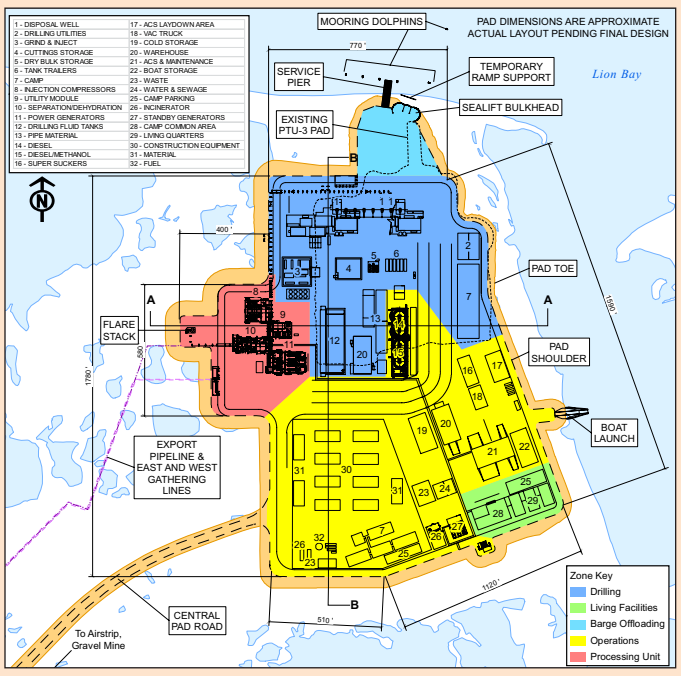
Petroleum news

page 4 Apache's Hendrix tells RDC company's Cook Inlet seismic shoot under way.

Vol. 16, No. 49 • www.PetroleumNews.com | A weekly oil & gas newspaper based in Anchorage, Alaska | Week of December 4, 2011 • $2

Proposed Thomson pad layout



ExxonMobil has submitted this proposed central pad layout to the Corps of Engineers as part of its application for Point Thomson facilities and pipeline work. See story on page 13.

Spartan 151 jack-up drilling rig arrives safety in Port Graham

The only jack-up rig in Cook Inlet is now in hibernation for the winter.

Furie Operating Alaska LLC, formerly Escopeta Oil Co., brought the Spartan 151 into Port Graham on Thanksgiving Day, according to Furie Strategic Officer Steve Sutherlin.

The rig will spend the winter getting light maintenance and repairs at the ice-free Cook Inlet port on the southern Kenai Peninsula before heading back out sometime next spring.

Furie used the rig this summer and early autumn to drill the first half of Kitchen Lights Unit No. 1, an offshore exploration well in the upper Cook Inlet. The company suspended operations at 8,805 feet on Oct. 28, but plans to drill to a total depth of about 16,500 feet.

—ERIC LIDJI

BRPC plans 3 Mustang wells in new Southern Miluveach unit

A joint venture led by Brooks Range Petroleum Corp. could complete as many as four wells this winter at its North Tarn prospect on the central North Slope of Alaska.

In addition to re-entering a sidetrack started this past winter, the local independent operating arm of Kansas-based Alaska Venture Capital Group plans to drill as many as three wells to delineate the prospect on the western boundary of the Kuparuk River unit.

The Mustang exploration program would take place from the North Tarn ice pad that Brooks Range Petroleum plans to build in its newly formed the Southern Miluveach unit.

The company expects to use Nabors rig 7ES for the program.

Brooks Range Petroleum drilled the North Tarn No. 1 well this past winter and began drilling the North Tarn No. 1-A sidetrack on leases farmed-in from Eni Petroleum.

The company expects to begin construction soon on an ice road running approximately four miles from an existing gravel road in the Kuparuk River unit to the to-be-built North Tarn ice pad, and plans to mobilize its camp and drilling rig toward the end of the year.

In early January, Brooks Range Petroleum plans to spend some 15 days re-entering and completing North Tarn No. 1-A

see MUSTANG WELLS page 19

EXPLORATION & PRODUCTION

Tight situation

Alaska oil explorers hit the limits on winter drilling rig availability

By ALAN BAILEY & KAY CASHMAN
Petroleum News

The surge in exploration activity planned for Alaska this winter has placed a major strain on the supply of drilling rigs suitable for use in the demanding conditions of a long Arctic winter. At last count four companies with exploration drilling plans — Linc Energy, Savant Alaska, UltraStar Exploration and Great Bear Petroleum — had yet to sign contracts for drilling rig use. And given the relatively small inventory of Arctic rigs it seems highly improbable that all of these companies will end up drilling in the coming months, assuming that companies with rig contracts do in fact proceed with their planned drilling.

Three other companies, Repsol, Brooks Range Petroleum and Pioneer Natural Resources have seven rigs under contract for this coming winter exploration season: Repsol expects to drill 12 wells; Brooks Range, two wells, plus re-enter a third; and Pioneer, two wells.

Nabors operates 12 rigs

On Nov. 29, David Hebert, general manager of Nabors Alaska Drilling, talked to Petroleum News about some of the issues involved in supplying rigs for Arctic Alaska exploration. Nabors currently operates 12 rigs that are suitable for Arctic use and that are in a fully operational status, Hebert said. An additional Nabors rig on the Kenai Peninsula has not been winterized for the Arctic.

Two of the Arctic rigs are workover rigs for infield use, while another has a design that is not

see RIG DEMAND page 18

NATURAL GAS

Mackenzie project lives

NWT premier reports 'some progress' on fiscal issues; Imperial confirms 'dialogue'

By GARY PARK
For Petroleum News

Canada's Mackenzie Gas Project has received a fresh infusion of hope with confirmation that discussions on a fiscal framework are under way between project leader Imperial Oil and the Canadian government.

The election in May of a majority federal government under Prime Minister Stephen Harper is viewed as the spark that has ended what Imperial spokesman Pius Rolheiser said was a "temporary hiatus" in the dialogue.

Bob McLeod, newly elected premier of the Northwest Territories, said he understands "some progress" has been made.

The study, which forecast Mackenzie gas can start flowing when prices rise above US$5.50 per million British thermal units, said the Arctic gas will be needed regardless of the projected growth of shale gas production.

He said the Aboriginal Pipeline Group, which has been offered a one-third equity stake in the proposed Mackenzie Valley gas line, and its members have held meetings with a number of federal government cabinet ministers.

"They seem to have received some positive sig-

see MACKENZIE LIVES page 20

ALTERNATIVE ENERGY

Co-op members object

Committee wants more information as Naknek Electric works through bankruptcy

By WESLEY LOY
For Petroleum News

Members of a troubled Southwest Alaska electric power cooperative have raised concerns about the utility's proposed bankruptcy reorganization plan.

Naknek Electric Association in September 2010 was forced to file for Chapter 11 protection from creditors due to complications with a geothermal energy program.

A committee representing the interests of Naknek Electric members on Nov. 28 filed a six-page objection to the co-op's disclosure statement for its reorganization plan. The filing was in

A big worry for the co-op, and for the members, is retaining the utility's major customers, which could elect to generate their own power if rates increase significantly.

advance of a scheduled Dec. 1 hearing on the plan in U.S. Bankruptcy Court in Anchorage.

The members committee raised concerns about the possibility of the co-op continuing with its geothermal drilling project, and the risks this could pose to the utility and to ratepayers.

see CO-OP OBJECTIONS page 20

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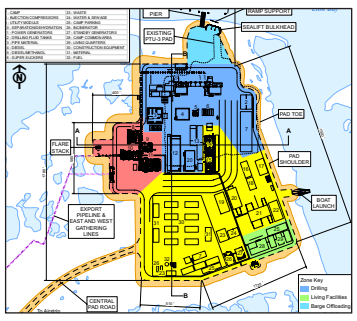

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15 Evaluation of VMT remote control planned

Alaska - Mackenzie Rig Report

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 Z-116	BP
Dreco 1000 UE	16 (SCR/TD)	Prudhoe Bay 01/11i	BP
Dreco D2000 UEBD	19 (SCR/TD)	Alpine CD4-03	ConocoPhillips
AC Mobile	25	Prudhoe Bay 04-350	BP
OIME 2000	141 (SCR/TD)	Kuparuk 3H-34	ConocoPhillips
TSM 7000	Arctic Wolf #2	In Nisku, AB	Available
Kuukpik	5	Standbye, waiting on ice road construction to Walakpa #11	North Slope Borough
Nabors Alaska Drilling			
Trans-ocean rig	CDR-1 (CT)	Stacked, Prudhoe Bay	Available
AC Coil Hybrid	CDR-2	Kuparuk 2K-28A	ConocoPhillips
Dreco 1000 UE	2-ES	Prudhoe Bay Stacked out	Available
Mid-Continental U36A	3-S	Prudhoe Bay Stacked out	Available
Oilwell 700 E	4-ES (SCR)	Prudhoe Bay X-22A	BP
Emsco Electro-hoist	7-E (SCR-TD)	Prudhoe Bay DS12-27A	BP
Dreco 1000 UE	7-ES (SCR/TD)	Milne Point MBS	BP
Dreco 1000 UE	9-ES (SCR/TD)	Has been released by Brooks Range Petroleum	Available
Oilwell 2000 Hercules	14-E (SCR)	Prudhoe Bay Stacked out	Available
Oilwell 2000 Hercules	16-E (SCR/TD)	Prudhoe Bay Stacked out	Available
Oilwell 2000	17-E (SCR/TD)	Prudhoe Bay Stacked out	Available
Emsco Electro-hoist -2	18-E (SCR)	Stacked, Deadhorse	Available
Emsco Electro-hoist Varco TDS3	22-E (SCR/TD)	Stacked, Milne Point	Available
Emsco Electro-hoist	28-E (SCR)	Stacked, Deadhorse	Available
Emsco Electro-hoist Canrig 1050E	27-E (SCR-TD)	Stacked at Deadhorse, will go to Oooguruk for exploration drilling in January	Pioneer
Academy AC electric Heli-Rig	106-E (SCR/TD)	Stacked at Deadhorse	Available
OIME 2000	245-E	Oliktok Point OP12-01	ENI

*Nabors 27-E will be under contract at Oooguruk/Nuna for Pioneer this winter

Nordic Calista Services			
Superior 700 UE	1 (SCR/CTD)	Prudhoe Bay Drill Site U-12AL1	BP
Superior 700 UE	2 (SCR/CTD)	Prudhoe Bay Well Drill Site 6-12B	BP
Ideco 900	3 (SCR/TD)	Kuparuk Well 2T-03	ConocoPhillips
Parker Drilling Arctic Operating Inc.			
NOV ADS-10SD	272	Prudhoe Bay final construction and commission	BP
NOV ADS-10SD	273	Prudhoe Bay final construction and commissioning	BP

North Slope - Offshore

BP (rig built & being assembled by Parker)			
Top drive, supersized	Liberty rig	Endicott SDI for Liberty oil field	BP
Nabors Alaska Drilling			
OIME 1000	19-E (SCR)	Oooguruk ODST-39	Pioneer Natural Resources
OIME 2000	245-E	Oliktok Point OI13-03	ENI
Oilwell 2000	33-E	Prudhoe Bay Stacked out	Available
Doyon Drilling			
Sky Top Brewster NE-12	15 (SCR/TD)	Spy Island SP27-N1	ENI

Cook Inlet Basin – Onshore

Aurora Well Service			
Franks 300 Srs. Explorer III	AWS 1	Stacked out south of Tyonek	Available
Cook Inlet Energy			
Atlas Copco RD20 34		Undergoing winterization at W. McArthur River Unit	Cook Inlet Energy
Doyon Drilling			
TSM 7000	Arctic Fox #1	Beluga, Stacked	Repsol
Marathon Oil Co. (Inlet Drilling Alaska labor contractor)			
Taylor	Glacier 1	Stacked Marathon Yard	Available
Nabors Alaska Drilling			
Continental Emsco E3000	273	Stacked, Kenai	Available
Franks	26	Stacked	Available
IDECO 2100 E	429E (SCR)	Stacked	Available
Academy AC electric Canrig	105-E (SCR-TD)	Kenai CLU-1	CINGSA
Rigmaster 850	129	Kenai Stacked out	Available

Cook Inlet Basin – Offshore

Chevron (Nabors Alaska Drilling labor contract)			
	428	M-11 Steelhead Platform	Chevron
XTO Energy			
National 1320	A	Coil tubing cleanout planned off Platform A in the near future	XTO
National 110	C (TD)	Idle	XTO
Spartan Drilling			
Baker Marine ILC-Skidoff, jack-up		Spartan 151 Upper Cook Inlet KLU#1	Escopeta

Mackenzie Rig Status

Canadian Beaufort Sea

SDC Drilling Inc.			
SSDC CANMAR Island Rig #2	SDC	Set down at Roland Bay	Available

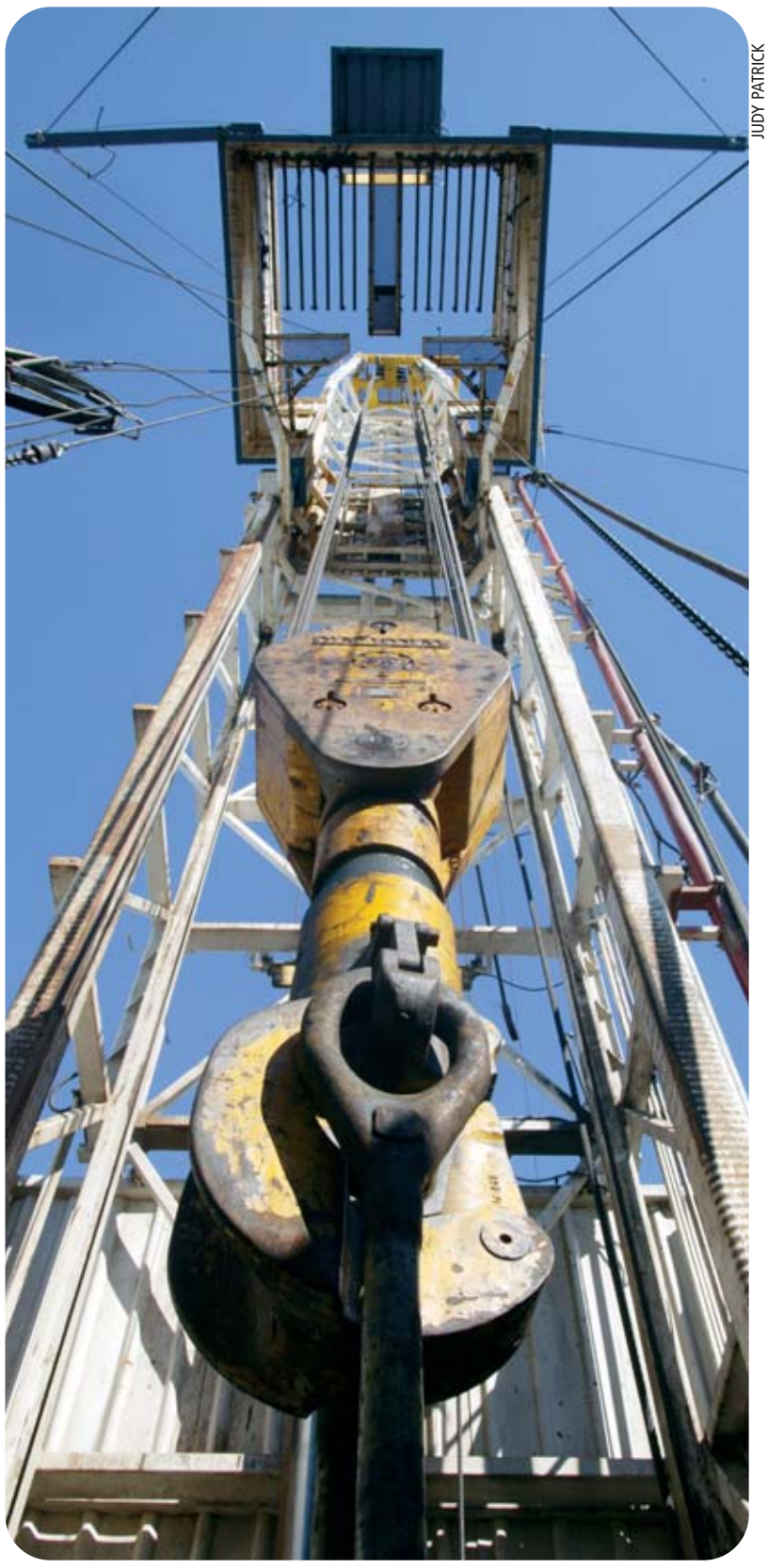
Central Mackenzie Valley

Akita/SAHTU			
Oilwell 500	51	Has left the NWT	Available

The Alaska - Mackenzie Rig Report as of December 1, 2011. 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*

	November 23	November 18	Year Ago
US	2,000	2,001	1,687
Canada	484	487	415
Gulf	38	36	20

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

● EXPLORATION & PRODUCTION

Cook Inlet energy projects under way

RDC annual conference hears updates from Apache, Buccaneer, Furie, Cook Inlet Energy, Enstar, CINGSA and Cook Inlet Region Inc.

By KRISTEN NELSON
Petroleum News

The Resource Development Council included a fairly complete Cook Inlet update on the program of its annual conference.

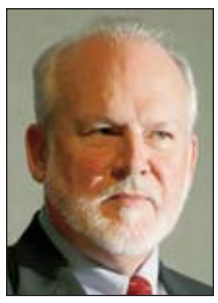
From oil and gas, through wind and underground coal gasification, to natural gas storage, companies involved in the current upsurge in Cook Inlet activities were on the podium Nov. 17.

■ Part 2 of 2

Apache

Apache Corp., Cook Inlet's newest big player, with more than 800,000 acres, was represented by its newly named Alaska general manager, John Hendrix, who told the RDC audience he remembers Cook Inlet in its heyday, before the discovery of Prudhoe Bay. But by the time he graduated from college and went to work for Schlumberger, the work was on the North Slope.


JUDY PATRICK PHOTOS
JOHN HENDRIX


JIM WATT

"All the focus, all the money, were going into Prudhoe Bay," Hendrix said.

Apache is focused on the historic oil play in Cook Inlet and is looking for oil "with new 3-D seismic technology," he said.

"We feel there's potential out there. We're more focused on oil — gas will come along with the oil … but we're oil focused."

Apache has begun a three-year 12,000-square mile 3-D seismic shoot in Cook Inlet using a new nodal technology.

Hendrix said there are 220 people on the west side of Cook Inlet deploying nodes with the first actual shoot done Nov. 11. He said crews will work until mid-December and then start back up Jan. 15. Twelve small drill rigs will be used to drill the holes onshore; offshore air guns will be used.

In all of its operations, Apache shoots a lot of seismic, Hendrix said.

"We're a very seismic, geo-science oriented company … and you have to know the data before you drill. You gather the data, you put your strategy forward and then we drill."

He also said that Apache's "chairman, in a number of meetings I've been with him, he doesn't want us to stop drilling until we hit bedrock. We don't want anybody to come behind us and turn over a stone and find there's oil reserves; we want to make sure when we drill, that we leave no … stone untouched."

Buccaneer

Jim Watt, president and COO of Buccaneer Alaska, said Buccaneer sees majors moving out and independents moving into Cook Inlet, "normal for a lot of maturing basins."

But, he said, Cook Inlet is an underexplored basin where recent U.S. Geological Survey reports show "tremendous upside" and where there is existing infrastructure, a strong local market and attractive natural gas prices.

Buccaneer has some 66,000 acres onshore and at one prospect, Kenai Loop, just north of the city of Kenai, it "leased, permitted and drilled our first well within nine months." That natural gas well will be on production in December, he said. Buccaneer has a contract with Enstar for delivery beginning in April, "but we hope we will sell in the spot market" before then, Watt said.

At West Nicolai on the west side of Cook Inlet Buccaneer expects to acquire seismic in 2012 and drill in 2013.

And at West Eagle on the southern Kenai Peninsula Buccaneer is reprocessing seismic and would like to drill in 2012.

The company also has offshore prospects and has completed purchase of the Endeavour jack-up drilling rig for use in Cook Inlet. Buccaneer is also looking at the potential for liquefied natural gas for use in Alaska. Watt said "we feel we can move LNG from the Cook Inlet to Fairbanks and be very competitive."

Furie/Escopeta

Drilling engineer Bob Laule, filling in for Furie Operating Alaska (formerly Escopeta Oil) President Ed Oliver, gave a brief update.

"Furie came; we drilled; and we found gas," he said.


JUDY PATRICK
BOB LAULE

He said the company got a late start and wasn't able to complete its well, but drilled to 8,800 feet and did "some testing which gave us some very good indications of gas in the Sterling and in the Beluga formations."

Laule said they will re-enter the well next spring, approximately mid-April and drill to total depth, "set a couple of extra additional stands of pipe and go into a testing program."

Then Furie will drill a second well. Laule said he didn't know if they'd get to testing the second well next year.

Cook Inlet Energy

JR Wilcox, president of Cook Inlet Energy, said his company "is one of the few small independent oil producers in the state." Cook Inlet Energy re-established production after Pacific Energy declared bankruptcy in 2009.

Production was shut down in September and Cook Inlet Energy was approved as successor operator in December, hired a staff and "within about two weeks we had some production going."

Over the next four months the West McArthur River unit was restarted and

see **INLET ENERGY** *page 14*

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

OWNER: Petroleum Newspapers of Alaska LLC (PNA)
Petroleum News (ISSN 1544-3612) • Vol. 16, No. 49 • Week of December 4, 2011
Published weekly. Address: 5441 Old Seward, #3, Anchorage, AK 99518
(Please mail ALL correspondence to:
P.O. Box 231647 Anchorage, AK 99523-1647)
Subscription prices in U.S. — $98.00 1 year, $176.00 2 years, $249.00 3 years
Canada — $185.95 1 year, $334.95 2 years, $473.95 3 years
Overseas (sent air mail) — $220.00 1 year, $396.00 2 years, $561.00 3 years
"Periodicals postage paid at Anchorage, AK 99502-9986."
POSTMASTER: Send address changes to Petroleum News, P.O. Box 231647 Anchorage, AK 99523-1647.

● EXPLORATION & PRODUCTION

Tensions simmer in Syncrude ranks

Operator and largest shareholder unable to agree on timing for C$15 billion expansion of world's largest synthetic crude plant

By GARY PARK
For Petroleum News

An apparent rift among owners of Syncrude Canada, the world's largest single synthetic crude operation, is stalling plans to increase capacity by 250,000 barrels per day to 600,000 bpd by 2020.

First announced in February 2010, the C$15 billion expansion proposal has operator Imperial Oil (69.6 percent owned by ExxonMobil) and Canadian Oil Sands, the largest stakeholder, at odds over the timing.

The original plans called for an initial 50,000 bpd "debottlenecking" followed by a two-phase hike in bitumen production of 100,000 bpd each in 2014 and 2020, placing about 115,000 bpd of excess raw bitumen supply on the open market.

But a spokesman for Imperial, a 25 percent owner, has told reporters that his company no longer believes the expansion will take place this decade, although he said it would be "premature to talk about specific project plans or timing or sequencing."

However, he said Imperial remains committed to "the economic development of the entire resource at Syncrude."

A spokeswoman for Canadian Oil Sands, whose stake is 36.74 percent, countered that all of the partners agreed to the last strategic plan, suggesting that Imperial was simply "putting out their own view."

She said there has been talk about cooperation between Syncrude and the nearby Kearl project, a joint venture by Imperial and ExxonMobil to build a 110,000 bpd mine at a cost of C$10.9 billion.

The spokeswoman said the discussions have involved sharing labor and some of the project management, but the Imperial spokesman insisted his company views Syncrude and Kearl separately.

The other Syncrude partners are Suncor Energy 12 percent, China's Sinopec 9.03 percent, Nexen 7.23 percent, Murphy Oil 5 percent and Mocal Energy 5 percent.

ExxonMobil hired 4 years ago

Following a series of unplanned outages, the Syncrude partners hired ExxonMobil four years ago to improve operations and reduce per barrel costs.

Currently, two processing units at the upgrading plant are offline, including a 100,000 bpd coking unit.

Imperial insists that its immediate priority is to improve reliability of the base operations.

FirstEnergy Capital analyst Michael Dunn said in a research note he has reduced capital spending forecasts for Canadian Oil Sands after indications by other partners — "either subtly or directly" — that expansions will not come on line this decade.

"Since major expansions require unanimous partner approval, we have reduced our cap-ex estimates materially in the 2012 to 2015 time frame." Dunn wrote.

He said a spending cut could be positive for Canadian Oil Sands by easing the strain on its balance sheet and allowing it to maintain dividend payments.

Suncor has been less than emphatic when asked about the future of its Syncrude stake and the role of Sinopec, which acquired ConocoPhillips' 9.03 percent interest for C$4.65 billion last year, has yet to take shape.

Export vs. value-added

Most observers believe Sinopec wants to pursue exports of raw bitumen from Syncrude to its refineries in China, which is inconsistent with the Alberta government's goal to see more of the value-added end of the oil sands remain in Alberta. But achieving the province's objective of upgrading 66 percent of bitumen production compared with 58 percent last year is not a simple matter.

Todd Hirsch, senior economist at ATB Financial, said that building more refineries and upgraders in Alberta would satisfy those "who believe we export too much raw resource when we should keep those jobs at home."

"But that doesn't solve the main problem of cost, which is the primary reason industry is not racing to build refineries in Alberta," he said.

Alberta currently has 1.2 million bpd of upgrading capacity and expects to add 270,000 bpd by 2016, but it is likely to be outstripped by the growth in bitumen output to 3 million bpd in 2016 from 1.6 million bpd in 2010.

In the process, the cost of labor, steel and other materials is expected to increase inflationary pressure, making an uneconomic aspect of the oil sands sector even more expensive.

C$5 billion upgrading project

The biggest upgrading project on the table is a C$5 billion joint venture by North West Upgrading and Canadian Natural Resources to build a 150,000 bpd refinery near Edmonton in three equal stages.

The Alberta government has already agreed to provide 37,500 bpd of feedstock bitumen to the plant from its royalty-in-kind program.

North West Upgrading Vice President Jerry Crail said a final investment decision is targeted for late this year or early 2012 as the partners try to head off rising capital costs.

He said a final plan is in place and private investors and financial institutions have pledged funding.

Canadian Natural Resources, which is expected to supply 12,500 bpd of bitumen, has indicated it hopes to gain board approval for the project in 2012.

Crail agreed there are operational and financial risks associated with building a refinery, but noted that substantial work has already been completed for initial conceptual studies and detailed engineering is due to start in March 2012. ●

Contact Gary Park through publisher@petroleumnews.com

INTERNATIONAL

Record number of vessels transit Arctic

According to a report in the Barents Observer a total of 34 vessels transited the Northern Sea Route along the Russian coast of the Arctic Ocean this year. With shrinking Arctic sea ice cover, both the Northern Sea Route and the Northwest Passage through the Canadian archipelago have started to become ice free after the summer ice melt. And Russia has a fleet of nuclear powered icebreakers to escort ships around its route, and assist with navigating the route when the sea is not entirely ice free.

According to the Barents Observer, the sailing season along the Northern Sea Route lasted five months this year, from the end of June to the end of November.

According to the Barents Observer, the sailing season along the Northern Sea Route lasted five months this year, from the end of June to the end of November.

The route remained open about one month longer than has become the norm, with the total of 34 vessels being a record for the number of vessels transiting the route in a single open water season, the Barents Observer said. Of those 34 vessels, 15 carried liquid cargos, three carried bulk cargo, four carried salmon under refrigeration, two carried general cargo and 10 sailed in ballast. Of particular note were the fact that a supertanker — the Vladimir Tikhonov — plied the route for the first time, and the 75,600-tons-deadweight bulk carrier Sanko Odyssey became the largest bulk carrier ever to use the route, the Barents Observer said.

According to the Voice of Russia website, developing the Northern Sea Route, the shortest marine route between Europe and the Far East, has become one of Russia's top priorities in the far north. In September at the International Arctic Forum, Russian Prime Minister Vladimir Putin said that Russia is developing the Northern Sea Route by expanding existing ports and building new ports along the route; upgrading the transportation infrastructure in the region; and expanding the country's icebreaker fleet.

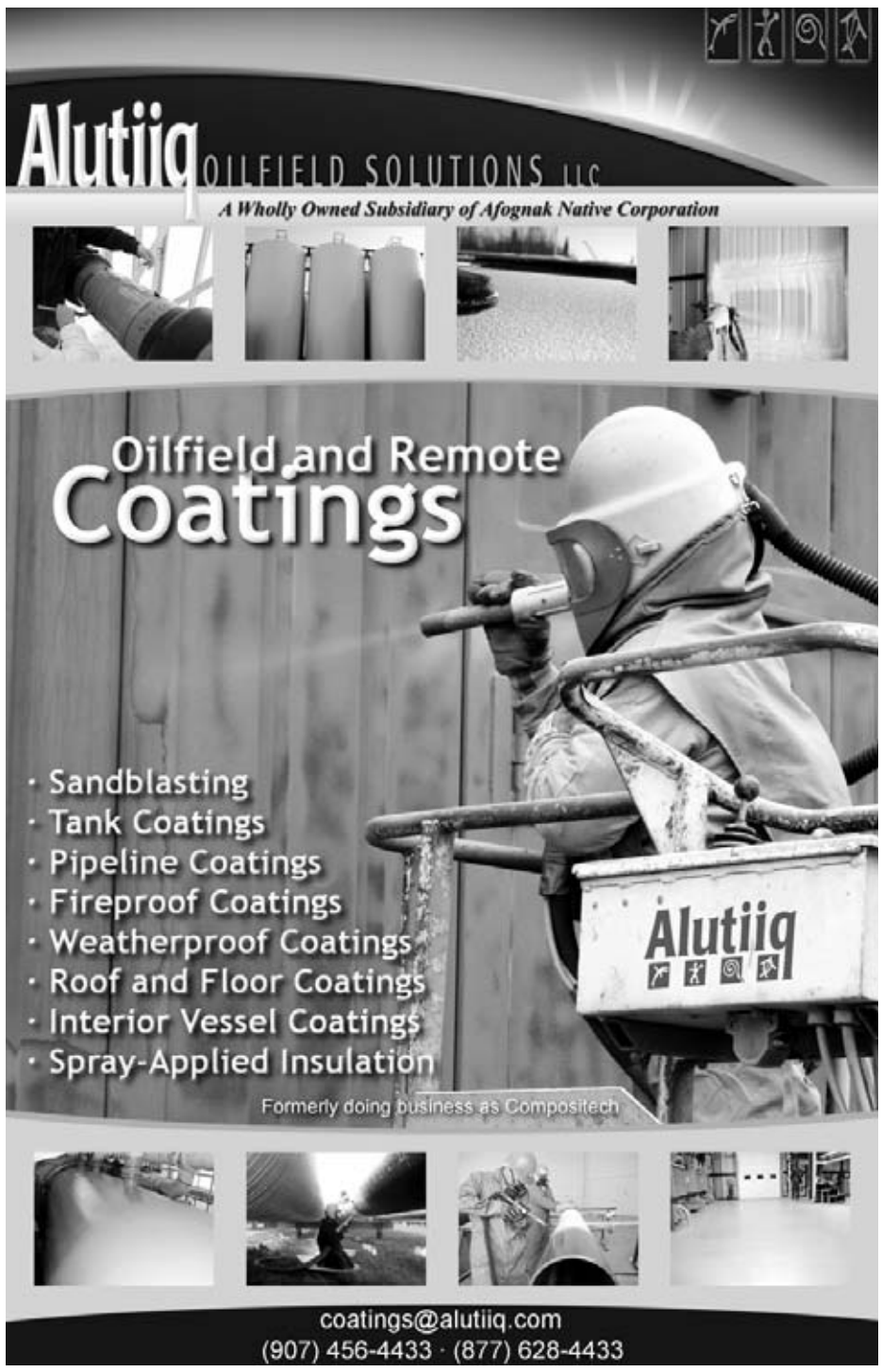
—ALAN BAILEY

LAND & LEASING

Potential Alaska state and federal oil and gas lease sales

Agency	Sale and Area	Proposed Date
DNR	Beaufort Sea Areawide	Dec. 7, 2011
DNR	North Slope Areawide	Dec. 7, 2011
DNR	North Slope Foothills Areawide	Dec. 7, 2011
BLM	NPR-A	Dec. 7, 2011
DNR	Cook Inlet Areawide	spring 2012
DNR	Alaska Peninsula Areawide	spring 2012
DNR	Beaufort Sea Areawide	fall 2012
DNR	North Slope Areawide	fall 2012
DNR	North Slope Foothills Areawide	fall 2012
BLM	NPR-A	2012
BOEM	2013 Cook Inlet	(special interest)
BOEM	Beaufort Sea	2015
BOEM	Chukchi Sea	2016

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.



● LAND & LEASING

Deep Creek on hold pending Hilcorp sale

Alaska Division of Oil & Gas, Cook Inlet Region Inc., agree to delay discretionary contraction until 6 months after sale or Sept. 1

By KRISTEN NELSON
Petroleum News

The Alaska Department of Natural Resources' Division of Oil and Gas and Cook Inlet Region Inc., which jointly manage Union Oil Company of California's Deep Creek unit, have agreed to delay any "discretionary contraction" of the unit "for a reasonable period of time after close of the pending asset sale between Union and Hilcorp Energy Alaska, LLC."

Division Director Bill Barron told Union in a Nov. 23 letter that because of the pending sale he will delay any discretionary contraction of the unit until six months after the closing of Union's sale of its Cook Inlet assets to Hilcorp or Sept. 1, 2012, whichever occurs earlier.

The ninth plan of development for the Deep Creek unit is due Dec. 31, and Barron said he is extending the expiration date of the eighth plan for the unit to coincide with the discretionary contraction delay, making the ninth plan due the earlier of six months after closing of the sale or Sept. 1, 2012.

Sale announced in July

The sale of Union Oil's Cook Inlet assets was announced July 19. Union Oil Company of California parent Chevron and Hilcorp did not disclose financial terms, but said in a statement that the transaction was expected to close by year end pending customary regulatory approvals.

Assets in the sale include Union Oil contracts and interests in the Granite Point, Middle Ground Shoals, Trading Bay and MacArthur River fields; interests in 10 offshore platforms; interests in onshore gas fields including the Ninilchik unit and the Beluga River unit; and two gas storage facilities.

The sale also includes interests in the Cook Inlet Pipe Line Co. and Kenai Kachemak Pipeline LLC.

Unit formed in 2001

The 20,000-plus acre Deep Creek unit is on the southern Kenai Peninsula, some five miles inland from Ninilchik, and produces natural gas from the Happy Valley participating area in the northern part of the unit. The division and CIRI approved the formation of the unit effective Dec. 31, 2001. Union Oil is 100 percent working interest owner in the unit. The division and CIRI approved formation of the Happy Valley participating Area Nov. 4, 2004.

Alaska Oil and Gas Conservation Commission records show gas production began in 2004; current production is from seven completions.

In its eighth plan of development, submitted in December 2010, Union said it had no plans for any exploration drilling in the unit, but said it planned to continue efforts to farm out southern Deep Creek exploration acreage.

Barron said a ninth plan of development "must provide for the exploration of the unitized area and for the diligent and expeditious drilling necessary for determination of the unit area or areas capable of producing unitized substances in paying quantities in each and every productive formation. The plan must be as complete and adequate as necessary for timely exploration and development of the remaining unit area outside the Happy Valley Participating Area, and must specify the number and locations of any wells to be drilled and the proposed order and time for such drilling."

Several potential accumulations

In a December 2004 decision denying a request by another leaseholder to expand the unit, the division said "Unocal's initial interpretation indicated that the unit area may encompass several potential hydrocarbon accumulations and exploration to date has confirmed the presence of the Happy Valley reservoir in the northern unit area."

The 2004 decision said that since the formation of the Deep Creek unit, the company drilled 10 wells and acquired 105 miles of proprietary seismic data. ConocoPhillips previously acquired five seismic lines over the unit area.

Current Alaska Oil and Gas Conservation Commission records show 13 Happy Valley wells drilled between 2003 and 2009; two of the 13 are showing as suspended.

The division said it "agrees with Unocal's assessment that the Deep Creek Unit may contain multiple accumulations," but said in its 2004 decision that the only confirmed commercial production is from the Happy Valley reservoir.

It said "Unocal's interpretation of the data also indicates a potential accumulation south of the Happy Valley reservoir that Unocal refers to as the Middle Happy Valley Prospect," and said that the company had planned to drill two wells from a new pad to evaluate the prospect, and in March 2004 requested approval of a plan to build a road and construct the Happy Valley Middle Saddle Pad.

Neither the road nor the pad was constructed and no Middle Happy Valley well was drilled. ●

Contact Kristen Nelson at knelson@petroleumnews.com

LAND & LEASING

When is an OCS commitment a commitment?

BSEE publishes appeal decision that agency says clarifies conditions for extending offshore lease term through commitment to produce

By ALAN BAILEY
Petroleum News

As illustrated by a long-standing dispute between the State of Alaska and oil companies over delays in the development of the Point Thomson field on the North Slope, governments expect firms owning oil and gas leases on public lands to actively explore for and develop publicly owned resources. And a recent "notice to lessees" published by the Bureau of Safety and Environmental Enforcement, or BSEE, illustrates something of the federal government's expectations for activity by leaseholders on the federal outer continental shelf.

On Nov. 15 the agency published an appeal decision over a request to extend the terms of some leases in the Gulf of Mexico. The decision will act as guidance over the circumstances under which the term of an OCS lease may be extended, a procedure known as a "suspension of production," BSEE said.

"Suspensions can be granted to leaseholders to extend a lease past the primary term for oil and gas leases on the outer continental shelf," BSEE said. "Typically a lease will have a primary term of five, eight or 10 years, depending on the water depth."

The appeal decision published by BSEE related to three leases owned by ExxonMobil Corp. and Statoil Gulf of Mexico LLC in an area of the Gulf of Mexico known as Walker Ridge.

Due diligence

Under the terms of the Outer Continental Shelf Lands Act, a lessee has the right to explore for, develop and produce oil and gas in an OCS lease, provided that the lessee shows "due diligence" in doing so. If a lessee requests a lease term extension the federal government determines whether the due diligence criterion is being met by assessing what is termed the lessee's "commitment to produce," a criterion that requires the lessee to have completed sufficient exploration and appraisal work within the leased land to enable a decision to proceed to the production of oil and gas.

Apparently, ExxonMobil and Statoil purchased the Walker Ridge leases in June 1998. About three years later the companies abandoned an initial plan to drill into rocks of Miocene age in their leases after exploratory wells in neighboring leases had failed to encounter oil in equivalent rock units. But in December 2006, prompted by some nearby oil discoveries in older and deeper Paleocene rocks, the companies drilled a well into the Paleocene within their Walker Ridge leases and found oil. That well was completed in April 2007, by which time the leases were in the ninth year of their 10-year terms.

In February 2008, with only a few months of life left in the leases, MMS approved lease unitization, with ExxonMobil as operator. At about the same time ExxonMobil started drilling a second well in the new unit, again finding producible oil.

That second well was completed in June 2008. And under federal regulations ExxonMobil had 180 days from that date to apply for an extension of the lease beyond the original lease termination date.

Extension request

In October 2008 the company duly applied for a seven-year lease extension, "to allow for proper development," the appeal decision says. The company said that this timeframe would accommodate a development concept in which production wells from the new unit would be tied back to facilities to be developed by Chevron for some adjacent fields.

However, ExxonMobil's extension application expressed some caution about whether Chevron's development would actually take place. The company said that it was also considering other options for its own field, including the possibility of a standalone development, but that it could not commit to a standalone development using the information that it currently had available.

In February 2009 MMS turned down the application for the lease extension, saying that, because ExxonMobil's plan depended on Chevron's facility development, a development not yet under way and not subject to any form of agreement between the two companies, ExxonMobil's commitment to produce claim was not based on activities within the company's control.

Decision appealed

Following an appeal by ExxonMobil, the Interior Board of Land Appeals, the Department of the Interior's internal land decision review body, subsequently overturned the MMS decision, saying that an agreement between ExxonMobil and Chevron to share the cost of front-end engineering design for shared field facilities demonstrated a commitment to produce. The board also said that MMS had previously granted lease extensions in situations where there was even less evidence for that "commitment to produce" criterion.

In February 2010 MMS asked Robert More, the director of Interior's Office of Hearings and Appeals, to review the board's decision — the board is a section within the Office of Hearings and Appeals. And on May 31 2011, More issued his review decision, upholding the original MMS decision to decline the lease extension. It is this decision that BSEE has now issued as guidance over the circumstances under which lease extensions may be granted.

Lack of commitment

More said that the lack of commitment by ExxonMobil to either a tie-in to the proposed Chevron facility or to a standalone field development demonstrated, at most, a commitment to development, but not the required commitment to produce. Moreover, under federal regulations, the requested lease extension of seven years exceeded a five-year extension limit, he said.

The signing of the agreement between ExxonMobil and Chevron to share the cost of developing the facility engineering design came after the date by which ExxonMobil had to establish a commitment to produce from its unit, More said. And, although by May 2009 MMS had satisfied itself that Chevron was going to build its facility for its fields, at that point ExxonMobil had not come to an agreement with Chevron for the use of that facility, nor had ExxonMobil committed to a standalone development should negotiations with Chevron fail, More said. Under the terms of the Outer Continental Shelf Lands Act, negotiations to use a third-party production facility are not considered to be field development, he said.

More also said that previous MMS decisions over lease extensions did not set a precedent for the decision under appeal. He additionally said that the Interior Board of Land Appeals had erred in not referring the board's decision back to MMS for verification that the decision met the national interest in resource development on public lands.

Agency duty

On Nov. 15, in commenting on the appeal decision, Michael Bromwich, the then director of BSEE, emphasized his agency's duty to ensure appropriate development of public resources.

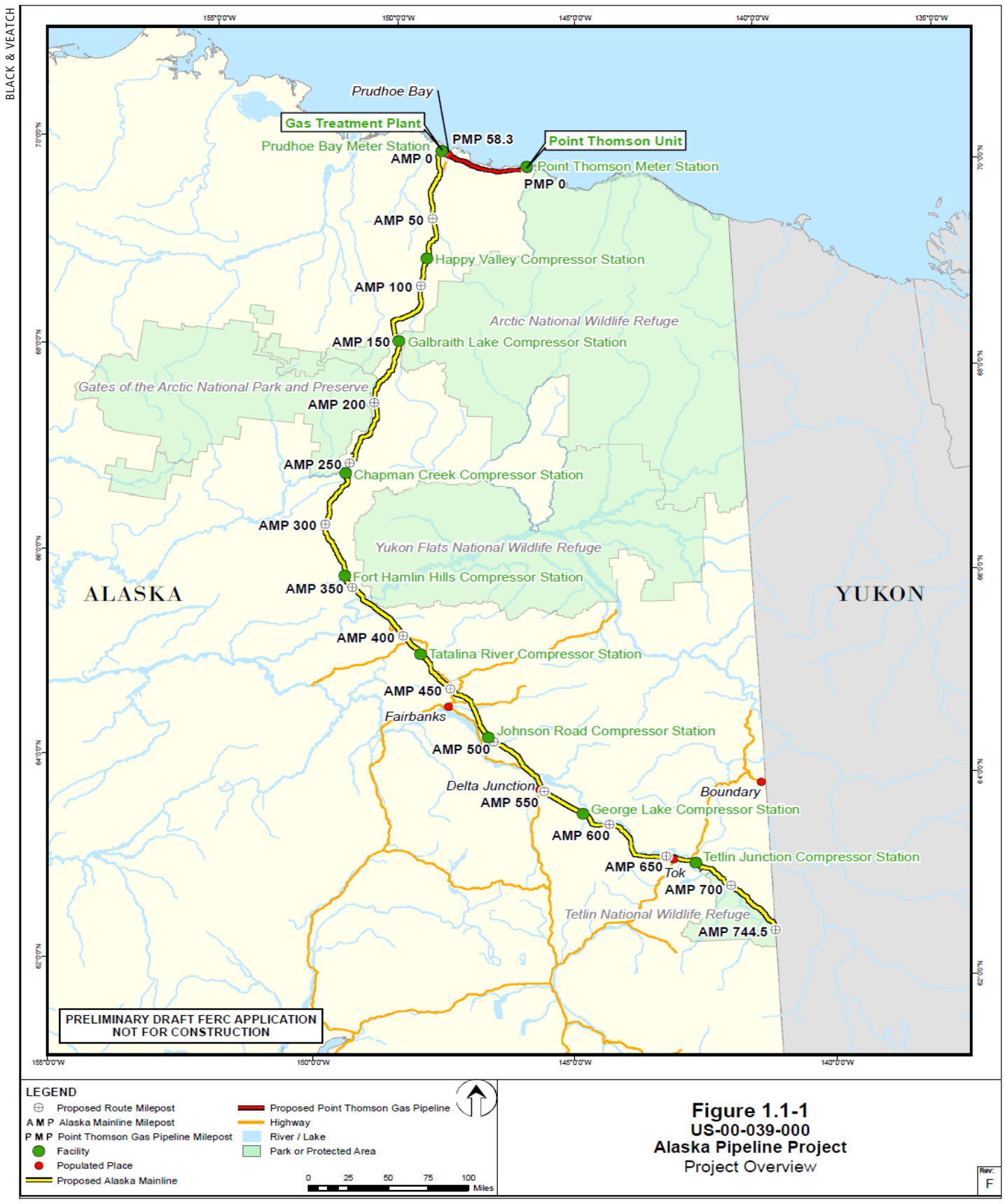
"BSEE takes its responsibilities as trustee of offshore public lands extremely seriously," Bromwich said. "The energy resources that are located on the outer continental shelf belong to all American taxpayers, and BSEE's responsibilities include ensuring that public resources are developed in an expeditious and orderly way. The Office of Hearings and Appeals decision highlighted in this notice to lessees underscores the need for lessees to take concrete steps to develop their holdings in a manner that is consistent with the terms of their lease agreements." ●

Contact Alan Bailey at abailey@petroleumnews.com

• NATURAL GAS

Black & Veatch study recommends stubs

Natural gas off-take stubs would be built as line from Alaska North Slope is built; activated when commercial agreements reached



By KRISTEN NELSON
Petroleum News

A study by Black & Veatch for the Alaska Gas Pipeline Project Office, GPPO, is recommending that the best way to provide local off-take from a large-diameter natural gas pipeline would be to install stubs during construction.

Kurt Gibson, GPPO director, said in a Nov. 28 press release that installing stubs as the line is built would provide gas off-takes that "are both reasonable and adaptable to community needs."

The focus of the Alaska Pipeline Project continues to be a line to commercialize Alaska North Slope natural gas, GPPO said.

Gibson said the Black & Veatch "study identified the possibility of installing stubs at strategic locations along the route that could be activated — 'hot tapped' — at some point in time after completion of a big gas line."

He said that "approach provides flexibility for communities, utilities and other parties interested in accessing natural gas to enter into commercial agreements for obtaining gas on their own schedule."

Capital costs for a community gas off-take system — not including the local distribution system — were in the $150,000 to $200,000 range, per location, with an estimate of $50,000 to $75,000 per year in operation and maintenance costs per location.

Two options considered

The Black & Veatch report said GPPO identified two potential options to facilitate delivery of natural gas to small communities and industry: compressor station side stream and stub gas delivery.

There will be eight compressor stations along the line to maintain gas pressure and they require natural gas at reduced pressures to fuel compressor turbines and other utilities, typically 600 psi compared to the 2,500 psi mainline operating pressure.

Drawing off gas at compressor stations would take advantage of the reduced pressure, but Black & Veatch said it found that "business and regulatory concerns" were likely to make such delivery points unfeasible. Also, such gas would be available only to communities "within a feasible distance to a particular compressor station."

The other option studied, the use of stubs, would include installation of stubs at points on the line identified for off-take during mainline construction.

A small diameter stub piece of pipe "would be welded on and tested during construction of the pipeline. The stub would not have live gas in it and its end location would be marked with a standard pipeline marker for future reference once a commercial agreement has been reached for the community the stub would serve," the report said.

Hot tapping

Once a local community or industry reached a commercial agreement to buy gas, the pipeline would need to be tapped.

"The hot tapping procedure would involve removing the stub cap and securing an isolation valve to the end of the stub. Hot tapping equipment would then be connected to the isolation valve, the

see **PIPELINE STUDY** *page 10*

NATURAL GAS

Europe — a loosening link to oil prices

By BILL WHITE

Researcher/writer for the Office of the Federal Coordinator

In some cases Gazprom is changing the basket of oil prices it uses, often adding spot gas prices to the formula, so gas-compared-to-gas pricing is gaining a toehold over gas-linked-to-oil pricing.

As occurred in Japan, the Arab oil embargo of 1973 hit European utilities between the eyes. The six-month embargo slashed world oil production by about 4 percent. An assertive OPEC pushed a doubling of world oil prices from 1972 to 1975.

Part 3 of 4

Western European demand for oil plunged 23 percent during those years. Europeans wanted new suppliers of energy, and in natural gas they had some good options.

Russia had giant gas fields looking for an export market. Norway had big new discoveries in the North Sea. And Algeria, too, was home to some giant fields.

Gas trading was relatively new in Europe at the time. Belgium, Germany and France were the first to import natural gas, from a major Netherlands field called Groningen discovered in 1959.

In trying to figure out how to price gas to provide a fair return as well as the fortune needed to develop the field and pipelines, the Dutch linked natural gas prices to the prices of substitute fuel oils and insisted on long-term contracts.

Russia, Norway and Algeria adopted that pricing structure for similar reasons, and it persists today for much of Europe's pipeline-gas imports. Those three nations and their handful of mega-fields remain Europe's top source of foreign gas supplies. (Russia, Norway and Algeria were the world's No. 1, 2 and 5 gas exporters last year, joined by Qatar and Canada in the No. 3 and 4 positions, with the Netherlands at No. 6. As for gas pricing in Europe, the United Kingdom gas market is more like North America's than continental Europe's, as will be discussed below.)

The price link to oil in Europe wasn't as iron-clad as in Japan, however. Exporters discounted gas prices to reflect the cost of competing fuels — heavy fuel oil for industry and distillate for power plants, the EIA said. Other notable contract features: the gas destination was locked in to prevent a buyer from diverting gas from a lower-priced market to a higher-priced market the exporter also was serving — blocking unwanted competition — and the gas price could get renegotiated periodically.

Since the pivotal economic year of 2008, this decades-long system has been under attack by gas buyers.

The oil-gas price link

With oil prices currently near historic highs and the local economies wobbly, many European gas buyers are demanding price relief. They're aiming their frustrations at Russia's Gazprom, whose pipelines dominate the European gas trade.

The big European gas buyers are playing tough. To show Gazprom they mean business, they have boosted their spot and short-term buys of LNG, often for lower prices than the pipeline gas. They've got a motivated LNG exporter in Qatar, which has far more capacity to make LNG than it has buyers. Qatar will negotiate its LNG price. Last year, Qatar sent some 40 percent of its LNG to Europe.

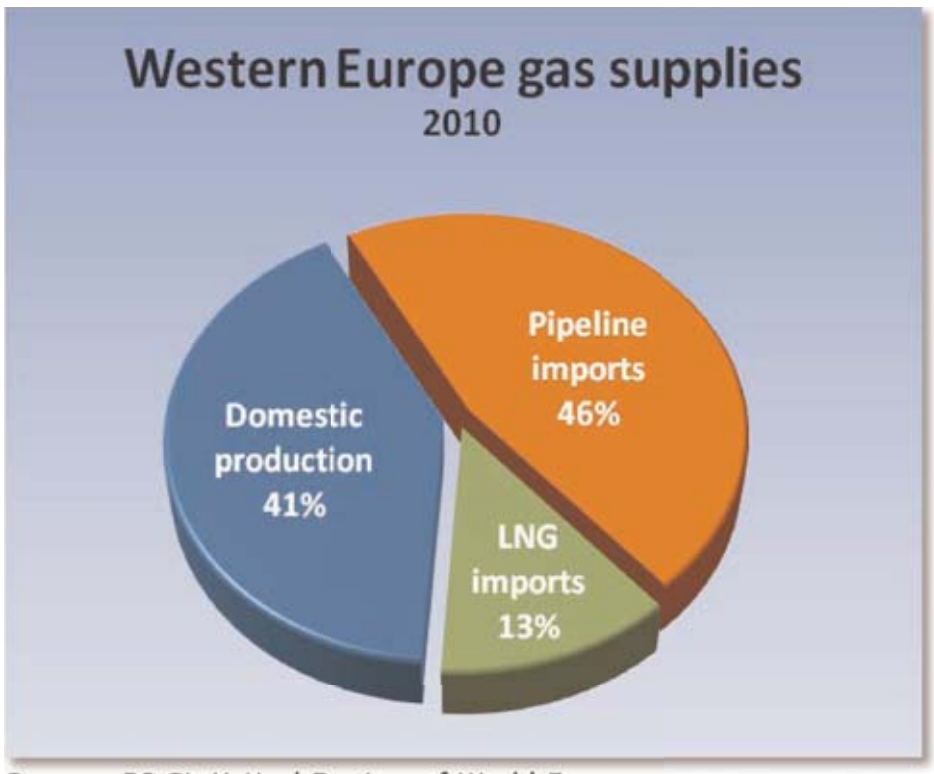
(Qatar gas sold for $15 to $16 per million Btu in East Asia in June, while selling for $9 to $12 in Europe that month and $4.25 in Texas, according to Argus.)

European imports of LNG grew by 26 percent last year, while pipeline-gas imports from Russia fell by 2 percent, the EIA said.

Gazprom is not powerless in this fight — long-term supply contracts are a potent weapon.

But Gazprom doesn't want to jeopardize its European market share, which underpins its export business.

see EUROPE'S OIL LINK page 11



Source: BP Statistical Review of World Energy

OFFICE OF THE FEDERAL COORDINATOR

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George Schmidt Memorial Raffle & Silent Auction to benefit Alaska Resource Education
Grand Prize - HOLLAND AMERICA CRUISE FOR TWO - Won by: Glynis Smith
RUNNER UP PRIZE - $500 CASH - Won by: Gene Pool

Drawing was at the conslusion of the Alaska Miners Association Convention Banquet on November 11, 2011

Roundtrip for 2 ANC-FBX
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Ten Car Washes
Donated by: Alaska Laser Wash
Won by: Sarah Whicker

Gift Basket
Donated by: Great Harvest Bread Co.
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Caribou Framed art - Artist is N. Gates
Donated by: Two Friends Gallery
Won by: Fraser Adams

.15 Troy Ounce Gold Nugget & Diamond Pendant & Earrings
Donated by: Oxford Assaying & Refining Corp.
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Donated by: Construction Machinery Industrial(CMI)
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Native Doll - Seal Gut Lady with Fishing Pole by Ursula Daniyak-Ir
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Won by: Holly Morris

Dowland-Bach Stainless Multi Tool
Donated by: Dowland-Bach
Won by: Paul Axelson

Santa Jingle Bell Rock(Retired Collectors Piece)
Donated by: Anonymous
Won by: Bill Cole

Antique Mining Scale and tour of Big Nugget Mine
Donated by: Big Nugget Mine/Parker Schnabel
Won by: Chris Gerondale

Logo Gear and Dry Bag
Donated by: TOTE
Won by: Jeff Norberg, Meg Day

Eagle Carved Antler
Donated by: Austin Powder
Won by: Bartly Kleven

Two Tractor Models
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Logo Apparel
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Replica Models
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Won by: Stan Foo, Traci Hekekey, Bill Cole

Alaska Railroad 5th Anniv. Framed Art
Donated by: Brenntag Pacific, Inc.
Won by: Tom Buntson

Four Day Passes
Donated by: Hilltop Ski Area
Won by: Sarah Whicker

Barbara Lavalee Print
Donated by: Artique
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Two tickets to Sea Life Center
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Won by: Stan Foo

Alaska Resouce Kit Speciman
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Corporate Luncheon for Eight
Donated by: Impressions Catering at ESS
Won by: Johanne Whalen

Lg.Hand Made-Birch Basket by Mersy Cleveland
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Won by: Fred Parady

32" Decorated Pre-Lit Christmas Tree
Donated by: Anonymous
Won by: Deedre Nicola, Louise Hall, Jerilee Musgrove

Volvo Loader Concept Model
Donated by: Construction Machinery Industrial (CMI)
Won by: Ryan Eiden

Banana Splits for 4
Donated by: Tastee Freeze
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Volvo Truck Concept Model
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Sm.Hand made Basket by Mersy Cleveland
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Hunters Basket
Donated by: Frontier Supply
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John Van Zyle Painting "Chickadee"
Donated by: Marathon Oil
Won by: Louise Hall

Jacket & Vest
Donated by: Gold Canyon Mining
Won by: Trisha Wooley

Replica Models
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Framed Watercolor - Native Woman
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AGU Newsletter/Corrected Issue
Donated by: Jim/Charlotte Barker
Won by: Gail Phillips

OUT CRY AUCTION ITEM WINNERS!

.625 Troy Ounce Gold Nugget
Donated by: Roger and DeLois Burgraff
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Tour for Two of Greens Creek
Donated by: Hecla Greens Creek Mining
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Airfare for 2 and 5 days at condo Kauai, HI
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15" Drum &Beater by Caroline Hendrixson (Haida)
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Won by: Bill Burnett

Fly-in Fishing Trip to Craig AK
Donated by: Construction Machinery Industrial (CMI)
Won by: Terry Williams

Tour for Two of Pebble
Donated by: Pebble Partnership
Won by: Joe Perkins

Ride in a Haul Truck and Tour of Usibelli
Donated by: Usibelli Coal Mine
Won by: Sarah Whicker

Proceeds benefited Alaska Resource Education, a 501©(3) non-profit whose mission is to educate students about Alaska's natural resources.
www.akresource.org

Thank you!

continued from page 8

PIPELINE STUDY

valve would be opened, and the pipeline would be tapped whilst in operation. With the isolation of the valve and removal of the hot tapping equipment, the gas delivery location would be ready for service," the Black & Veatch report said.

The stub would have to be extended and a metering/regulating station installed, consisting of three sections where the pressure would be reduced in three steps from the 2,500 psi on the mainline to an outlet range of 125-300 psi.

Four stages of gas heating would also be required.

Black & Veatch said the metering/regulating sections would be prefabricated offsite and installed once the site has been prepared.

The estimated cost for the metering/regulating station of $150,000 to $200,000 is based on discussions with equipment suppliers, prefabricators and contractors who build equipment, the report said. The estimate is also based on the assumption that several metering/regulating stations are built at the same time, "and does not include any line items for the stub, hot tapping operations or the distribution system downstream of the M/R station," Black & Veatch said.

Heating value issue

The report said that in addition to the difference between the mainline operating pressure and gas pressures needed for local distribution, the mainline gas "will likely have a heating value higher than what is typically delivered to residential customers."

Based on available gas analysis provided under the Alaska Gasline Inducement Act, Black & Veatch said "The gas specification proposed for transmission in the pipeline is relatively uncommon in a number of its characteristics, namely the high calorific value of the gas and its low water content." AGIA included "rich" and "lean" gas cases, with the rich gas having a heating value of 1,118 British thermal units per cubic foot and the lean case having a heating value of 1,067 Btu.

Black & Veatch said parts of gas systems in Alberta, Canada, and in the eastern United States, have Btu content ranging from 1,000 to 1,110 Btu per cubic foot without "significant issues" related to the high Btu content.

Black & Veatch also looked at volumes of potential gas usage by communities along the pipeline in Northern Economics' "In State Gas Demand Study," and estimated that the majority of communities along the pipeline (Wiseman, Coldfoot, Stevens Village, Harding-Birch Lakes, Dot Lake, Tok/Tanacross/Tetlin, Northway Junction/Northway Village, Paxson, Gakona, Gulkana, Glennallen, Copper Center, Willow Creek and Tonsina) would have average usage of less than 1 million cubic feet per day. Big Delta, Delta Junction and Deltana are estimated at 1 million cubic feet per day. Valdez is estimated at 7 million cubic feet per day and Livengood at 9 million cubic feet per day.

Black & Veatch said it anticipates "that the small diameter stub size will allow for sufficient gas supply volumes for all potential delivery point sites except for Fairbanks or Anchorage." ●

Contact Kristen Nelson at knelson@petroleumnews.com

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EUROPE'S OIL LINK

In some cases Gazprom is changing the basket of oil prices it uses, often adding spot gas prices to the formula, so gas-compared-to-gas pricing is gaining a toehold over gas-linked-to-oil pricing. Usually, the new price is good for a fixed period, such as two or three years. This suits the buyers, who know that oil prices can fall as well as rise.

European buyers also are playing tough with LNG suppliers, not only by sometimes getting better prices than they pay for pipeline gas. Supply contracts are shorter — five to 10 years instead of perhaps 25-year terms from a few years ago. And new language is letting buyers divert cargos to other markets — such as the premium-priced Japan spot market in 2011.

It's unclear how loose the oil-price link will become for continental Europe gas prices. But Norway recently "switched as much as 30 percent of their contracted volumes to spot-market pricing," the EIA said.

The British difference

Natural gas pricing in the United Kingdom is different from pricing on the continent.

Natural gas is the top fuel source in Great Britain, while in many European countries gas is a mere sidekick to oil as an energy source — in Germany gas was No. 3 behind oil and coal last year.

Like North America, the gas market in the U.K. developed over the past several decades based on its own gas reserves, often from small to medium-sized fields, not imports. That is different from continental Europe's high dependence on imports from giant fields, according to the Energy Charter Secretariat, a group that upholds international laws to ensure the smooth flow of energy between exporters and importers.

Further, Great Britain began liberalizing its markets in the 1980s, while continental Europe is still deregulating its energy markets.

The nation even developed a hypothetical trading hub called the National Balancing Point, through which gas in the country must "pass." NBP is akin to the Henry Hub in the United States, an actual trading hub, and the NBP price is typically cited in lists of European gas prices. An active futures market tied to the NBP also helped Great Britain separate itself somewhat from the rest of Europe on natural gas pricing.

During the peak years of Britain's North Sea production, some gas was dirt cheap, creating another departure from the continent's oil-linked gas prices. This cheap gas came up wells with oil or valuable gas condensate. Because gas flaring was not allowed and gas injection sometimes wasn't cost-effective, producers discounted the gas just to get rid of it — just as occurred in Alaska's Cook Inlet during the 1960s and 1970s, the early years of production there.

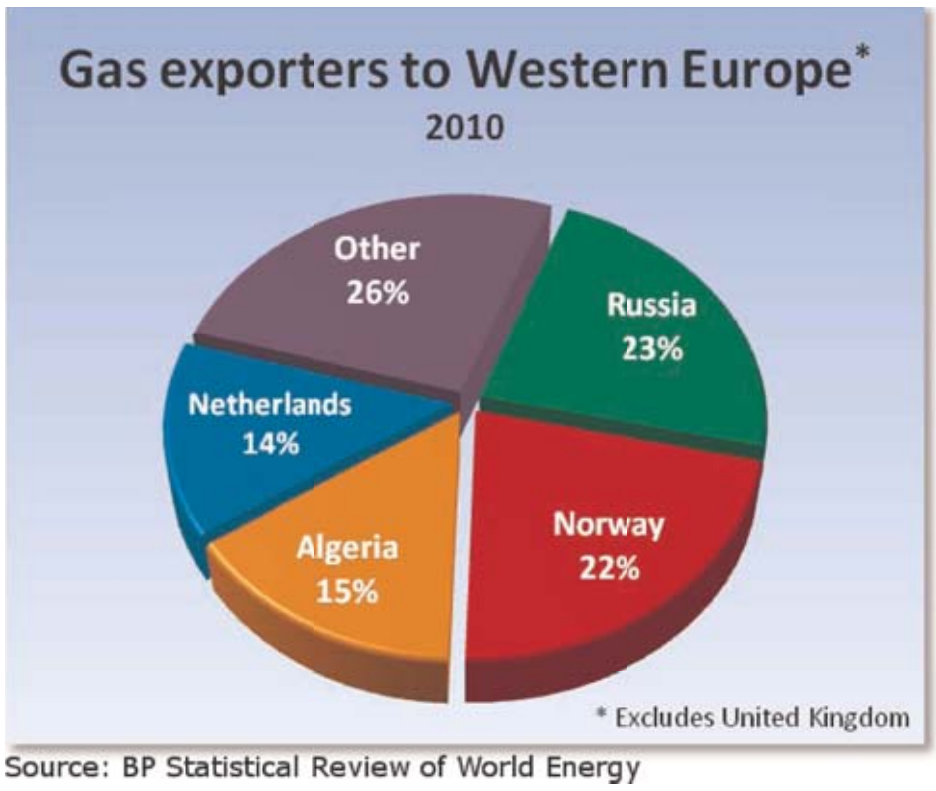
All this let U.K. price its gas based on supply and demand within the country, not oil prices. The continent's oil-linked prices did influence U.K. gas prices, however, because excess British production was exported.

But those exports have ended. Great Britain hasn't been self-sufficient in natural gas since 2003. The U.K.'s gas production plunged 45 percent from 2003 through last year, while gas consumption dipped 2 percent.

As a result, British utilities and other gas consumers import some gas, mainly via pipeline from Norway's North Sea fields, but also via pipeline from the Netherlands, especially during winter. This means the nation's gas price is not completely divorced from the long-term, oil-linked-pricing contracts found on the continent. But the NBP price usually is a little lower than prices found on the continent.

Last year, the U.K. also was officially Europe's No. 2 LNG importer, behind Spain. But much of the LNG gas landed in the U.K. was then piped to the continent — with Britain's well-developed gas infrastructure and better-developed gas trading markets a catalyst for delivering the LNG there rather than elsewhere in Europe. (Russia's Gazprom is a minority investor in one pipeline connecting Britain to the continent.)

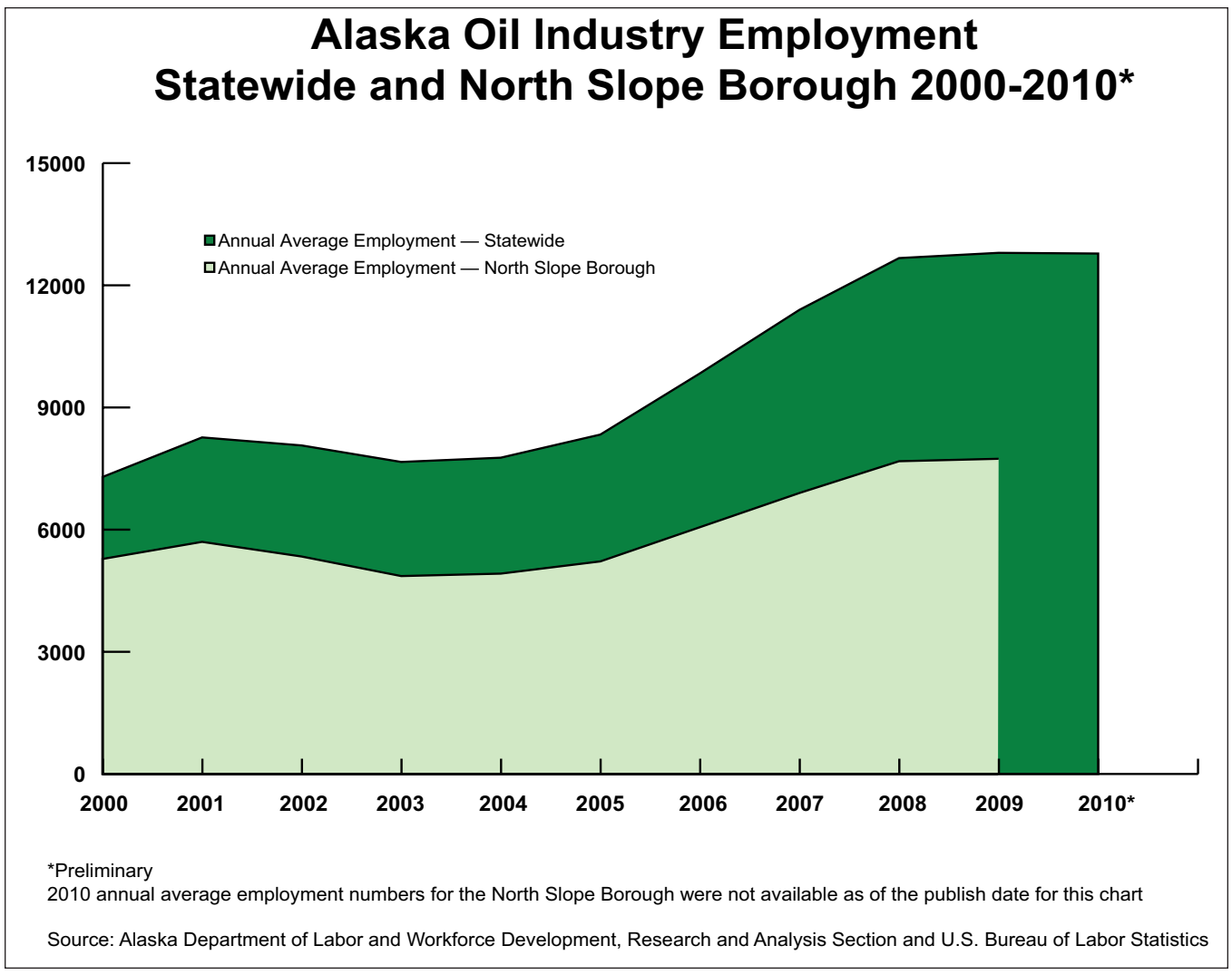
Editor's note: This is a reprint from the Office of the Federal Coordinator, Alaska Natural Gas Transportation Projects, online at www.arcticgas.gov/print/Europe-a-loosening-link-to-oil-prices.



Source: BP Statistical Review of World Energy

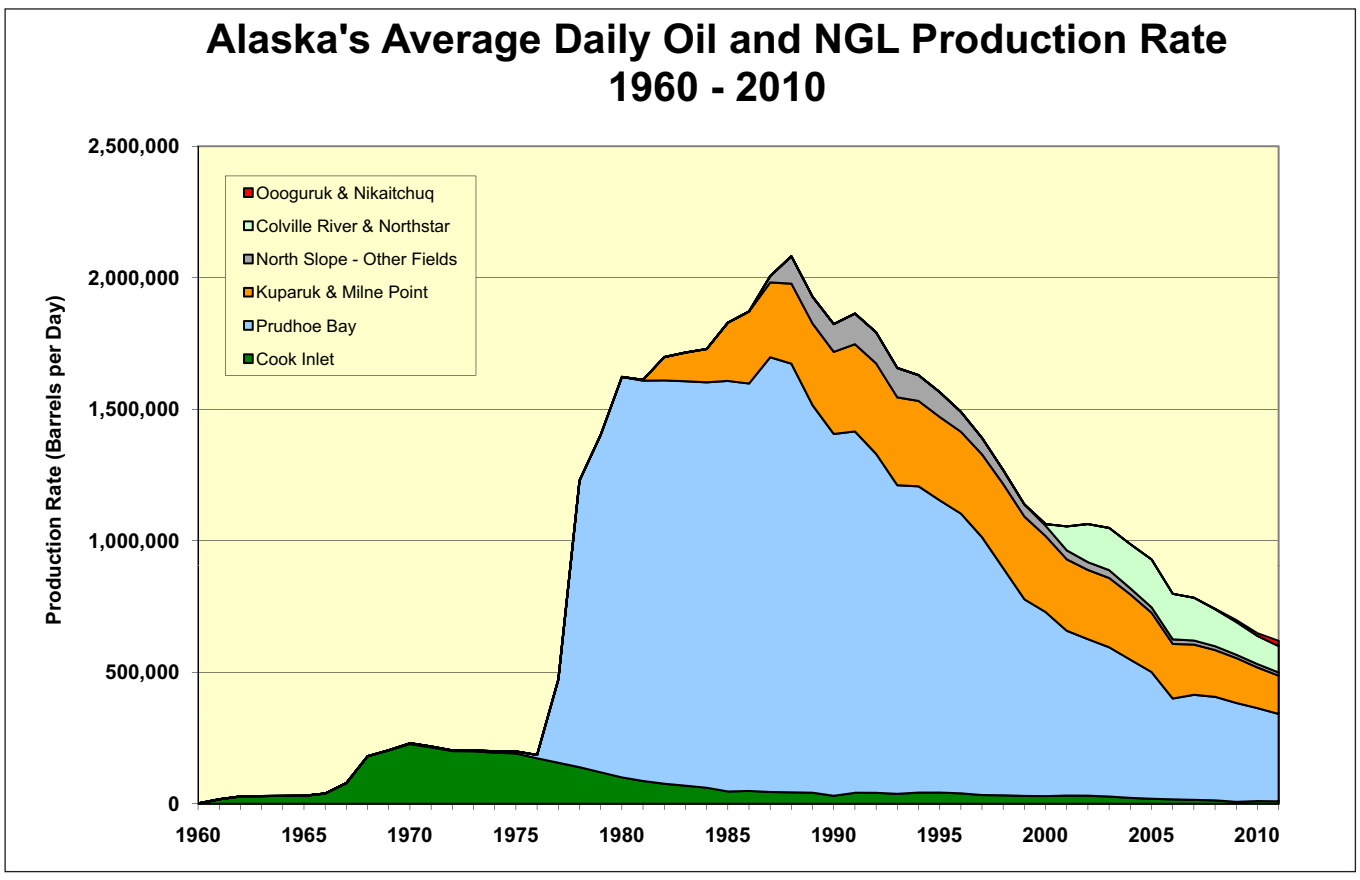
OFFICE OF THE FEDERALCOORDINATOR

Alaska Statistics



*Preliminary
2010 annual average employment numbers for the North Slope Borough were not available as of the publish date for this chart

Source: Alaska Department of Labor and Workforce Development, Research and Analysis Section and U.S. Bureau of Labor Statistics



PREPARED BY STEVE DAVIES OF THE ALASKA OIL AND GAS CONSERVATION COMMISSION

Petroleum News will be reproducing this standalone chart from the Alaska Oil and Gas Conservation Commission on a regular basis because of the interest in the decline in Alaska's oil production.

● FINANCE & ECONOMY

BP Alaska involved in big EPA settlement

Subsidiaries agree to pay $426,500 penalty, arrange 'financial assurance' to close and clean up contaminated industrial sites

By WESLEY LOY
For Petroleum News

BP Exploration (Alaska) Inc. is among several subsidiaries of BP America Inc. involved in a complex, multistate settlement of "financial assurance" violations with the U.S. Environmental Protection Agency.

"Financial assurance protects taxpayers from having to foot the bill for costly cleanups," Cynthia Giles, assistant administrator for the EPA's Office of Enforcement and Compliance Assurance, said in a Nov. 29 press release out of Washington, D.C.

Under the settlement, BP has lined up financial assurance such as letters of credit, insurance policies and other forms of coverage, the EPA said.

The EPA determined that BP Alaska, BP Products North America Inc., BP West Coast Products LLC, BP Corporation North America Inc. and Atlantic Richfield Co. had inadequate finance assurance.

The settlement "will ensure that BP's subsidiaries have the funds available to cover any necessary cleanup costs," Giles said.

Terms of settlement

The settlement covers hazardous waste facilities and Superfund sites in eight Lower 48 states, plus 10 "non-hazardous waste underground injection control (UIC) wells" on Alaska's North Slope.

The BP subsidiaries have agreed to pay a $426,500 penalty and ensure that more than $240 million in funds are secured to resolve violations of hazardous waste, drinking water and Superfund financial assurance requirements, the EPA press release said.

Under the settlement, BP has lined up financial assurance such as letters of credit, insurance policies and other forms of coverage, the EPA said.

In Alaska, the 10 injection wells were subject to financial assurance requirements under the Safe Drinking Water Act.

BP has provided assurances of $19.2 million to address the closure, plugging and abandonment of the UIC wells, the EPA said.

BP also had inadequate financial assurance coverage for facilities, including the wells, for which the states have primary enforcement responsibility, the agency said.

"EPA worked with its state partners to obtain from BP a total of $76.4 million in compliant financial assurance coverage for these obligations," the EPA said.

Petroleum News on Nov. 29 asked BP for additional information on the alleged Alaska violations, including the field location and function of the injection wells.

BP Alaska uses the injection wells "to dispose of non-hazardous waste at remote oil field sites at Prudhoe Bay, Badami, Northstar, Milne Point and the Duck Island/Liberty project," BP spokesman Scott Dean said by email. "Most of the injected fluids are brine, which is produced when oil and gas are extracted from the field."●

Contact Wesley Loy at wloy@petroleumnews.com

● EXPLORATION & PRODUCTION

November production up 6% from October

By KRISTEN NELSON
Petroleum News

Alaska North Slope production averaged 624,687 barrels per day in November, up 6.2 percent from an October average of 588,287, according to figures based on pipeline receipts as reported by the Alaska Department of Revenue's Tax Division.

The BP Exploration (Alaska)-operated Prudhoe Bay field had the largest increase, 11.1 percent, averaging 361,656 bpd compared to 325,502 bpd in October.

October production figures for Prudhoe Bay as reported by Petroleum News in early November have been adjusted by adding production from Milne Point and Northstar. Beginning with November, Revenue is reporting Milne Point and Northstar as part of Prudhoe Bay. Previously Prudhoe Bay production figures included only Prudhoe Bay and its satellite fields, Aurora, Borealis, Midnight Sun, Orion and Polaris.

The BP-operated Lisburne field had the second-largest month-over-month production increase, 7.2 percent, averaging

see **PRODUCTION** *page 15*

EXPLORATION & PRODUCTION

Corps public notices Thomson application

Comments due Jan. 3 on ExxonMobil proposal for facilities, pipeline project; construction projected to begin winter of 2012-13

By KRISTEN NELSON
Petroleum News

The Alaska District of the U.S. Army Corps of Engineers has public noticed an application from Exxon Mobil Corp. and PTE Pipeline LLC for Point Thomson project development. The proposed work in federal waters at Point Thomson, some 60 miles east of Prudhoe Bay and 60 miles west of Kaktovik, would initiate commercial hydrocarbon production and delineate and evaluate hydrocarbon resources in the Point Thomson area.

Three gravel pads, an export pipeline, an airstrip, mine site and support pad are proposed, the corps said in a Nov. 18 public notice; comments are due on the proposal Jan. 3, which is also the closing date for comments on the draft environmental impact statement which was released for public comment in mid-November.

The corps said it will prepare a final EIS after the close of the draft EIS public comment period in response to comments received and will make a permit decision after the final EIS has been published.

A record of decision will describe its decision on the permit application.

The draft EIS analyzes environmental impacts of the project proposed by the applicant, and compares that proposal and three other alternatives to the human and environmental impacts associated with the no action alternative.

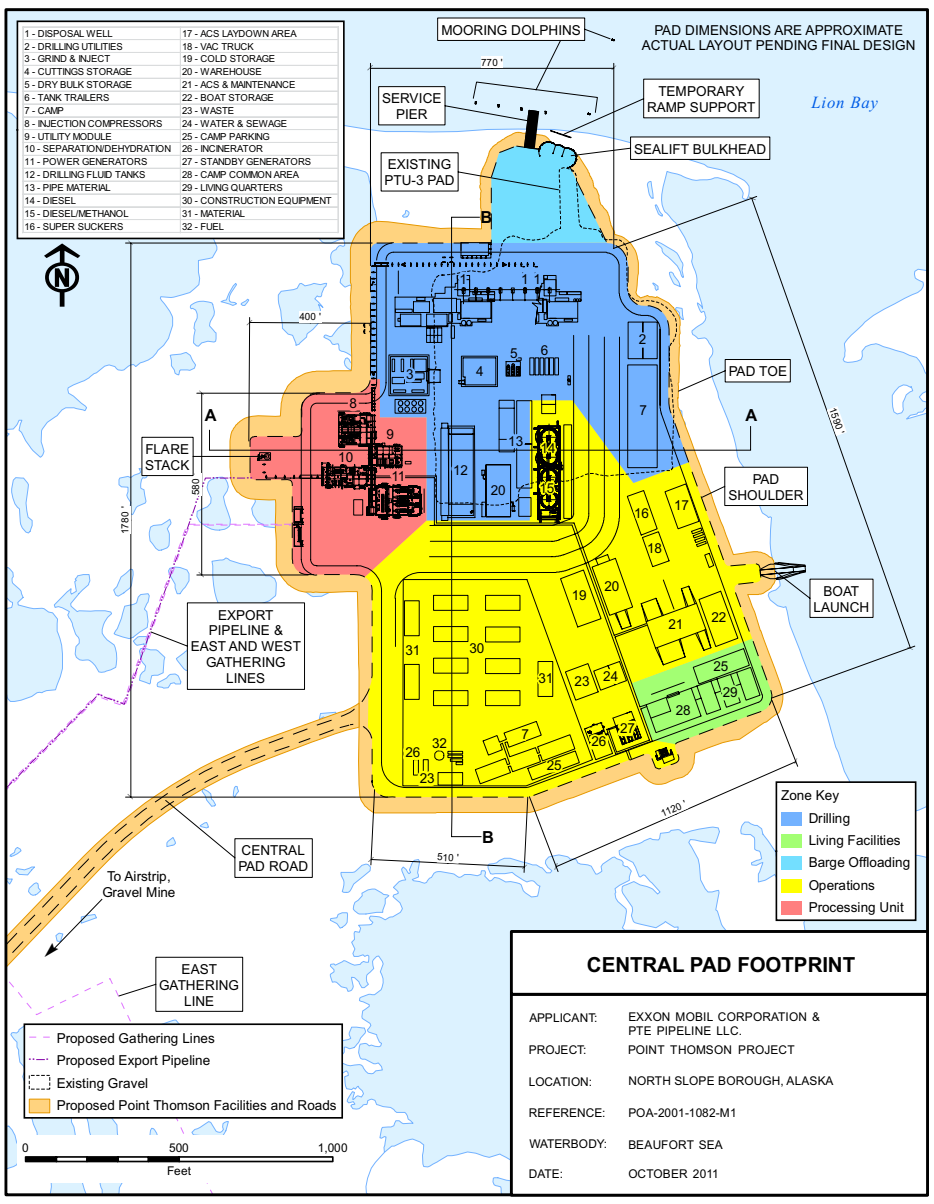
Wetland fill

The corps said that the total acreage of wetland fill for the project as proposed by ExxonMobil would be approximately 267.5 acres, and would include gravel for drilling-production pads and connecting roads, airstrip, gravel mine and overburden replacement, vertical support members for in-field pipeline and export pipeline and pilings for a proposed barge offloading facility and service pier. The fill material would come from a new mine site approximately 2.5 miles inland.

The project would include three gravel pads, five development wells, infield gathering lines, 12 miles of infield gravel roads, a 5,600-foot airstrip, a gravel mine, processing facilities and support infrastructure and a sales oil pipeline to Badami.

Two of the wells were drilled in 2009-10 from the existing central pad and did not require new fill.

Long-reach directional drilling will be used to develop the primarily offshore Thomson Sand reservoir from onshore pads near the coast.



U.S. ARMY CORPS OF ENGINEERS

The central pad (56 acres including 13.2 acres of existing fill) involves expansion of the existing Point Thomson Unit No. 3 pad. Processing facilities at the central pad would separate hydrocarbon liquids from natural gas, re-inject the gas and stabilize liquid hydrocarbons for transport in the Point Thomson export pipeline.

The west pad, approximately 19 acres, would be a new pad 4 miles west of the central pad; the east pad would connect a new 11-acre pad on the coast to the existing 4.6-acre North Staines River No. 1

see **THOMSON APPLICATION** *page 14*

continued from page 4

INLET ENERGY

production was up to 400 percent of what it was when it was shut-in.

Wilcox said the company has continued to optimize wells at its onshore properties.

It took longer to get the Osprey platform back into operation, but first oil came off the platform in June, he said. With a $100 million credit facility work began on a big rig for the Osprey platform so the company could begin drilling sidetracks from the platform and increase production. About a third of that rig is now in Nikiski, Wilcox said, and work will begin on the platform in the next few months.

Cook Inlet Energy is also building a small rig on the west side that will be truck mounted and "should be just an ideal rig for drilling gas on the west side."

The company is "getting set up to execute our second phase of development on the Osprey platform" with the new rig, is continuing to optimize production from existing wells and continuing to exploit oil and gas reserves near its facilities, Wilcox said.

Enstar, CINGSA

John Sims, director of corporate communications for Cook Inlet Natural Gas Storage Alaska and Enstar Natural Gas, told the RDC audience that while Enstar is "very cautiously optimistic about all the activities going on here in Cook Inlet," it has concerns until it has a contract for gas delivery before the Regulatory Commission of Alaska.

Semco Energy, Enstar's parent company, and MidAmerican LLC, partners in Cook Inlet Natural Gas Storage Alaska, or CINGSA, were joined in October by First Alaska and Cook Inlet Region Inc., Sims said.

The five injection-withdrawal wells are being drilled for the storage project, with the project on schedule and slightly under budget. The first well cost about $7 million and the second two came in at about $5 million each, prior to perforating.

The middle three wells, technically the easiest, were drilled first, Sims said. It has taken about 30 days per well, with about half of that time required to move the rig. The wells should be completed by February.

With four customers for storage capacity — Enstar, Chugach Electric Association, ML&P and Homer Electric coming in later — CINGSA is at 11 percent capacity for the 11 billion cubic feet of gas storage.

JUDY PATRICK

JOHN SIMS

There is expansion capacity at the facility and Sims said expansion will be "dependent on performance and also the market demand."

Having storage, which will be available for withdrawal in the winter of 2012-13, helps with swing demand in the winter, he said, helps producers with production in the summer when gas is injected and acts as an insurance policy should there be equipment failure.

Asked whether with successful gas exploration and storage the utilities will still need LNG, Sims said, "storage isn't the savior for Cook Inlet by any means; it's a part of the puzzle."

"Another piece involves the additional exploration and development that we're seeing."

But, he said, Enstar and the utilities are still evaluating the LNG option, "not just for gasifying going forward put also for an insurance policy."

And, he said, "until we actually have those contracts that erase that need, it's something that we're still going to have to move forward with."

Cook Inlet Region Inc.

Ethan Schutt, senior vice president, land and energy development, for Cook Inlet Region Inc., said the Fire Island wind project has regulatory approval for contracts from the Regulatory Commission of Alaska.

Financing for the project needs to be closed, "so that we can move into project construction in April," he said, adding that the project has all its permits.

CIRI is also working on an underground coal gasification or UCG project.

The Cook Inlet basin has a "world-class coal resource that's really never been exploited at a commercial level," Schutt said.

CIRI has been working on UCG for almost three years, he said, and to date has "drilled 13 stratigraphic core holes to test both the geology and the resource," and collected a suite of oil and gas type data during that program, "so we have a pretty robust data set from that site, a place just north of the Beluga River on the north side of Cook Inlet on CIRI surface and subsurface land."

The data has been incorporated into a geological model.

CIRI is currently shooting some eight and a half line miles of "shallow high-resolution 2-D … to tie together all the data points that we collected with the drilling program and enhance our data set as we move towards a … characterization program to begin sometime in 2012."

The project represents some 300-plus million tons of coal, Schutt said, "the equivalent of more than 4 (trillion cubic feet) of natural gas on an energy basis, so just in our little site we have quite a world-class resource in that coal." ●

Contact Kristen Nelson
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THOMSON APPLICATION

exploration pad. The existing pad at the east pad location would be used for temporarily staging equipment and camps during drilling.

Beginning in 2012-13

The corps said construction activities are proposed to begin in the winter of 2012-13 and be completed by the winter of 2015-16, with civil construction — including gravel placement and gravel mining — to be conducted mainly in the winters of 2012-13 and 2013-14.

Production infrastructure construction would begin in early 2013 and be completed in the winter of 2015-16, with large processing modules arriving by sealift in the summer of 2015.

Drilling would begin in early 2015 and be completed in early 2017.

Facility module installation, commissioning and startup are planned for 2015 and early 2016.

The common carrier export pipeline would be subject to Federal Energy Regulatory Commission regulation. The 22-mile 12-inch diameter line would take processed liquid hydrocarbons from the central processing facility to a connection with the sale oil pipeline at the Badami facility. ●

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LAND & LEASING

Trio secures Newfoundland parcels

Offshore Newfoundland and Labrador has received a strong vote of confidence from a trio of international companies which has committed to spending C$348 million exploring two parcels.

The Canada-Newfoundland and Labrador Offshore Petroleum Board said Norway's Statoil, Spain's Repsol and U.S.-based Chevron made successful bids of C$202 million for one 610,300-acre block in the Flemish Pass/North Central Ridge and C$146 million for a nearby 461,300 acres.

The bids represent the amount of money the companies plan to spend on exploration.

Statoil will operate both blocks with a 50 percent stake; Chevron will hold 40 percent and Repsol 10 percent.

Among other offerings in the call for bids, privately held Ptarmigan Energy secured rights to two parcels, covering a combined 875,000 acres, off Newfoundland's west coast for C$2 million.

2009 discovery at Mizzen

The Flemish Pass license is adjacent to Statoil's Mizzen discovery that was drilled in 2009, with Husky Energy as a 35 percent partner, although the company has kept a tight lid on information about the well.

It said only that "hydrocarbons were encountered" during deepwater drilling about 300 miles east-northeast of St. John's, the capital of Newfoundland, and would not indicate whether the find was oil or natural gas.

A company spokesman said it would take at least two years to analyze the data and decide whether to conduct appraisal drilling.

He said that if reserves would support a commercial operation it could take another 10 or 15 years before development and production was possible.

Statoil is already involved in the province's producing Hibernia and Terra Nova fields and is a partner in the Hebron project that is moving towards production.

The Flemish Pass area has been only lightly explored, but has been rated as a potentially import frontier.

—GARY PARK

PIPELINES & DOWNSTREAM

Evaluation of VMT remote control planned

An oil industry watchdog organization wants to study how remote control operations are working at the tanker terminal in Valdez.

The Prince William Sound Regional Citizens' Advisory Council says it intends to hire a consultant by Dec. 15 to conduct the study.

The consultant will examine such questions as whether Anchorage-based controllers of assets at the Valdez Marine Terminal, or VMT, are "properly trained," says a council request for proposals.

The terminal is where tankers pick up Alaska North Slope crude oil for delivery to West Coast refineries. Alyeska Pipeline Service Co., an energy company consortium headquartered in Anchorage, operates the terminal, which sits at the southern end of the 800-mile trans-Alaska pipeline.

The VMT is a massive complex of oil storage tanks, ship piers and loading arms.

Remote operations centers

The pipeline and Valdez terminal have been in operation since 1977.

The facilities previously were run from a control center in Valdez. In 2007 and 2008, Alyeska established two new centers, the main one in Anchorage and a backup in Palmer, and shifted to remote control operations.

Alyeska said at the time it was an efficiency move made possible by such technological advances as high-speed Internet and fiber optics.

The citizens' council, a congressionally sanctioned and industry-funded nonprofit established after the Exxon Valdez oil spill, said its consultant will assess the capability of remote controllers to "reliably control operations at the VMT or to appropriately interface with local controllers at the VMT."

Specifically, the consultant will identify which VMT assets are subject to remote control and which are under local control; review whether Anchorage-based controllers are properly trained; verify the extent to which redundancy of communications exists for VMT control; assess the likelihood that damage to communications could affect Alyeska's ability to control the terminal; assess whether remote control provides the same level of VMT control as when the operations center was located in Valdez; and verify the extent to which Alyeska can control the VMT from Anchorage without "environmental incident."

The consultant's final report will be due Aug. 15, 2012.

The citizens' council is charged with oversight of the marine terminal and associated tankers; it does not have oversight over the length of the pipeline.

—WESLEY LOY

continued from page 12

PRODUCTION

33,259 bpd in November compared to 31,041 bpd in October. Lisburne includes production from Point McIntyre and Niakuk.

The BP-operated Endicott field also saw an increase in month-over-month production, up 1.1 percent to 12,024 bpd in November from 11,893 bpd in October. Endicott production includes the Savant-operated Badami field.

Kuparuk, Alpine down

The ConocoPhillips Alaska-operated Kuparuk River field averaged 137,038 bpd in November, down 0.5 percent from an October average of 137,657. Kuparuk includes production from Meltwater, Tabasco, Tarn and West Sak, as well as from the Eni-operated Nikaitchuq field and the Pioneer Natural Resources Alaska-operated Oooguruk field.

The Alaska Oil and Gas Conservation Commission reports production by field and pool, but that data is only available on a delayed basis. AOGCC October data for Nikaitchuq shows 185,118 barrels for the month, an average of 5,972 bpd, and a total of 194,878 barrels for Oooguruk, an average of 6,286 bpd.

November production from the ConocoPhillips-operated Alpine field averaged 80,710 bpd, down 1.8 percent from an October average of 82,194 bpd. Alpine includes satellite production from Fiord, Nanuq and Qannik.

AOGCC October production figures for Cook Inlet show a total of 335,780 barrels, an average of 10,832 bpd. Production comes from Beaver Creek (4,432 barrels), Granite Point (62,479 barrels), McArthur River (121,421 barrels), Middle Ground Shoal (73,604 barrels), Redoubt Shoal (10,997 barrels), Swanson River (16,142 barrels), Trading Bay (15,407 barrels) and West McArthur River (31,298 barrels). ANS crude oil production peaked in 1988 at 2.1 million bpd; Cook Inlet crude oil production peaked in 1970 at more than 227,000 bpd. ●

Contact Kristen Nelson at knelson@petroleumnews.com

Petroleum news

Oil Patch Bits

Crowley sells CATCO All-Terrain vehicle assets to Peak

Crowley Maritime Corp. said Nov. 29 that it has sold its fleet of company-owned CATCO® Arctic All-Terrain vehicles and related assets, including a warehouse and office facility in Deadhorse, Alaska, to Peak Oilfield Services Co.

COURTESY CROWLEY

Though the sale ends nearly 40 years of Crowley-provided specialized tundra transportation services, the company remains committed to providing tug and barge transportation and project management services for North Slope producers.

"Crowley has enjoyed a long successful history with our CATCO operations on the North Slope, starting in 1972," said Crowley's Craig Tornga, vice president of Crowley's solutions group. "We've used these specialized assets to support North Slope exploration with remote off-road arctic transportation and construction of ice islands and ice roads. The CATCO assets were not a part of our long-term business plans to offer marine services and project solutions. We will continue to offer these specialized services to our customers as we have since the early days of Prudhoe Bay development."

Since 1953, Crowley has provided various marine, petroleum distribution and energy support services in Alaska — from the North Slope to Southcentral Alaska and both coastal and inland communities, including those along the Kuskokwim and Yukon Rivers — and today has offices and operations throughout the state with more than 650 employees.

Doyon donates $1 million for new health center

Alaska Native News said Nov. 24 that Doyon Ltd. is donating $1 million to Tanana Chiefs Conference in support of the construction of the new Chief Andrew Isaac Health Center. The Doyon board of directors approved the contribution at their regular quarterly meeting held in mid-November in Fairbanks.

In approving the contribution, the Doyon board stated that it is an investment that will benefit Doyon shareholders and the Native community as whole. A significant number of Doyon shareholders and their descendants reside in Interior Alaska and receive health care services through Tanana Chiefs Conference programs.

"Doyon is pleased to make this donation," said Aaron Schutt, Doyon's president and CEO. "It is symbolic of the unity between TCC and Doyon. The clinic and its new features will improve the health care services provided in Interior Alaska."

Tanana Chiefs Conference is the traditional tribal consortium of the 42 villages of Interior

see **OIL PATCH BITS** *page 17*

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

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Northwest Technical Services 15
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All of the companies listed above advertise on a regular basis with Petroleum News

EXPLORATION & PRODUCTION

Groups appeal Shell's Beaufort air permit

Earthjustice, on behalf of nine environmental groups, filed an appeal Nov. 28 with the Environmental Appeals Board against the Environmental Protection Agency's decision to issue an air quality permit for Shell's use of its Kulluk floating drilling platform for exploratory drilling in Alaska's Beaufort Sea starting in 2012.

The appeal comes just over a month after an appeal against the air quality permit for Shell's use of the Noble Discoverer drillship in both the Chukchi and Beaufort seas.

"These air permits violate the Clean Air Act and open the door to dangerous drilling in the Arctic," said Vera Pardee of the Center for Biological Diversity when announcing the appeal. "Rather than turning the pristine Arctic into an industrial zone, the Obama administration should be focusing on safer, cleaner sources of energy."

"Shell has made every effort to reduce emissions to the lowest possible level. That includes hundreds of millions in upgrades and modifications to both of our drill ships and the use of ultra low sulfur diesel fuel on all of our vessels," Shell spokesman Curtis Smith told Petroleum News in a Nov. 29 email. "We are confident in the EPA's finding that our drilling program will have no negative impact on coastal communities and we are equally confident that we will have a usable air permit once this challenge has run its course."

—ALAN BAILEY

continued from page 16

OIL PATCH BITS

Alaska and provides a unified voice advancing tribal governments, economic and social development, promoting physical and mental wellness, educational opportunities, protecting language, traditional and cultural values.

Usibelli taps Brown for VP Southcentral operations

ROBERT BROWN

Usibelli Coal Mine Inc. said Nov. 23 that it has named Robert Brown as the new vice president for Southcentral Operations. Brown has worked for UCM for the past three years as the project manager of the Wishbone Hill coal mining project north of Palmer, as well as the general manager of Aurora Energy Services' coal loading facility in Seward. He is a graduate of the South Dakota School of Mines, and holds a bachelor's degree in Industrial Engineering.

Brown previously worked for Wilder Construction, now Granite Construction, and serves on the Alaska Export Council. In his spare time, he serves as a coach for his son's sports teams.

Founded in 1943 by Emil Usibelli, Usibelli Coal Mine Inc. is located in the Alaska Range near the town of Healy. UCM operates year-round and during more than 60 years of operation, mine production has grown from 10,000 tons to an average 1.5 million tons of coal per year.

Crowley christens one of largest ATBs in industry

Crowley Maritime Corp. said Nov. 3 that as a part of its industry-leading new vessel building program, it christened its largest and fastest articulated tug-barge, the Legacy/750-1, in New Orleans.

The high-capacity tank barge is able to carry up to 330,000-barrels of petroleum products and the 16,000-horsepower tug can generate speeds of 15 knots or more, making the ATB an industry leader. When coupled together, the vessels measure 674 feet in length, only 23 feet shorter than One Shell Square, the tallest building in New Orleans and the state of Louisiana. The ATB's design, construction and systems exceed industry standards for the safest possible transportation of petroleum and chemical products.

"This class of ATB is among the largest, safest and fastest in the trade," said Crowley's Chairman, President and CEO Tom Crowley. "We are raising the bar in terms of reliability, cargo flexibility and environmental friendliness through our industry-leading new-build program. And the investments we are making will serve the needs of our customers for many years to come."

Vessel sponsors Christine Crowley, wife of Tom Crowley, and Carole Shaffner, wife of Senior Vice President of Transportation and Logistics George Shaffner of Marathon Petroleum Corp., performed the time-honored tradition of christening the vessels. More than 200 guests attended.

Racecar driver Kurt Busch visits Shell oil rig

Shell said Nov. 17 that driver of the No. 22 Shell-Penzoil Dodge, Kurt Busch, traveled to New Orleans, La., to the offshore Shell oil rig Brutus.

Following a cross-country trip from the Kobalt Tools 500 at Phoenix International Raceway Nov. 13, Busch visited the rig for an exclusive behind-the-scenes tour to develop a further understanding of deepwater oil exploration and to meet with the rig crew members, and also recognizing Brutus and Shell for their charitable giving in 2011.

"What an experience! It was one of those situations where you go in not knowing exactly what to expect and once you get out there, the 'WOW FACTOR' kicks in", said Busch. "I have a whole new appreciation for how technology gets oil out of the ground."

Brutus is the newest Tension Leg Platform in the Gulf of Mexico for Shell and is an eight-slot platform with facilities processing capacity of 120,000 barrels of oil per day.

Before the trip to the rig, Busch went through a safety briefing and then boarded a helicopter for the hour-and-a half ride to Brutus. Busch received an overview of deepwater oil exploration on how Brutus produces oil, which was proceeded by a tour of the massive structure. Kurt also recognized Brutus and Shell for their charitable giving and support of the United Way. During the visit he spent time talking with crew members answering questions and signing autographs.

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 March.

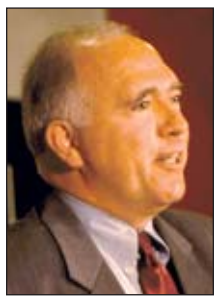
Four-month jobs tough sell

The surge in North Slope exploration activity has produced another problem: convincing experienced rig workers who have left the state for the Bakken shale fields, or elsewhere, to quit their jobs and come back to Alaska for a mere 3-4 months.

Or training new workers but only being able to guarantee them a few months of work a year in one of the harshest environments in the world.

In most regions of the country exploration drilling is allowed year-round, using temporary gravel roads to reach road-less tracts of land.

But temporary gravel roads are rejected by state, federal and borough regulatory agencies in Alaska, which prefer winter ice roads and pads, thus limiting the annual exploration season to 3-4 months.


JUDY PATRICK

JIM WEEKS

Jim Weeks, managing member of Alaska independent UltraStar Exploration and former ARCO Alaska executive, recently wrote a letter for an early November special meeting of the House Resource Committee, meeting to hear testimony on impediments to filling the Trans Alaska Pipeline System, or TAPS.

Weeks proposes a change to the current lease form by the Division of Oil and Gas that requires the use of ice roads and pads, saying allowing temporary year-round gravel roads could lower the cost of exploration — and speed up both exploration and development of new fields.

"As it now is, the successful bidder at a lease sale is awarded a contract to explore, develop and extract oil and gas from that lease," Weeks wrote. "The contract stipulates that there will be no exploration on the lease except from approved ice roads and pads, built only when there is sufficient snow cover and frozen depth to carry the heavy loading of drilling rigs and equipment.

"This restricts the exploration drilling window to generally mid-January to no later than about April 15, depending upon the status of the well," he said.

"So there is essentially a 90 day period in which to construct the ice road and pad and move in the rig and associated 50 truckloads of parts, plus camps, shops, generators, fuel storage tanks and other supporting facilities," restricting the number of wells that can be drilled each year.

"Companies like Repsol, with nearly 400,000 acres to explore and delineate, will require multiple years to prove up commercial reserves and make plans for development. So it will need to re-build the needed ice roads and pads multiple times before development decisions are made. Linc Energy faces a similar challenge at Umiat," Weeks said.

"The state should let private industry decide the most efficient and lowest cost manner to conduct exploration," he said. "Ice roads and pads may be the best way forward for close in exploration. But for access to locations further from the road system, re-building ice roads every year for several years gets pretty expensive."

If existing, or newly constructed permanent or semi-permanent gravel roads, airstrips and drilling pads would be more cost effective, they should be allowed, Weeks said.

Year-round access to leases being explored would shorten the time to production by years, he said.

"The ability to drill throughout the year will also significantly shave the winter peaking demand for drilling equipment, materials and manpower, thereby further reducing costs," for the operators.

"An all-weather road to the location of the drilling also provides year round access for emergency response equipment and personnel, adding another level of safety to the already very high operating standards for humans and the environment," Weeks said.

—KAY CASHMAN

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RIG DEMAND

especially suitable for exploration drilling.

Any of the other active rigs could potentially be used for exploration drilling, but three of those rigs are under contract for development drilling in North Slope oil fields during the winter. Another rig is drilling wells for Cook Inlet Natural Gas Storage Alaska's new natural gas storage facility on the Kenai Peninsula.

All six remaining Arctic rigs are already contracted for winter exploration drilling, Hebert said. However, Repsol, a company that has contracted for the use of four Nabors rigs during the winter, has recently informed Nabors that it will not in fact require one of those rigs, thus putting one rig back on the market, he said.

However, specific rigs are only suitable for certain types of exploration drilling project — the question of whether a particular rig is available for a particular project will depend on both the design of the rig and the nature of the project, he explained.

"It requires matching a certain rig to a certain type of location."

Nabors has three rig types

In particular, the weight and means of transportation of a rig impacts the type of drilling site that a rig can reach, Hebert said.

Essentially, Nabors operates three rig types: large wheeled, self-propelled rigs that can traverse ice roads but that cannot cross ice bridges over waterways; truck-pulled rigs that require ice roads but can cross a heavy-duty ice bridge; and modular rigs that can be broken down into truck loads for transportation to remote sites, crossing floating ice bridges en route if necessary.

Nabors has an additional wheeled, self-propelled rig that is currently mothballed and would require at least two months of work to bring back into service, Hebert said, adding that Nabors is not in an immediate position to activate that rig, given the company's current workload.

A second mothballed rig requires substantial refurbishment involving quite a few months of work, he said. And, although Nabors has other mothballed rigs in Alaska, these rigs require major refurbishment, involving many millions of dollars in expense. Given the substantial cost and time required to bring any of these rigs into operation, an exploration company would have to make a firm commitment for rig use well in advance of a drilling operation, Hebert said.

Another variable in rig availability is the amount of in-field development drilling that is taking place, given that both in-field drilling and exploration drilling draw on the same rig inventory.

"That would take some sizable commitment on someone's part," he said. "That would not be something that most (drilling) contractors would speculate on."

Winterization has to be done correctly

Another way of increasing the size of the active Alaska drilling rig fleet would be to bring rigs from Canada or from the Lower 48. However, winterizing a rig for use in northern Alaska's extreme climate is a major exercise, involving significant cost and time, Hebert cautioned.

"It can be done, but it has to be done correctly," he said.

Rig winterization involves attention to many details — for example, electrical wiring and hydraulic hosing needs to be Arctic rated, especially given the likelihood of having to transport an unheated rig over a lengthy ice road in extreme cold before a drilling operation starts. Even rigs from Canada require customization for Alaska conditions, Hebert said.

Again, a firm contractual commitment well in advance of when a rig is needed would be essential to embarking on a rig winterization project. And the rig market outside Alaska is tight, potentially making rig acquisition difficult.

Bringing in new rigs is also an option.

Three and a half years ago Nabors delivered the first purpose-built AC rigs for the North Slope in 13 months, from design to delivery. Two and a half years ago the company delivered CDR-2 to ConocoPhillips at Kuparuk; it was the first purpose-built coiled tubing rig designed for the Arctic. It took 18 months, from design to delivery.

Tax, in-field demand are factors

Another variable in rig availability is the amount of in-field development drilling that is taking place, given that both in-field drilling and exploration drilling draw on the same rig inventory. People are projecting the possibility of even more exploration activity in the 2012-13 winter season, Hebert said. But if BP and ConocoPhillips' field development activity also increases due to the Alaska Legislature passing the governor's bill that reduces the state's production tax, rig availability in 2012-13 would pose an even bigger challenge than at present.

"We could easily run out of rigs again next winter," Hebert said. And some of the Nabors rigs currently under contract for exploration are especially suitable for use on North Slope oilfield well pads, thus making these rigs especially desirable for in-field work, he said.

There is time to refurbish mothballed rigs for next winter, but Nabors would need that up-front commitment for rig use before bringing a rig out of hibernation, he said.

Seven Doyon rigs

Ron Wilson, general manager of Doyon Drilling, told Petroleum News Nov. 30 that Doyon has seven active drilling rigs in Alaska.

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MUSTANG WELLS

to drill the Mustang No. 1, Mustang No. 2 and Mustang No. 3 wells between January and April and demobilize in May. The company is also planning summer studies.

The joint venture includes Brooks Range Development Corp., Calgary-based independent TG World Energy Corp. and Nabors subsidiary Ramshorn Investments Inc. (Editor's note: In a deal that closed in early November, Ramshorn purchased TG World Energy's Alaska acreage interest.)

Mounting the Mustang

The Mustang project is studying the potential of the Kuparuk Formation in the area.

North Tarn No. 1, drilled to 6,223 feet, identified an oil reservoir in the Kuparuk C sand. Brooks Range previously estimated that the Kuparuk Formation at North Tarn could contain 6 million barrels of oil, enough to make the play economic. The company also said North Tarn included a target in the shallower Brookian Formation that could hold 35 million barrels, but would be more difficult to produce because of complex geology.

Under the terms of the Southern Miluveach unit, Brooks Range must complete North Tarn No. 1-A, as well as two Mustang wells (or a Mustang well and a sidetrack) into the Kuparuk Formation by May 31, 2012. The working interest owners must also decide by Oct. 1, 2012 whether or not they will sanction a development program at Mustang.

Brooks Range recently got approval to form four units on state land in the central North Slope, all in the fairway between the Kuparuk River unit and the Colville River. From north to south those are the Southern Miluveach, Kachemach, Tofkat and Putu units.

—ERIC LIDJI

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RIG DEMAND

Six of those rigs are under contract to North Slope oilfield operators for the coming winter and the other rig, the Arctic Fox, is under contract to Repsol for exploration drilling.

The Arctic Fox is a lightweight rig that can be trucked almost anywhere, he said.

Doyon used to own another lightweight exploration rig, the Arctic Wolf, but that rig is now in Canada; it is owned by Akita Drilling and has been disassembled, Wilson said.

One of the Doyon rigs under contract for in-field work has proved especially successful in the past for exploration drilling, although any of Doyon's rigs could potentially be used for exploration, depending on whether the transportation route to the drilling site can accommodate the rig's weight, Wilson said.

Build rather than convert

Wilson said that, given the tight rig supply situation in the Lower 48 and the work required to modify a rig for Arctic use, it could prove simpler to build a new rig rather than convert an existing rig, should additional rigs be needed in Alaska.

However, rig construction might take 16 to 18 months and the construction cost would raise the issue of how much a company like Doyon would be willing to invest on speculation, Wilson said. The investment risk would best be managed by linking rig construction to a specific drilling project, he said.

Wilson also commented on the difficulties that Doyon experienced a few years ago when trying to use a Canadian rig for Arctic Alaska exploration. Severe cold spells in Alaska seem to last longer than in the areas of Canada where Canadian rigs operate, and northern Alaska can also experience challenging wind conditions, he said.

Kuukpik's 3 rigs drilling in fields

Kuukpik Drilling has an Arctic-equipped drilling rig, suitable for exploration drilling and based in Alaska. However, that rig is under contract for the entire winter of 2011-12, doing gas well drilling in the Barrow gas fields, at the extreme western end of the North Slope.

Kuukpik anticipates its rig being available for drilling on other projects in the winter of 2012-13, Randy Hicks, general manager of Kuukpik, told Petroleum News on Nov. 28.

Nordic-Calista Services has three drilling rigs in operation on the North Slope. Although one of these rigs was used in an exploration project a few years ago, all of the rigs are currently under contract for in-field drilling and are likely to remain in that situation for the foreseeable future, Udo Cassee, Nordic-Calista's operations superintendent, has told Petroleum News. ●

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Laptops for Foster Kids

Do you have an extra laptop you'd be willing to part with? No, I'm not adding to my own stockpile of consumer electronics or trying to strike it rich on the pawn shop circuit. Rep. Les Gara is working with Facing Foster Care Alaska to collect laptops for foster youth. Laptops are a critical tool for foster youth to keep up with schoolwork and stay connected with family and friends while they are moved to different homes and schools.

If you are interested in donating a laptop, please make sure it is fully functional and meets the following standards:

Is in excellent working order;
Is no more than 4 years old;
Has a word processing program;
Does not need any repairs.

For more information, or to donate a laptop, please contact either Rep. Gara's office at (907) 465-2647, or Amanda Metivier at Facing Foster Care Alaska at (907) 230-8237.

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CO-OP OBJECTIONS

Co-op members are concerned that Naknek Electric "emerges from this process with a future," the objection said.

Members are further concerned the utility "will be pushed to raise additional cash by increasing rates, but the members do not have deep pockets, and raising rates will also raise the risk that larger users, with the capacity to buy their own generators, will abandon their membership thus actually reducing" co-op revenue, the objection said.

Expensive well

Naknek Electric serves the Bristol Bay area, known for its enormous summer salmon fishery. It was incorporated in 1949 and began distributing electricity in 1960. It is a nonprofit business, owned by its members. The utility has about 700 members and 1,100 meters in and around the villages of Naknek and King Salmon.

The utility's major commercial customers are fish processing plants. It also has an important wholesale customer in the U.S. Air Force at King Salmon.

In the 1990s, Naknek Electric began looking at alternatives to expensive diesel for running its generators.

In early 2008, the co-op bought a 120-acre drill site some 17 miles outside of King Salmon, and the following year bought a National 1320 drilling rig.

It began drilling its first exploratory geothermal well on Aug. 16, 2009.

But problems securing grants, unexpected regulatory requirements and technical problems with the well — which refused to flow as hoped — drove the utility into bankruptcy court.

By the Sept. 29, 2010, bankruptcy filing date, Naknek Electric said it "had incurred approximately $40 million of debt that was in one way or another associated with the geothermal project."

'Independent verification' sought

Naknek Electric filed its disclosure statement and reorganization plan on Sept. 15. The plan proposes, among other things, selling off the drilling rig, valued at $11 million, according to the disclosure statement.

The co-op said that, going forward, it would focus again on diesel electricity generation. But it held out the chance that the geothermal program might continue, contingent on federal grants coming through.

The co-op has said it was pursuing a $50 million loan guaranty from the U.S. Department of Agriculture's Rural Utilities Service, or RUS. The loan would be used to pay off debt and develop more wells and a geothermal power plant.

The members committee, in its Nov. 28 objection, said members need to be fully engaged in the co-op's plans.

The committee requested more information about how the co-op used its existing loans.

And the committee seemed wary of getting in deeper with what it called "a failed attempt to switch from diesel power to geothermal."

"The Members Committee believes that before the Debtor again attempts a geothermal project, the proposal should be subjected to independent verification of assumptions and the Committee should be allowed to weigh in on behalf of the general membership," the objection said. "For example, if the Debtor proceeds with a RUS loan guarantee for $50 million (half of which is used to pay off existing geothermal obligations) and the geothermal assumptions are erroneous, area communities would be swamped in huge rate increases to service that additional debt. The Debtor should explain the process it intend to follow in deciding whether to proceed with geothermal power and whether it will do so without court approval, independent consulting to verify its assumptions, and involvement from the Members Committee."

Keeping customers

Naknek Electric is expected to file a revised disclosure statement following the Dec. 1 court hearing.

A big worry for the co-op, and for the members, is retaining the utility's major customers, which could elect to generate their own power if rates increase significantly.

The members committee said it also is concerned about the co-op's ability to handle new power demand. Some fish processors "report they have been turned down by Debtor when inquiring of their expansion plans," the committee's objection said.

"An inability to accommodate expansion, actually leads to rate base shrinkage, as commercial users either take the plunge to self-generate for the expansion (developing expertise and comfort going it alone) or begin to expand outside of Debtor's service area," the objection said.

The committee also noted Naknek Electric's diesel plant is old and needs upgrading. It said the co-op should include an analysis of the issue in its revised disclosure statement. ●

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MACKENZIE LIVES

nals," McLeod said. "In their view, everything is looking promising and we (the NWT government) are cheering them on."

He said that although he did not have access to the details, the indications are "very promising," but he emphasized that important deadlines are looming.

First deadline in 2013

Canadian government approval of the project last March gives the partners — Imperial 34.4 percent, the Aboriginal Pipeline Group 33.3 percent, ConocoPhillips 15.7 percent, Shell Canada 11.4 percent and ExxonMobil Canada 5.2 percent — until December 2013 to provide updated cost estimates and a decision to proceed with the MGP. (Shell said four months ago that it was open to bids for its stake, including 100 percent ownership of the 1 trillion cubic foot Niglintgak field and seven other pools. The company said it was making relevant data available to a "broad group of prospective purchasers" after deciding to "focus its resources on other options" in the Alberta oil sands and British Columbia shale gas plays. It has yet to announce a deal.)

McLeod said that leaves only two years for the partners to complete engineering and geotechnical work and for the Canadian government to include a fiscal package of royalties, taxes and other items, in its next budget which is expected in February or March 2012.

The government approval also requires a start on construction in 2015 to allow the first shipments of gas from the Mackenzie Delta in 2018.

2013 deadline 'challenging'

However, Rolheiser said the proponents have indicated the 2013 deadline "will prove challenging, if not difficult to achieve and will be dependent on how long it takes to reach agreement with the federal government on fiscal terms."

He said the framework is essential to restaff and resume engineering, permitting and field work that was suspended in 2007 "in order to see thousands of permits we need before we can make a decision to construct."

The framework has been "under discussion with the federal government for quite some time. Our objective remains to work with the government to develop a framework that provides an appropriate balance of risk and benefit to the investors and for the government of Canada," Rolheiser said.

But, because of the confidential nature of the discussions, he would "not go any further into what may or may not be under discussion."

New NEB study

A new National Energy Board study released Nov. 22 gave a lift to the MGP by predicting gas prices will strengthen enough to justify delivering gas from the Mackenzie Delta by 2020, although McLeod said his government is still looking at late 2018 or early 2019 as the startup date.

The study, which forecast Mackenzie gas can start flowing when prices rise above US$5.50 per million British thermal units, said the Arctic gas will be needed regardless of the projected growth of shale gas production.

It said Canadian gas output declined 15 percent from 2008 to 2010 and will continue that trend through 2015 to 13.1 billion cubic feet per day, before resuming growth again in 2016 when gas from the Arctic and unconventional deposits start driving production towards 18 bcf per day in 2035. ●

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