimated 1.3 million bpd last year, down some 50,000 bpd from 2011, and EIA said it expects GOM production to increase to 1.4 million bpd this year, primarily due to new projects that started production last year. GOM production is projected to average 1.5 million bpd in 2014, "as several relatively high-volume deepwater projects are expected onstream."

U.S. liquid fuel net imports, including crude oil, peaked in 2005 at 12.5 million bpd and fell to 7.5 million bpd last year. EIA said it expects imports to continue to decline to an average of 6.1 million bpd in 2014.

"Similarly, the share of total U.S. consumption met by liquid fuel net imports peaked at more than 60 percent in 2005 and fell to an average of 40 percent in 2012," EIA said. It expects the net import share to fall to 32 percent in 2014 "because of continued substantial increases in domestic crude oil production."

Natural gas

EIA said it expects U.S. natural gas consumption to average 70.3 billion cubic feet per day in 2013 and 70 bcf per day in 2014, in what the agency called a "significant upward revision" from January's projection of 69.7 bcf per day in 2013 and 69.4 bcf per day in 2014. The agency attributed the upward revision to "changes to historical industrial sector consumption data" in the recently released EIA Natural Gas Annual.

With closer-to-normal winter weather forecast for 2013 and 2014, compared to record warmth in 2012, EIA said there would be increases in natural gas use for residential and commercial heating.

Henry Hub natural gas spot prices, which averaged $3.33 per million British thermal units in January, were relatively unchanged from December, EIA said, despite colder weather in January. The Henry Hub spot price is projected to average $3.53 per million Btu this year, up from $2.75 per million Btu last year and to rise to $3.84 per million Btu in 2014.

EIA said the projected increase in natural gas prices contributes to a decline in natural gas used for electric power gener-

see EIA FORECAST *page 6*

GOVERNMENT

Walker presses Point Thomson challenge

Bill Walker isn't giving up. He's taking his challenge of the state's Point Thomson settlement to the Alaska Supreme Court.

Walker, an Anchorage attorney and former candidate for governor, had filed an administrative appeal in state Superior Court following the March 29, 2012, resolution of the legal dispute surrounding the Point Thomson field on the eastern North Slope.

Superior Court Judge Catherine Easter dismissed Walker's suit on Dec. 7.

Now Walker is petitioning the Supreme Court to review Easter's ruling.

Walker questions the legality of the Point Thomson settlement on numerous levels. State officials failed to put the deal out for public comment, and failed to obtain legislative approval for some provisions, he says. He further contends the agreement contained no firm work commitments, and that Point Thomson leaseholders could choose a wasteful development option to exploit the field's natural rich gas reserves while leaving valuable liquids behind.

Under the settlement, ExxonMobil and its partners are now moving to construct facilities to produce gas condensate from Point Thomson. State officials have long pushed for production from the field, discovered in 1977.

Martin Schultz, supervisor of the Alaska Department of Law's Oil, Gas and Mining Section, told state legislators in a Feb. 7 hearing that the state stands by the Point Thomson deal.

"We're confident of our position that the settlement agreement is valid," he said.

He continued: "This is a great settlement for the state. It means that development is going forward at Point Thomson, and that's a wonderful thing."

The Point Thomson field is located along the Beaufort Sea coast, next to the Arctic National Wildlife Refuge. ExxonMobil is operator, with BP and ConocoPhillips holding significant stakes.

—WESLEY LOY

LAND & LEASING

Aurora transfers parts of Nicolai Creek

Apache and Hilcorp separately acquire portions of leases around the west side Cook Inlet unit; Buccaneer denied royalty transfer

By ERIC LIDJI
For Petroleum News

Aurora Gas LLC has transferred portions of six leases on the west side of Cook Inlet to two big-hitting newcomers in the basin: Apache Alaska Corp. and Hilcorp Alaska.

At ADL 388233, an onshore lease one mile north of the village of Tyonek and formerly in the Three Mile Creek unit, Aurora transferred portions of four segments to Apache.

For Segment A, which covers the entire lease below the boundary between the Upper and Lower Tyonek formations, Aurora transferred a 70 percent working interest and a 58.06133 percent royalty interest. For Segment B, which covers 200 acres of the lease (in Section 22 and Section 23) below the same boundary, Aurora transferred a 70 percent working interest and a 59.0833 percent royalty interest. For Segment C, which covers 160 acres of the lease (in Section 23) below the same boundary, Aurora transferred a 30 percent working interest and a 23.64533 percent royalty interest. For Segment D, which also covers 160 acres of the lease (also in Section 23) below the same boundary, Aurora transferred a 30 percent working interest and a 24.0833 percent royalty interest.

> *Also in Cook Inlet, Marathon Alaska Production LLC transferred interests in 69 leases across the basin to Hilcorp Alaska LLC, as the legacy player works to hand over its assets in the region to the fast moving newcomer.*

The remaining five leases are in and around the Nicolai Creek unit.

Aurora transferred a 100 percent working interest and 82 percent royalty interest in two segments of ADL 391471 to Apache Alaska. The onshore unit west of Tyonek contains two non-contiguous leases, ADL 391471 and ADL 63279. ADL 391471 includes four participating areas in their entirety: West Tyonek, West Beluga, Beluga and Nicolai Creek South. Aurora is retaining its interest in the other lease in the unit, ADL 63279.

At ADL 391472 — a larger lease that held by the unit — Aurora transferred a 100 percent working interest and 82 percent royalty interest in Segment A and a 100 percent working interest and 81.75 percent royalty interest in Segment B to Apache Alaska.

At ADL 391265, a lease adjacent to the northwest corner of the unit, Aurora transferred a 100 percent working interest and 86 percent royalty interest to Apache Alaska.

Aurora transferred portions of two leases just south of the unit to Hilcorp. At ADL 017598, Aurora transferred a 100 percent working interest and 85 percent royalty interest in Segment A and a 100 percent working interest and 84.75 percent royalty interest in Segment B. At ADL 017585, Aurora transferred a 100 percent working interest and 85 percent royalty interest in Segment A, a 75 percent working interest and 63.125 percent royalty interest in Segment B, a 75 percent working interest and 64.125 percent royalty interest in Segment C, a 100 percent working interest and 85 percent royalty interest in Segment D and a 75 percent working interest and 63.125 percent royalty interest in Segment E. Both ADL 17598 and ADL 17585 are currently held by production.

In recent years, Aurora has pursued a gas storage project at Nicolai Creek.

Other leasing news

The state denied a request from Buccaneer Alaska LLC to transfer a small royalty interest (0.75 percent) in 16 leases across Cook Inlet to Er Alaska LLC, a company formed in May 2012. The leases include acreage at both the offshore Southern Cross and Northwest Cook Inlet units and at both the onshore West Nicolai Creek and West Eagle prospects.

Also in Cook Inlet, Marathon Alaska Production LLC transferred interests in 69 leases across the basin to Hilcorp Alaska LLC, as the legacy player works to hand over its assets in the region to the fast moving newcomer. (See page 1 story on Hilcorp, which has completed its acquisition of Marathon's Cook Inlet assets.) And Stellar Oil & Gas LLC transferred small royalty interests (all in values less than 1 percent) in four leases at the Northwest Cook Inlet unit to a variety of players including, David W. Fulton, David J. Doherty, Bang Energy LLC, William Allen Huckabay, Strong Energy Resources LLC, Mark R. Landt and the Moore Family Living Trust Dated Nov. 14, 1998, retroactive to September.

On the North Slope, Armstrong Oil & Gas President William D. Armstrong transferred small royalty interests — at 0.1 percent or smaller — in some 160 onshore and offshore leases operated by Repsol E&P USA Inc. to Matthew X. Furin, a company vice president. ●

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

Contact Eric Lidji at ericlidji@mac.com

continued from page 5

EIA FORECAST

ation from 25 bcf per day in 2012 to 23.1 bcf per day projected in 2013 and 22.6 bcf per day in 2014.

"Consumption over the forecast period is less than the record high 2012 levels, but remains high by historical standards and reflects an ongoing structural shift toward using more natural gas for power generation," EIA said. ●

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FINANCE & ECONOMY

Shell drill vessel won't face state tax

ASSOCIATED PRESS

A stranded Royal Dutch Shell PLC drilling barge will not be subject to an Alaska state property tax obligation, according to revenue officials.

Jim Greeley, the Alaska Department of Revenue oil and gas tax assessor, said that state policy for more than three decades has been to not tax drilling equipment that operates outside state waters. That includes the Kulluk, which drilled in the Beaufort Sea last year beyond the state's 3-mile jurisdiction.

"Because this vessel is dedicated for those activities outside of the state in federal (continental shelf) waters, it falls outside (the law)," Greeley told the Kodiak Daily Mirror.

The property tax issue came up as drilling critics questioned why Shell moved the barge in late December, when the Gulf of Alaska is notoriously rough. They suggested, and Shell denied, that the company was attempting to dodge the 2 percent property tax, which could have exceeded several million dollars.

Shell has said consistently that the Kulluk was being towed to the Pacific Northwest for maintenance and upgrades.

The vessel left Dutch Harbor in the Aleutian Islands and ran into trouble in heavy seas when tow lines failed. The Kulluk ran aground Dec. 31 off remote Sitkalidak Island. Salvors refloated the barge Jan. 6 and moved it to shelter in a Kodiak Island bay, where responders continue to plan for its next move.

Weeks in Dutch Harbor

The Kulluk spent weeks in Dutch Harbor but is affected by a legal opinion issued by former Attorney General Avrum Gross in 1977, the year oil first flowed through the trans-Alaska pipeline. Gross addressed the question of whether the state could tax property used to drill for oil more than three miles offshore. Oil companies objected to taxes on support vessels, and Gross decided the policy also applied to drill ships in federal waters.

"It is our opinion that property used or committed by contract for use solely in OCS (outer continental shelf) exploration and development in federal waters off Alaska cannot be taxed," he wrote.

State oil and gas attorney Martin Schultz said the policy covers the Kulluk.

"It's a pretty straightforward interpretation as it applies to the Shell Kulluk," Schultz said. "That particular definition has not changed since this attorney general's opinion was issued."

The Kulluk is a 266-foot diameter barge with a 160-foot derrick in its center. It was designed for extended drilling in Arctic waters and has an ice-reinforced, funnel-shape hull. The conical shape is designed to deflect moving ice downward and break it into small pieces. ●

LAND & LEASING

Potential Alaska state and federal oil and gas lease sales

Agency	Sale and Area	Proposed Date
DNR	Cook Inlet	May 8, 2013
DNR	Alaska Peninsula	May 8, 2013
DNR	Augustine Island Geothermal	May 8, 2013
DNR	Beaufort Sea Areawide	fall 2013
DNR	North Slope Areawide	fall 2013
DNR	North Slope Foothills Areawide	fall 2013
BLM	NPR-A	fall 2013
BOEM	Cook Inlet (special interest)	2016
BOEM	Chukchi Sea	2016
BOEM	Beaufort Sea	2017

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

This week's lease sale chart sponsored by:

Geokinetics

● EXPLORATION & PRODUCTION

Apache's first CI well nears total depth

Company plans to take rock core and test production, to assess reservoir potential for other prospects identified from seismic

By ALAN BAILEY
Petroleum News

The drilling of Apache Corp's Kaldachabuna No. 2 well near the village of Tyonek on the west side of Alaska's Cook Inlet has reached a depth just 1,000 feet above the well's planned target depth, John Hendrix, Apache's general manager in Alaska, told Commonwealth North's Energy Action Coalition on Feb. 8. Coring at the well should start during the week of Jan. 11, he said.

Apache spud the Kaldachabuna well, the company's first well in Alaska, in mid-November. The well has proved very challenging to drill, having involved penetrating more than 100 coals seams, with 24 of those seams being more than 10 feet thick, Hendrix said.

Production?

Hendrix said that there will be a pause in field operations following the coring while geoscientists evaluate the rock cores. Apache will then try stimulating the well, possibly through hydraulic fracturing, with the aim of flowing oil from the well by mid-March, if the well proves productive. Apache has been working with Hilcorp Alaska for arrangements to enable oil produced from the well to move through Hilcorp's facilities, to bring the well on line, Hendrix said. And if the well produces natural gas, Aurora Gas, a Cook Inlet gas producer, can help ship that gas to market, he said.

JOHN HENDRIX

But Hendrix emphasized that, although Apache would like to produce from the Kaldachabuna well, the company is primarily drilling the well for the purposes of testing.

"We're drilling this well to understand what the (reservoir) formation is all about," Hendrix said.

3-D seismic

Apache is in the throes of conducting a major multi-year 3-D seismic program, using state-of-the-art nodal seismic technology across large areas of the Cook Inlet basin, onshore and offshore. Having drilled a well into a reservoir formation at Kaldachabuna and tested the properties of that formation, Apache wants to use the information it obtains from the drilling to infer the potential of other prospects identified from the company's seismic data, Hendrix explained.

And Hendrix emphasized the importance that Apache attaches to the acquisition of 3-D seismic as a perquisite for drilling, saying that drilling success requires the insights about the subsurface that 3-D seismic brings — Cook Inlet geology is complex to interpret.

"If you're drilling off 2-D seismic you're not going to be successful," Hendrix said. "I've seen it time and time again."

Holding leases

Hendrix questioned the practice of requiring the drilling of wells to hold state leases; he wondered whether it would encourage the gathering of 3-D seismic data if the state allowed the shooting of seismic to qualify as a means of retaining leases. Apache, having spent more than $200 million in Alaska so far, could lose 150,000 acres of state leases next year, he said.

The company has already gathered about 317 square miles of seismic data, on the west side of the inlet and along a fairway across the middle of the inlet. The intent now is to shoot another 200 square miles on the east side of the inlet and onshore the Kenai Peninsula, including in land owned by Cook Inlet Region Inc. in the Kenai National Wildlife Refuge.

Apache wants to be able to line up sufficient prospects to tie up a rig or two for continuous drilling opportunities, Hendrix said.

"Drilling one-off wells is very expensive," he said.

Permitting delays

But Apache has been stymied by delays in obtaining some federal permits that it needs to continue its seismic program. In particular, the company needs an authorization from the National Marine Fisheries Service for the incidental disturbance of marine mammals during planned offshore surveying. And a lawsuit against the Fisheries Service for the issue of a similar authorization for offshore seismic work in 2012 has yet to be resolved.

Hendrix said that Apache's offshore seismic surveying has not disturbed any beluga whales. Beluga whales are protected under the Endangered Species Act.

In the fall of 2012 surveying came to a halt when the company did not receive permits that it needed to work onshore in the Kenai National Wildlife Refuge, despite being told that the permits would be forthcoming by Oct. 1, Hendrix said.

"We shut down a $50 million seismic program and it cost Apache $10 million to do that," Hendrix said, adding that the delay could have cost Alaskans the discovery of an oil or gas field. There will be a delay of a more than a year, because Apache cannot return there until next year, he said.

Gas and oil

Hendrix emphasized that Apache will develop any viable gas resources that it discovers, as well as oil.

And asked about the economics of developing a new gas field in the Cook Inlet basin, should one be discovered, given the small size of the local gas market, Hendrix said that, if more new gas comes on line than the utility market can handle, there is the potential to restart production at the existing liquefied natural gas and fertilizer plants on the Kenai Peninsula. He said that he would be happy if Apache ended up "awash with gas and oil."

And the impact on Apache of Alaska's tax credits for Cook Inlet exploration?

Rather than necessarily attracting Apache to the Cook Inlet basin as a new exploration area for the company, the tax credits have enabled the company to execute a much broader exploration program than would otherwise have been possible, Hendrix said. That will provide both Apache and the State of Alaska more information about potential new oil and gas resources, he said. ●

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On the web

See previous Petroleum News coverage:

"NMFS issues proposed IHA for Apache," in Dec. 23, 2012, issue at www.petroleumnews.com/pnads/521915410.shtml

"Apache optimistic on Cook Inlet basin," in Oct. 7, 2012, issue at www.petroleumnews.com/pnads/844526274.shtml

"Making strides," in June 17, 2012, issue at www.petroleumnews.com/pnads/426944557.shtml

Apache wants to be able to line up sufficient prospects to tie up a rig or two for continuous drilling opportunities, Hendrix said. "Drilling one-off wells is very expensive," he said.

● GOVERNMENT

BOEM brings new air quality approach

Process for industry air emission regulation changes as Interior agency takes over Arctic OCS air quality jurisdiction from EPA

By ALAN BAILEY
Petroleum News

Following intense frustration for many people during the multi-year tennis match involving the Environmental Protection Agency, or EPA, and environmental organizations over the permitting of air emissions from Shell's planned exploration drilling in Alaska's Beaufort and Chukchi seas, at the end of 2011 the U.S. Congress passed legislation, transferring jurisdiction for Arctic outer continental shelf air quality from EPA to the Department of the Interior. Decades ago Interior had been responsible for managing air quality on the U.S. outer continental shelf, or OCS. But legislation in 1990 transferred that authority to EPA, other than in part of the Gulf of Mexico. The 2011 legislation restored Interior's air quality jurisdiction in much of the U.S. Arctic offshore.

But what impact will this change of jurisdiction have on those seeking to drill in U.S. Arctic waters? And what significance do the changes have for North Slope communities concerned about potential air pollution from industrial activities in the region?

On Feb. 5 officials from the Bureau of Ocean Energy Management, or BOEM, the agency within Interior responsible for OCS air quality regulation, talked at the Alaska Forum for the Environment about how BOEM proposes dealing with Arctic air quality issues, and how BOEM's approach differs from that of EPA.

Michael Routhier, BOEM's program analysis officer for the Alaska OCS region, said that the new BOEM air quality jurisdiction applies to those portions of the OCS that lie adjacent the North Slope Borough, essentially encompassing the federal waters of the Beaufort and Chukchi seas, outside the three-mile limit of state coastal waters.

Environmental assessment

Virginia Raps, BOEM staff meteorologist, pointed out that, whereas EPA requires companies to apply for air quality permits for OCS operations, BOEM has no air quality permitting requirement. Instead, BOEM evaluates potential air emissions from an OCS project when conducting an environmental assessment or an environmental impact statement for a proposed project, a company's proposed exploration or development plan, for example.

The data required for this formula review will come from a major study into Arctic weather systems and air emissions that BOEM plans to start this year and conduct with assistance from the Alaska Department of Environmental Conservation, Raps said.

In fact, BOEM already carries out this type of environmental evaluation, under the terms of the National Environmental Policy Act, or NEPA, for any planned project on the federal OCS, regardless of whether that project will take place in the Arctic. The agency reviews and verifies data that a company submits for air emissions from its planned activities, considering the complete inventory of emissions associated with the project, potentially including emissions from drilling units, support vessels and aircraft, and from land-based elements of the project, such as crew housing, Raps explained.

Using air quality modeling for the impacted region, the agency then assesses what changes to the overall air quality the project may cause, determining any mitigation measures that appear necessary to prevent unacceptable levels of air pollution.

Regulatory program

However, with BOEM having jurisdiction over Arctic air quality, a proposed project on the Arctic OCS will now trigger an additional procedure, known as the BOEM Air Quality Regulatory Program, Raps explained. As with EPA air permitting, the BOEM program will apply to drill ships when they are anchored to the seafloor for drilling operations and are hence viewed as stationary emissions sources. However, unlike EPA which requires consideration of emissions from both the drillship and all support vessels within 25 miles of the drilling site, BOEM's regulatory program only takes into account emissions from the drill ship itself, Raps said.

And while EPA, operating under the terms of the Clean Air Act, requires special emissions controls such as catalytic converters if the drilling fleet would otherwise emit any of a specified list of pollutants at a rate of more than 250 tons per year, the BOEM program, operating under the Outer Continental Shelf Lands Act, determines if emissions from the drill ship may significantly impact air along the coastline.

see AIR QUALITY page 10

ASSOCIATIONS

AAEE to hear about production forecasting

Ed King of the Alaska Department of Revenue will discuss production forecasting and changes in methodology at a meeting of the Anchorage Association for Energy Economics Feb. 20 in Anchorage.

The meeting will be from noon to 1 p.m. at the BP Energy Center.

King, the petroleum economist in charge of oil production forecasting for the state, will talk about recent changes in how the Department of Revenue forecasts oil production and the impact of those changes on future production expectations.

—PETROLEUM NEWS

continued from page 9

AIR QUALITY

Dispersion analysis

If BOEM assesses that the drillship may have a significant air quality impact at the shoreline, the agency requires the company involved to conduct an emissions dispersion analysis to determine whether the shoreline impact would indeed be significant. And, in the event of a significant impact being found, BOEM will require best available emission controls on the drill ship's various engines and other equipment, to reduce the emissions to acceptable levels. On the other hand, if the air quality impacts are deemed insignificant, BOEM will take no further action under its regulatory program, instead reverting to the findings and any mitigation requirements in the agency's NEPA analysis, Raps said.

EPA, by contrast, has attempted to view an operational drill ship in the same light as an onshore industrial facility, defining a "fence" around the drillship as analogous to an onshore facility's fence, the boundary within which the public has no access and beyond which emissions from the facility need to meet air quality standards. Initially EPA tried to use the railing of the drillship as the "fence" but, after finding this definition impractical, defined the fence as the U.S. Coast Guard's 500-meter exclusion zone around the vessel.

GOM formula

Initially in the Arctic, BOEM will employ the formula that it uses in the Gulf of Mexico to determine whether a drillship may have a significant environmental impact at the shoreline and, hence, require a dispersion analysis, Raps said. That formula involves multiplying a specific number for each pollutant by the distance in miles between the drill ship and the coast to obtain the threshold in tons per year of the pollutant, above which BOEM would consider the air pollution significant, she said. For example, if the number for nitrogen oxide was, say, 32.6 and the drilling operation was 100 miles from the coast, the drill ship would be allowed to emit up to 32,600 tons of nitrogen oxide per year without triggering a requirement for further emissions analysis.

At first blush, this suggests that BOEM's emissions thresholds will be far above EPA's 250-tons-per-year threshold. But, if a drill ship is working at a drill site close to the three-mile limit of the OCS, the BOEM threshold could be lower than EPA's, Raps cautioned. And, separately from BOEM's regulatory program for the drill ship, the agency could require the drill ship and its support operations to apply emissions mitigation as a consequence of the agency's NEPA assessment of a company's plans, she said.

Review process

Another key difference between the BOEM and EPA approaches relates to the processes that the agencies use to handle public reviews and appeals against agency decisions, the processes for dealing with the types of dispute which significantly delayed final approval of Shell's air permits.

Under the EPA system, a draft air permit undergoes a 30-day public review period, after which EPA modifies the permit as necessary before issuing a final permit. That issued permit can then be appealed to the Environmental Appeals Board. The company which applied for the permit cannot undertake any operation covered by the permit until the Environmental Appeals Board makes a decision upholding the permit, with no legally mandated time limit within which the board must make its decision. If the board does uphold the permit, the appeal can be elevated to the 9th Circuit Court of Appeals.

The BOEM procedure involves opportunities for public review during the NEPA process. If the outcome of the NEPA process is approval of, say, a company's exploration plan, that plan approval can be appealed to the 9th Circuit.

Formula review

Raps said that, although BOEM will initially use its Gulf of Mexico formula for assessing whether an Arctic drillship may have a significant air quality impact at the shoreline, the formula involving the distance of the drillship from the shoreline, the agency anticipates reviewing the formula to be used in the Arctic, after evaluating the differences between the Gulf of Mexico and Arctic weather systems. In particular, the prevailing wind system in the Gulf of Mexico tends to blow directly onshore, while the winds along the coasts of the Beaufort and Chukchi seas tend to hit the coastline at an angle, she said.

Major new study

The data required for this formula review will come from a major study into Arctic weather systems and air emissions that BOEM plans to start this year and conduct with assistance from the Alaska Department of Environmental Conservation, Raps said. This study, called the Arctic Air Quality Impact Assessment Modeling Study, will use historic climate data to develop a meteorological dataset for both the Beaufort and Chukchi seas. Arctic Alaska does not have the abundance of weather observing stations that exists around the coast of the Gulf of Mexico, Raps commented.

The major component of the BOEM study, which the agency anticipates taking four to five years to complete, will consist of the development of a complete inventory of all existing North Slope and Arctic OCS air emissions, and of anticipated future offshore oil industry emissions, based on activities that are likely to result from BOEM's OCS lease sale program, Raps said. The emissions inventory will consist of a single dataset assembled from a variety of information sources such as company exploration plans.

Improved modeling

The new inventory and weather models will enable BOEM to model the movement and concentrations of industrial emissions over offshore waters and across the shoreline, allowing the agency to compare emissions levels with EPA's air quality standards, and also allowing an evaluation of emission control strategies, Raps said. The emissions and weather models will enable the agency to better assess the potential impacts of proposed new industrial projects, such as offshore exploration or offshore oil development, when conducting NEPA analyses of proposed plans, she said. The models will also assist in the assessment of the cumulative impacts of multiple offshore projects, proposed to be carried out in parallel. And a further anticipated outcome of the models is an evaluation of the fate of air emissions allowed offshore in excess of normal onshore air quality standards, in situations where the shoreline impact of a drilling unit operating far offshore is deemed insignificant, Raps said. ●

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GOVERNMENT

Flint Hills oil supply contract offered

Alaska proposes to sell up to 30,000 barrels a day of North Slope royalty crude to North Pole refinery operator in five-year deal

By WESLEY LOY
For Petroleum News

Alaska officials are proposing a new contract to sell state royalty oil to Flint Hills Resources, which operates one of the state's largest refineries near Fairbanks.

The state natural resources commissioner already has made a preliminary "best interest finding" in support of the contract.

However, a number of steps remain before the deal is sealed. The Alaska Royalty Oil and Gas Development Advisory Board must endorse the sale, and lawmakers in Juneau will need to pass legislation approving the contract.

The Royalty Board is to meet on Feb. 26 in Fairbanks.

Flint Hills, a subsidiary of Koch Industries Inc. of Wichita, Kan., operates the refinery at North Pole and produces large volumes of jet fuel, plus gasoline, heating oil and other products.

The refinery draws crude oil from the nearby trans-Alaska pipeline.

Existing contract expires in 2014

The DNR's Division of Oil and Gas on Feb. 8 published a newspaper notice of the commissioner's preliminary best interest finding. The finding and the draft sales contract were to be posted on the division's website, but the documents were not immediately available.

Flint Hills currently has a 10-year contract for state royalty oil that expires on March 31, 2014.

The proposed new contract would be for a five-year term, and would provide for the sale of 18,000 to 30,000 barrels per day of North Slope crude.

"Deliveries of royalty oil under this proposed contract will commence on April 1, 2014 and continue until March 31, 2019," the notice said. "The price provision in the proposed contract is based on a formula that relies on accepted industry price reporting services and is similar to the formulas applied to the calculation of the royalty value paid to the State by the North Slope producers."

The state's share

Royalty oil is that share of crude the state receives from companies producing on state leases. In general, the state gets 12.5 percent of the oil produced from Prudhoe Bay and other North Slope oil fields.

The state has two options for selling its royalty oil. It can take its oil "in kind" and sell it in Alaska, or it can take the oil "in value" by letting producers such as ConocoPhillips, BP and ExxonMobil market it along with their own volumes.

In recent months, DNR approached potential buyers, sending letters in August to refiners inquiring about their interest in acquiring some or all of the state's North Slope royalty oil once the Flint Hills contract expires.

The letters held out the possibility of DNR auctioning the oil.

In an Aug. 20 letter back to DNR, Bradley Razook, Flint Hills chief executive, wrote that his company was interested in negotiating the purchase of royalty oil, and if necessary would be "interested in participating in a competitive sealed bid auction for the oil in 2014."

No bargain oil

The proposed five-year contract appears to be for less royalty oil per day than the current contract, which was announced in 2004 at up to 77,000 barrels a day.

A Flint Hills website says the North Pole refinery has a crude oil processing capacity of about 220,000 barrels per day.

see **SUPPLY CONTRACT** *page 14*

ENVIRONMENT & SAFETY

Post-spill repairs continue at Lisburne

Work continues in the wake of a 2011 spill in the Lisburne field on Alaska's North Slope, according to a final "situation report" the state Department of Environmental Conservation issued Feb. 12.

An estimated 1,764 gallons of blended methanol and produced fluids spilled onto a gravel pad and wet tundra after an 8-inch line in a piping system known as a test header ruptured. Contractors for field operator BP Exploration (Alaska) Inc. discovered the spill on July 16, 2011.

The spill volume was somewhat lower than the original estimate.

The pipeline failure occurred during a pressurized leak test to check newly installed valves.

The line ruptured underground at a roadway crossing at the L-1 drill site, the DEC situation report said.

Substantial work has been done to clean up the site and rehabilitate tundra vegetation.

And some engineering work is ongoing.

"BPXA redesigned the pipeline at the road crossing, eliminating some of the 90-degree elbows and changing the pipe profile to elevate the pipeline above water level," the report said. "Installation of the newly fabricated pipeline segment should be completed in spring 2013. The test header pipeline has remained out of service."

The ruptured line was used to divert production from wells to a test separator required by regulation, not to transport production to the Lisburne processing facility, BP said at the time of the spill.

The Lisburne field is a reservoir located within the BP-operated Prudhoe Bay unit. Lisburne began production in 1986.

—WESLEY LOY

High ice melt in Greenland causes concern

An exceptionally high rate of melt on the surface of Greenland's ice cap in 2012 is causing concern among climate scientists, according to a report from the National Snow and Ice Data Center, or NSIDC. Apparently satellite surveillance of the ice cap indicated rates of surface melting far in excess of melting observed in previous years, since satellite observations began in 1979.

In particular, following an exceptional weather event in July 2012, surface melting took place over 97 percent of the entire ice sheet, NSIDC says.

The melting of land-based ice such as is found in Greenland, as distinct from the melting of floating sea ice, is of particular significance because the unlocking of huge quantities of freshwater locked up in ice supported on land would directly cause a rise in worldwide sea levels.

A large-scale melt of the Greenland ice cap could raise sea levels sufficiently to flood many coastal areas where people live around the world, NSIDC says.

"The ice sheet normally gains snow during the winter and melts some during the summer, but in recent decades its mass has been dwindling due to strong melting," NSIDC says.

Because of persistent high atmospheric pressure and clear skies during the summer of 2012, temperatures between June and August were more than 4 degrees F higher than average in areas of Greenland normally susceptible to summer ice melt, and more than 3 degrees F higher than average across the entire ice cap.

And, as further evidence of accelerated melting, zones exhibiting different snow and ice features characteristic of the summer melt have been moving to higher elevations on the ice sheet. In 2012 there was unprecedented melting at the highest elevations of the ice.

—ALAN BAILEY

PIPELINES & DOWNSTREAM

Alyeska considering dry flow in TAPS

Alyeska Pipeline Service Co., operator of the trans-Alaska oil pipeline, is investigating the possibility of drying oil entering the line on the North Slope, to help resolve some of the emerging problems associated with low oil flow, as North Slope oil production declines, Tom Barrett, president of Alyeska, told the Alaska Senate Special Committee on TAPS Throughput on Feb. 5. With the temperature in the line now dropping below 32 degrees F at some points along the pipeline route during the winter, as the oil flow slows, the potential for water mixed with the oil freezing presents a growing threat to reliable line operation.

Alyeska has started to add heat to the oil by recirculating the oil at pipeline pump stations. But, eventually, adding heat will not be sufficient, Barrett told the committee.

"The operational challenges are complex, and just adding more heat will not solve the problems in this line," Barrett said. "Right now we're devoting significant resources to study and test what we call 'cold dry flow' … figuring out if we can remove water from the oil before it enters the pipeline … and run the line in a cold condition."

As well as the possibility of ice formation, low oil flow also raises the specter of the increased deposition of wax from the oil, potentially clogging the line or obstructing "scraper pigs," the devices sent down the inside of the line to clean the pipeline walls. Barrett said that on New Year's Day a dense wax cloud had caused one of these pigs to become trapped at pump station 9, but that the pump station crew had succeeded in freeing the pig without any interruption to oil throughput.

—ALAN BAILEY

GOVERNMENT

Revenue makes electronic filing available

The Alaska Department of Revenue said Feb. 11 that its data capture tool is complete and available for use in entering 2012 oil and gas production tax returns.

John Larsen, audit master in the department's Tax Division, said in an email that while use of the data capture tool is not required, the department encourages its use. Users entering 2012 data using the data capture tool will be able to import properties used in the 2012 filing next year, and only properties coming on line after the 2012 calendar year will have to be added for the 2013 filing.

Larsen said the department will hold weekly workshops to demonstrate use of the data capture tool; workshops will also be available over the Internet via Webex; a workshop schedule will be released later. A link to the data capture tool is at https://myalaska.state.ak.us/OTIS/APTR/Setup.exe.

—PETROLEUM NEWS

EXPLORATION & PRODUCTION

BRPC planning Tofkat wells

A well and potentially a sidetrack at the unit near Nuiqsut would follow an early 2008 oil discovery in the Kuparuk formation

By ERIC LIDJI
For Petroleum News

Brooks Range Petroleum Corp. plans to drill a well and potentially a sidetrack at its Tofkat unit this winter to follow up on an oil discovery the company made in 2008.

The independent plans to use Nabors rig 106 to drill the Tofkat No. 2 well and Tofkat No. 2A sidetrack this winter at the unit along the Colville River, near Nuiqsut.

The program involves constructing a 5.7-acre or smaller ice pad in the unit, and a short ice road of less than one mile in length connecting the pad to the Alpine ice road.

The state is taking comments on the program through March 8.

10 oil samples

Tofkat is one of Brooks Range Petroleum's earliest drilling efforts in Alaska.

In early 2008, the operating arm of Alaska Venture Capital Group used Nabors rig 27E to drill the Tofkat No. 1 well and two sidetracks at the prospect. The well collected 10 oil samples from three sandstone reservoirs in the Brookian formation and a fourth sandstone in the deeper Kuparuk formation, where it found six feet of net pay. That winter, Brooks Range Petroleum also acquired some 200 square miles of 3-D seismic over the prospect.

In late 2011, the company formed the Tofkat unit over 21 state and Arctic Slope Regional Corp. leases covering some 9,131 acres. Under the unit plan of exploration, Brooks Range Petroleum must drill and complete a well into the Kuparuk by May 31, 2013, and the working interest owners at the unit must sanction a Tofkat development project by Oct. 1, 2013 — and keep it sanctioned through production — or terminate the unit.

Brooks Range Petroleum previously estimated that Tofkat holds about 40 million barrels of recoverable oil in the Kuparuk C sands and another 20 million in the Jurassic sands.

Some 60 million barrels in place

Brooks Range Petroleum previously estimated that Tofkat holds about 40 million barrels of recoverable oil in the Kuparuk C sands and another 20 million in the Jurassic sands.

The company said it already has an approved C-Plan for the program.

When Brooks Range Petroleum initially permitted exploration at Tofkat in 2007, it called the prospect Titania, but eventually changed the name to avoid confusion with an earlier and unrelated exploration effort by ConocoPhillips called the Titania Exploration Program.

In addition to Tofkat, Brooks Range Petroleum is also beginning development activities this winter at the Mustang field of its Southern Miluveach unit, due east of Tofkat. ●

Contact Eric Lidji at ericlidji@mac.com

NATURAL GAS

Buccaneer brings Kenai Loop No. 4 online

Buccaneer Energy Ltd. is expecting a bump in Kenai Loop production this quarter.

The increase would come from a second well the Australian independent recently brought online at the onshore gas field near the city of Kenai, and from the increased capacity of permanent production facilities that the company expects to be operational by late April.

Buccaneer started Kenai Loop production in January 2012 with the Kenai Loop No. 1 well and brought the Kenai Loop No. 4 well online on Feb. 10. The well is currently producing at 2 million cubic feet per day, but Buccaneer expects production to increase to between 3 million and 4 million cubic feet per day under the permanent facilities.

Weather delay

While Buccaneer began installing the facilities and associated pipelines back in November, it said "severe weather conditions" forced it to suspend work in December.

With Kenai Loop No. 1 now producing some 6.5 million cubic feet per day, Buccaneer believes the field could produce between 10 million and 11 million cubic feet per day.

The majority of the 8.5 million cubic feet per day currently in production is going to Enstar Natural Gas Co., according to Buccaneer. While Buccaneer is currently contracted to provide a minimum of 5 million cubic feet per day to Enstar at an average weighted price of $6.24 per thousand cubic feet, the company said that winter peak pricing of incremental gas supply has hit $22.00 per thousand cubic feet within the past 60 days.

While continuing to utilize the winter spot market for the time being, Buccaneer also said it is negotiating "a new long term gas sales agreement with potential purchasers."

—ERIC LIDJI

● NATURAL GAS

House Resources hearing AGDC bill

Parnell says he can't support bill as filed; committee gets answers to questions, including contract vs. common carriage issue

By KRISTEN NELSON
Petroleum News

House Bill 4, establishing the Alaska Gasline Development Corp. as a separate entity and authorizing it to move forward toward an open season for an in-state gas pipeline project, has had three hearings in House Resources and was scheduled for a fourth on Feb. 15 after Petroleum News went to press.

Committee members had a lot of questions on the bill. The bill's prime sponsor, committee member Rep. Mike Hawker, R-Anchorage, responded in writing to a number of questions, as did Legislative Counsel Donald Bullock and the Department of Natural Resources.

Gov. Sean Parnell has concerns and said at a Feb. 6 press availability he couldn't support the bill as originally filed. He said the sponsors know that and "are working with our office and with every legislator in the building who's interested in that topic to boost AGDC's ability to get Alaska's gas to Alaskans."

Parnell has been pushing a large liquefied natural gas export project for North Slope natural gas and has given the partners in the Alaska Pipeline Project until Feb. 15 to select a concept for an all-Alaska project, the LNG project he proposed in 2011, including details such as pipe size, daily volume and location of facilities.

The APP partners, TransCanada which holds the state's license under the Alaska Gasline Inducement Act and ExxonMobil, have been working with BP and ConocoPhillips, and in October met an earlier benchmark set by the governor, hardening numbers on the project, with an estimate of $45-$65 billion.

The governor said at the time that they had also met another benchmark, completing discussions with the AGDC on the potential to consolidate the work of the two projects.

Now is the time

House Speaker Mike Chenault, R-Nikiski, a prime sponsor of the bill and of its predecessor, HB 9, which failed in the Senate in the last legislative session, said at the Feb. 4 hearing that the in-state line is a project the sponsors believe "has the best opportunity to bring gas to Alaskans any time in the near future."

The AGDC project would bring natural gas to Fairbanks, lowering utility costs there, bring a long-term energy supply to Cook Inlet and could help rural Alaska along the way by providing propane, he said.

The process began with HB 369, passed by the Legislature in 2010, which established AGDC.

Chenault said AGDC has done what the Legislature asked in HB 369, but needs tools to continue "to get Alaska to an open season to see if there really is a market out there ... to sell our gas."

He said it's time for a choice.

AGDC developed the plan the Legislature called for in HB 369, and "now we need to give AGDC its next direction and the tools that it needs to carry out their mission or we need to pull the plug. There's no half way unless we're OK with driving up the cost to Alaskans who'll eventually pay for gas. And ... every time we wait, it just costs us more. I think it's time now to deliver ... the promise to Alaskans that we have gas through the Railbelt system. ...

> *AGDC developed the plan the Legislature called for in HB 369, and "now we need to give AGDC its next direction and the tools that it needs to carry out their mission or we need to pull the plug. There's no half way..."*
> **—House Speaker Mike Chenault**

Answers for committee

DNR responded to a question on its administration of right-of-way leases, specifically concerns expressed that an oil pipeline could switch from common carrier to contract carrier under the provisions of HB 4.

The trans-Alaska oil pipeline is a common carrier line and under the provisions of common carriage space must be made available for new oil offered for shipment — and in the event the line is full, volumes from existing shippers would be prorated to make room for the new volumes. While that isn't a problem with the trans-Alaska oil pipeline since it is running well below capacity, it would be a problem for a natural gas pipeline where the volumes are going to utilities which count on receiving those volumes to keep heat and light on for consumers.

DNR said in a Feb. 12 response to the committee that under the HB 4 proposal, "A lease with contract carrier covenants rather than common carrier covenants may be issued only to an applicant eligible to be regulated" under the statutory provisions in HB 4, and since those provisions are "limited to in-state natural gas pipelines, no oil pipeline can become a contract carrier."

Other natural gas pipelines could apply under the proposed statute to become contract carriers, but DNR that that would require public notice and a determination by the DNR commissioner that the applicant can perform the transportation and that it would be in the public interest. A change from common carriage to contract carriage by an existing natural gas pipeline would require the same finding the commissioner makes in granting the original lease, the department said.

Concerns answered by Hawker included: exemption of AGDC from the state procurement code; amount of board compensation; exemption from the State Personnel Act; exemption of AGDC from the Executive Budget Act; and provision for AGDC to retain independent legal counsel. ●

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● FINANCE & ECONOMY

Committee says ACES could be factor

Senate TAPS throughput passes governor's oil tax bill on, along with conclusions, recommendations; Democrats introduce own bill

By KRISTEN NELSON
Petroleum News

The ACES production tax structure "has likely contributed to advancing the decline of oil production" from Alaska's North Slope and to reduction in throughput in the trans-Alaska oil pipeline.

That was one of the findings of the first committee to hear the governor's proposed oil tax change bill, the Senate Special Committee on TAPS Throughput. The committee passed along a letter of intent as it sent Senate Bill 21 on to the Senate Resources Committee on Feb. 7.

While the committee's minority member, Sen. Berta Gardner, D-Anchorage, proposed amendments, none were adopted.

Feb. 11, the same day House Resources and Senate Resources started their hearings on the governor's bill, House and Senate Democrats introduced their own oil tax bill. While a notable feature of the governor's bill is the elimination of the progressivity feature of ACES, Alaska's Clear and Equitable Share, the state's existing production tax, the Democratic tax change bill retains progressivity, although capping state take at 55 percent (ACES sets the cap at 75 percent).

The House version of the Democrats' tax bill, House Bill 111, goes to the Resources and Finance committees; the Senate version, SB 50, goes to the TAPS Throughput, Resources and Finance committees.

Letter of intent

The letter of intent from the Senate Special Committee on TAPS Throughput, signed by co-chairs Sens. Peter Micciche and Mike Dunleavy, said the committee arrived at several key findings in evaluating the bill.

The state has little control over many factors impacting state revenues, "including the price of North Slope oil. Total government take through oil taxation is the only lever under the control of the people of Alaska," the letter said.

"The ACES tax structure has likely contributed to advancing the decline of oil production and throughput in TAPS, primarily due to a lack of competitiveness with other OECD (Organization for Economic Cooperation and Development) producing regions."

Because increased production was a primary objective of the credits in ACES, those "credits should have been more specifically directed toward projects resulting in production and less toward general spending," the letter said.

"Specific incentives and a competitive oil tax regime in Alaska will likely result in additional production-related spending."

The letter noted "a direct correlation" in other OECD producing regions between "production-related spending and increased production" and said the state's spending policies have "an adverse effect on the business climate and willingness to invest in the State of Alaska." State policies, the letter said, "must deliver the clear message to the business community that Alaska will not continue taxing to fund unsustainable levels of government spending."

'Adequate platform'

The letter was not a wholehearted endorsement of the governor's bill, calling it "an adequate platform from which a respectful dialogue can begin," but recommending a number of areas for changes.

First the letter recommended evaluation of a way to provide "a guarantee of investment in Alaska and a further incentive for stemming production decline" from North Slope leases "by fixing the amount of production used in determining the reasonable transportation costs to determine transportation deduction costs for pipelines and gas treatment plants" so producers receive a benefit for increased oil throughput "but incur a corresponding limitation on deductions due to throughput declines" occurring after Dec. 31, 2015.

The letter also recommended expanding the gross revenue exclusion to legacy areas, specifically expansions of existing participating areas, increasing recovery in existing participating areas and participating areas that contain oil with an API gravity of 20 degrees or less.

The gross revenue exclusion exempts 20 percent of production from new fields from taxation.

Specific production-related credits allowed under ACES should be evaluated for inclusion in the bill "as a direct incentive for costs that deliver production," the letter said, but credits should be charged against actual production, eliminating the current "negative revenue liability to the state."

Other recommendations

The letter also recommended other areas for inclusion in SB 21, noting those are not related to throughput: incentives for Alaska hire and Alaska purchase; incentives for unconventional and heavy oil; a production credit system for provision of propane fuels to rural Alaska; and evaluating "progressivity as a tool to level the proportion of take for Alaskans across the various oil price environments."

The letter said the committee's minority member requested that several considerations be passed along: evaluation of a time limit for the 20 percent gross revenue exclusion; evaluating removing the net operating loss provision in the bill; evaluating adding a 10 percent minimum gross tax; and considering bracketing progressivity at varying rates as the price of oil varies.

Tax, leasing changes

The Democrats' tax proposal targets new production, but also requires the Department of Natural Resources to require a minimum work commitment as part of its leasing program.

The new leasing provisions would require "a company desiring to bid on leases to provide a plan of development. The Department of Natural Resources must review each plan and determine if it will develop the state's resources in the best interest of the state before 'qualifying' the company to bid on a lease," according to the sectional analysis of the bills. "The plan of development shall be included within the lease terms. DNR shall determine each year whether the lease is being developed in the best interest of the state."

The bill also requires DNR to perform an economic analysis every five years "to determine whether the proposed development is in the best interest of the state," and whether the lessee is in compliance with the lease terms. "DNR is empowered to enforce lease terms including imposing penalties for noncompliance," the analysis says.

An annual report to the Legislature is required, identifying leases out of compliance, and the actions taken by the commissioner to remedy such noncompliance.

Time limits

The Democratic bill would limit the 20 percent gross revenue, GRE, exclusion for oil from new units to seven years.

It creates a 10 percent GRE for oil from new participating areas, with a five-year limit; provides a 10 percent GRE for all heavy oil produced; and provides a GRE of 10 percent for production in an existing unit above the level of 2012 production.

AIDEA, the Alaska Industrial Development and Export Authority, is authorized "to acquire an interest in an oil project as necessary to provide working or venture capital," "to acquire an interest in a lease if they have determined that the leaseholder has been unable to obtain private financing," adds oilfield development to the definition of project in AIDEA statutes; and authorizes AIDEA to make loans for "constructing or improving an oil processing facility on the North Slope," limited to small producers and new units and with loan terms not to exceed the prime rate plus 1 percent.

The bill provides an incentive for heavy oil research and development by creating a heavy oil research and development tax credit of 20 percent "limited to in-state expenditures targeting Alaska heavy oil" and capped at $10 million per year per producer.

The bill also requires that information be provided by producers in order to claim capital or exploration credits, with descriptions "in some detail" of the nature and location of expenditures; the Legislature would receive an annual report on the disclosures. ●

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SUPPLY CONTRACT

The site says about 60 percent of the refinery's production is destined for the aviation market.

While the refinery is regarded as a vital energy asset for Alaska, especially the Interior, state law doesn't allow royalty oil to be sold at a bargain or discount, said Kevin Banks, a former state oil and gas director now working in the Division of Oil and Gas as a petroleum market analyst. ●

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NATURAL GAS

Japan set to tap hydrates

Japan is about to embark on the world's first experiment in producing gas from hydrates, starting a two-week long flow test in late February.

The Ministry of Economy, Trade and Industry, METI, said it will analyze the results in fiscal 2013-14 before attempting to set up the necessary technology for commercial production by 2019.

Japan Petroleum Exploration is operator of the test offshore central Japan and has hired contractor Japan Drilling Co. to run the test.

The test will include drilling a well to about 1,000 feet from the seabed in a water depth of about 3,300 feet, about 50 miles south of the Atsumi Peninsula.

The plan involves generating gas from hydrates using a decreasing pressure system which was successfully tested in the Canadian Arctic in 2008.

METI has its sights set on achieving a sustained flow rate of around 1.9 billion cubic feet per day, although the production test is expected to reach only 180 million cubic feet per day.

It emphasized that the initial objective is not volume, but the accumulation of data.

METI has estimated Japan's known hydrate resources at 40 trillion cubic feet, sufficient to meet its total gas needs for about 14 years.

Nobuo Tanaka, former executive director of the International Energy Agency and now a special adviser to Japan's Institute of Energy Economics, said methane hydrates could be a "game-changer" for Japan, affecting its role in the LNG market.

Currently the world's largest buyer of LNG, it imported 78.5 million metric tons in 2011, up 12 percent from 2010, with its import prices averaging US$14.61 per million British thermal units in 2011, up 35 percent from the previous year — one of the reasons Japanese LNG buyers are attempting to drive a hard bargain to shift LNG from oil-priced contracts to Henry Hub prices.

—GARY PARK

EXPLORATION & PRODUCTION

US rig count down by five to 1,759

Oilfield services company Baker Hughes Inc. says the number of rigs actively drilling for oil and natural gas in the U.S. dropped by five the week ending Feb. 8 to 1,759.

The Houston-based company said in its weekly report that 1,330 rigs were actively drilling for oil and 425 for gas. Four were listed as miscellaneous. A year ago, Baker Hughes counted 1,989 working rigs.

Of the major oil- and gas-producing states Louisiana gained five rigs, Pennsylvania rose by two and Colorado increased by one. New Mexico lost three rigs, North Dakota and Texas each decreased by two and Alaska, West Virginia and Wyoming dropped one each. Arkansas, California and Oklahoma remained unchanged.

The rig count peaked at 4.530 in 1981 and bottomed at 488 in 1999.

—ASSOCIATED PRESS

GOVERNMENT

Judge sides with Idaho conservationists

A federal judge has sided with environmentalists and ruled the U.S. Forest Service erred by not exercising its regulatory authority when the state allowed huge trucks to haul giant oil refinery equipment along U.S. Highway 12.

U.S. District Judge B. Lynn Winmill issued a decision Feb. 7 that handed Idaho Rivers United a victory in the case.

The group sued the government in 2011 after the state allowed ExxonMobil's Canadian unit to ship hundreds of so-called mega-loads from Idaho's Port of Lewiston along the two-lane highway. The roadway runs through a scenic corridor protected by the 1968 Wild and Scenic Rivers Act.

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IRU claimed the forest service neglected its duty by not getting involved in the decision-making process.

Winmill agreed, saying the agency has the authority to intervene in such cases.

—ASSOCIATED PRESS

● INTERNATIONAL

Iceland joins Arctic exploration plays

By GARY PARK

For Petroleum News

Iceland has joined the oil and natural gas exploration plays in the Arctic region by issuing licenses covering about 12,500 square miles off its northeastern coast.

The island country's National Energy Authority granted the formal permits to consortiums led by the United Kingdom's Faroe Petroleum and Valiant Petroleum, which follow provisional licenses awarded in December for the offshore Dreki Area.

Both consortiums include 25 percent stakes for Norway's state-owned Petoro.

One license was granted to Faroe 67.5 percent, Petoro 25 percent and Iceland Petroleum 7.5 percent, while the other went to a partnership of Valiant 56.25 percent, Iceland Petroleum 18.75 percent and Petoro 25 percent.

The Iceland energy agency, known as Orkustofnun said the licenses were in accordance with a 1981 agreement between Norway and Iceland.

An initial licensing round was scuttled in 2009 when four companies pulled out. The second round was launched in October 2012.

Water depths 2,600-6,600 feet

The blocks on offer sit in water depths of 2,600 to 6,600 feet and are part of what Petoro describes as a "micro-continent" containing the Norwegian island of Jan Mayen and located between the Norwegian and Greenland continental shelves.

Petoro said seabed samples from the area have pointed to the presence of sedimentary rocks and an active hydrocarbon system.

Norway's Oil Minister Ola Borten Moe said the region could contain "substantial assets," while Faroe Chief Executive Officer Graham Stewart said the Jan Mayen Ridge license has "significant hydrocarbon potential."

Icelandic Foreign Minister Ossur Skarphedinsson was reported last year as saying his country expects commercial discoveries to be made in three separate areas by 2025.

Petoro Chief Executive Officer Kjell Pedersen said he was confident the industry can handle challenges such as the remote location and large transportation distances if commercial quantities of petroleum are discovered.

Petoro's Iceland head Jan Rosnes said the next step involves an agreement among the partners on a budget to fulfill the work commitments, starting with seismic- and other information-gathering work over the next few years.

Orkustofnun said it has ensured the parent companies of the license holders have "sufficient financial strength to conduct the activities for the long-term and can handle corresponding environmental and safety elements."

Analogous to Norway

The U.S. Geological Survey has estimated that the Arctic region contains about 13 percent of the world's undiscovered crude and about 33 percent of its undiscovered natural gas.

Although United Kingdom-based Cairn Energy drew a blank from a US$600 million, five-well exploration program offshore Greenland in 2011, it has said its interest in the region is undiminished.

Leilla Reddy, with the British investment bank of Panmure Gordon, said the Icelandic government views its waters as geologically analogous to Norway's offshore.

She said the play is high risk and high reward, similar to East Africa which has emerged as a "hot spot" in only five years. ●

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Petroleum news

Oil Patch Bits

Usibelli Coal Mine Inc.

Founded in 1943 by Emil Usibelli, Usibelli Coal Mine Inc. is located in the mountains of the Alaska Range, near the town of Healy, Alaska. UCM has a work force of about 130 employees, and operates year round. Mine production has grown from 10,000 tons in 1943 to an average above 2 million tons of coal per year and is currently the only operational coal mine in Alaska.

Beverly Weis, CPA — Controller


COURTESY PHOTO
BEVERLY WEIS

Born and raised in Fairbanks, Weis attended college in Washington, returning to complete an accounting degree at the University of Alaska Fairbanks. She joined the Usibelli team as controller for Usibelli affiliated companies working in the Fairbanks office.

Weis has been married for 29 years to her husband Wayne and has three grown children. She enjoys cross country skiing and in 2009 completed the Boston Marathon and more recently the 50th Equinox Marathon.

Vindeola joins Global Diving & Salvage Inc.


JOSE' VINDEOLA

Global Diving & Salvage Inc. said Feb. 1 that it has hired Jose' Vindeola for its Gulf Coast Region in the business development and technical support position. Vindeola will be essential in providing Global's current client base with high quality solutions and also stewarding expansion both nationally and abroad. He has cultivated an extensive background within the maritime industry, with more than 30 years of diving experience in both the offshore and inland sectors. Vindeola comes to Global Diving & Salvage Inc. having spent several years in project management and business development roles.

"Jose's wealth of experience and industry knowledge has already made him a key addition to the Global family. We view his appointment as a sign of our commitment to being a leading maritime service provider. Jose' brings a diverse technical and business development background that will fit in well with Global. We are excited to have him part of the Gulf Coast team," said Ryan Smith, general manager Gulf Coast Region.

Editor's note: All of these news items — some in expanded form — will appear in the next Arctic Oil & Gas Directory, a full color magazine that serves as a marketing tool for Petroleum News' contracted advertisers. The next edition will be released in September.

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TAKEOVER

into competitive concerns over the purchase delayed purchase completion — with Hilcorp already having purchased Chevron's Cook Inlet assets, Hilcorp was set to become the dominant gas producer in the basin.

With something of a hiatus over new gas development in Marathon's fields while the sale was in progress, Southcentral Alaska power and gas utilities, already hard pressed to find adequate gas supplies from the aging Cook Inlet gas fields, became concerned about the length of time that the deal was taking to complete. Marathon, with its gas fields earmarked for sale, was not in a position to move forward on new field developments, while Hilcorp was reluctant to negotiate new supply contracts before its purchase of the Marathon assets was finally secured.

However, a consent decree agreed in November between the state and Hilcorp paved the way for the purchase of the Marathon assets to proceed. That consent decree puts a price cap on Hilcorp gas sold for local Southcentral Alaska use over the next five years and prohibits Hilcorp from selling gas for export as liquefied natural gas unless all local gas supply needs are met.

Aggressive strategy

Hilcorp has adopted an aggressive strategy for developing oil and gas resources in its Cook Inlet properties. In November Greg Lalicker, president of Hilcorp Energy, described to the Resource Development Council's annual Alaska Resources Conference how Hilcorp's refurbishment of the Cook Inlet assets that it had obtained from Chevron and the company's efforts in new in-field drilling had started to reverse the fortunes of the company's decades-old oil fields. Oil-field production increases ranged from 8 percent at McArthur River to 122 percent at Swanson River during the first nine months of 2012, Lalicker said.

At that point the company had seen more mixed results in the gas fields where it had an ownership interest. But the company has said that it anticipates chasing improved gas production in the same manner that it is pursuing oil. In December Hilcorp began production from a new gas field at Red Pad on the Kenai Peninsula, delivering much needed utility gas into Enstar Natural Gas Co.'s pipeline system.

"Providing a reliable energy source for Southcentral is a priority for Hilcorp," Nelson said, with reference to Hilcorp's newly acquired Marathon assets. "We're committed to a long-term capital investment plan that aims at slowing decline and increasing production from Cook Inlet's existing, aging fields." ●

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KERTTULA Q&A

status of the state advancing a pipeline project?

Kerttula: I'm concerned about it. Watching the Asian market and watching the fracking outside, I think that Alaskans have not yet put together how we get our gas to market so we can take advantage of things. That's part of our problem. The question is how do we do this so we can be successful. I've always thought that the large line was our best bet, but perhaps it's LNG through Valdez. I disagree with the small bullet line to Cook Inlet for a number of reasons. I'm in agreement with the governor in being concerned with the mega agency and having rights to do things that might not be economically wise for Alaskans. There is gas in Cook Inlet. Do we want to put millions and billions into something like this only to undercut what we've been trying to get going for decades in Cook Inlet? I think gas is incrementally more complicated than oil for Alaskans and we haven't managed to get our paths straight. I thought AGIA (the Alaska Gasline Inducement Act) was the right thing. I think if the fracking and the lower cost of gas hadn't come in, we might be there by now.

Petroleum News: There's a lot of talk about restricting the export of LNG, and many believe Alaska should be exempted from those discussions and treated separately from the Lower 48. What are your thoughts on that?

Kerttula: I think we are a separate market and frankly a separate world. There are so many differences between Alaska and the Lower 48. I do think we should be exempted. What worries me and I think about it late into the night, we have a problem of how do we serve our own Alaskan citizens well? How do we get low cost energy across the state and by what method? Of course that isn't just obviously gas. I believe the answer lies with renewable resources. That is what we are going to have to go to more and more. We have such inequities. For example, we have right next to each other, one with high-cost energy next to one with low-cost energy.

Petroleum News: Still on natural gas, what are your thoughts on HB 4, which is currently under review with the House Resources Committee?

Kerttula: It still has some problems that last year's bill did (under HB 9). I still have great concerns about the economics and about the mega agency. You've got to be concerned about the economics for the consumer.

Petroleum News: Shifting north, you had Arctic exploration. You had a shorter season than you would have liked and there were problems with the rig afterward.

Kerttula: I have two major concerns. No matter if we do get production, that money is on the outer continental shelf. That's going to the U.S. government, not to Alaska. We need to nail down revenue sharing and we need it before there is much more going on up there so we aren't feeding the federal coffers while putting ourselves and the Arctic at great risk. That's my second concerned.

The Kulluk became a big joke. Every time you turned around, there was a problem. I talked to a few of the guys who came up to work on the emergency crew. They told me there was never any risk of any oil leaking and more important nobody was hurt, but this is the next small step to a bigger problem. So I think we have got to figure out the technology. Mark Meyer sitting at the University of Alaska right now, that's a really good thing.

Until we know how things are going to be cleaned up and what is the actual prevention, I have a real problem. If you look at the problems in the Gulf of Mexico, just wait until you see the problems of a big spill in the Chukchi Sea. They've got to do it right. I'm all for exploration. I want to see what the plans are and I want to be sure they can be performed safely. I know that sounds harsh, but with that environment and with that kind of risk, they have got to be sure they can do it safely and environmentally sound. Then we've got to be sure we get the money. Why put ourselves at risk. Alaskans are the ones who get hit. We would we do that if we can't share the revenue.

Petroleum News: Have you been in touch with our D.C. delegation on that issue?

Kerttula: That isn't news to any of them. They know that. I know they are both honest (Sens. Lisa Murkowski and Mark Begich). It's still a problem complicated with the sheer geography.

Petroleum News: So in summary what would your priorities be for this legislative session?

Kerttula: I know we wind ourselves around oil taxes every year. That isn't going to end. But I believe some of our answers lie with technology. How do we drill in the conditions of the Arctic? How do we foster low-cost access in to an aging pipeline? How do we tanker cost effectively out of Valdez? More and more that's the future. The Legislature can try to bog itself down into trying to give the companies more and more money. It's not about the taxes. It's about the world price and it's about how do you get to the oil and get it out. So my goals are to be sure Alaskans get a fair return, be sure that anytime we give a reduction in oil taxes, it's linked to further production and try to work on the technology and incentivizing these ideas. ●

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ELF WAR

Forest Oil.

The firms are working interest owners in certain "participating areas" of the Prudhoe Bay unit, the most productive unit on Alaska's North Slope.

The participating areas, or satellite fields, include Aurora, Borealis, Midnight Sun, Orion, Polaris and Point McIntyre.

All the satellites are strongly integrated with the main Prudhoe Bay field, with all but Point McIntyre having no production facilities of their own.

For many years, oil produced from these satellite fields enjoyed a very low tax rate, due to the application of a tax break calculation known as the "economic limit factor," or ELF.

"Very broadly, the purpose of the ELF was to prevent fields from becoming uneconomic due to an excessive rate of taxation," said the decision dated Oct. 13, 2012, from the Alaska Office of Administrative Hearings. "The ELF was intended to scale the tax rate downward as the field approached its economic limit."

Tax break removed

Over time, officials in the Department of Revenue began to have misgivings about the application of ELF to the Prudhoe satellites.

By the end of 2004, the tax rate being applied in the satellites was "miniscule" in comparison to the rate applied to production from the main Prudhoe Bay field, the administrative law judge's decision said. While Prudhoe production was taxed at an effective rate of about 12.5 percent, production from the satellites was taxed at less than half of 1 percent.

Department of Revenue officials saw how the satellites shared Prudhoe production facilities, and how the satellite oil was "commingled without reliable metering," the judge's decision said.

Further, the officials noted a "production-shifting technique" whereby Prudhoe wells were being choked back, with production increased from satellite wells. This was done to help manage problematic rates of natural gas coming out of the older Prudhoe wells. But the effect was to replace high-tax oil with low-tax oil, the administrative law judge's decision said.

On Jan. 12, 2005, the Department of Revenue issued a decision informing the oil companies that the satellites would be aggregated for ELF purposes. In other words, a major tax increase.

Gov. Murkowski announced the surprise tax hike the same day in his State of the State address.

A few days later, at a major oil industry conference in Anchorage, Murkowski received a chilly reception. He said after he felt "a little like a pork chop being thrown around the wolf cage."

Judge's decision

The central issue before the administrative law judge, Christopher Kennedy, was whether the Department of Revenue's aggregation action constituted a regulation.

"If so, it would be invalid because it was adopted without following the procedures that Alaska law requires to create a binding regulation," Kennedy wrote. Such procedures would include advance public notice and opportunity for public comment.

Kennedy, in his 20-page decision, held that Revenue's action was not a regulation, and was proper.

The tax period at issue covers only about a year, from Feb. 1, 2005, to March 31, 2006. That's because the ELF statute was repealed effective April 1, 2006, as part of state tax reform.

But despite the short period, the production tax revenue at issue is huge, in the hundreds of millions of dollars, Martin Schultz, supervisor of the Alaska Department of Law's Oil, Gas and Mining Section, told state legislators in the Feb. 7 hearing. ●

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RIG MOVE

uled for winter maintenance work at a West Coast shipyard.

Shell is also moving the drillship Noble Discover to Asia, to a shipyard in Korea, for repair, Smith said. Like the Kulluk, the Discoverer had been en route for the West Coast for maintenance. The drillship made the trip as far as Seward before being beset with the propulsion problems. And while the vessel was in Seward a U.S. Coast Guard inspection spotted deficiencies in some crew safety and pollution prevention systems.

Shell owns the Kulluk but contracts the Noble Discoverer from Noble Corp., the drillship's owner and operator.

Dry tow

Smith said that the Kulluk will be first towed to Dutch Harbor. Both the Kulluk and the Noble Discoverer will be transported to Asia using what is called a "dry tow," a procedure in which the vessel being transported sits on the deck of a large heavy-lift vessel.

The time required for the shipyard work and the return to service of the rigs will depend on further inspections of both rigs, Smith said.

Shell will presumably need two operational drilling vessels to continue its Arctic exploration drilling program in the summer of 2013. In addition to wanting to drill simultaneously both in the Chukchi and Beaufort seas, each drilling operation will need a second rig to be available for relief well drilling, in the unlikely event of a well blow out that incapacitates the rig drilling the problem well.

"We have not made any final decision on 2013 drilling in Alaska," Smith said. "Mapping the next steps for the Kulluk and the Noble Discoverer is a multifaceted operation and today's update is a result of those new plans being solidified."

Standing down

A Feb. 13 press release from the Joint Information Center for the Kulluk grounding incident said that the unified command for the incident is standing down.

"Agency representatives will return to their normal roles and responsibilities," said Capt. Paul Mehler III, the U.S. Coast Guard federal on-scene coordinator. "The Coast Guard will continue to monitor the activities involved in prepping the Kulluk for movement and I will lift the captain of the port order (detaining the Kulluk) once all the requirements have been met."

"Our objectives for the duration of this response have been to ensure the safety of all responders involved, protect the environment, and prepare the Kulluk for its next port. Thanks to the hard work and professionalism of all those involved in this extraordinary effort, we have achieved these goals," said Sean Churchfield, Shell incident commander. "I want to thank all of the individuals involved in the recovery effort for their dedication to ensuring a successful outcome."

Ready for tow

Det Norske Veritas, the engineering firm commissioned to assess the condition of the Kulluk, has validated that the vessel has the necessary structural integrity and stability to be towed, and has issued appropriate certification for the vessel. However, an independent warranty surveyor will need to approve the towing arrangements, as well as witness the connection of tugs. Three tugs, accompanied by the Nanuq, Shell's Arctic oil spill response vessel, will tow the Kulluk to Dutch Harbor, a transit that should take about 10 days, the press release said. The departure date will depend on a favorable weather window.

Smith has told Petroleum News that it would likely take two to four week weeks to transport the Kulluk and the Noble Discoverer to Asia, once suitable dry-tow vessels have been transitioned to Alaska for the tows.

Damaged

According to the Joint Information Center press release, the damage assessment of the Kulluk at Kiliuda Bay showed that the Kulluk's inner hull had not been breached during the grounding but that the outer hull had suffered damage that could be anticipated from a grounding in adverse weather. The Kulluk has sustained water damage to its superstructure and some technical equipment; seawater breached some windows and hatches; but the vessel's fuel tanks remain intact.

In preparation for the tow, crews at Kiliuda Bay have secured all windows and hatches, and where necessary have installed temporary steel structures to ensure that the vessel is weather tight, the press release said.

Shell has contracted the Native corporation for Old Harbor, the village close to the grounding site on Sitkalidak Island, to oversee teams that will clear lifeboat debris from the Kulluk from the shore where the vessel ran aground. The recovery of the debris will take some time because of the challenging terrain and the need for safety, the press release said.

More than 750 people have worked on the response to the incident. Shell has estimated the cost of the response to the Kulluk grounding and the salvage of the vessel to be around $90 million.

Questions raised

The Kulluk grounding did not happen in the Arctic and did not occur as part of a drilling operation. However, environmental organizations, vehemently opposed to Arctic offshore oil exploration, have made much of Shell's problems, saying that a string of incidents culminating in the Kulluk grounding illustrate the risks associated with seeking oil in Arctic waters and raise questions over Shell's ability to operate safely in the challenging Arctic marine environment.

"These serious transportation, logistics, and drilling failures — collectively — provide strong evidence of Shell's inability to effectively undertake oil drilling in the harsh environment of the Arctic Ocean, and raise questions about any company's capacity to do so," said Lois Epstein, Arctic program director of the Wilderness Society.

The U.S. Coast Guard is conducting a formal investigation of the Kulluk grounding. And, as a result of the grounding, in January the U.S. Department of the Interior announced a 60-day, high-level assessment of Shell's operations in the Arctic in 2012, examining Shell's safety systems, the company's oversight of its contracted services and the company's ability to meet the strict standards in place for Arctic development. ●

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WARNING FLAGS

will notice that the progress towards piecing together LNG ventures — which currently involves eight partnerships — is being threatened by First Nations' challenges like those that have stalled and threatened to derail the plans by Enbridge and Kinder Morgan to run pipelines from the Alberta oil sands to tanker terminals on the British Columbia coast.

Water one of concerns

The message from aboriginal communities is starting to gain momentum and attention.

The Carrier Sekani Tribal Council, CSTC, a coalition of eight First Nations whose territorial land covers the bulk of the pipeline rights of way to carry natural gas to liquefaction plants on the Pacific Coast, said that unless it is consulted and involved in the approval process it will not allow those pipelines to go ahead.

Separately, the Fort Nelson First Nation, in the heart of massive shale gas deposits in the Horn River formation of northeastern British Columbia, is ready to engage in a legal fight over the use of hydraulic fracturing to extract shale gas and the associated pipelines.

"We are not going to let them get away with it," Lana Lowe, director of land and resources for Fort Nelson, told the Globe and Mail.

"The major concern is what happens in five years when it's all systems go and we have 10 oil companies drilling our land and taking all our water."

She said her community views LNG development as a "disaster waiting to happen" and is preparing to wage a legal battle.

Right of way, bitumen issues

Adding to the aboriginal concerns, the Gitxaala Nation and the Gitga'at First Nation say LNG exports from the terminal and by tanker would have serious adverse impacts on their aboriginal rights and titles, with the Gitxaala arguing the application is "deficient and premature."

CSTC Chief Terry Teegee said the LNG pipelines are at risk because there are no agreements in place for First Nations to assess the projects and Chief Reg Louis said his community is not prepared to risk the environment, native land title rights and future generations for the sake of engaging in business activities.

Louis said the Canadian government has stripped environmental protections to make it easier for projects to gain approval.

Teegee said "we are raising the alarm that (the LNG) projects are at risk. While there have been some initial discussions with CSTC and our member First Nations there are no agreements in place for our First Nations to review or understand the cumulative impacts of these projects."

Setback to earlier deal

That stance is a setback to a deal struck four years ago by the CSTC to take advantage of a British Columbia government offer of C$32 million to help First Nations acquire a 30 percent equity stake in the 280-mile Pacific Trail pipeline which is designed to ship natural gas to a liquefaction terminal for the Chevron-operated Kitimat LNG project.

It is estimated that if First Nations take advantage of that proposal they could collect C$522 million over the first 30 years of the pipeline's operation.

The First Nations battle against bitumen exports has also expanded, with Coastal First Nations, CFN, a coalition of nine communities, abandoning participation in the regulatory review of Enbridge's Northern Gateway application, saying the C$280,000 they had available to participate in the process could not compete with the C$250 million Enbridge is spending on a team of lawyers.

The CFN informed the regulatory review panel that it was dismayed at the process and the fact that the Canadian government had removed the final decision on Northern Gateway from the panel.

Executive Director Art Sterritt said the review had simply become "gamesmanship."

Energy corridor planned

Taking an altogether different direction, leaders of the aboriginal business community have formed Eagle Spirit Energy Holdings aiming to create a First Nations-owned energy corridor to carry oil, natural gas and electricity.

The idea holds out hopes of large equity stakes in pipelines, major construction contracts and participation in spill response measures for First Nations.

Eagle Spirit President Calvin Helin said that if First Nations can secure an equity role in new pipelines "they will be a lot more conducive to wanting to see projects develop in their territory (especially) if they are going to get a fair share of what's going on and be in a position of reasonable stewardship and control."

Also joining the initiative is Aquilini Development and Construction, run by a Vancouver family that owns the Vancouver Canucks of the National Hockey League and has struck deals with First Nations to develop native land in British Columbia.

Aquilini President David Negrin said his company believes an oil pipeline across British Columbia is inevitable, although a natural gas pipeline may come first.

But unlike Enbridge, which has offered a 10 percent equity stake in Northern Gateway to First Nations, Eagle might offer 50 percent, with the balance likely going to Aquilini, he said.

Negrin said every First Nation along the pipeline corridor would be offered jobs in building and monitoring the facility, working at a refinery if one was built and working at ports.

The biggest challenge is posed by unresolved land claims in British Columbia that often involve overlapping territories, preventing communities from working together and adding to the difficulty of reaching agreement on a pipeline rights of way.

—GARY PARK

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EXXON DEAL

ated on state-owned land on the eastern North Slope about 60 miles east of Prudhoe Bay. The company is embarking now on construction of a project to produce natural gas condensate from Point Thomson, which is considered one of the richest undeveloped oil and gas accumulations in North America.

Full development of Point Thomson is expected to require billions of dollars in investment. ExxonMobil isn't going it alone, as BP and ConocoPhillips also are stakeholders in the field.

The condensate development is proceeding under a legal settlement the companies struck with the state of Alaska on March 29, 2012. ExxonMobil has pledged field startup by May 2016, with a modest initial production level of 10,000 barrels per day of condensate.

The expectation is that, down the road, much greater volumes can be pulled from Point Thomson formations, which are believed to hold 8 trillion cubic feet of natural gas, 200 million barrels of recoverable condensate plus some crude oil.

Chevron replacement?

Another major company, Chevron, previously held a sizeable stake in Point Thomson. But Chevron assigned its interest to ExxonMobil at the time state settlement was announced.

Assignment of Chevron's 11.6 percent working interest in Point Thomson bumped up ExxonMobil's share to 68.3 percent, with BP holding 27.2 percent, ConocoPhillips 3.2 percent, and 20 others combining for 1.2 percent.

A Chevron spokesman told Petroleum News on April 3, 2012, that "we determined that Point Thomson is unable to compete for capital with other global opportunities in Chevron's portfolio."

Could it be that Point Thomson holds greater appeal for Rosneft? And that ExxonMobil sees the Russian oil giant as a replacement for Chevron?

"Participation in the Point Thomson project will increase Rosneft's access to the latest gas and condensate field development technologies used in harsh climatic conditions," Igor Sechin, president of Rosneft, said in the Feb. 13 press release.

The release said Sechin and Stephen Greenlee, president of ExxonMobil Exploration Co., signed agreements to explore seven new blocks in the Chukchi Sea, Laptev Sea and Kara Sea. Rosneft's website had a photo of Russian President Vladimir Putin standing over the two company men as they signed.

A separate "heads of agreement," or preliminary deal, was signed providing Rosneft, or its affiliate, with an option to acquire a 25 percent interest in the Point Thomson unit, the release said.

Alaskans react, and the BP angle

Asked about the timeline for Rosneft potentially taking a stake in Point Thomson, Kim Jordan, an ExxonMobil spokeswoman in Houston, said she couldn't provide any further comment.

Elizabeth Bluemink, a spokeswoman for the Alaska Department of Natural Resources, said DNR officials were informed of the ExxonMobil-Rosneft agreement late Feb. 12, the day before the deal was announced.

She provided this statement from DNR Commissioner Dan Sullivan:

"Any lease assignments must be approved by the state. We will be analyzing such a request for assignments if and when it is received. Additionally, any new working interest owner would need to comply fully with the Point Thomson settlement terms."

Rosneft is a state-owned Russian oil titan that has made other big deals recently with Western oil and gas firms.

In November, BP announced it had signed binding agreements to sell its half of the Russian oil and gas company TNK-BP to Rosneft for $17.1 billion in cash plus shares in Rosneft. At the conclusion of this and related transactions, BP said it would own 19.75 percent of Rosneft.

—WESLEY LOY

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