Petroleum news

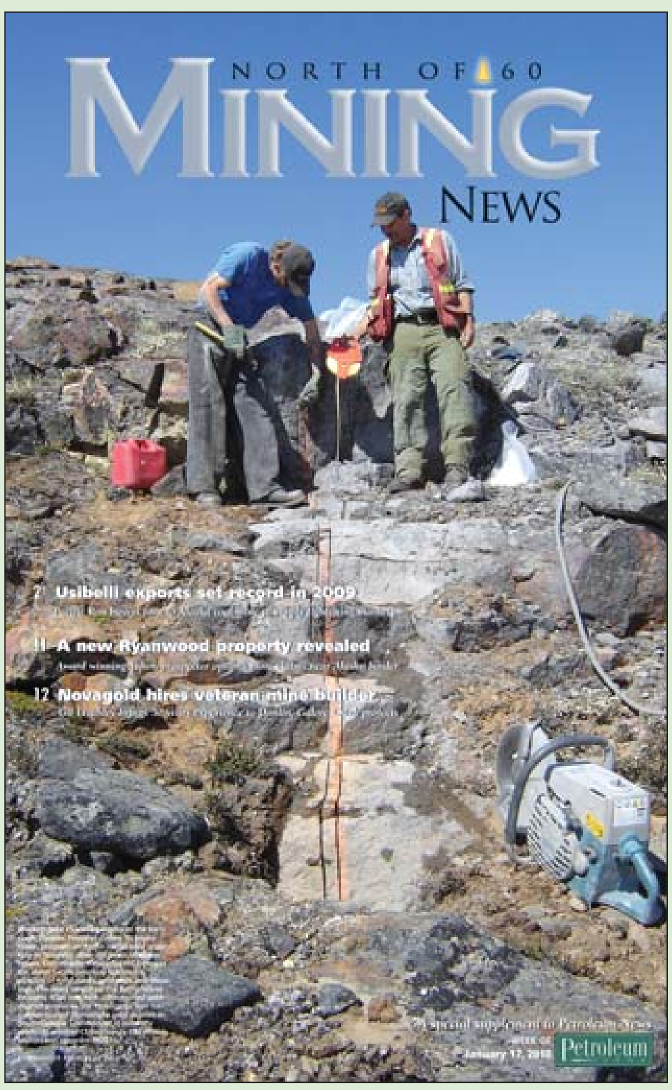
Vol. 15, No. 3 • www.PetroleumNews.com — *A weekly oil & gas newspaper based in Anchorage, Alaska* — Week of January 17, 2010 • $2

page 11 Petroleum News starts new online magazine at greeningoffoil.com

BREAKING NEWS

PAGE 5: Gov. Parnell proposes changes to ACES tax credit rules

January Mining News inside



The January issue of North of 60 Mining News is enclosed

Canada's upstream on upswing; '09 drilling licenses down 47%

With Canadian government land sales slumping to a 17-year low and average natural gas prices at their lowest point in the past decade, it was no surprise that cash-squeezed producers slashed their drilling programs in 2009.

Provincial government regulators issued 12,721 new well licenses during the year, off 47 percent from 2008 in the sharpest change on record in Canada, the poorest showing since 1998 and a staggering 18,196 short of the 2005 record.

But there has been the faintest glimmer of hope over the past month, with an uptick in natural gas prices from a winter that is pounding most regions of North America, adding weight to the

see **UPSTREAM** *page 14*

Chukchi air permit takes Shell closer to 2010 drilling program

The U.S. Environmental Protection Agency's Jan. 7 decision to propose an amended air quality permit for Shell's planned exploration drilling in the Arctic Alaska outer continental shelf of the Chukchi Sea marked a significant step towards the point at which the company can make a go/no-go decision on whether to drill in the Chukchi during the 2010 open water season.

"We very much appreciate the work done by EPA Region 10 to issue Shell a draft air permit for our 2010 Chukchi

see **PERMIT** *page 17*

LAND & LEASING

Exxon wins a round

For second time, judge disallows breakup of Alaska's Point Thomson unit

By WESLEY LOY
For Petroleum News

An Alaska judge on Jan. 11 dealt the state government a blow in its quest to wrest control of the rich Point Thomson oil and gas field from ExxonMobil and other leaseholders.

Superior Court Judge Sharon Gleason reversed state Natural Resources Commissioner Tom Irwin's April 2008 decision dissolving the Point Thomson unit for lack of an acceptable development plan.

It marks the second time that Gleason, after oil company appeals, has blocked state attempts to terminate the unit.

And, for the second time, it could mean the matter will bounce back to the Department of Natural Resources for a high-profile hearing on Point Thomson's fate.

> *Gleason concluded that, based on common definitions of "rate," ExxonMobil is entitled to a Section 21 hearing despite having no production at Point Thomson.*

State officials expressed disappointment with the ruling, though they note the conflict with ExxonMobil has induced what they have long desired — actual drilling at Point Thomson with an eye toward production by the end of 2014, according to ExxonMobil's timeline.

"It's about development for us," state Oil and Gas Director Kevin Banks told Petroleum News.

see **RULING** *page 18*

NATURAL GAS

Denali sets open season date

Will submit package to FERC in April, conduct 90-day OS beginning in July

By KRISTEN NELSON
Petroleum News

Both Alaska natural gas pipeline projects have now set dates for their open seasons, the quest for customers to commit to filling a proposed line with natural gas.

BUD FACKRELL

Denali, a joint venture of BP and ConocoPhillips, announced Jan. 12 that it will file its open season plan with the Federal Energy Regulatory Commission in April and — subject to FERC approval of the plan — conduct its open season beginning in July.

The TransCanada-ExxonMobil project will file its open season package with FERC at the end of January and begin its open season in May. TransCanada committed to a schedule as part of its application for a state license under the Alaska Gasline Inducement Act.

Denali has said it would hold an open season in 2010, but Denali President Bud Fackrell's statement that the company would file its open season plan with FERC in April was the first specific date the company has provided.

Filing for an open season is a step in getting financing for a line, since financing is based on agreements from shippers to pay for space in a line, so-called ship-or-pay contracts.

see **OPEN SEASON** *page 19*

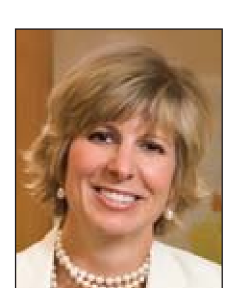
EXPLORATION & PRODUCTION

West Alpine on hold

Without corps permit, ConocoPhillips can't start work in 2010-11 winter season

By KRISTEN NELSON
Petroleum News

Work on ConocoPhillips Alaska's Alpine West or CD-5 satellite — the first satellite planned for development in the National Petroleum Reserve-Alaska — has been delayed by at least a year. The company had planned to begin construction in the winter of 2010-11, with two winter construction seasons required.



HELENE HARDING

While the company received permits it needs from the North Slope Borough and the State of Alaska, it has not received its 404 permit from the U.S. Army Corps of Engineers, Helene Harding, vice president of North Slope operations and development, told Petroleum News Jan. 14.

She said they've been getting a lot of questions on when the project will go ahead, and felt they needed to make the delay public. The corps has known since mid-December that lack of the permit would delay the project, she said.

Harding said the corps has said it is trying to do a diligent review.

"It seems for us it's a little difficult to understand, given that they've had this since 2005 — basically the same permit that they've been able to work on since 2005. And there is an approved EIS with this development scenario so it's quite disconcerting," she said.

see **WEST ALPINE** *page 20*

contents

Petroleum News *North America's source for oil and gas news*

Alaska - Mackenzie Rig Report

The Alaska - Mackenzie Rig Report as of January 14, 2009.
Active drilling companies only listed.

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

This rig report was prepared by Marti Reeve

Alaska Rig Status

North Slope - Onshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Doyon Drilling			
Dreco 1250 UE	14 (SCR/TD)	Prudhoe Bay AGI-01A	BP
Sky Top Brewster NE-12	15 (SCR/TD)	Stacked at Kuparuk, awaiting mobilization to Badami to work for Savant Alaska.	Available
Dreco 1000 UE	16 (SCR/TD)	Prudhoe Bay DS13-27	BP
Dreco D2000 UEBD	19 (SCR/TD)	Alpine CD3-122	ConocoPhillips
OIME 2000	141 (SCR/TD)	Kuparuk annual maintenance	ConocoPhillips
TSM 7000	Arctic Wolf #2	Stacked at Prudhoe Bay	FEX/Available
Nabors Alaska Drilling			
Trans-ocean rig	CDR-1 (CT)	Stacked, Prudhoe Bay	Available
AC Coil Hybrid	CDR-2	Kuparuk 2T-29	ConocoPhillips
Dreco 1000 UE	2-ES	Prudhoe Bay, Stacked out	BP
Mid-Continental U36A	3-S	Stacked, Milne Point	BP
Oilwell 700 E	4-ES (SCR)	Milne Point MPJ-19	BP
Dreco 1000 UE	7-ES (SCR/TD)	Prudhoe Bay DS 07-23	BP
Dreco 1000 UE	9-ES (SCR/TD)	Borealis V-123	BP
Oilwell 2000 Hercules	14-E (SCR)	Kuparuk 2A-27	ConocoPhillips
Oilwell 2000 Hercules	16-E (SCR/TD)	Currently mobilizing from Deadhorse to Sak River #1 location.	Brooks Range Petroleum
Oilwell 2000	17-E (SCR/TD)	Stacked, Point McIntyre	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)	Point Thompson PTU-15	ExxonMobil
Academy AC electric Canrig	105-E (SCR/TD)	Stacked at Deadhorse	Available
Academy AC electric Heli-Rig	106-E (SCR/TD)	Stacked at Deadhorse	Available
OIME 2000	245-E	Shut down, plan to recommence drilling at OPP in January	ENI
Nordic Calista Services			
Superior 700 UE	1 (SCR/CTD)	Prudhoe Bay Drill Site 18, well #30	BP
Superior 700 UE	2 (SCR/CTD)	Milne Point Drill Site L, well #02	BP
Ideco 900	3 (SCR/TD)	Kuparuk Drill Site 1J, well #162	ConocoPhillips

North Slope - Offshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Nabors Alaska Drilling			
OIME 1000	19-E (SCR)	Oooguruk ODSK-14	Pioneer Natural Resources
Oilwell 2000	33-E	Northstar, Stacked out	BP

Cook Inlet Basin – Onshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Aurora Well Service			
Franks 300 Srs. Explorer III	AWS 1	Currently mobilizing from Tyonek to Cook Inlet Energy's West McArthur River unit for a workover program.	Available
Doyon Drilling			
TSM 7000	Arctic Fox #1	Stacked at Beluga	Available
Marathon Oil Co. (Inlet Drilling Alaska labor contractor)			
Taylor	Glacier 1	Sunrise Lake #2	Marathon Oil
Nabors Alaska Drilling			
Continental Emsco E3000	273	Stacked, Kenai	Available
Franks	26	Stacked	Available
IDECO 2100 E	429E (SCR)	Stacked, removed from Osprey platform	Available
Rigmaster 850	129	Kenai SLU 41-33RD	Chevron
Rowan Companies			
AC Electric	68AC (SCR/TD)	Hansen #1A-L1 Cosmopolitan	Pioneer Natural Resources

Cook Inlet Basin – Offshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Chevron (Nabors Alaska Drilling labor contract)			
	428	M-10 Steelhead platform Kenai	Chevron
XTO Energy			
National 1320	A	Platform A no drilling or workovers at present	XTO
National 110	C (TD)	Idle	XTO
Kuukpik	5	Stacked in Kenai	Available

Mackenzie Rig Status

Canadian Beaufort Sea

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

Mackenzie Delta-Onshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
AKITA Equtak			
Modified National 370	64 (TD)	Racked in Inuvik	Available

Central Mackenzie Valley

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Akita/SAHTU			
Oilwell 500	51	Racked in Norman Wells, NT	Available


JUDY PATRICK

Baker Hughes North America rotary rig counts*

	Jan. 8	Dec. 31	Year Ago
US	1,220	1,189	1,589
Canada	342	209	360
Gulf	41	38	65

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

● NATURAL GAS

Responses split on RCA storage authority

CINGS request for declaratory ruling draws response: CEA, ML&P say storage should be regulated utility; Aurora, Marathon say not

By KRISTEN NELSON
Petroleum News

There is unanimity on one thing: Third-party natural gas storage is needed in Cook Inlet.

That was a theme running through responses received by the Regulatory Commission of Alaska when it asked for responses to a number of questions about a request by Cook Inlet Natural Gas Storage for a declaratory ruling on whether third-party gas storage would be regulated as a utility.

CINGS is proposing to create third-party natural gas storage at the Cannery Loop field on the Kenai Peninsula. The storage would be available for purchase by entities — expected to be utilities — needing to store gas to meet peak needs in the winter.

RCA asked for responses to a series of questions by Jan. 8; legal briefs on the issues are due Jan. 15.

There is no question RCA would be involved because it would approve gas storage charges utilities paid to CINGS and then included in tariffs to be paid by consumers. The issue is whether RCA has the authority to regulate CINGS directly as a utility under laws governing either utilities or pipelines; the commission heard different opinions.

On the Web

See previous Petroleum News coverage:

"Need regulatory clarity," in Jan. 3, 2010, issue at www.petroleumnews.com/pnads/83286464.shtml

"RCA holds workshop on gas storage issues," in Dec. 13, 2009, issue at www.petroleumnews.com/pnads/545722585.shtml

Enstar urges speed

Enstar Natural Gas Co., the local gas distribution company for Southcentral Alaska, has been working with CINGS on the gas storage project and is expected to be the largest user of the facility. It said gas storage is essential to its continuing ability to serve customers.

Enstar said regardless of whether CINGS is regulated as a utility, it requests that the commission "see that the project is developed quickly and successfully; … establish just and reasonable rates for storage service; and … explicitly find those costs recoverable by Enstar and other utilities from their customers. The RCA's decision on CINGS' regulatory status should be guided by these goals," Enstar said in its comments.

Enstar said it believes RCA should review storage rates for a number of reasons, including: CINGS will be the only entity providing the service to utilities in Alaska; there is no market rate for storage services in Cook Inlet; "utilities should be allowed to recover the reasonable costs of that service"; and the most efficient way for the commission to approve rates is through a consolidated hearing.

CEA, ML&P call for regulation

Chugach Electric Association, supported by Matanuska Electric Association and the City of Seward, said it believes that while the gas storage project could be reviewed either as a new regulated utility service or through requests by public utilities purchasing storage services, it believes regulating CINGS as a utility is the appropriate approach.

CEA also asked for a more detailed description from CINGS of its proposed gas storage facility, and also asked for additional explanation of why Enstar subsidiary Alaska Pipeline Co., rather than CINGS, would own and operate the pipeline to be built between the storage facility and existing gas pipelines.

Municipal Light & Power told the commission it "strongly believes that the development of gas storage in Cook Inlet is needed to ensure the reliable provision of electric service (and gas service by Enstar) in periods of peak demand, supports CINGS' proposed development of gas storage, and anticipates contracting with CINGS for gas storage and related services," but believes the CINGS' facility should be regulated by the commission and believes more detailed information is needed for the commission to make that determination.

Marathon, Aurora oppose regulation

Marathon Alaska Production said it supports CINGS request for a declaratory order and urges RCA to find that it "has no jurisdiction over natural gas storage facilities that provide third party storage."

Marathon said it agrees with CINGS that neither the Alaska Public Utilities Act nor the Pipeline Act was designed to regulate a standalone natural gas storage service. "The Commission should not employ a strained reading of its jurisdictional statutes, which it would need to do to exert jurisdiction over

see **STORAGE** page 17

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CORRECTION

The article titled "Savant completes ice road to Badami" in the Jan. 10 issue of Petroleum News incorrectly stated that Savant is using the Nabors rig 15 to drill at Badami this winter. In fact, Savant is using the Doyon rig 15.

SAFETY & ENVIRONMENT

Point Thomson EIS public meetings set

Five public meetings have been set on the Point Thomson project environmental impact statement. The proposed project is an oil and natural gas condensate extraction operation at Point Thomson on the North Slope.

Each meeting includes a presentation followed by questions and answers.

The meetings are:

Jan. 11, 5-8 p.m., Westmark Hotel in Fairbanks;
Jan. 12, 4-7 p.m., Community Hall in Kaktovik;
Jan. 13, 5-8 p.m., Trapper School in Nuiqsut;
Jan. 14, 5-8 p.m., Inupiat Heritage Center in Barrow; and
Jan. 19, 5-8 p.m., Dena'ina Convention Center, Anchorage.

For more information or to sign up for the project newsletter, go to www.pointhomsonprojecteis.com or contact Julie McKim, Corps of Engineers at 907-753-2773 or e-mail comments@pointthomsonprojecteis.com.

The scoping comment deadline is Feb. 25 for consideration in the draft environmental impact statement.

—PETROLEUM NEWS

FINANCE & ECONOMY

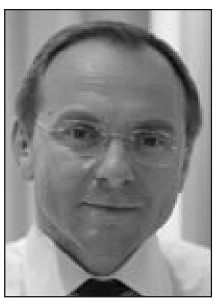
Talisman puts eggs in shale basket

By GARY PARK

For Petroleum News

Talisman Energy is keeping mum about its Alaska interests as it gears up for the possible sale this year of 40,000 barrels of oil equivalent per day of gas-weighted properties which could fetch up to C$3 billion.

It also doesn't rule out a copycat move by following EnCana's lead and reorganizing into two separate, publicly traded units — but emphasized that a split is not yet on the horizon.


JOHN MANZONI

The Canadian independent rolled out some of its near-term strategies Jan. 11 in announcing a 2010 capital budget of C$5.2 billion, up 10 percent from 2009, with no mention of Alaska, where Talisman's interests are operated by subsidiary FEX.

The program merely reinforced Talisman's intense pursuit of "portfolio transition" to its North American shale properties, which will receive C$1.6 billion, little changed from 2009.

Close to C$1 billion is allocated to the Marcellus play in Pennsylvania and C$550 million will go to the Montney play in northeastern British Columbia and northwestern Alberta.

Ramping up development

The company said its main goal this year will be to move from adding to its shale holdings to ramping up development from 70 development and pilot wells in 2009 to more than 200 in 2010.

That includes a doubling of development drilling in Pennsylvania's portion of the Marcellus, which stretches from New York to Quebec.

An initial horizontal pilot well is scheduled for Quebec and two more are likely in 2010.

"North American shale emerges as the main near-term production growth engine," said chief executive officer John Manzoni.

"Having built an inventory of 10 years' worth of shale gas drilling locations, this year the focus will shift to commercial development and drilling," he said.

> *"Having built an inventory of 10 years' worth of shale gas drilling locations, this year the focus will shift to commercial development and drilling."*
> —Talisman Energy CEO John Manzoni

Manzoni said there is flexibility in the capital program — based on forecast oil prices of US$60 per barrel and gas prices of US$3.50 per million British thermal units — to shift spending up or down throughout the year.

While Talisman will remain vigilant for strategic acquisition opportunities, its divestitures will be heavily concentrated on the central Alberta Foothills, greater Hinton and greater Peace River Arch regions.

Montney program could be dialed up

Manzoni said that Marcellus output should reach 250-300 million cubic feet per day by the end of 2010, up from 65 million currently, while Montney is targeted at 40-60 million cubic feet per day.

"We have the flexibility to dial up our Montney program," said Paul Smith, executive vice president of North American operations.

Production for 2010 is expected to be 425,000 boe per day, excluding any asset sales, about the same as 2009, from Talisman's far-flung operations in the British North Sea, Norway and Southeast Asia.

Probed on whether a corporate split along the EnCana lines could unlock greater value, Manzoni said he has always "maintained that the portfolio today is working in a complementary way."

"Maybe as we go forward it's quite possible that the different parts of the company could stand alone.

"That would be a nice problem to have. I don't think we're there yet and you only get that opportunity once," he said.

Manzoni said he is open to "structural adjustment of the company if we believed that value was being somewhat trapped inside the company." ●

Contact Gary Park through publisher@petroleumnews.com

GOVERNMENT

Parnell proposes changes to ACES credits

Alaska Gov. Sean Parnell announced Jan. 14 that his administration is proposing some changes to the tax credit rules within the state's ACES oil production tax to increase incentives for firms to invest in Alaska oil exploration and development. Parnell does not propose any changes to the ACES tax rates.

The specific changes that the administration will ask the Legislature to enact are:

- To make available to in-field, well-related activity, such as infill drilling, the 30 percent tax credit currently only available to drilling activities more than three miles from existing wells.
- To enable companies to use all of their capital credits in the year that the credits are earned, rather than having to defer the use of at least half of the credits into the following year.
- To enable new explorers to claim tax credits for exploration costs without having to make subsequent investments equal to the value of the credits.
- To waive state claims for interest on additional taxes that a company might have to pay in arrears, as a consequence of the retroactive application of ACES tax regulations that the state is currently finalizing.

Parnell said there is significant evidence that the tax credits in ACES are encouraging companies to explore in Alaska and that the administration's proposed changes to the tax would bolster that effect, with the main goal being the creation of more jobs for Alaskans in the near future.

On the other hand, the administration's discussions with oil companies failed to discover any evidence that the lowering of the progressive tax rates in ACES would result in new investments in Alaska, regardless of claims that lower rates would make Alaska more competitive for those investments, Parnell said.

"At this moment I am working for providing more opportunity for Alaskans in jobs," Parnell said. "I'm not interested in changing progressivity so they (the companies) can take that money and invest it somewhere else. If they're willing to invest it here, I'm open to considering it, but I'm standing up for Alaskans in this, not some other country."

—ALAN BAILEY

● PIPELINES & DOWNSTREAM

BP seeks approval for new cost method

Trans-Alaska oil pipeline carriers want FERC's help with rates; settlement efforts fail in long-running interstate tariffs dispute

By ROSE RAGSDALE
For Petroleum News

Fed up with losing money, the company with the largest ownership stake in the trans-Alaska oil pipeline has asked the Federal Energy Regulatory Commission to approve a new method for allocating the cost of operating the 800-mile conduit in interstate shipping rates.

BP Pipelines (Alaska) Inc., which owns slightly more than a 50 percent interest in the Alaska pipeline, filed the request Dec. 29, saying it was intended to comply with the commission's June 30 order directing the pipeline's owners to develop a pooling mechanism that re-allocates all of the carriers' costs based on throughput or usage.

The pipeline transports oil produced in fields on Alaska's Arctic coast region known as the North Slope. Currently, the line carries an average of about 700,000 barrels per day of oil and other petroleum liquids, down substantially from an average of more than 2 million bpd at peak flow in the late 1980s.

FERC, which regulates interstate shipping rates for oil pipelines, is currently hearing a prolonged dispute over the Alaska pipeline's interstate tariffs.

Effort to reach agreement

BP said it has made significant efforts over the course of more than a year to reach agreement with the other four carriers on a pooling arrangement that would comply with the commission's orders.

"Despite those efforts, the (pipeline) carriers have not reached an agreement, and BPPA believes that no agreement is possible at this time," the company said. "In the meantime, as required by the Commission, the (pipeline) carriers are continuing to charge rates that are calculated on a uniform basis, with the result that some (pipeline) carriers, including BPPA, are under-recovering their costs, while others are over-recovering their costs. In fact, BPPA has under-recovered its costs by ($113 million in 2009, or) an average of about $9.4 million per month since Jan. 1, 2009."

In its filing, BP also asked the commission to require the other carriers — ConocoPhillips Transportation Alaska Inc., ExxonMobil Pipeline Co., Koch Alaska Pipeline Co. LLC and Unocal Pipeline Co. — to incorporate the cost allocation mechanism that BP proposes into their respective tariffs on an interim basis, subject to investigation and adjustment.

The carrier said that doing so would enable the carriers to comply with the commission's orders and avoid prolonging "the significant hardship being experienced by BPPA."

The company also asked the commission to refer any challenges to its proposal to the administrative law judge assigned to investigate and review other issues in the broader tariffs dispute.

Koch, Unocal seek interstate rate changes

One day earlier, FERC issued an order that granted waivers requested by Koch and Unocal in November and accepted and suspended their tariffs, subject to refund, to become effective Jan. 1, 2010, as proposed. The commission also added the proceeding to the consolidated proceedings in Docket Nos. IS09-348-000 et al., which concern prospective rates filed by the pipeline carriers and shippers.

Koch and Unocal both proposed changing the interstate shipping rates for transportation of crude oil on their share of the pipeline's capacity using base period and test period adjustments and cost, revenue and throughput data that are consistent with data reflected in the other carriers' recent tariff filings. They said the requests were consistent with a 2008 Commission order that requires the carriers to charge a uniform rate for interstate transportation.

After two meetings with all parties in the case in November and December, FERC Settlement Judge H. Peter Young reported to the Commission and the chief judge Dec. 17 that parties in the case said they were unable to close the gaps between their various positions concerning appropriate return on equity for the pipeline.

Settlement proceedings fizzle

Meanwhile, the consolidated case has undergone a few significant twists and turns in recent months.

In October, Chief Administrative Law Judge Curtis L. Wagner Jr. ordered the consolidated case to go to settlement procedures and appointed a settlement judge to handle the matter.

After two meetings with all parties in the case in November and December, FERC Settlement Judge H. Peter Young reported to the Commission and the chief judge Dec. 17 that parties in the case said they were unable to close the gaps between their various positions concerning appropriate return on equity for the pipeline.

"They reported further that they did not anticipate being able to resolve these or any other issues involved in these dockets going forward in a settlement judge posture. They unanimously requested that the hearing procedures previously held in abeyance be re-activated and that these settlement judge proceedings be terminated," Young wrote in his report, before personally endorsing the request.

Wagner then appointed Administrative Law Judge Michael Cianci Jr. to hear the consolidated case and established a schedule calling for Cianci to reach an initial decision in the consolidated case by March 9, 2011.

Cianci has scheduled a pre-hearing conference for Jan. 20. ●

SAFETY & ENVIRONMENT

NOAA extends beluga comment period

At the request of Alaska's congressional delegation the National Oceanic and Atmospheric Administration has extended by 30 days the public comment period on the proposed designation of 3,000 square miles in Cook Inlet as critical habitat for the Cook Inlet beluga whale.

Alaska's senators, Lisa Murkowski and Mark Begich, and its congressman, Don Young, jointly requested the extension in December, citing concern with economic and national security impacts and the fact that the public comment period, originally from Dec. 2 through Jan. 31, fell over "the seasonal holidays during which the attention of most Alaskans is rightly focused on their families and not issues of public policy."

The delegation requested the extension Dec. 23, telling NOAA Administrator Jane Lubchenco that while NOAA has statutory timelines for determining critical habitat, "we are concerned about taking such action without adequate analysis of the economic and national security consequences of this designation."

NOAA's National Marine Fisheries Service listed the Cook Inlet beluga whale as endangered in October 2008 and published its proposed critical habitat designation Dec. 1.

The habitat area encompasses all of upper Cook Inlet, all of Knik Arm and Turnagain Arm, the middle part of Cook Inlet to south of Kalgin Island, Kachemak Bay and nearshore areas of the western coast of lower Cook Inlet.

The new comment deadline is March 3.

—PETROLEUM NEWS

● PIPELINES & DOWNSTREAM

Tales of woe on North America's refinery row

By GARY PARK
For Petroleum News

The trail of wreckage on North America's Refinery Row gained another victim Jan. 7 with Royal Dutch Shell's decision to turn its Montreal facility into a fuel terminal after failing to find a buyer for the 130,000 barrel-per-day plant.

Shell weighed a full set of options for the 76-year-old refinery as part of its global review of underperforming assets, which could also see buyers surface for one British and two German refineries.

Despite investing C$150 million in 2002 into the Montreal East Refinery to make it capable of producing low-sulfur gasoline, Shell has now decided the plant no longer has a place in its long-term strategy.

The refinery will now be converted into a terminal for gasoline, diesel and aviation fuels, likely before the end of 2010.

But there will be no significant impact on the Canadian crude producing sector, which delivered only about two cargoes of about 300,000 barrels each per year to the refinery, which was drawing most of its feedstock from the North Sea and West Africa.

More than half a million barrels

Shell's planned closure will mean about 543,000 bpd of North American capacity has been targeted for idling in the last four months, including Valero Energy's 210,000 bpd facility in Delaware which had been losing about US$1 million a day and Sunoco's 145,000 bpd refinery in New Jersey, along with Western Refining's small refinery in New Mexico.

In addition, Petro-Canada closed its 80,000 bpd Ontario refinery in 2005.

But analysts, including Ann Kohler with investment bank Caris & Co., estimated at least 1 million bpd must be permanently closed because of forecasts that U.S. motorists will burn 8 percent less gasoline between 2006 and 2018.

Kohler said companies will close refineries that are not closely linked to their own production or are inefficient.

But analysts, including Ann Kohler with investment bank Caris & Co., estimated at least 1 million bpd must be permanently closed because of forecasts that U.S. motorists will burn 8 percent less gasoline between 2006 and 2018.

No turnaround seen

Michael Irvin, vice president at Kent Marketing Services, a refining consultant, said the surplus capacity is "not likely to turn around any time in the near future" because refining margins do not justify continued production at marginal operations.

Although the current round of shutdowns will stem some of the flow of red ink, it's not yet clear how much more capacity will have to be mothballed or closed.

Montreal East accounted for about 7 percent of Canada's 1.8 million bpd of refining capacity, primarily supplying the Quebec and Maritime markets.

Suncor Energy and Valero have given no indication that they are under any pressure to close their Quebec refineries, which could have an important role in processing heavier crudes from the Alberta oil sands.

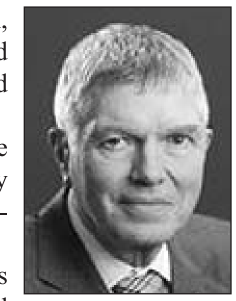
But there is no sign that BP and Irving Oil have any intention of reviving plans for their proposed C$8 billion, 300,000 bpd refinery in Saint John, New Brunswick, or that Korea National Oil Corp. (now that it has taken over Harvest Energy Trust) is ready to dust off plans to spend C$2 billion adding 75,000 bpd to the refinery it inherited at Come By Chance, Newfoundland. ●

Contact Gary Park through publisher@petroleumnews.com

GOVERNMENT

Alberta energy minister demoted

Alberta Premier Ed Stelmach has caved in to industry pressure and his government's freefall in the latest opinion polls by dumping Energy Minister Mel Knight in a major cabinet house-cleaning Jan. 13.



MEL KNIGHT

Ron Liepert moves to the energy portfolio from health, where he has gained a reputation for being hard-nosed and blunt, but will need to show considerable diplomacy to mend fences with Alberta's oil and gas leaders.

Since Stelmach was elected premier at the end of 2006 he has turned the energy reins over to Knight, who initially refused to back away from plans to increase the government's royalty revenues by about 20 percent.

But, as billions of dollars of upstream investment was diverted to British Columbia, Saskatchewan and the United States and thousands of jobs started to disappear, Knight was forced to engage in a series of modifications to the new royalty framework.

Five changes made

Five separate changes have been made and the government is now awaiting the results of a competitiveness review that compared Alberta with similar oil and gas jurisdictions in North America.

One of Liepert's first steps will likely be to restore confidence in natural gas royalties to aid a sector that has been struggling to survive over the past year.

Knight will become Sustainable Resource Development Minister as part of the sweeping cabinet shuffle, which Stelmach said will "tackle Alberta's fiscal challenges with determination. … We are going to take the necessary steps to ensure we emerge from this economic downturn even stronger than before."

The future road map will be unveiled in more detail Feb. 9 when the 2010-11 budget is released.

—GARY PARK

ASSOCIATIONS

Climate policy implications for Alaska

The implications of emerging national and international climate policy for Alaskans will be presented by Dr. Matthew Berman of the Institute for Social and Economic Research at the Anchorage Chapter of the International Association for Energy Economics, on Wednesday Jan. 20 at 12 noon at the BP Energy Center. Admission is free for members. There is a suggested donation of $5 for non-members. Contact Roger Marks at 250-1197 or rogmarks@gmail.com for information.

—PETROLEUM NEWS

FINANCE & ECONOMY

EIA forecasts $80 oil price this year

Henry Hub natural gas spot price projected to average $5.36 per thousand cubic feet in '10; storage levels expected to remain high

PETROLEUM NEWS

The U.S. Department of Energy's Energy Information Administration said Jan. 12 in its Short-Term Energy Outlook that it expects the price of West Texas Intermediate crude oil to average $80 per barrel this year and $84 in 2011, compared to a 2009 average of $62 per barrel.

EIA said that forecast is based on a growth of 2 percent in U.S. real gross domestic product this year, and a 2.7 percent growth in 2011, with world oil-consumption-weighted real GDP growing by 2.5 percent this year and by 3.7 percent in 2011.

The annual average Henry Hub spot price for natural gas is expected to average $5.36 per thousand cubic feet this year, a $1.30 increase over the 2009 average of $4.06.

The price is forecast to continue to grow, averaging $6.12 in 2011.

Tightening world oil market

EIA said if global economic recovery continues as projected the world oil market should gradually tighten this year and next. Countries outside the Organization for Economic Cooperation and Development will lead the recovery, but OECD countries are expected to show significant oil demand growth in 2011, the agency said, with projected OECD economic growth expected to more than double from 1.2 percent in 2010 to 2.7 percent in 2011.

"Continued high (natural gas) storage levels combined with enhanced domestic production capabilities and slow consumption growth are expected to keep prices from rising dramatically through the forecast" period of 2010-11, EIA said.

Compliance with Organization of the Petroleum Exporting Countries production cuts has weakened and global oil inventories and spare production remain very high by historical standards, EIA said, but "expectations of a continued global economic turnaround have continued to buttress oil markets."

"EIA expects that WTI prices, which have been trending upward since February 2009, will continue to increase in 2010 and 2011," the agency said.

2009 was a second consecutive year of decline in global oil demand, the first time that has occurred since 1983, but the decline bottomed out in mid-2009 as the world economy began to recover, a recovery which EIA said it expects to see continue in 2010 and 2011, contributing to global oil demand growth of 1.1 million barrels per day this year and 1.5 million bpd in 2011.

An increased demand of 200,000 bpd is expected in the U.S. this year, but China continues to lead consumption growth with projected increases of more than 400,000 bpd in both 2010 and 2011.

Non-OPEC supply up

There was an increase of more than 600,000 bpd in non-OPEC supply in 2009, the largest annual increase since 2004, EIA said, driven by higher production in the United States, Brazil and the Former Soviet Union.

Large declines in North Sea and Mexican production are expected to offset a large projected increase from Brazil in 2010 and 2011, with low overall non-OPEC growth expected in that period.

OPEC kept its current oil production levels unchanged at its December meeting.

"Although OPEC faces a global oil market that has firmed in response to its production cuts since last January, the strength and durability of the global economic recovery is still uncertain," EIA said.

Annual average OPEC crude oil production declined almost 2.2 million bpd on average in 2009, and EIA said it expects an increase of some 500,000 bpd in 2010 and 2011.

OPEC surplus crude oil production averaged 2.8 million bpd in 1998-2008, is expected to remain high and could reach almost 6 million bpd by the end of 2011, EIA said.

WTI crude oil spot prices averaged $74.50 per barrel in December, down some $3.50 per barrel from November, reflecting spot weakness in the first two weeks of the month. Colder-than-normal temperatures helped push the WTI spot price back up to $79 per barrel by the end of December.

EIA said it is forecasting weaker WTI spot prices over the next few months, with an average of $76 per barrel in March, before prices rise to some $82 per barrel in late spring and to $85 by the beginning of next winter.

Natural gas use down

EIA said it estimates that natural gas consumption fell by 1.5 percent in 2009, "primarily because of the economic downturn." Low natural gas prices contributed to an increase in gas-fired electric power generation, but the agency said that was offset by declines in industrial, residential and commercial sector consumption.

EIA expects total natural gas consumption to remain relatively unchanged this year, with higher natural gas prices expected to cause a 2.8 percent decline in electric power sector consumption of natural gas, offsetting growth in the residential, commercial and industrial consumption.

A 0.4 percent increase in natural gas consumption is forecast for 2011, led by a 2.5 percent growth in industrial consumption.

There was a 59 percent decline in working natural gas rigs from September 2008 to July 2009, but EIA estimates total marketed natural gas production increased by 3.7 percent last year.

Working natural gas rigs reached a low of 665 in mid-July, but the number was at 759 on Dec. 31, the agency said.

2009 production growth was supported by enhanced productivity of new wells, but "steep declines from initial production at these newly drilled wells and the lagged effect of reduced drilling activity" are expected to contribute to a 3 percent decline in production this year.

The agency expects a 1.3 percent increase in marketed production in 2011 as growth in production from Lower 48 non-Gulf of Mexico fields offsets a decline in Gulf of Mexico production.

Working natural gas in storage was 3.123 trillion cubic feet on Jan. 1, 316 billion cubic feet above the previous five-year average and 286 bcf above the level for the corresponding week in 2009.

There were large December draw-downs due to colder-than-normal temperatures, but EIA said it expects the end-of-March storage level of 1.734 tcf will be about 16 percent greater than the previous five-year average for that period.

The Henry Hub spot price averaged $5.50 per thousand cubic feet in December, $1.73 above the November average.

The 2009 average Henry Hub spot price was $4.06 per thousand cubic feet, and an average of $5.36 is projected for 2010 and $6.12 for 2011.

"Continued high storage levels combined with enhanced domestic production capabilities and slow consumption growth are expected to keep prices from rising dramatically through the forecast" period of 2010-11, EIA said. ●

● PIPELINES & DOWNSTREAM

Alyeska plans pipeline bullet-hole drill

Exercise will involve field testing hydraulic clamp designed to quickly seal high-pressure oil leak; 2001 shooting caused big spill

By WESLEY LOY
For Petroleum News

ALYESKA PIPELINE SERVICE CO.

Alyeska Pipeline Service Co. teamed with Fairbanks firms, Mustard Engineering and Holaday-Parks metal shop to design and build the HC 320 Hydraulic Clamp after the Milepost 400 bullet-hole incident in 2001. Once applied to the trans-Alaska oil pipeline as a temporary patch, the clamp can be left in place. This allows Alyeska to deploy multiple clamps, if needed.

Alyeska Pipeline Service Co. is planning a field exercise this year to test a hydraulically powered clamp designed to stop oil squirting out of the trans-Alaska oil pipeline through a bullet hole.

The drill is part of a series of oil spill response exercises the Anchorage-based operator of the 800-mile line aims to conduct this year and in 2011.

The bullet-hole exercise is planned for Milepost 438 of the pipeline at the Chatanika River, say documents Alyeska recently filed with the Alaska Department of Environmental Conservation.

A test piece of 48-inch mainline pipe will be placed at the scene and pressurized with water to simulate a high-pressure oil spray through a bullet hole, an exercise description says.Equipment including Alyeska's HC 320 hydraulic clamp will be dispatched from the company's Fairbanks Response Base.

A simulated 60-barrel release is expected over the course of the planned 12-hour exercise, and Alyeska and regulators will time and evaluate all the activities, the exercise description says.

The drill is scheduled for the third quarter of this year, though Alyeska spokesman Matt Carle said it could come sooner to avoid conflicts with planned summer maintenance shutdowns along the pipeline.

The HC 320 clamp already has been field tested twice, Carle said.

"We know it works," he said, adding the next exercise will give Alyeska a chance to test its equipment and workers in front of regulators.

The pipeline shooter

Alyeska developed the HC 320 clamp after a man shot the pipeline with a high-powered rifle in October 2001 near the Livengood community about 80 miles north of Fairbanks. The bullet pierced the steel pipe and insulating jacket, unleashing a jet of oil into nearby woods.

An estimated 285,600 gallons of oil spilled, and it took responders 36 hours to relieve pressure in the line and seal the bullet hole amid worry the fine oil mist in the air might explode. Alyeska drew both praise and criticism for its performance.

The drunken shooter, Daniel Carson Lewis of Livengood, was convicted on a variety of charges and drew a multiyear prison sentence.

With the help of some Fairbanks contractors, Alyeska worked to develop a lighter and more maneuverable clamp better able to deal with high-pressure leaks than the crane-lifted hydraulic clamp used in the 2001 incident.

How it works

Petroleum News, in October 2007, published a story that described the HC 320 clamp.

"The concept for the clamp was based on large excavators used in the logging industry," the story said. "Those machines have an arm attached that is used to pick up huge logs."

An Alyeska emergency preparedness manager said the HC 320 can quickly latch onto the pipe, covering a hole. The clamp under certain conditions can stay attached as a temporary repair, allowing the pipeline to re-start. Alyeska has more than one of these clamps, Carle said, but he declined for security reasons to specify how many. ●

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● EXPLORATION & PRODUCTION

Marathon tests downhole RFID techniques

The use of RFID tags to control downhole gear could reduce drilling time, save millions of dollars and reduce environmental impacts

By ALAN BAILEY
Petroleum News

In perhaps its most visible form, radio frequency identification, or RFID, has become familiar to many as the magic badge that you wave in the air to unlock an office door, open a security gate or perhaps gain admission to a ski lift. But, behind the scenes in many industries, RFID has become something of an ubiquitous technology, widely used to track freight and perform many of the functions of a traditional bar-coding system.

Marathon Oil Corp., working with various industry partners, has been spearheading efforts to apply RFID technology in the drilling of oil and gas wells, to cut costs and save time by more efficiently controlling the drilling equipment deep underground in a well bore, Tim Deines, Marathon's well performance manager for upstream technology, told Petroleum News. And improved efficiency translates to a reduced environmental impact, thanks to less time spent running the engines that power the drilling rigs; less need to "trip," or pull, the drill pipe from a well; and less need to vent gas when completing natural gas wells, Deines said.

Marathon's industry partners in its RFID initiative include Weatherford International, a company with expertise in downhole electronics, and Petrowell, a U.K. company that specializes in downhole equipment design, including RFID tools, said Phil Snider, Marathon's senior technical consultant for upstream technology.

MARATHON OIL CORP.

Marathon's Tim Deines (left) and Phil Snider (right) holding samples of RFID tags, used to control downhole equipment in oil wells. The tiny tags consist of computer chips embedded in glass cylinders.

Micro-electronics

In essence, an RFID application has a micro-electronic radio receiver that acts as a code reader, to control some device, say an office building door lock. An RFID tag, placed in proximity to the reader and consisting of a tiny radio transmitter-receiver in the form of a micro-electronic chip, is activated by signals transmitted by the reader device, then responds by sending a coded signal back to the reader. If the reader receives the appropriate code, it activates the required operation, such as the unlocking of the office door.

There are several ways in which this type of technology could be applied when drilling an oil or gas well. However, Marathon's main focus is on fitting RFID readers into downhole well equipment and then using RFID tags to pass instructions to the equipment: In the same way that an RFID security badge will open an office door, an RFID tag passed down a well will activate a piece of equipment, shut it down or perhaps open or close a valve. Marathon is investigating the operation in this manner of as many as 30 types of downhole tools, Snider said.

Tiny tags

A typical RFID tag used in a downhole operation is about 3 millimeters in diameter and about 3 centimeters long.

"It's just a very small computer chip that's embedded in a cylindrical piece of glass, and we'll either pump it down to the downhole tool that we're trying to actuate, or we'll gravity drop it," Snider said.

When pumped down a well, tags are injected through a small side port in the drill pipe into the drilling fluid, typically drilling mud, that circulates through the well. The drillers program the tags for whatever operation the subsurface equipment needs to perform, and typically send several identically programmed tags down the well, to ensure that at least one tag triggers the required action.

"Most of the tags read a lot better if they're parallel to the reader," Snider said.

Lab testing has indicated a 99.9 percent successful read rate with just a handful of tags, he said.

Reprint

This article is a reprint from Greening of Oil magazine that posted 1-13-10. Visit www.greeningofoil.com.

Pre-planning

Some pre-planning is needed — given the time that it takes for the tags to pass down the well, the drillers need to inject the tags into the well ahead of the precise time at which the downhole well operation needs to take place.

And the tags and RFID readers have to be constructed in a way that protects the micro-electronics from pressures of perhaps 15,000 to 20,000 pounds per square inch in the lower reaches of a well, while also withstanding the mechanical jostling within the well.

"One of the bigger challenges that we've had is that a lot of these tools are being used in a drilling environment, so the pipe is turning … there's a lot of downhole shock and vibration," Snider said.

And although there are alternative technologies for controlling downhole equipment, such as sending signals in the form of pressure pulses through the drilling mud, the RFID technique enjoys the advantage that multiple tags can simultaneously control multiple items of equipment, each with a unique RFID code, while not interfering with the mud pulsing techniques that are typically used in applications such as making continuous downhole measurements while drilling.

In addition, the RFID tags can sometimes simply be dropped down the well, or

see **RFID** page 11

continued from page 10

RFID

used in situations where some well fluid other than drilling mud is being used.

Multiple perforations

In one of the first of its applications of RFID techniques, Marathon used RFID tags to fire perforating guns when stimulating multiple gas-bearing zones in the complex reservoir of a gas field on Alaska's Kenai Peninsula.

"We're building out with this RFID a bunch of ways to do multizone stimulations," Deines said. "In that case we can stimulate all the zones in the well in one day, without having to flow back the well or do any other well operation."

This new way of executing a well completion avoids the need to vent any gas from the well, and enables the well to go straight on line for gas sales, he said. The multizone stimulation technique forms part of Marathon's Excape® Completion Process technology, used by the company to complete gas wells in Alaska's Cook Inlet basin and to complete the horizontal wells that produce gas from tight shale-gas reservoirs. Shale-gas plays have become a key part of the company's exploration and development portfolio in the Lower 48, Deines said.

In Alaska alone, Marathon has saved 150 million cubic feet of otherwise vented gas by using multizone stimulations, Deines said. The company has received a U.S. Environmental Protection Agency natural gas STAR award for the Excape technology, he said.

Underreamers

Marathon has been testing the use of the RFID technology to control underreamers, devices used to widen a well bore below a narrower section of pipe.

Underreamers wear out quite rapidly when in use, causing the drillers to pull the drill pipe and the tool from the well to install a new tool for continuing the operation. But with an RFID system, the drillers can run perhaps three underreamers down the well simultaneously, with each of the tools controlled by a unique RFID code. As each tool wears out, RFID tags can shut that tool down and start up a new one, thus eliminating the need to pull the drill pipe from the well.

And that's a really big deal in some of the areas that companies like Marathon now operate.

For example, Marathon has major interests in the deepwater oil and gas regions of the Gulf of Mexico and Indonesia, where drilling now takes place in water depths of around 8,000 feet and is moving into depths of 10,000 to 12,000 feet, with drilling rig operational costs running at about $1 million per day, Deines said.

Millions of dollars

In these deepwater situations, avoiding the need to pull the drill pipe from a well, thanks to RFID-controlled underreamers, could save major dollars in drilling costs per tool-change operation, Snider said. And keeping the drill pipe in the hole reduces the operational risks for the drillers, while also avoiding damage to the well bore.

RFID techniques can also reduce costs in downhole pipe retrieval operations by enabling the tag-triggered disconnection of a section of downhole drill pipe from the tools at the bottom of the well, in a situation where perhaps the bottom section of the drill string has become stuck.

"We think a drilling disconnect, where we're circulating a chip down and disconnecting from the tools, could save us easily half a day or maybe even a whole day, by the time we mobilize equipment," Deines said. "Just a single activation by a chip in the deepwater environment we believe could save us anywhere from $1 million to $3 million, each time we use the technology."

In one of the first of its applications of RFID techniques, Marathon used RFID tags to fire perforating guns when stimulating multiple gas-bearing zones in the complex reservoir of a gas field on Alaska's Kenai Peninsula.

In another application, Marathon has been partnering with drilling fluid firm M-I Swaco to use RFID technology to control a device called a circulating sub that enables drillers to circulate fluids in a well above the drill bit, to clean the well bore, for example. With the RFID-controlled equipment in place in the well, tags dropped into the well can cause the port on a circulating sub to open or close, while other appropriately coded tags can control a barrier valve within the well bore, Snider said. It's also possible to instruct the downhole equipment to perform an operation at a specific time, he said.

And it's even possible to run multiple circulating subs in a single drill string, with each device controlled by an individual RFID code.

Field trials

So, given the benefits that RFID technology can bring to drilling operations, how far have Marathon and its business partners progressed in bringing the technology into regular use?

"We are field trialing the prototype tools, just ahead of full-blown commercialization," Snider said.

Those field trials are on the increase and have been taking place in the North Sea and North Dakota, in addition to the initial use of the technology in Alaska. The idea is to test the technology in safe situations, where wells are already being drilled, before going to full-blown commerciality, Snider said.

And the use of RFID technology is but one example of how state-of-the art electronics, computer systems and materials science are transforming the modern oil field, greatly improving efficiency, improving safety and reducing environmental impacts, he said. ●

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MEDIA

Greening of Oil magazine launches

Anchorage-based Petroleum News has launched a new, international online magazine at www.greeningofoil.com. Greening of Oil is a science-based publication that tracks the environmental footprint of fossil fuels, scrutinizing what is being done to make hydrocarbons a more earth-friendly energy source during what is expected to be a decades-long shift to cleaner and cleaner power.

Greening of Oil also tracks the environmental impact of alternative energy sources.

How green can oil, natural gas and coal get? The answer is repeatedly pursued in the online publication, which posts new articles daily and is free to subscribers.

Written by experienced journalists and free to everyone, Greening of Oil contains no opinion pieces or editorials. It is a fact-based magazine, free from the clutter of personal opinions, and a key resource for people who care about the environmental performance of energy companies.

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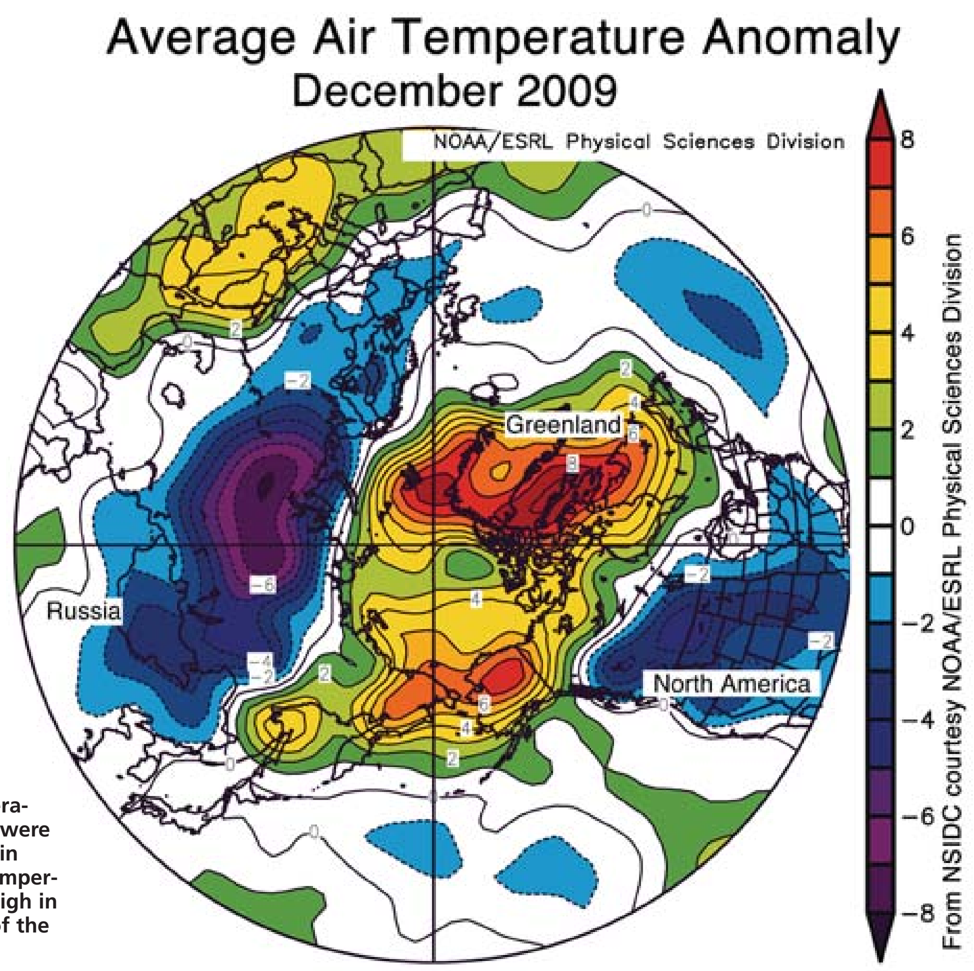
Student resources include scholarships for any field of study, energy internships, a chance to publish a synopsis and link to final project papers, and an online reference generator for academic research.

The primary readership target of the magazine is the next generation of university-age students. Other targets include the energy industry, energy opinion leaders, energy-conscious consumers, and science and technology buffs.

—PETROLEUM NEWS

NATIONAL SNOW AND ICE DATA CENTER



Average air temperatures in the Arctic were abnormally warm in December, with temperatures especially high in the Arctic region of the North Atlantic.

● SAFETY & ENVIRONMENT

Arctic warms while Europe and L48 freeze

Unusual weather pattern sweeps frigid air south while warmer than normal conditions in North Atlantic reduce rate of sea ice formation

By ALAN BAILEY
Petroleum News

Newsreel shots of blizzards in central Europe, the sight of snow storms in Oklahoma and reports of Arctic-like temperatures in Scotland and Scandinavia may leave people wondering what the weather has been like in the Arctic, where seriously cold conditions normally prevail at this time of year.

But the Arctic and the extreme northwestern part of North America were unusually warm in December, causing the Arctic sea-ice extent to remain below normal, especially in the Arctic regions of the North Atlantic, the National Snow and Ice Data Center reported Jan. 5.

But a negative phase of the Arctic oscillation affects the winds that typically blow sea ice out of the Arctic Ocean and could, as a consequence, end up retaining second- and third-year Arctic sea ice and rebuilding some older multiyear ice, NSIDC said.

"Average air temperatures over the Arctic Ocean were much higher than normal for the month, reflecting unusual atmospheric conditions," NSIDC said.

How come?

Arctic oscillation

December saw an extreme negative phase of a climatic feature called the Arctic oscillation, resulting in a major change in wind patterns and an unusual pattern of temperatures in the Earth's northern hemisphere, NSIDC said.

It's all to do with the distribution of air pressures at low altitudes in the atmosphere. Low atmospheric pressure normally characterizes the northern polar region, with a counterbalancing area of relatively high pressure at mid-latitudes. In the North Atlantic, this pressure pattern gives rise to prevailing southwesterly winds that bring warm, moist air into northern Europe, causing, for example, the legendary grey skies, rain and mild temperatures of the British Isles.

The term "Arctic oscillation" refers to variations over time in the pressure levels in the pressure pattern. In a positive phase of the oscillation the atmospheric pressure in the Arctic is especially low, while in a negative phase the pressure is abnormally high. And this winter the negative phase dropped to the lowest negative value observed since 1950, shifting the normal warm southwesterly air flow in the Atlantic and causing temperatures in Europe to plummet to levels not seen in decades.

see WARM ARCTIC page 18

● NATURAL GAS

Apache takes control of Kitimat LNG

By GARY PARK

For Petroleum News

U.S. independent Apache has made a decisive move to the forefront of North America's changing energy markets by taking control of British Columbia's Kitimat LNG project.

The Canadian unit of Apache announced Jan. 13 it will acquire a 51 percent stake of the proposed export terminal and 51 percent of the facility's capacity.

That follows a deal last August which would have seen Apache take an equity position in the C$3 billion project that is expected to have capacity of 700 million cubic feet per day if it comes on stream as scheduled in 2014.

The financial terms were not disclosed.

Apache Chairman and Chief Executive Officer Steven Faris said in a statement that the growing gas supply in the U.S. and Canada is "transforming" the continental market.

"This increased resource has significant potential for global impact," he said.

"Development of the Kitimat LNG project has the potential to open new markets in the Asia-Pacific region for gas from Apache's Canadian operations, including the Horn River basin in northeast British Columbia, where our net estimated resource potential exceeds 10 trillion cubic feet of gas."

Alfred Sorenson, chief executive officer of Galveston LNG, the current owner of Kitimat LNG, said the "economic fundamentals remain strong for exporting natural gas from Western Canada to international markets where natural gas is in demand, such as Asia."

"As natural gas supply and reserves continue to increase in North America, Kitimat LNG's terminal will provide producers in Canada with secure access to key worldwide markets."

Kitimat would be linked to Western Canada's fast-emerging shale and tight gas producing regions through the planned Pacific Trail Pipeline, a C$1.1 billion, 300-mile link to the deepwater port at Kitimat on the northern British Columbia coast.

By acquiring a 51 percent interest in the Kitimat project, Apache would take a 25.5 percent stake in the pipeline, which is currently a joint partnership between Galveston LNG and Pacific Northern Gas.

The pipeline has Canadian and British Columbia government environmental approvals and has established an arrangement to partner with First Nations along the pipeline route.

Kitimat also has British Columbia and federal certificates for the liquefaction terminal.

Kitimat had a memorandum of understanding with EOG Resources to supply gas to the project and sales deals with Spain's Gas Natural and Korea Gas. It is not immediately clear where those agreements stand. ●

Contact Gary Park through publisher@petroleumnews.com

● NATURAL GAS

Action on six B.C. gas-related bombings

Royal Canadian Mounted Police search property, interrogate and release; say new evidence will be submitted to prosecutors

By GARY PARK

For Petroleum News

An arrest, 10 hours of interrogation, about 150 officers from the Royal Canadian Mounted Police scouring a 750-acre property in northwestern Alberta, talk of a possible extortion charge — everything pointed to a breakthrough in an 18-month investigation into six natural gas-related bombings in northeastern British Columbia.

Operating under a five-day search warrant, the RCMP descended Jan. 8 on five homes and 14 outbuildings on the rural compound of former religious leader and convicted oil patch bomber Wiebo Ludwig and about 50 followers.

They took Ludwig into custody, grilled him and released him without charge.

RCMP Inspector Tim Shields said Jan. 9 that new evidence will be submitted to government prosecutors, but conceded that the prosecutors don't agree with the RCMP that there are "reasonable and sufficient grounds" to lay charges.

Ludwig told his attorney Paul Moreau he expected to be charged with extortion.

RCMP 'trail of evidence'

The RCMP said only that they have "followed a trail of evidence that ultimately led to the execution of the search warrant."

Shields told reporters he was "not about to say what it is we've found and I'm not even saying we found it on this property."

He said the RCMP was compelled to arrest Ludwig "out of an obligation to provide public safety," but would not say whether the RCMP suspected an imminent attack, adding to the six explosions on EnCana properties over the October 2008-July 2009 period.

EnCana has posted a C$1 million cash reward — double its original offer — for information directly leading to the arrest and prosecution of those responsible for the bombings.

Six explosions

"We have had six explosions so far," Shields said. "They were becoming increasingly dangerous.

"We are satisfied we made the arrest at the right time, for the right reasons and with the right amount of legal justification," he said.

"Everything that has happened over the past three days is advancing this case and getting us closer to the finish line," said Shields.

Anonymous letters were sent to local newspapers last year warning of further attacks.

Ludwig spent 18 months in jail on five charges of bombings of Alberta oil and gas facilities in the 1990s.

He has made repeated claims that the health of his family members and livestock have suffered from gas-well drilling, flaring and industry-related activities near his properties.

While denying he has been involved in the latest bombings, he said on Jan. 10 he is concerned that those "who are being abused by the industry are neglected."●

Contact Gary Park through publisher@petroleumnews.com

NATURAL GAS

Mackenzie project gets hearing dates

The Mackenzie Gas Project has been given its roadmap for the final regulatory phases.

Canada's National Energy Board said it will start hearing concluding arguments April 12 in Yellowknife and wrap up in Inuvik on April 25.

"With the schedule that we have announced, our goal is to set out clear 'rules of the game' for the many people and organizations who are interested in the outcome of this hearing," NEB panel Chairman Kenneth Vollman said in a release.

During the final phase, applicants and intervenors will have a chance to make their case to the NEB either for or against the MGP.

But those arguments must be based on evidence that has already been presented to the NEB.

Before the hearings, the NEB will coordinate a written process to gather comments on the Joint Review Panel's 176 recommendations related to the environmental and social impact of the MGP from the project applicants and individuals who participated in either the NEB's initial round or the JRP's hearing process.

The NEB will also coordinate the collection of comments on the JRP recommendations aimed at other government departments and agencies.

Once final arguments have been presented, the NEB will be able to prepare its final decision, which is expected about September, turning the matter over to the Canadian government.

The NEB started hearings four years ago on five applications filed by the major partners — Imperial Oil, ConocoPhillips Canada, Shell Canada, ExxonMobil Canada and the Aboriginal Pipeline Group.

The NEB schedule allows hearings in Yellowknife from April 12-17 and Inuvik April 20-25.

—GARY PARK

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UPSTREAM

sustained US$80-per-barrel oil price.

For Western Canada, December was the strongest month for 2009, posting a total of 2,105 new licenses, while the last five months of the year spurred a revival of oil drilling interest in Alberta and Saskatchewan.

Gas prices up

Entering 2010, gas prices at the Alberta AECO trading hub have nudged C$5.75 per Gigajoule, about C$2 above last year's average closing day spot prices and C$3 above the 1999 average.

That gave producers something to cheer about after they tallied their dismal returns from the 2009 average of C$4.35, down 32 percent from the final quarter of 2008.

While gas continued on its rollercoaster, a rally in oil prices, helped by a steadily recovering North American economy, gave that sector reason for hope.

Although the average price was down 36 percent from 2008's record of more than C$100 per barrel, light, sweet crude at Edmonton averaged C$66.46 per barrel for all of 2009, within sight of the C$69-$77 prices posted in the 2005-07 period.

Lloydminster heavy crude prices averaged C$58.50 last year, a hefty setback from the previous year's C$82.87, but the second best price in the past decade.

Heavy oil producers benefited from a continued narrowing of the gap between heavy and light oil, with Fort Hills Lloyd Blend averaging C$58.50, down 29 percent from 2008, while Imperial Bow River yielded C$60.14, a drop of 28.9 percent from 2008.

The differential between Flint Hills blend and the average Canadian price declined to C$7.90 per barrel from C$20.56 in 2008.

The cancellation or postponement of many oil sands programs hammered that sector, which obtained only 1,674 approvals for evaluation wells, compared with 3,567 in 2008 and 5,132 in 2007.

Gas wells down

Against this mixed and uncertain backdrop, Canadian operators found more comfort in oil than gas as they sought regulatory approval for new wells.

Alberta, British Columbia and Saskatchewan approved 5,507 gas permits (including coalbed methane) last year, compared with 12,082 in 2008 and the benchmark 21,503 in 2005.

Gas was the major drag, with operators licensing only 661 new gas wells in December, down from 1,095 a year earlier, but Alberta issued 468 new oil permits during the month (283 conventional and 185 bitumen), the most for December since 2000. East-central Alberta, the focal point of the sizzling Cardium play, posted 522 new oil well permits in the final quarter, up 9 percent from the same period of 2008.

The hardest hit regions in 2009 were southeastern Albert's shallow gas plays, with only 2,652 permits issued, down 2,424 from 2008, and southwestern Saskatchewan's shallow gas plays, where new licenses plunged to 537 from 2,113 in 2008.

In Alberta, the Energy Resources Conservation Board approved 1,041 new coalbed methane permits, barely half the 2008 total of 2,031 and about one-third of the record 3,106 in 2005.

The cancellation or postponement of many oil sands programs hammered that sector, which obtained only 1,674 approvals for evaluation wells, compared with 3,567 in 2008 and 5,132 in 2007.

EnCana leading operator

Leading the operators were EnCana, with 2,210 licenses, and Canadian Natural Resources, 1,180, compared with 3,445 and 1,508, respectively, in 2008. Next in line were Husky Energy 575, Enerplus Resources Fund 498 and Suncor Energy 397.

The trade publication Rig Locator reported that 598 of the available 798 rigs were at work in Western Canada in the first week of January, a level not seen since 2008.

Chad Friess, an analyst with UBS Securities, said the performance is better than last year and a spokeswoman for the Canadian Association of Oilwell Drilling Contractors said there is evidence of a "little more stability" than a year ago.

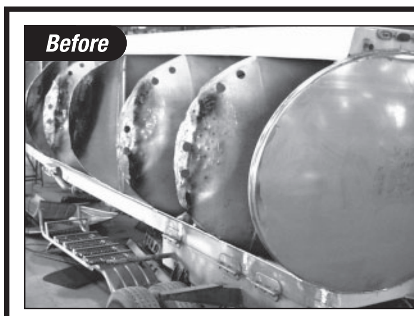
Friess forecasts the active rig count will ease by late February, but less dramatically than last year because there are a lot better balance sheets out there. Companies are able to continue spending, whereas last year the winter budgets had been set even before the financial crunch gripped.

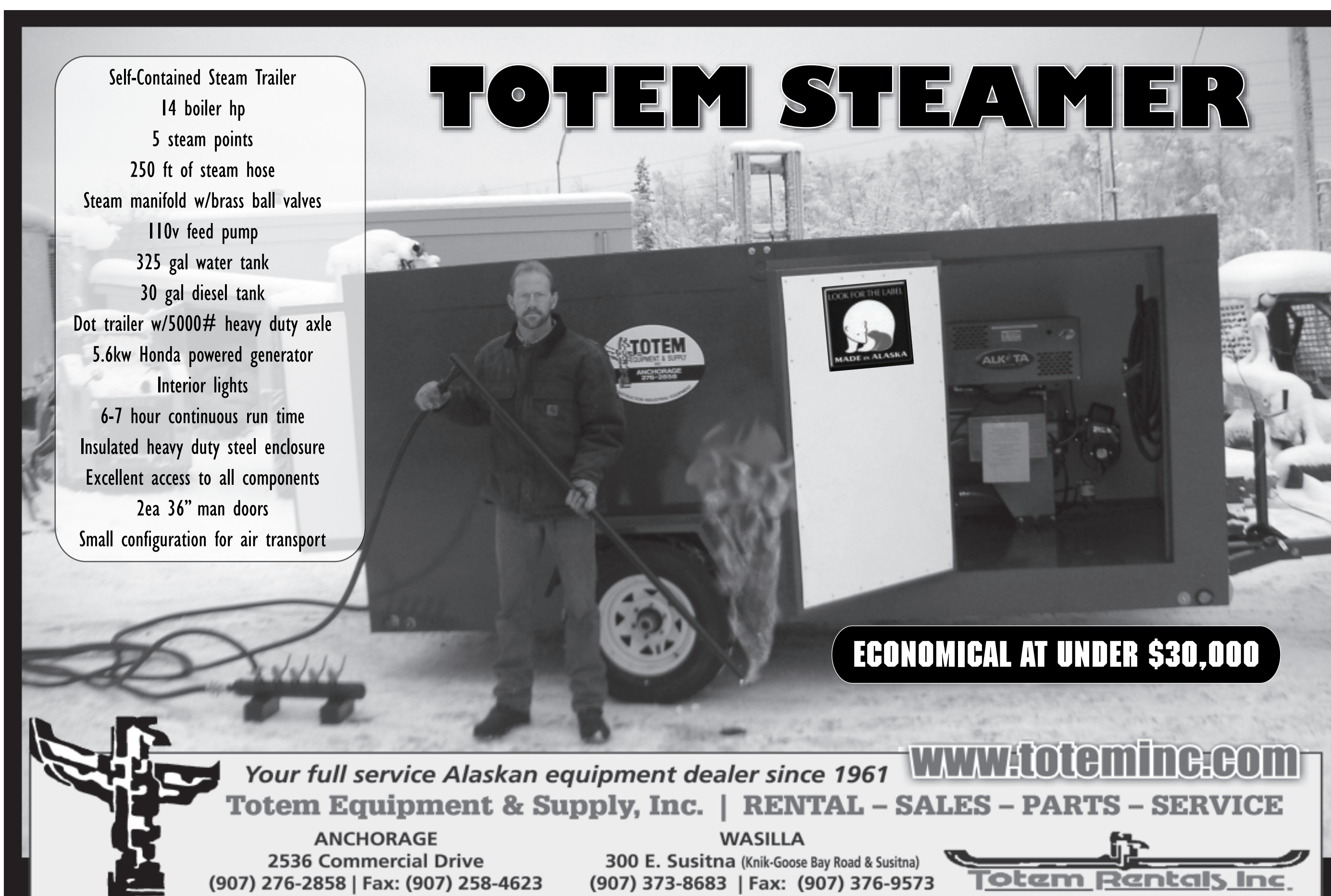
He is counting on 3,100 wells during the first quarter, with an average 351 rigs working, compared with 311 a year earlier.

In the United States, observers are concerned that expanding activity levels will deliver more gas to an already saturated market and could deflate commodity prices that have just started to regain solid ground.

Macquarie Capital analyst Waqar Syed said the next two months will be critical for the gas sector, based on how much gas is drawn out of storage, where the surplus is currently estimated at 11 percent.

—GARY PARK



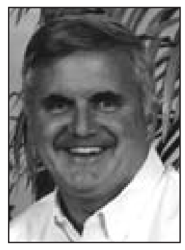


Petroleum news

Oil Patch Bits

Crowley restructures senior management team


JOHN DOUGLAS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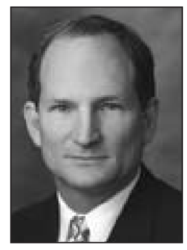
ROCKWELL SMITH

Crowley Maritime Corp. said Jan. 11 that it is restructuring its senior management team with John Douglas taking over as senior vice president and general manager of Crowley's Puerto Rico/Caribbean liner services; Rob Grune will be taking over as senior vice president and general manager of Crowley's petroleum transportation group. In addition, Rockwell Smith, Crowley's senior vice president and general manager based in Seattle, will assume responsibility for all of Crowley's marine contract services both domestically and internationally, continuing to oversee the company's Alaska operations and West Coast harbor services. For more information visit www.crowley.com.

Air Liquide to double its production capacity

Air Liquide said Jan. 4 that it has begun building a new production unit in Anchorage to double its liquid oxygen and nitrogen capacity in Alaska. Air Liquide has been a leading provider of industrial gases in the state of Alaska for 41 years, with 75 employees ensuring the production of oxygen, nitrogen and acetylene gases distributed in bulk tankers and cylinders, providing equipment to customers in the petrochemical, refining and mining sectors. Scheduled to start in the fall of 2010, the new unit will allow Air Liquide to provide reliable production and distribution of industrial and medical gases to Alaskans, which is particularly important, due to the state's geography and distribution challenges. For more information visit www.airliquide.com.

ExxonMobil grants $500,000 to Teach for America

ExxonMobil said Jan. 6 that its $500,000 grant to Teach for America will be used to recruit more than 1,500 top college graduates from across the United States to teach middle-school math and science. The funds will also support Teach for America's rigorous program of pre-service training, ongoing professional development and mentoring for these teachers. "Improving the quality of math and science education in America's classrooms is a primary focus for ExxonMobil because we believe that education is the key to progress, development and economic growth," said Gerald McElvy, president of ExxonMobil Foundation. ExxonMobil has supported Teach for America for 16 years, and in 2009 invested more than $90 million in education initiatives worldwide. For more information visit www.exxonmobil.com/community.

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

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

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PERMIT

drilling program," said Shell Alaska Vice President Pete Slaiby on Jan. 7. "The issuance of this draft permit starts the clock on a critical timeline of events that will ultimately determine if we can explore our Alaska leases in 2010."

Shell plans to drill up to three exploration wells in the Chukchi Sea in 2010, and the company applied for a major prevention of significant deterioration air quality permit, rather than a minor permit, for the drilling. Shell is making a $25 million modification to the Frontier Discoverer, the drillship that the company plans to use for the drilling, to install catalytic reducers to scrub the engine exhaust and thus reduce the emission of pollutants by more than 90 percent. And the company has committed to the use of low-sulfur fuel in the Frontier Discoverer's diesel engines.

Shell plans to drill up to three exploration wells in the Chukchi Sea in 2010, and the company applied for a major prevention of significant deterioration air quality permit, rather than a minor permit, for the drilling.

Public comments

But with the public comment period on the new proposed air quality permit due to end on Feb. 17, Shell must still wait for another few weeks before EPA can finally issue the permit.

"While today's announcement is good news, the length of the public comment period combined with likely appeals still pushes the boundaries of our ability to drill in 2010," Slaiby said. "Obviously, the windows in which we have to operate are limited and a decision to move forward is an extremely expensive one. We will continue to monitor our options in the days ahead as we get closer to making that critical decision."

Alaska politicians expressed cautious satisfaction at the EPA decision.

"The EPA's decision to approve an air-quality permit for Shell's Chukchi Sea exploration has been a long time coming," said Sen. Lisa Murkowski Jan. 7. "Today's decision represents progress. While several additional hurdles remain, the agency's action offers some reassurance that exploration for oil and gas resources off Alaska's coast will be allowed to proceed."

"Alaska has long been America's energy storehouse and a green light on this Shell development means Alaska's energy will continue to help fuel our nation's factories and automobiles," Sen. Mark Begich said. "It has become increasingly clear that energy policy is national security policy, and the U.S. needs to focus more on production of our rich energy resources right here at home. Let's stop paying billions a year to hostile countries and start putting Alaskans to work."

Modified permit

EPA originally published a proposed air quality permit in August for Shell's Chukchi Sea drilling. However, following a public comment period, the agency decided to modify the permit, to reflect some of the comments that the agency received.

Major changes to the permit issued in August will result in allowed emissions of particulate matter being reduced from 184 tons per year to 52 tons per year, and a reduction in allowed sulfur dioxide emissions from 181 tons per year to less than 2 tons per year, EPA said. And among a series of changes to the air emissions stipulations, the permit now requires catalytic diesel particulate filters on engines in the oil spill response vessel planned to stand by the Shell drilling operations, as well as tighter limits on the incineration of waste in the Frontier Discoverer.

Previous air quality permitting for Shell's planned Alaska outer continental shelf drilling operations raised questions regarding what constitutes an outer continental shelf emissions source, for the purpose of determining the quantity of emissions that the operations would generate: The broader the definition of the source, the greater the amount of emissions that would fall within the scope of the permit.

The new proposed permit offers two alternative definitions of the regulated emissions source, with an invitation for the public to comment on which of these definitions would be more appropriate. One definition would consider the Frontier Discoverer to be an outer continental shelf source for the period during which it is attached to the seabed by at least one anchor at a specific drill site; the other definition would consider the vessel to be a source during the period that the vessel's crew has determined the vessel to be sufficiently stable and secure to carry out drilling at the site.

These definitions reflect the way in which the Frontier Discoverer is stationed to drill a well.

Drilling turret

Essentially, the drillship has a drilling turret that enables the ship's hull to rotate into the wind or ice while the drilling rig remains in a fixed position over a well location. The drilling turret is anchored to the seafloor, with the assistance of an anchor handling vessel, using eight mooring lines extending radially from the vessel.

EPA's regulations say that a vessel is considered to be an OCS emissions source only if permanently or temporarily attached to the seabed, "erected thereon," and used for the purposes of exploring, developing or producing resources from the seabed, EPA said.

And, although the use of a single mooring anchor might be sufficient to constitute attachment to the seafloor, "erected thereon" may imply the placement and tensioning of enough anchors to render the vessel sufficiently stable for drilling, the agency said.

The U.S. Minerals Management Service told EPA in December that MMS does not consider a drillship such as the Frontier Discoverer to be permanently or temporarily attached to the seabed until all anchors have been set, with the vessel being operated under and "subject to maritime laws and practices" at other times, EPA said.

But the supply vessel that services the drillship will also be considered an OCS emissions source when physically attached to the drillship.

Other vessels in Shell's drilling support fleet are not considered to be OCS sources, although the emissions from these vessels when within 25 miles of the drillship need to be added into the overall emissions inventory for the drillship, EPA said.

—ALAN BAILEY

On the Web

See previous Petroleum News coverage:

"Going major on the OCS," in Aug. 23, 2009, issue at www.petroleumnews.com/pnads/106898981.shtml

GOVERNMENT

Dennis McLerran to head EPA region 10

The U.S. Environmental Protection Agency said Jan. 13 that Dennis J. McLerran has been selected to be the regional administrator for EPA's region 10, which includes Alaska, Idaho, Oregon, Washington and Pacific Northwest Indian Country.

The agency said regional administrators are responsible for managing regional activities under the direction of the EPA administrator, promoting state and local environmental protection efforts and serving as liaisons to state and local government officials. Regional administrators are tasked with ensuring EPA's efforts to address the environmental crises of today are routed in science-based policies and programs, adherence to the rule of law and transparency.

McLerran has more than 20 years experience as an advocate, attorney and administrator and most recently served as executive director of the Puget Sound Clean Air Agency, a state-chartered regional agency that adopts and enforces air quality standards that protect the health of 3.5 million Washington residents.

As executive director McLerran led the development of an innovative strategy to reduce emissions at the ports of Seattle, Tacoma and Metro Vancouver.

Prior to that, McLerran served as city attorney for the City of Port Townsend and director of the Seattle Department of Construction and Land Use. McLerran received his bachelor's degree from the University of Washington and a J.D. from the Seattle University School of Law.

—PETROLEUM NEWS

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STORAGE

such natural gas storage," Marathon said.

Marathon said it has a significant interest in natural gas storage in Alaska and owns a majority interest in and operates the Cannery Loop unit where CINGS proposes to construct and operate its third-party natural gas storage facility.

Marathon said experience has shown that utility-style regulation "is slow, costly, cumbersome and has the effect of discouraging the construction and development of new natural gas facilities."

And, it told the commission, neither statute was written to be applied to stand-alone facilities.

Marathon also said that in making its decision on the declaratory judgment sought by CINGS, "the Commission should be careful to confine its decision to the specific factual context proposed by CINGS since no other factual context is before the Commission for evaluation."

Aurora Gas had a similar concern about a possible broadening of the scope of an RCA decision and requested "that any declaratory ruling by the Commission be limited to CINGS and the specific asserted facts and circumstances of this case."

Aurora is in the process of establishing gas storage on the west side of Cook Inlet. ●

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RULING

"We've always been focused on that."

ExxonMobil issued a statement saying it is "encouraged that Judge Gleason has agreed with our position regarding the process DNR followed" in considering the company's development plan for the Point Thomson unit.

The energy giant also sounded a conciliatory tone: "We are ready to work with the DNR on all aspects of Point Thomson development in a mutually satisfactory manner for the benefit of all Alaskans."

Two holdings

Gleason's ruling found that state officials made two mistakes that denied ExxonMobil and the other major leaseholders — BP, Chevron and ConocoPhillips — a fair shake at preserving the Point Thomson unit.

First, she held that the leaseholders were denied a hearing under provisions of a key section of the Point Thomson unit agreement, which dates to 1977.

Second, Gleason said state officials failed to assure at least the appearance of fair and impartial administrative proceedings that followed her initial Point Thomson ruling of Dec. 26, 2007.

The first holding pertains to the unit agreement's Section 21, titled "Rate of prospecting, development and production."

The section says the state oil and gas director has the "authority to alter or modify from time to time in his discretion the … rate of production under this agreement."

The section, as modified in 1985, adds that the director's powers can be exercised only after the unit operator, ExxonMobil, has the opportunity for a hearing to consider, among other things, whether a required increase in the production rate would violate "good and diligent oil and gas engineering and production practices."

Many industry observers see Point Thomson gas as vital for an Alaska natural gas pipeline, though state officials have said a pipeline project could go forward without Point Thomson.

The state had resisted such a hearing for ExxonMobil, arguing in part that it's not required in a situation where the production rate is zero.

The lack of any oil or gas production from Point Thomson decades after its discovery is the basis for the state's efforts to break up the unit and potentially put the state acreage up for lease again.

"The question presented is whether 'rate of production' as used in Section 21 includes the rate of zero production," the judge wrote in her 29-page ruling.

Gleason concluded that, based on common definitions of "rate," ExxonMobil is entitled to a Section 21 hearing despite having no production at Point Thomson.

The judge also shot down another of the state's arguments — that she had ruled in 2007 that the leaseholders were in default of the Point Thomson unit agreement.

Not so, Gleason said.

In summary, DNR does have the right to seek increased production from Point Thomson, "but it can only enforce that right in accordance with … Section 21," the judge held.

'Entirely ethical'

Gleason's second major finding against the state involves the aftermath of her December 2007 ruling.

In that ruling, Gleason affirmed DNR's rejection of ExxonMobil's development plan for Point Thomson, but reversed the department's unit termination decision.

She remanded the unit termination to DNR with instructions to give the oil companies "an opportunity to be heard … as to the appropriate remedy" for the rejection of the development plan.

DNR subsequently held a weeklong administrative hearing in March 2008 before Commissioner Irwin, with the department's Nan Thompson serving as hearing officer. Thompson was manager of the Point Thomson unit in DNR's Division of Oil and Gas.

A couple of weeks before the hearing, ExxonMobil offered up a new, $1.3 billion plan of development for Point Thomson that included drilling several wells with an "unconditional commitment" to produce 10,000 barrels a day of natural gas condensate by 2014.

On April 22, 2008, Irwin rejected the development plan as inadequate and declared the unit terminated.

The oil companies, as they had done once before, appealed again to the Superior Court.

Part of the strategy for ExxonMobil lawyers was to go after Thompson, arguing she had been an "advocate" for the state against the company and had no business serving as hearing officer in the remand proceeding.

The ExxonMobil lawyers used public records requests to dig up documents, including e-mail, to make their point against Thompson.

"Long before the remand, the Hearing Officer, with the assistance of DNR's litigation counsel, coordinated an inter-agency effort to frustrate ExxonMobil's development efforts at Point Thomson and impugned ExxonMobil's motives for undertaking that development," ExxonMobil's lawyers wrote in a May 26, 2009, court filing.

They offered an April 25, 2007, e-mail from Thompson to another state official that purportedly said in part: "I think EM has instructed their troops to try to create a record that the state is blocking EM's efforts to develop these leases so they can make a record in court. Posturing rather than a sincere effort to move the project forward, is the more likely motivation."

ExxonMobil argued that the same state lawyers who defended DNR along with Thompson after the leaseholders first appealed the unit termination in court later provided private legal advice to Irwin during the remand proceeding, in violation of their constitutional right to due process.

Lawyers for the state countered that, well, Thompson wasn't the decision maker, Irwin was.

Gleason, in her Jan. 11 ruling, sided with ExxonMobil, writing, "There is no indication that the advocates in this case took any active part in the substantive deliberations of the Commissioner, and this Court has no doubt that the purpose of their private meetings with the Commissioner during the remand proceeding was entirely ethical. Nonetheless, in order to assure both the fact and appearance of impartiality … DNR's litigation counsel should not have been providing legal guidance to the Commissioner at the remand hearing, nor should DNR's agency representative in the first appeal have served in the position of hearing officer at the remand proceeding."

What now?

The unit designation is extremely important. Unitization is the glue that binds together leases with different owners, ensuring orderly and efficient development of an oil and gas field. Significantly in this case, it allows companies to retain otherwise expired leases.

Barring some sort of settlement, the Point Thomson conflict now appears headed for months, if not years, of further jousting in court. All parties seem to agree that, once it exhausts the Superior Court, the case will advance to the Alaska Supreme Court.

Control of an asset worth billions of dollars is at stake.

Point Thomson holds an estimated 8 trillion cubic feet of gas — about a quarter of all the known gas reserves on the North Slope — plus hundreds of millions of barrels of petroleum liquids.

Many industry observers see Point Thomson gas as vital for an Alaska natural gas pipeline, though state officials have said a pipeline project could go forward without Point Thomson.

Gleason gave both sides 30 days to file arguments on whether she should again remand the matter to DNR for another administrative hearing, or whether the judge should retain jurisdiction and conduct what's known as a trial de novo.

Meantime, ExxonMobil is going ahead with drilling on a pair of Point Thomson leases, which Irwin is allowing despite the still undetermined status of the unit and 29 other leases the state considers expired. ●

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WARM ARCTIC

Warm air

At the same time the higher-than-normal pressure in the Arctic lodged warmer-than-normal air in the region.

"The strongest anomalies (more than 7 C/13 F) were over the Atlantic side of the Arctic, including Baffin Bay and Davis Strait, where ice extent was below average," NSIDC said.

But a negative phase of the Arctic oscillation affects the winds that typically blow sea ice out of the Arctic Ocean and could, as a consequence, end up retaining second- and third-year Arctic sea ice and rebuilding some older multi-year ice, NSIDC said.

Meantime, the average Arctic Sea ice extent in December was 26,000 square miles, the fourth lowest extent since the start of satellite Arctic ice observations in 1979, NSIDC said. ●

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OPEN SEASON

Open season dates are significant but holding an open season does not mean a line will be built. The pipeline has to receive bids for enough volume to justify building the line and additional open seasons may be required. The pipeline also has to negotiate and sign precedent agreements with potential shippers after the open season closes.

"The results of the open season will provide an understanding of shipper requirements, which will be important as we consider our next steps," Fackrell said.

Successful open season the goal

Fackrell said Denali's objective is to have a successful open season, but "we are concerned that shippers may hesitate to make the financial commitments needed to support the project due to issues outside of Denali's control."

Those issues are the increased gas supply in the Lower 48, the legal status of leases at the Point Thomson field and "the lack of a long-term fiscal regime for North Slope gas production," he said.

Fackrell said Denali's potential shippers have said publicly that resolution of those issues "will be important in their decisions" to make the multibillion-dollar commitments necessary to move the project forward.

Fackrell said in a November report to the Legislature that work to estimate the cost of the pipeline and the gas treatment plant was "nearing completion."

He also said in November that Denali had "initiated pre-open season discussions with potential anchor shippers and is formatting its open season plans."

The company's willingness to commit to an April date to file its open season package with FERC is based on work the company has accomplished.

"Our engineering and cost estimating work has progressed to the point we feel we'll be ready to start our open season in April," Denali spokesman Dave MacDowell said in an e-mail.

He said Denali's plan is to have a commercial offering that is attractive to customers, based on the $130 million in work Denali has done. A successful open season — with commitments from shippers — "will enable the project to move forward," MacDowell said.

Timelines

Alaska Gov. Sean Parnell welcomed the news that the Denali open season process would start in April.

"Denali's move marks another milestone as competition drives the parties closer together," Parnell said in a statement.

The governor also said the announcement by Denali puts the open season for the TransCanada-ExxonMobil and the BP-ConocoPhillips Denali projects "in sync."

"Though there remains a long road ahead, this is good news for Alaska." he said.

Denali said it has invested $130 million in the project over the past 20 months, primarily in field work, engineering and stakeholder engagement. The company said the work underpins "a robust project plan and cost estimate."

Denali's proposal is to deliver more than 4 billion cubic feet of natural gas per day from the North Slope to markets in the Lower 48, Alaska and Canada.

The company's schedule for the open season starts with submittal of an open season package to FERC in April, followed by a 60-day public comment period. Once FERC approves the bid package, there is a 30-day public notice, and then, in July, the 90-day open season begins.

The Denali schedule shows one to two months to sign precedent agreements after the end of the open season, then posting of open season results and filing copies of the precedent agreements with FERC.

Shipper concerns

In its November report to the Legislature Denali discussed its concerns about the natural gas market at some length.

It said emergence of new sources of unconventional gas and the potential for import of large volumes of liquefied natural gas have "the potential to change the perception of the long-term market for North American natural gas."

The competitiveness of natural gas delivered from the North Slope is an issue because of reduced demand and growth in supply from shale gas and LNG imports, the company told legislators.

It also said that one of the few publicly available long-range natural gas price forecasts — from the U.S. Department of Energy's Energy Information Administration — "does not represent a consensus view of the market."

"Ultimately, it is the shippers who will assess the economic viability of the pipeline based upon their own proprietary market perspectives as they determine whether or not they are willing to make the multibillion dollar, multiyear commitments that will be required to finance and construct the project."

The company also told legislators that recent natural gas price volatility and the potential for new supplies highlight "the market risk potential shippers face." ●

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> *"The results of the open season will provide an understanding of shipper requirements, which will be important as we consider our next steps."*
> —Denali President Bud Fackrell

FERC staff offer example

Federal Energy Regulatory Commission staff members from the Office of Energy Projects Division of Pipeline Certificates were in Anchorage Jan. 12 for a workshop on the open season process for Alaska.

The goal of an open season is precedent agreements, said Richard Foley, a regulatory gas utility specialist. Precedent agreements are contracts, and the shippers best suited for the line are identified in open season for further negotiations leading to precedent agreements.

From the pipeline's perspective, a precedent agreement says the pipeline will build the line if specified conditions are met; from the shipper's perspective, a precedent agreement says the shipper will pay the pipeline for capacity to move gas, if certain conditions are met.

Foley offered a recent example of publicly available precedent agreements for the Ruby Pipeline, a 675-mile, $1.3 billion, 1.5 billion-cubic-foot-per-day line with multiple shippers.

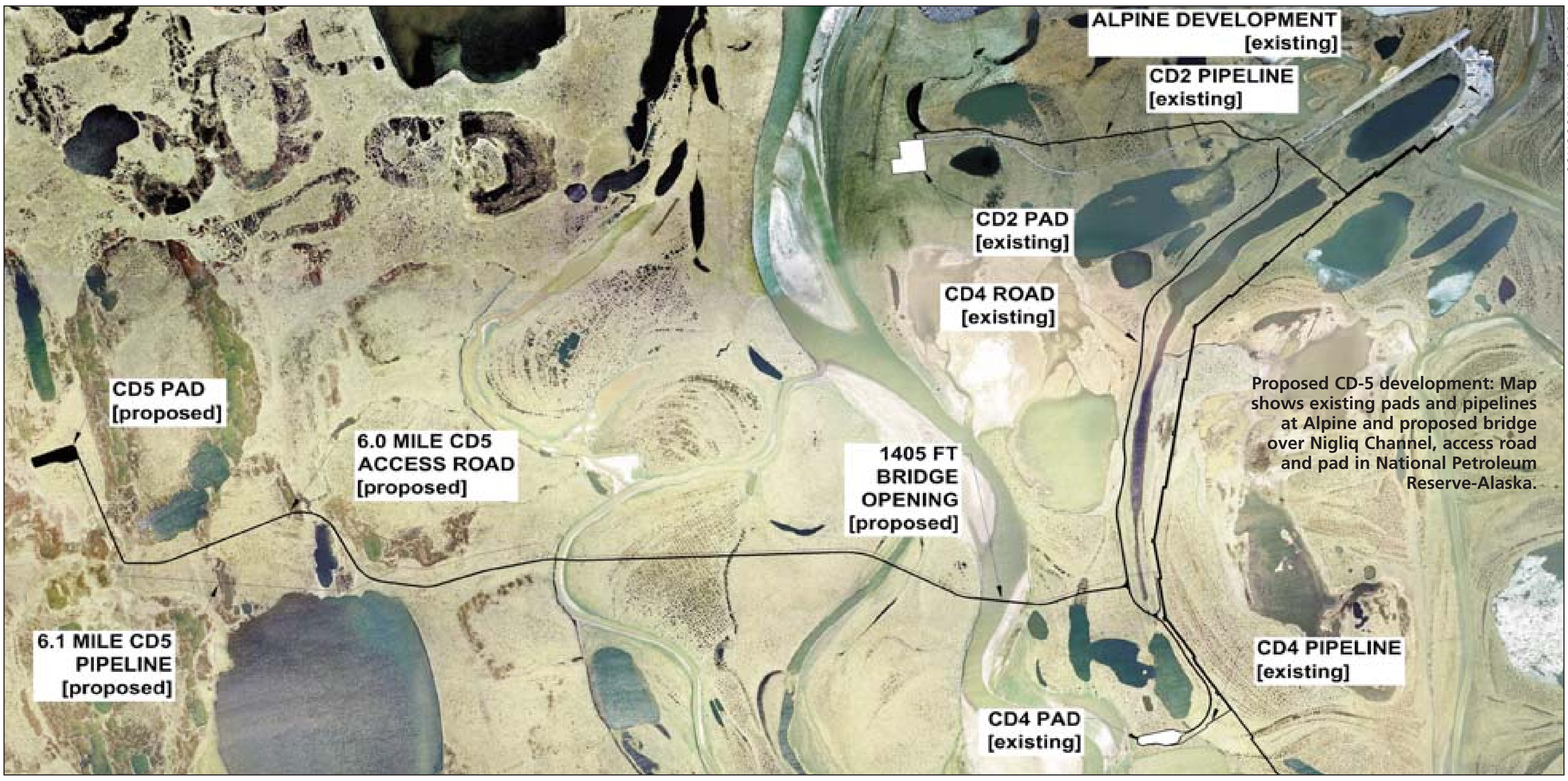
Negotiations with anchor shippers began in early 2007 and precedent agreements were signed in mid-2008 through early 2009, with one agreement modified in mid-2009.

Precedent agreements for the Ruby Pipeline included conditions including:

- The pipeline files and gets all approvals with agreeable terms and conditions;
- The pipeline starts and completes construction;
- The shipper can't terminate if the pipeline is already in the 16-month construction time, but the clock stops if government stops the work;
- There are options for carbon and greenhouse taxes;
- Creditworthiness requirements must be satisfied; and
- Anchor shippers' precedent agreements are approved by the state commission.

The overview included some items that are special features for an Alaska open season, including anchor shippers. Anchor shippers are allowed, Foley said, but other bidders are allowed to get matching terms if there are such pre-subscription agreements.

No bid can be rejected solely because a bidder has a bid pending in another open season, and second-chance bids — after the initial due date — must be considered as long as the project's progress does not prohibit capacity changes.



CONOCOPHILLIPS ALASKA

Proposed CD-5 development: Map shows existing pads and pipelines at Alpine and proposed bridge over Nigliq Channel, access road and pad in National Petroleum Reserve-Alaska.

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WEST ALPINE

A spokeswoman for the Corps of Engineers told Petroleum News that the corps had no comment.

Alpine West, also called CD-5, is included in a 2004 Environmental Impact Statement which includes now-developed drill sites at CD-3 and CD-4 (Fiord and Nanuq), and other NPR-A drill sites at CD-6 and CD-7 (now called Greater Mooses Tooth 1 and 2), Harding said.

The preferred alternative for CD-5 in the EIS was a development with a bridge across the Nigliq Channel and a road connecting CD-5 with the main facilities at Alpine, she said.

Alpine is not connected to the North Slope road system but is accessed by ice road in the winter and by air.

The bridge issue

ConocoPhillips submitted a 404 permit to the corps in 2005 and "spent the next few years working on that," Harding said.

But there were issues on the bridge location with Nuiqsut and Kuukpik, the village corporation for Nuiqsut, and while ConocoPhillips worked those issues in parallel with work on the corps permit, the project was put on hold and the permit withdrawn in 2008.

Harding arrived in Alaska in January 2008 and began working with Kuukpik and the Village of Nuiqsut on the bridge location. Local concerns were with fishing in the area originally proposed for the bridge and also with erosion, she said.

Agreement was reached to move the bridge to the south and the corps permit was basically re-submitted in December 2008.

With the exception of the bridge and pad locations, "it was pretty much the exact same permit," Harding said.

The pad was moved because over the years ConocoPhillips had done "some more extended reach drilling into some of the area that we called Alpine West," which led to the pad relocation.

The corps holdup

ConocoPhillips has "had extremely strong support" from Nuiqsut — the village corporation, the city and the Native village.

"All three had done resolutions in support of this," she said. The project also received support from the Alaska Department of Natural Resources, the North Slope Borough and the Arctic Slope Regional Corp., Harding said.

By September, however, ConocoPhillips realized "that things were not going as quickly as we'd hoped, so we really put on a pretty big push with the corps."

Harding said ConocoPhillips told the corps it had to have the permit by the end of the year.

In fact the original deadline was early November because of long-lead items, but because of changes in the steel market and lowered demand, "we were able to push that out another two months."

But without the corps permit — and a permit from the U.S. Coast Guard which can only be issued following the corps permit — the company lost its construction window for next year.

"We won't be able to get prepared for that construction season without the approval to be able to go forward," Harding said.

And it's not just CD-5 because there are three other projects stacked up behind it: Fiord West, Greater Mooses Tooth 1 and Greater Mooses Tooth 2.

CD-5 has been pegged at about half a billion dollars, Harding said, and the others at a similar cost, so some $2 billion in work is on hold.

At least a year

The delay will be at least a year, Harding said, because ConocoPhillips doesn't have a permit and if a permit is issued, the company doesn't know what stipulations it will contain. "There's always the chance that we don't get what we've asked for in the permit," she said.

The EPA opposes the project, she said, and both EPA and Fish and Wildlife are opposed to taking oil across the Nigliq Channel on a bridge, and are asking for horizontal directional drilling under the channel.

Harding said that is what was done at the Colville River for Alpine, "except that's sales oil and this would be three-phase fluid," because CD-5 oil will be processed at Alpine.

It's not the same as the Oooguruk field, where three-phase oil comes to shore in a pipeline, she said. The Oooguruk line is in a trench, "a very flat profile." HDD under the Nigliq Channel would involve a pipeline with "very deep bends" to go under the channel, "so you have a lot more corrosion-erosion issues."

And without a bridge there would have to be another airport across the Nigliq Channel. Harding said one thing ConocoPhillips has heard continuously from Nuiqsut "is they don't like planes flying in this area." Another runway increases the air traffic.

ConocoPhillips also has an agreement with Nuiqsut to fund up to $8 million for a road from the Alpine road system to Nuiqsut. The road would allow year-round access from Nuiqsut to Alpine, opening up employment opportunities, and would also give road access for Nuiqsut residents to some key hunting areas to the west.

A roadless development would also require larger pads, Harding said, because you wouldn't have year-round access to Alpine, and would require, among other things, emergency response capability, "something we are definitely not comfortable with," Harding said.

It could be done, she said, but it's "a different level of capability due to the weather conditions out there. It's much easier if you have a road to access it." ●

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