Petroleum news

page 11 TransCanada, ExxonMobil file open season plan; sweeten initial offering

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Greening of Oil's latest weekly cover.

Greening of Oil: Latest from Mac Ackers

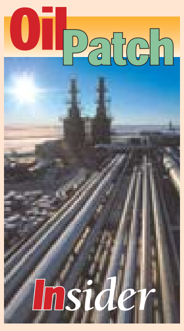
MAC ACKERS

SPEAK SLOWLY, IN SIMPLE SENTENCES … On Feb. 1 Financial Times' Energy Source blog ran an article that said natural gas producers "have started to contemplate exporting natural gas from the US." The only actual producer quote supporting the reporter's claim came from a 174-word statement by Russ Ford, Royal Dutch Shell's executive vice president for onshore gas. Ford said that Shell wants to export shale gas expertise developed in North America to other places in the world. However, only 50 words were actually quoted from his 174-word statement: "I consider the Haynesville one of our core areas. Shell has placed a big emphasis on North American gas; it's an area of growth for us. We've invested something like $15bn since 2004 in the onshore. What you develop here, you'd like to export to the rest of the world."

Whoever said, "less is more"?

see **GREENING OF OIL** *page 18*

Conoco reportedly looking for another Chukchi partner



ON JAN. 25 CONOCOPHILLIPS and Statoil USA announced a deal that gave Statoil a 25 percent working interest in 50 Conoco leases in the Chukchi Sea off the northern coast of Alaska. Three days later a Petroleum News source said Conoco was close to a deal with a second partner on the same acreage.

Although the source, who asked not to be identified, would not reveal the name of the soon-to-be partner, he did say the company will acquire a working interest of "just under 25 percent" in the 50 leases, leaving operator Conoco with a slim ownership majority.

ConocoPhillips was unwilling to confirm or deny the information.

see **INSIDER** *page 20*

EXPLORATION & PRODUCTION

Supreme help sought

Staggered by Point Thomson loss, Alaska officials go for high court review

By WESLEY LOY

For Petroleum News

Fresh off a significant setback in its tilt with ExxonMobil for control of the rich Point Thomson oil and gas field, lawyers for the state are now asking for a break in the action while they seek an Alaska Supreme Court review of a key aspect of the case.

The move seemed to dampen recent public statements from Gov. Sean Parnell and Rich Kruger, president of ExxonMobil Production Co., that it's time the case was settled.

On Jan. 11, Superior Court Judge Sharon Gleason dealt the state a blow when she reversed Department of Natural Resources Commissioner Tom Irwin's termination of the Point Thomson unit.

Among her findings, Gleason held that ExxonMobil and other leaseholders at Point Thomson were wrongly denied a hearing under Section 21 of the Point Thomson unit agreement, which dates back to 1977.

Among her findings, Gleason held that ExxonMobil and other leaseholders at Point Thomson were wrongly denied a hearing under Section 21 of the Point Thomson unit agreement, which dates back to 1977.

Section 21 says the state oil and gas director has authority to alter or modify the rate of pro-

see **REVIEW** *page 20*

EXPLORATION & PRODUCTION

Good news at Badami?

Savant exec guarded until data further analyzed, but two pay zones possible

By ERIC LIDJI

For Petroleum News

While the company remains somewhat guarded about revealing results until it gleans more information from well logs, rumors of a significant hydrocarbon discovery from a well Savant Alaska completed drilling at Badami this winter appear to have a basis in truth.

When asked for results of the B1-38 well, testing the Red Wolf prospect at the eastern North Slope field, company executive Greg Vigil responded in a Feb. 1 e-mail:

"A review of the measurement while drilling logging suite has reasonably determined the primary objective Kekiktuk formation had an apparent water contact with additional gross interval above it. Although we cannot say definitively that the apparent hydrocarbon interval is filled with movable light oil.

GREG VIGIL

"Additionally another hydrocarbon bearing interval was encountered in a shallower secondary objective formation.

"A significant amount of hydrocarbon has been introduced into the drilling mud system, and in the interest of health, safety, environment and preserving our investment in the well, no additional open-hole diagnostic work will be conduct-

see **BADAMI** *page 19*

NATURAL GAS

Mackenzie for the birds

Gas project proponents say recommended sanctuary noise levels 'rigid, untested'

By GARY PARK

For Petroleum News

The "entire" Mackenzie Gas Project could hang on whether the National Energy Board upholds a recommendation to protect a bird sanctuary on the Mackenzie Delta, Imperial Oil and its partners have told the federal regulator.

Responding to 176 recommendations contained in the findings of a Joint Review Panel, which examined the environmental and socioeconomic impacts of the project, the MGP proponents said enforcing strict noise limits at the Kendall Island Bird Sanctuary could undo the project.

The JRP said the noise levels should be kept below 50 decibels at almost 1,000 feet from the sanctuary's fence line.

"To make this condition for any approvals for facilities in the Kendall Island Bird Sanctuary would have the potential effect of preventing development of the Taglu and Niglintgak anchor fields, and therefore, the entire Mackenzie Gas Project."

—Imperial Oil

Imperial said the proponents are "concerned about imposing a rigid, untested noise abatement requirement at this time, without adequate practi-

see **SANCTUARY NOISE** *page 19*

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UTILITIES

Alaska - Mackenzie Rig Report

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

Alaska Rig Status

North Slope - Onshore

Doyon Drilling

Dreco 1250 UE	14 (SCR/TD)	Prudhoe Bay AGI-01A	BP
Sky Top Brewster NE-12	15 (SCR/TD)	Badami B1-38	Savant Alaska
Dreco 1000 UE	16 (SCR/TD)	Prudhoe Bay DS 16-08A	BP
Dreco D2000 UEBD	19 (SCR/TD)	Alpine CD3-122	ConocoPhillips
OIME 2000	141 (SCR/TD)	Alpine CD3-106	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 31-11L	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 MPF-94	BP
Dreco 1000 UE	7-ES (SCR/TD)	Prudhoe Bay DS 17-09	BP
Dreco 1000 UE	9-ES (SCR/TD)	Prudhoe Bay DS 03-37	BP
Oilwell 2000 Hercules	14-E (SCR)	Kuparuk 2A-27	ConocoPhillips
Oilwell 2000 Hercules	16-E (SCR/TD)	Sak River #1A	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

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

Aurora Well Service

Franks 300 Srs. Explorer III	AWS 1	Workover at West Mac #5	Cook Inlet Energy

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

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

SDC Drilling Inc.

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

Mackenzie Delta-Onshore

AKITA Equtak

Modified National 370	64 (TD)	Racked in Inuvik	Available

Central Mackenzie Valley

Akita/SAHTU

Oilwell 500	51	Racked in Norman Wells, NT	Available

The Alaska - Mackenzie Rig Report as of February 4, 2010.
Active drilling companies only listed.

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

This rig report was prepared by Marti Reeve


JUDY PATRICK

Baker Hughes North America rotary rig counts*

	Jan. 29	Jan. 22	Year Ago
US	1,317	1,282	1,472
Canada	531	495	432
Gulf	41	41	59

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

RCA: We can't rule on storage regulation

Commission says that changes to state statutes would be the simplest way of clarifying whether Cook Inlet gas storage regulated

By ALAN BAILEY
Petroleum News

On Jan. 27 the Regulatory Commission of Alaska issued an order declining to rule that the commission would not regulate a natural gas storage facility that Cook Inlet Natural Gas Storage LLC plans to build in the Cannery Loop gas field on Alaska's Kenai Peninsula. The order leaves open the question of whether RCA would ultimately regulate the facility.

Faced with the likelihood of gas deliverability shortfalls in the winter of 2011-12 unless more gas storage comes into operation in the Cook Inlet basin, gas utility Enstar Natural Gas Co. has been working with CINGS, a subsidiary of pipeline company TransCanada, to fast track the construction of the storage facility, for use by utilities or gas producers that need to store summer-produced gas to meet peak winter demand.

And, worried about the potential impact of regulatory uncertainty on the economics of the gas storage project, CINGS had on Dec. 21 petitioned the commission for a declaratory judgment not to regulate the facility, and had requested a rapid decision on the ruling — during a December RCA technical workshop on natural gas storage CINGS and Enstar expressed concern that any required regulatory approval for the facility would need to be in place prior to the 2010 summer construction season.

Unclear

But Alaska statutes do not spell out with unambiguous clarity RCA responsibilities when it comes to gas storage.

And in its Jan. 27 order RCA emphasized that the question of its current jurisdiction over gas storage is a matter of law rather than of public policy. The commissioners said that RCA does not have the authority to rule on the legal question of the scope of its jurisdiction, and that any ruling on this matter by the commission "will ultimately be given no weight." Consequently, a ruling by the commission would not remove the regulatory uncertainty regarding the storage facility.

The Alaska Supreme Court has ultimate authority in interpreting the statutes governing RCA jurisdiction, but "the most expeditious way to clarify our jurisdiction is through amendment to our statutes, explicitly authorizing us to regulate natural gas storage or exempting natural gas storage from our regulation," RCA said.

RCA said that attorneys, all "leading practitioners of our regulatory bar," had confirmed the statutory fuzziness over gas storage regulation by presenting diametrically different interpretations of the statutes in legal briefs submitted to RCA by various utilities and Cook Inlet gas producers.

Utility statute

The state statute for public utilities specifies that a regulated utility must own, operate, manage or control a plant, pipeline or system for "furnishing by transmission or distribution of natural … gas to the public for compensation."

And, in the absence of the term "gas storage" in the statute, much legal argument centers on the term "transmission," the commission said. In fact no one has argued for regulating the planned gas storage facility as a natural gas pipeline, it said.

In its December petition to RCA, CINGS had argued that it would not be involved transporting gas because its customers would deliver gas for storage and accept gas deliveries from storage at a single facility boundary close to the facility gas reservoir.

And gas producers Marathon Alaska Production and Aurora Gas supported CINGS' position, saying that, since CINGS would not be involved in gas "transmission," the storage facility did not fall under RCA jurisdiction.

No transportation

"Natural gas storage is not within the normal understanding of what constitutes 'transmission and distribution,' particularly in light of the limitation of the (Alaska) Pipeline Act which defines natural gas transportation in terms of the physical movement between different points," said attorney Andrea Wolfman in Marathon's brief to RCA. "The meaning of 'transportation' under the Pipeline Act is a relevant indicator of the meaning of the word 'transmission' under the Utilities Act as well. Since storage in an underground reservoir does not involve the physical movement between different points, it would not constitute transportation under the Pipeline Act and should not constitute transmission under the Utilities Act either."

Not so, said attorney Donald Edwards in power utility Chugach Electric Association's brief.

"CINGS proposes to use pipes to move gas to and from the public at transmission pressures and therefore can be said to furnish natural gas by transmission," Edwards said. The CINGS facility would operate in the middle of a gas transmission system, accepting gas from the public, moving the gas through a system of pipes into storage and then later moving the gas back through its pipe system to the public, for delivery to the utilities, he said. ●

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EXPLORATION & PRODUCTION

Alaska seeks intervention in Chukchi case

The State of Alaska is seeking permission from the 9th Circuit Court of Appeals to intervene in a lawsuit by environmental groups challenging the U.S. Department of the Interior's approval of an exploration plan for the Chukchi Sea.

"OCS exploration and development will increase jobs and revenue for Alaskans and for all Americans," Gov. Sean Parnell said in a Jan. 30 statement. "We will continue to fight for the right to responsibly develop the Beaufort and Chukchi."

The state has been granted intervention in a separate case brought by many of the same plaintiffs against an exploration plan for the Beaufort Sea and is seeking to intervene due to the economic importance of offshore oil and gas production.

The Shell exploration plans for the Chukchi Sea are for federal waters, but the state's motion for intervention stresses the impact that approval or denial of exploration can have on the state treasury and economy.

"The investments that a company makes in infrastructure for exploration on federal land can lower the costs for exploration on adjacent state land," said Alaska Attorney General Dan Sullivan. "Any oil discovered likely will increase the flow through the trans-Alaska pipeline, which in turn will increase state revenue. Also, especially given the currently adverse economic conditions, the state has an interest in job opportunities for its citizens."

Sullivan said that intervention by the state is particularly important when, as in these cases, no other party to the lawsuits can represent all of the state's interests.

—PETROLEUM NEWS

● EXPLORATION & PRODUCTION

Alberta value-added goal gets boost

Canadian Natural Resources comes to rescue of stalled bitumen upgrader, positioning joint venture for share of royalties in kind

By GARY PARK
For Petroleum News

Canadian Natural Resources, an emerging oil sands force, and privately held North West Upgrading have teamed up in one of the most surprising of all turnarounds in Alberta oil sands projects over recent weeks.

They have submitted a 50-50 joint-venture proposal to the Alberta government to build and operate a bitumen upgrading plant near Edmonton, tossing a lifeline to a scheme that was caught in a quagmire.

The partnership gives a sharp boost to North West's hopes of obtaining some of the initial 75,000 barrels per day of bitumen the government plans to collect under its royalty-in-kind program as part of its drive to keep more of the value-added end of oil sands development in the province. (Imperial Oil is also seeking a share of the royalty-in-kind bitumen, along with several other firms who have not been identified.)

North West is applying for 37,500 bpd of the government's feedstock, with an additional 12,500 bpd coming from Canadian Natural, which is just ramping up first-stage production at its Horizon mining operation.

The North West proponents believe that when liquids are added to raw bitumen, the feedstock will equal 77,000 bpd and, because of the plant efficiencies, the output will also be 77,000 bpd.

Could be onstream in 2013

Although there is more detailed engineering to complete, construction on the plant could start this fall and the upgrader could come onstream in 2013, said North West Chairman Ian MacGregor.

He would not be drawn into answering questions on what will happen if the upgrader does not receive government bitumen, but said he is confident the joint venture will "provide the best proposal the government is going to get."

However, North West is due to receive a "minor" financial allocation from Alberta's C$2 billion carbon capture and storage program because the upgrader is being designed to produce pure carbon dioxide to be carried south by pipeline for use in enhanced oil recovery projects.

Under the deal, Canadian Natural will buy 50 percent of North West's assets for an undisclosed amount.

Although neither partner would disclose the current cost estimates for the upgrader, it has previously carried a price tag of C$4.2 billion.

The companies said the upgrader will produce a finished product, not just synthetic crude, which is then refined into transportation fuels. In other words, the resulting fuel will have the same carbon footprint as diesel made from light crude, which MacGregor said "is a green solution for bitumen. This is going to change the way the world looks at the oil sands."

MacGregor said the diesel from the facility will go mostly into the Canadian market, but some could be exported if the demand surfaced.

Single conversion to diesel

Because the upgrader will produce diesel with no residual oil, it will be the first plant to use a single conversion from bitumen to diesel.

MacGregor said the partners are aiming to "set a new world standard for environmental performance," with North West offering its expertise in refining heavy oil with technology that reduces the volumes of carbon dioxide.

He said the "relatively modest-scale refinery" should eliminate carbon dioxide emissions equivalent to taking 300,000 cars off the road.

Canadian Natural President Steve Laut said the plan extends his company's three-pronged heavy-oil marketing strategy by increasing its conversion capacity.

"We are also supporting the Alberta government's efforts to build upgrading and refining capacity in Alberta, creating additional employment and wealth opportunities," he said.

Chris Feltin, an analyst with Macquarie Research, said the joint venture is a chance for Canadian Natural to benefit from the work done by North West and "maybe stay ahead of the curve with some expected cap-and-trade and CO2 taxes that might be implemented. This will give them a bit of a head start to figure out ways to mitigate CO2 emissions."

Proposals being reviewed

North West is just one of "several" proposals for upgrading and refining projects in the Industrial Heartland region north of Edmonton that are before the government, Assistant Deputy Energy Minister Mike Ekelund told a stakeholders' meeting Jan. 29.

He said a detailed review is now under way and a decision on who will receive a share of the bitumen is expected by May.

Newly appointed Energy Minister Ron Liepert praised the Industrial Heartland organization for leading the way in advancing Alberta's effort to do more than simply ship its bitumen out of the province, despite objections from the City of Edmonton which had demanded a share of additional tax revenues generated from industrial growth in its surrounding areas.

But that rift was ended Jan. 29, when Edmonton Mayor Stephen Mandel praised the Industrial Heartland group for doing an "amazing job" in the process of signing the city on as the association's fifth municipal member.

Neil Shelley, executive director of the Industrial Heartland association, said the surge in bitumen prices over the past 12 months from $27 a barrel to $63 today has triggered corporate decisions to spend C$16.7 billion on oil sands projects, adding 719,000 barrels per day of production.

"But note that these are all extraction projects and the other half of the value comes from upgrading and refining," he said. "So we have a lot of work to do," which the bitumen royalty-in-kind program should assist. ●

Contact Gary Park through publisher@petroleumnews.com

● FINANCE & ECONOMY

ConocoPhillips earns $1.54B in 2009

Oil prices down, but natural gas prices up, production continues to drop, profits rise year over year in the fourth quarter

By ERIC LIDJI

For Petroleum News

Lower oil prices in the first three quarters of 2009 meant lower year-end earnings in Alaska for ConocoPhillips, despite increased profits in the fourth quarter of the year.

ConocoPhillips earned $1.54 billion in Alaska last year, a 33 percent decline from the $2.31 billion the company earned in the state in 2008. Despite that drop, the largest oil producer in the state earned $536 million in Alaska in the fourth quarter of 2009, a 17.5 percent increase over the $456 million it earned here in the fourth quarter of 2008.

That year-over-year increase represents the dramatic change in oil prices between the end of 2008, when a global recession drove oil down to $25 a barrel, and the end of 2009.

While liquids prices fell considerably between 2008 and 2009, Alaska natural gas prices actually rose, and all commodity prices increased year over year for the fourth quarter.

The delivered price of Alaska North Slope crude oil is currently around $75 a barrel.

While ConocoPhillips saw significantly decreased profits in Alaska, the company actually lost money over the course of the year from its assets across the Lower 48, reporting a loss of $37 million in 2009, compared to profits of $2.673 billion in 2008.

However, reported earnings of $131 million in the fourth quarter of 2009 ended a run of four unprofitable quarters for ConocoPhillips from its assets across the Lower 48.

Companywide, ConocoPhillips reported adjusted earnings of $5.37 billion for 2009, a 67 percent drop from the $16.43 billion in adjusted earnings reported in 2008. In the fourth quarter of 2009, ConocoPhillips earned $1.73 billion, down from $1.91 billion in 2008.

Oil down, natural gas up

While liquids prices fell considerably between 2008 and 2009, Alaska natural gas prices actually rose, and most commodity prices increased year over year for the fourth quarter.

ConocoPhillips reported an average delivered price for North Slope crude oil of $59.19 per barrel in 2009, down from an average of $99.23 over the course of 2008. However, prices increased year over year for the fourth quarter, with the company reporting an average price of $74.34 per barrel in 2009, up from $64.13 per barrel in 2008.

ConocoPhillips sold natural gas liquids for $60.46 on average in 2008, down from $94.29 in 2009. For the fourth quarter, liquids sold for $74.60 in 2009 and $64.23 in 2008.

While natural gas prices fell nationally in 2009, they rose in Alaska.

ConocoPhillips reported an average price of $6.25 per thousand cubic feet in Alaska in 2009, up 43 percent from $4.38 per mcf in 2008. The company saw prices of $5.22 for the final quarter of 2009 in Alaska, up from $4.90 per mcf in the fourth quarter of 2008.

In the Lower 48, ConocoPhillips reported an average price of $3.42 per mcf in 2009, down 56 percent from $7.71 per mcf in 2008. The company saw prices of $4.03 for the final quarter of 2009 in Alaska, down from $4.76 per mcf in the fourth quarter of 2008.

That split reflects the unique natural gas market in Alaska, where prices are set through long-term contracts based on indices, rather than on a spot market, as in the Lower 48.

Production declines continue

While prices rose and fell with atypical extremity over the past year, production rates maintained their regular direction from recent years: slight but steady declines.

ConocoPhillips produced 235,000 barrels per day on average in Alaska last year, down 3.7 percent from the 244,000 bpd the company produced in the state in 2008. In the fourth quarter of 2009, ConocoPhillips produced 234,000 bpd, down 9.3 percent from the 258,000 bpd the company produced in Alaska during the final three months of 2008.

Natural gas liquids production in Alaska in 2009 held even at 17,000 bpd, despite a 10 percent drop year over year in the fourth quarter, to 18,000 bpd from 20,000 bpd in 2008.

ConocoPhillips produced 94 million cubic feet of natural gas per day in Alaska in 2009, down 3 percent from the 97 million cubic feet it produced in 2008. The company saw increased fourth-quarter production year over year, though, producing 95 million cubic feet per day here in the final three months of 2009, up 8 percent from the 88 million cubic feet in the fourth quarter of 2008.

ConocoPhillips saw significantly reduced sales from the Kenai Peninsula liquefied natural gas facility it owns with Marathon Oil. ConocoPhillips reported selling 59 million cubic feet per day in 2009, down 20 percent from the 74 million cubic feet per day sold in 2008.

That drop mainly reflects lower sales over the first half of the year, but ConocoPhillips also saw year-over-year declines in the fourth quarter, selling 64 million cubic feet per day from the facility in the last three months of 2009, compared to 74 million cubic feet over the same period in 2008.

In January 2009, Tokyo Electric Power and Tokyo Gas renewed supply contracts to buy Alaska LNG from ConocoPhillips for another two years. Without an extension from the federal government, the export license for the facility will expire in March 2011.

Filing comes amid scrutiny

ConocoPhillips is not drilling any exploration wells in Alaska this year. The company has said this is a first for ConocoPhillips and its predecessors since 1965, before the discovery of the Prudhoe Bay oil field.

The company argues that Alaska's Clear and Equitable Share, or ACES, the production tax code approved in November 2007, made Alaska uncompetitive for investment.

The state believes the bill balances increased tax revenue with increased tax credits for certain spending, like exploratory drilling. In its current session, the state Legislature is expected to consider changes to the tax code. Gov. Sean Parnell wants an increase to the tax credit program, but as of yet has not advocated changing the production tax rate.

While ConocoPhillips is not drilling exploration wells this winter, it still plans to drill in the Chukchi Sea in 2012 and to pursue recent finds in the National Petroleum Reserve-Alaska, although both projects depend on overcoming legal and permitting obstacles. ●

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● SAFETY & ENVIRONMENT

Oil sands gets government cleanup order

Minister not prepared to see Canada's reputation sullied; says government willing, empowered to protect 'clean energy' standing

By GARY PARK

For Petroleum News

If not exactly the shot heard around the world, it certainly whistled across the bow of Canada's oil sands sector as federal Environment Minister Jim Prentice admonished the industry to clean up its act.

Reportedly unhappy that oil sands proponents failed to make their case at the Copenhagen climate-change summit in December and unhappier still that he was the recipient of Fossil of the Day awards at the conference, Prentice flatly told energy companies and the Alberta government to clean up their act.

JIM PRENTICE

Speaking to a business audience in Calgary Feb. 1, Prentice said his government is determined to "ensure" the oil sands are developed in an environmentally responsible manner before they give Canada an international black eye.

"It is no secret and should be no surprise that the general perception of the oil sands is profoundly negative," he said. "What is at issue on the international stage is our reputation as a country."

Prentice said the environmental footprint created by the extraction of bitumen in northern Alberta has become a global issue that "transcends the interests of any single corporation. We have a lot of work to do."

He said that means continuing investments in environmental technologies that will show the world how environmental responsibility and excellence can be taken to new levels.

Failure to show that kind of leadership means Canada will be "cast as a global poster child for environmentally unsound resource development. Canadians expect and deserve more than that."

"For those who doubt the government of Canada lacks either the willingness or the authority to protect our national interests as a 'clean energy superpower,' think again," he said.

"We do and we will. And in our efforts we will expect and we will secure the cooperation of those private interests which are developing the oil sands.

"Consider it a responsibility that accompanies the right to develop these valuable Canadian resources."

Without responding directly to the lecture, Rick George, chief executive officer of Suncor Energy, told a conference call Feb. 2 his company has and will continue to "demonstrate a continuous record of environmental performance."

That has seen Suncor in the forefront of companies developing ways to reduce their consumption of natural gas and water, reduce their per-barrel greenhouse gas emissions and now shrinking their needs for toxic waste tailings ponds at oil sands plants.

Canada to follow US

Prentice's speech came two days after his announcement that the Canadian government has dumped its three-year-old climate-change policy to follow the United States' lead in lowering greenhouse gas emissions.

He told a low-key news conference in Calgary Jan. 30 that Canada has now set a goal of lowering GHGs by 17 percent from 2005 levels by 2020, copying the Waxman-Markey bill now before the U.S. Senate.

The old target was a 20 percent reduction from 2006 levels by 2020.

As Prime Minister Stephen Harper has insisted all along, Prentice made clear: Canada and the U.S. have "set the same level of ambition and we will move forward in concert with an identical base year and an identical target."

Throughout the Copenhagen negotiations in December, Canada "maintained that our clear policy was to support the outcome of Copenhagen and also to align our clean-energy and climate-change policies with those of the Obama administration," Prentice said.

He said Canada will not introduce legislation until the U.S. decides whether it will adopt a cap-and-trade system or a regulatory approach.

"We have indicated a willingness to proceed with a North American cap-and-trade system. We have also indicated a willingness to proceed by way of a harmonized regulatory system," said Prentice, noting that the two approaches are "quite different ... and it's impossible to harmonize on a continental basis if one half of the continent, namely the United States, hasn't yet made that choice."

US needs to make choice

But, before Canada proceeds with legislation, "the United States government is going to have to make a choice," he said.

Prentice would not say what course Canada will take if the Waxman-Markey bill is abandoned, as many observers expect it will, given the priority in Washington to focus more intensely on the economy and jobs.

The Harper government has linked itself to the U.S. over the past year on climate change, unwilling to take an independent route that could endanger its major trading relationship, or put at risk the 60 percent of its oil and natural gas production that is shipped to the U.S.

The new target was filed with the United Nations, one day ahead of the Jan. 31 deadline established in the Copenhagen Accord, as proof that Canada is committed to the accord, Prentice said.

"It is a framework that applies to everyone who emits carbon and is therefore an approach that has the prospect of success," he said.

The United Nations filing said Canada's goal will be "aligned with the final economy-wide emission target in the United States in enacted legislation."

Canada's new goal would lower GHGs to 606.7 million metric tons in 2020 from 731 million metric tons in 2005.

The Canadian Association of Petroleum Producers said the new target is "very ambitious" and puts pressure on lawmakers to "arrive at the appropriate and achievable balance between environmental and economic performance and continued supply and stable and secure energy."

Although Prentice did not provide any details about what actions the government would take, he promised there would be specific measures related to the oil sands — pinpointed as the largest single source of GHG increases in Canada — as there would for all sources of GHGs.

Although Prentice did not provide any details about what actions the government would take, he promised there would be specific measures related to the oil sands — pinpointed as the largest single source of GHG increases in Canada — as there would for all sources of GHGs.

Government lambasted

The Harper government was lambasted for its policy direction.

Dale Marshall, a policy analyst for the David Suzuki Foundation, said Ottawa's delays in introducing legislation have allowed the Alberta oil sands sector to rebound from a year-long hiatus, reviving or launching new projects.

"Probably a significant part of the reason that we haven't seen anything (on the regulatory front) is that we know the oil sands will be a major political obstacle, but also a major challenge in terms of growth of emissions over the next decade," he said.

Graham Saul, of the Climate Action Network of Canada, said Canada's decision to wait for U.S. action is an "incredible abdication of responsibility, not to mention sovereignty."

David Martin, a climate and energy coordinator with Greenpeace, estimated the government's previous energy targets would have reduced GHGs by 3 percent, while the latest target will increase emissions by 2.5 percent.

"Not only has (the government) reneged on the target it adopted (in 2007), it has failed to put in place the regulations it promised last year," he said.

"I think (the government) is really beholden to the oil and gas industry in Alberta and doesn't want to address how to make serious reductions to protect the planet and the environment."

David McGuinty, environment spokesman for the federal Liberal party, said that if the Waxman-Markey bill does not get passed by the U.S. Senate, Canada will be left with no real targets.

The risk Canada is taking is waiting to see if a policy designed in the U.S. "is for our benefit. The chances are, I can guarantee you, is that it won't," he said. ●

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SAFETY & ENVIRONMENT

Competing agendas clash in AK permitting

Differing resource priorities, climate change concerns seem set to increase litigation over permit approvals as GHG debate heats up

By ALAN BAILEY

Petroleum News

Uncertainty may not be what businesses like, but uncertainty is probably what businesses will find, as various interest groups spar over competing agendas and opinions in the permitting of Alaska projects.

And at the Seminar Group's Permitting Strategies in Alaska seminar, held in Anchorage on Jan. 15, lawyers representing different positions on the spectrum of environmental discourse described their views on where the permitting situation in Alaska has reached and where it is heading.

Jeffrey Leppo, a lawyer with major experience in supporting permit applications and a managing partner in law firm Stoel Rives LLP, characterized the current permitting situation in Alaska as "a very litigious time," involving a confluence of different natural resource interests and evolving environmental policies.

"Just about every major permitting decision that is made in the next year is going to get challenged," Leppo said.

Driving the uncertainty

But, with little likelihood of anything around the current climate change debate in the United States being resolved in 2010, issues involving climate change legislation, regulation and litigation will drive much permitting uncertainty, an uncertainty compounded by a proliferation of climate change-driven challenges involving the use of the Endangered Species Act in Alaska.

"At a minimum, these things are going to complicate permitting in Alaska," Leppo said.

> **On the Web**
>
> See previous Petroleum News coverage:
>
> "Time to take a stand on climate change?" in Jan. 10, 2010, issue at www.petroleumnews.com/pnads/344909072.shtml
>
> "Climate change legal impacts heat up," in Dec. 6, 2009, issue at www.petroleumnews.com/pnads/342066412.shtml

And climate change considerations are already essential components of any environmental review under the National Environmental Policy Act, he said. NEPA is the federal legislation that often leads to the preparation of environmental assessments and environmental impact statements.

On the other hand, there are signs of the blurring of hitherto sharp distinctions in the debate over environmental protection, as Native corporations, for example, become active in pursuing natural resource-based projects.

"There may be … more of a focus on what's a responsible development, less on development-no development alternatives," Leppo said.

And published scientific data have become increasingly important in adding strength to arguments, on either side, over permit approvals.

"I don't think that all is lost, at all," Leppo said: It will continue to be possible to permit projects.

"It has always been the case … that … you (need) to be thoughtful in your permitting strategy, to think not only about what you want, but what others are thinking about your projects, to involve the various interests that have a stake in the outcome … and then be persistent," Leppo said.

Administrative law principle

Peter Van Tuyn, a partner with Bessenyey and Van Tuyn LLC who has represented environmental conservation groups and Alaska Native groups in Alaska-related litigation, emphasized the legal importance of the administrative law principle, a principle involving the delegation of expertise within government administration to specialist government agencies for the implementation of environmental law.

In effect, the government agencies act along similar lines to trial courts, with people presenting evidence for or against a permitting case, Van Tuyn said. Several different groups may present evidence to the agency, and the agency will struggle to establish the truth from all of the information, to come up with a decision.

As a consequence of the administrative law principle, a court will, in general, only overturn an agency permitting decision if the court determines that the decision was "arbitrary, capricious or contrary to law," Van Tuyn said, adding that the terms "arbitrary" and "capricious" imply that an agency decision was in some way irrational.

The hard questions

And the need to ensure that an agency decision is viewed as rational puts the onus on people applying for permits to not ignore the hard questions relating to the activities that they want to carry out.

If someone has a hard question in a permitting situation and tries to gloss over the question or perhaps ignore or avoid it, there is a significant possibility of an appeal court finding that the regulating agency acted in an arbitrary or capricious manner when approving a permit, Van Tuyn said.

"That's why NEPA's such an incredibly powerful statute," Van Tuyn said. "… It doesn't mandate the least environmentally damaging alternative be chosen. It just mandates that you ask the hard questions … In asking the hard questions and in the struggle that you go through in trying to come up with the rational answer for them — that is where projects can get improved so that their environmental impacts are … eliminated or minimized as best you can."

Being realistic

And in working through the permitting process, it is especially important for people to ensure that promises they make match reality, Van Tuyn said. People need to be realistic, he said.

"Those promises made by yourself, or possibly others, can trip you up later on," he said.

For example, Alaska politicians of both major parties and the oil industry have often claimed that Alaska has the most stringent oversight in the world over the oil and gas industry, that Alaska takes great pride in protecting the environment and that oil companies can operate nowadays with minimal environmental impact, Van Tuyn said.

But there have been recent oil spills on the North Slope; there has also been a tug grounding incident in Prince William Sound; there were problems responding at night to a recent Adak fuel spill incident; and then there was the recent major oil spill from a well blowout offshore Australia, Van Tuyn said.

Van Tuyn questioned what the history of these recent incidents might say in terms of oil spill risks in a region such as the Chukchi Sea.

"What does that lead an agency to do?" Van Tuyn asked. If people don't answer these hard questions realistically, they leave themselves open to lawsuits.

Climate change

Tom Lindley, a partner with Perkins Coie LLP, spoke at the seminar about climate change, a topic of critical importance to the energy industry and an issue that is starting to have a major impact on the regulation of industrial activity.

In the United States there is a dramatic division in opinion on climate change between the country's two major political parties, while worldwide there is a general acceptance of the prevailing theory of greenhouse gas-fueled global warming, Lindley said. But, regardless of what people's beliefs are in the climate change debate, climate change regulation is coming and people are going to have to deal with it when permitting projects.

Following the recent Copenhagen international climate change conference, viewed by many as a failure, it is difficult to say whether the future will see a global system for managing greenhouse gas emissions. On the other hand, there may well be regional systems, with the United States driving what happens in North America.

"Canada and Mexico both want to work with us … and the larger the (carbon) market, the more economically efficient it is," Lindley said.

Congressional action

At the national level, Congress has been wrestling with both House and Senate bills for introducing a U.S. cap-and-trade system for greenhouse gases — the House bill passed the House in 2009, while the Senate bill has been tabled, its future uncertain in 2010.

Bills in both houses have clean energy components, Lindley said.

If cap-and-trade legislation does pass, that will particularly impact coal-fired power stations, driving a need for carbon capture and sequestration technology, with potential use of the carbon dioxide in, for example, enhanced oil recovery from oil fields and the production of biofuels. One Oregon coal-fired plant has already announced that it will close rather than install new emissions controls, Lindley said.

Meantime, the Obama administration is focusing on research into clean energy technologies. But this type of incentives-based approach to dealing with climate change has not so far achieved much, Lindley said.

And, in the absence of a U.S. cap-and-trade system for greenhouse gases, the Environmental Protection Agency has

see CLASH page 9

continued from page 8

CLASH

moved ahead with the regulation of carbon dioxide under the Clean Air Act — on Dec. 7 the agency finalized its endangerment finding for the gas, with the likely outcome being new federal regulations such as tailpipe standards for vehicles and the consideration of greenhouse gases in industrial air emissions permitting.

However, many people think that regulation through the Clean Air Act is an inefficient way of managing carbon dioxide emissions, and that new federal legislation specific to greenhouse gas emissions would be a preferable route, Lindley said.

"It's one of the reasons why there is some belief that legislation will in fact pass," Lindley said. "… You've got many large industry sources now supporting revised … climate legislation that will pre-empt the Clean Air Act, take it out of the picture."

Meantime, some regions within North America have been forging ahead with their own moves to do something about greenhouse gases and there are moves to establish international standards for the reporting of greenhouse gas emissions.

Court actions

But, in the absence of national legislation or international agreements on greenhouse gas emissions, the courts will likely drive what happens in the immediate future.

"There will be more judicial action before there's active federal legislation or international agreement," Lindley said.

There has already been legal action in relation to the protection of animals such as the polar bear and the ribbon seal; there are several lawsuits against coal-fired power plants and there are challenges at the state level, seeking greenhouse gas consideration in environmental reviews.

And the Clean Water Act has now come into play in the debate over carbon dioxide emissions, because of concerns about ocean acidification. In fact, Washington State has been required to list its coastal waters as impaired under the CWA, because of carbon dioxide acidification, Lindley said.

People are especially concerned about where all of this is heading in terms of common law, the form of law relating to claims of nuisance or neglect, he said.

"Common law … is really I think is what has people scared these days, in some ways on both sides. No one quite knows where it will go," Lindley said. For example, appeals courts have recently been upholding nuisance complaints under federal common law against major greenhouse gas emitters.

Environmental view

Rebecca Noblin, an Anchorage-based attorney with the Center for Biological Diversity, the environmental organization closely associated with moves to list under the Endangered Species Act various animals that use Arctic Sea ice, presented her views on the climate change and greenhouse gas emission situation.

People need to view environmental laws and environmental permitting as a means of improving projects, Noblin said.

"Most if not all of us want to live in a world where we still have polar bears and walruses and clean air and clean water," she said.

People are seeing a drastic loss of Arctic Sea ice as the world's climate warms, with the rate of ice loss exceeding most model predictions, she said. And that spells trouble for many Arctic species that rely on the sea ice, including polar bears, walrus and several species of ice seal.

Hence the listing in 2008 of the polar bear as threatened, and the petitions to list other Arctic marine mammals.

When reviewing permit applications, government agencies need to consider the impact of projects on a listed species in conjunction with the impact of climate change on the species, Noblin said. And then there may be impacts from the project on the climate change that is affecting the species habitat, she said, adding that case law indicates that this is the type of issue that the Endangered Species Act is intended to address.

Marine Mammals Protection Act

The Center for Biological Diversity would also like government agencies to take into account whether a species is impacted by climate change when applying the Marine Mammals Protection Act in reviewing proposed project activities, Noblin said.

Noblin also commented on the question of applying the Clean Water Act to the acidification of seawater by carbon dioxide, saying that increasing acidity in the oceans is causing, among other things, the erosion of corals and the inhibition of shell growth of creatures like oysters.

She also commented on the Clean Air Act, saying that this act has achieved success in regulating pollutants, with benefits that greatly outweigh the act's costs. The CAA can be used to regulate greenhouse gases, she said.

"There's a record of the regulated industries thinking it's a lot worse than it is," Noblin said. In fact, when the CAA was originally passed, anticipated negative impacts on the economy failed to materialize. On the other hand, the act forced the use of new technologies that had a major impact on air quality, she said. ●

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EXPLORATION & PRODUCTION

Eni onshore pipeline work on schedule

Nikaitchuq developer has offshore island in place, laid 3.8-mile pipeline bundle to shore last winter; working onshore connection

By KRISTEN NELSON
Petroleum News

After slowing the pace of its Nikaitchuq project on Alaska's North Slope last year, Eni Petroleum is on schedule for first production from the field's onshore pad this December, and for first production from the field's offshore drilling pad south of Spy Island in December of 2011.

Crude oil from Nikaitchuq will be the first production on the North Slope not processed through facilities operated by either BP or ConocoPhillips.

Production was initially scheduled to begin in December 2009, but the Alaska Division of Oil and Gas said (in a May 2009 decision extending the term of the Nikaitchuq unit by two years) that Eni revamped the project after work stoppage at the Houma, La., fabrication yard due to Hurricane Ike, a drop in oil prices from $140 a barrel to $40 a barrel and worldwide economic conditions.

Work on those facilities in Louisiana is now nearing completion, Larry Burgess, the company's Alaska health, safety and environment manager, told the Alaska Support Industry Alliance Jan. 28.

The facilities will come by sealift this summer from the construction site at Houma, La., he said. The two large modules — a process facility and a utilities facility — are scheduled for completion in April and will be loaded for the trip to the North Slope in May.

"We have four turbines in the utility module we'll be running. We'll generate our own electricity.

"All the oil that we produce will be run through our process facilities, not through ConocoPhillips or BP. We're standalone completely," Burgess said.

In addition to the large sealift modules, Eni is constructing truckable modules in Anchorage.

On the Web

See previous Petroleum News coverage:

"DEC proposes new Nikaitchuq air permit," in Jan. 24, 2010, issue at www.petroleumnews.com/pnads/447796901.shtml

"Eni aims for 2010 oil," Aug. 16, 2009, issue at www.petroleumnews.com/pnads/960418039.shtml

"Slowing Nikaitchuq," in March 8, 2009, issue at www.petroleumnews.com/pnads/681155498.shtml

Work completed

Eni has completed an 11-acre island 3.8 miles offshore, just north of Oliktok Point, Burgess said, along with an onshore drill site at Oliktok Point. Nabors rig 245E has begun drilling at the onshore pad; that drilling will start up again in June.

Last year a 3.8-mile subsea pipeline bundle was installed, by trenching through the sea down into the sea floor. The pipeline bundle was buried with materials dredged up in the trenching work.

"We had to ground the ice all the way out to the island," Burgess said, "… building an ice road and grounding the sea ice to the sea floor so we can take heavy equipment out."

Burgess said Eni has a grind-and-inject facility at its onshore Oliktok Point pad, with one disposal well on site.

"We're going to drill another one offshore. And we'll have a grind-and-inject facility offshore as well, for disposal of Class 1 and Class 2 wastes as well as the cutting spoils.

"This project is a zero-discharge project," he said.

Onshore pipeline this winter

Eni has 14 miles of ice roads complete now, and is on schedule to complete the onshore pipeline this winter. The pipeline will take processed oil from the Oliktok Point facility to a connection with a ConocoPhillips pipeline which goes to Pump Station 1 of the trans-Alaska oil pipeline.

The sealift of the large modules from Louisiana is scheduled to begin in June, Burgess said, and to arrive at the North Slope in August.

Hook up of the facilities is scheduled to be completed in November and once the facilities are installed and commissioned, first oil is expected to be produced in December.

Another milestone will be offshore drilling, scheduled to begin in September 2011; hook up of facilities at the offshore drill site will be completed and the facility commissioned in November 2011, with first oil from the offshore pad scheduled for December 2011.

The facilities are rated at 40,000 barrels per day, Burgess said, with expected production of 28,000 bpd, and the life of the field is estimated at 40 years, based on equipment, but with technology it could run longer.

International company

While Eni is a small player in Alaska, the company is the world's fifth- or sixth-largest oil and gas company, Burgess said, and the third-largest producer in the Gulf of Mexico.

Nikaitchuq is not the only project Eni has in Alaska.

The company also has leases at North Tarn, Rock Flour and Maggiore onshore, in the Beaufort Sea and in the Chukchi Sea.

Eni acquired a 30 percent interest in Nikaitchuq in August 2005 when it acquired the North Slope assets of Armstrong Alaska.

In January 2007 Eni acquired the remaining 70 percent interest in Nikaitchuq from Anadarko Petroleum and sanctioned project development in January 2008. ●

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● NATURAL GAS

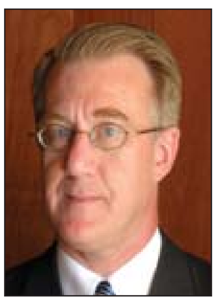
$500M reduction for initial open season

TransCanada, ExxonMobil say better terms for Alaska gas pipeline project include lower rate of return, slower recovery by pipeline

By KRISTEN NELSON
Petroleum News

Alaska Pipeline Project partners TransCanada and ExxonMobil have filed their open season plan with the Federal Energy Regulatory Commission, making public an estimated cost range for building an Alaska natural gas pipeline as well as projected tariff rates for shipping on the project, which will go either to Alberta or to Valdez, depending on where customers wish to ship their gas.

As Tony Palmer, TransCanada's vice president for Alaska development, has been at pains to relate, this is information which for any other gas pipeline proposal would be available only to potential shippers under confidentiality agreements.



TONY PALMER

Under FERC regulations for the Alaska gas line project, however, open season plans are available for public comment; Alaska Pipeline Project plans are on the FERC Web site and the pipeline's Web site, www.thealaskapipelineproject.com.

Because TransCanada applied for a license under the Alaska Gasline Inducement Act, the company's initial plans were also publicly available and analyzed by both the State of Alaska's departments of Revenue and Natural Resources before a license was recommended and by the Alaska Legislature before the license was approved.

Competitors, Palmer says, have known what TransCanada was proposing since its AGIA application was made public and now know what the pipeline's open season proposal is.

Sweetening the deal

With a goal of getting commitments as early as possible, the State of Alaska included provisions in AGIA which would benefit producers committing to ship gas on the line in the initial open season.

TransCanada and ExxonMobil have sweetened the deal for shippers committing in an initial open season by an estimated $500 million a year, by reducing the pipeline's rate of return from an estimated 14 percent in the AGIA application to 12 percent and by designing the tariff to recover only 80 percent of the capital cost of the line over the initial shipping term, which has been shortened from 25 years to 20 years.

Details became public Jan. 29 when the Alaska Pipeline Project filed its open season plan with FERC.

Palmer and Paul Pike, senior project manager for the project, an ExxonMobil Development Co. employee, reviewed the open season filing in a teleconference that day.

There is a 60-day FERC review period for the plan, including a 30-day public comment period.

Once FERC has approved the plan, the open season will be held May through July.

Palmer said a separate Canadian process for the Alberta option will be conducted at the first time.

He said following the open season negotiations are expected with potential shippers to resolve conditional issues, a process expected to be completed by the end of 2010 if resolution can be reached.

Cost estimates

Pike said the cost estimates are $32 billion to $41 billion for the Alberta project and $20 billion to $26 billion for the Valdez option. The Alberta option takes gas to Canada where there are existing lines on which customers could move gas into the Lower 48. The Valdez option would ship gas for customers who wish to liquefy it and ship it to markets as liquefied natural gas; the Valdez costs do not include liquefaction facilities or ships, which would be the responsibility of the shippers.

Pike said the range of cost estimates is normal at this stage of the project, and reflects more than a quarter of a million hours of work since the AGIA license was signed in December 2008. While substantial work has been completed to date, the majority of the engineering work for the project lies ahead, Pike said.

The better commercial terms offered for the initial open season — pegged at a savings to shippers of $500 million a year — would save customers $12.5 billion over the course of a 25-year contract, Palmer said.

The first-gas date is set at 2020, which is later than TransCanada originally proposed, but Alaska's commissioners of Revenue and Natural Resources said in a statement that the updates to the project cost and schedule "are in line with the analysis done by the AGIA technical team as part of the AGIA license review," and validate the economic analysis the commissioners relied on in the AGIA findings.

First gas in 2020

Pike said that when TransCanada made its AGIA application it focused on the pipeline and made it clear that while it would build the gas treatment plant, it was looking for others with expertise in that area to build and own the plant.

Alaska's commissioners of Revenue and Natural Resources said in a statement that the updates to the project cost and schedule "are in line with the analysis done by the AGIA technical team as part of the AGIA license review," and validate the economic analysis the commissioners relied on in the AGIA findings.

ExxonMobil brought GTP expertise to the project, Pike said.

A line to Point Thomson was also added to the project, available if Point Thomson gas owners want to move their gas to market.

Palmer said that in addition to cost increases since TransCanada filed its AGIA application there have been changes in the world, including "an epic financial crisis" and shale gas development in the Lower 48. But based on the latest U.S. Department of Energy gas price forecast, there is still a margin of $3 to $4 per million Btu to be split between governments and shippers, he said.

Pike said the North Slope GTP was a factor in the 2020 first-gas timeframe; he said the 2020 date is a refinement of the estimate provided by TransCanada in its AGIA application based on further understanding of what it takes to develop and construct a project of this size.

Three sealifts

Palmer told Petroleum News that the work TransCanada had done on the gas treatment plant for its AGIA application "was conceptual in nature rather than the details that we had developed on the pipeline," and said TransCanada has learned a lot as a result of working as a team with ExxonMobil, including that the two sealifts TransCanada had in its application were too few because of the short weather window at Prudhoe Bay.

The addition of a third sealift is "a significant part of the reason for the shift in the in-service date," Palmer said.

They looked at using more barges, or larger barges, but went with barges of a tonnage that has been used to get into Prudhoe Bay in the past. The tonnage of the barges affects the dredging needed at the docks, and with the sizes of the modules, "some of the largest modules in the world," Palmer said they didn't want "to have technological challenges" in addition to the magnitude and weight of the modules.

Throughout the project, "we've tried to use accepted and standard technology as opposed to cutting edge," he said, because there are already sufficient challenges on the project without "trying to go with cutting-edge technology that hasn't been used elsewhere."

And it's not just the sealift, Palmer said,

see OPEN SEASON page 18

PIPELINES & DOWNSTREAM

U.S. COAST GUARD

The tugboat Pathfinder, badly damaged when it ran aground Dec. 23 in Prince William Sound, has left the Port of Valdez and is headed for Seattle.

Damaged tug Pathfinder towed to Seattle

The tugboat Pathfinder, badly damaged when it ran aground Dec. 23 in Prince William Sound, has left the Port of Valdez, a spokesman for Crowley Maritime Corp. told Petroleum News.

A second Crowley tug, the Pt. Thompson, took the 136-foot Pathfinder under tow and departed Valdez on the morning of Jan. 31, said Mark Miller, director of corporate communications for Crowley, based in Jacksonville, Fla.

Crowley has used the 85-foot Pt. Thompson at Alaska's Prudhoe Bay.

The Pathfinder was being taken to the Port of Seattle, specifically Crowley's Pier 17 location, Miller said.

The journey south was expected to take seven days, putting the Pathfinder's arrival time in Seattle at around Feb. 7 assuming favorable weather, he said.

No decision has been made, Miller said, on whether to repair or scrap the Pathfinder, built in 1970.

Severe damage

The Pathfinder was among a stable of tugs Crowley uses at Valdez to help dock and escort tankers picking up North Slope crude oil at the Alyeska pipeline terminal.

The Pathfinder had been out patrolling for drifting icebergs in the shipping lanes in Prince William Sound and was on its way back to Valdez when it ran aground on infamous Bligh Reef, the same rock the tanker Exxon Valdez hit with disastrous consequences in 1989.

No one was injured and the tug didn't sink, but it sustained serious keel damage and some of its fuel tanks were breached.

see **PATHFINDER** *page 18*

● UTILITIES

Utilities and state revise GRETC bill

Revised bill to go to Legislature envisages private co-op to manage power generation and transmission in the Alaska Railbelt

By ALAN BAILEY
Petroleum News

One of the hotter issues facing Alaska lawmakers in the current legislative session is the question of whether and how to unify the operation of the six electricity utilities that supply power to consumers along the Alaska Railbelt, a question with major implications for future Railbelt power costs and reliability of supply. Already in a sense unified by an interconnected power grid, the utilities face a need for major upgrades to the electricity infrastructure, while also having to deal with an increasingly challenging fuel supply situation as gas supplies from the Cook Inlet decline — gas fired power stations dominate the current portfolio of Railbelt power generation facilities.

The Feb. 3 meeting of Anchorage Mayor Dan Sullivan's Energy Task Force consisted of a workshop to review the status of work on a draft bill to establish a Greater Railbelt Energy and Transmission Co., or GRETC, to eventually manage all of the power generation and transmission in the grid — under the GRETC concept, the existing utilities would simply take delivery of power from the transmission grid for distribution to power consumers.

Apparently five of the utilities have now agreed to support the proposed bill, ahead of the bill being forwarded to legislators for consideration, with just Municipal Light and Power, the utility owned by the Municipality of Anchorage, still finding issues that deter it from signing up to GRETC as currently envisaged.

2008 study

A 2008 study commissioned by the Alaska Energy Authority concluded that the funding required for the required Railbelt electrical infrastructure upgrades is far in excess of the funding capabilities of the existing utilities. A single entity to manage and operate power generation and transmission in the Railbelt is needed both to act as a fundraising conduit and to achieve economies of scale in Railbelt power supplies, the study found.

And in March 2009 then-Gov. Sarah Palin introduced a bill in the Legislature to form GRETC, a power generation and transmission cooperative along the lines of the entity recommended by the AEA study. But with insufficient time remaining in the 2009 legislative session to deal with the proposed legislation, the governor's bill was deferred to the 2010 session.

Since then the utilities and the state have been working on the draft bill, to massage it into a form that seems workable to the chief stakeholders in the GRETC concept. Legislators will then need to do further work on the bill before deciding whether to enact it into law.

"This is a piece of legislation. … It's had a variety of cooks and continues to evolve," Mark Johnson, general counsel for Chugach Electric Association and one of the members of the utilities' task force that has been revising the bill, told the Mayor's Energy Task Force.

Voluntary co-op

In its currently envisaged form GRETC would consist of a privately owned cooperative, established by state statute, with any or all of the Railbelt utilities as members. The cooperative would operate the power grid and would supply electrical power, either from its own power generation facilities or by buying power from independent power producers.

Membership in GRETC would be voluntary, in a business model that Jim Walker, senior counsel with Matanuska Electric Association, characterized as having "lots of carrots and no sticks."

The carrots would essentially consist of the financial benefits of joining GRETC: GRETC would provide the only means of obtaining state financial assistance for major power projects; it would be able to obtain funding more cheaply than individual utilities; and major projects sponsored by GRETC could achieve economies of scale probably unachievable otherwise.

The intent of GRETC, as currently envisioned, is to supply power at "postage stamp" or consistent rates all along the Railbelt; there would be an individual postage stamp rate for power from each power generation facility, with each

see **GRETC** *page 19*

EXPLORATION & PRODUCTION

ANS production drops 2.4% in January

Decline from December driven by Prudhoe Bay field, where a drop of 13,614 bpd accounted for most of the 16,776 bpd overall drop

By KRISTEN NELSON
Petroleum News

Alaska North Slope crude oil production averaged 671,989 barrels per day in January, down 2.44 percent from a December average of 688,765 bpd.

The average drop in barrels was 16,776, and the largest per-barrel decline was at the North Slope's largest field, Prudhoe Bay, which averaged 338,915 bpd in January, down 3.86 percent from a December average of 352,529 bpd, a drop of 13,614 bpd. The BP Exploration (Alaska)-operated field includes production from satellites at Aurora, Borealis, Midnight Sun, Orion and Polaris.

BP's Milne Point field had a larger percentage drop in production from December to January, 4.61 percent, but on a much smaller volume of oil. Milne production averaged 26,608 bpd in January, down from 27,895 bpd in December. Milne's main production is from the Kuparuk River formation, but it also produces a small amount of oil from the Sag River formation and a substantial portion of its volume, almost 35 percent, from the viscous Schrader Bluff formation.

The BP-operated Lisburne field averaged 34,855 bpd in January, down 2 percent from a December average of

The majority of Alpine oil comes from the main Alpine formation; the second-largest producer is Fiord, which accounted for 22 percent of oil processed at Alpine in December, the most recent month for which such details are available.

35,564 bpd. Lisburne, a part of greater Prudhoe Bay, includes production from Point McIntyre and Niakuk.

Oooguruk production at 9,100 bpd

The ConocoPhillips Alaska-operated Kuparuk River field averaged 142,345 bpd in January, down 1.94 percent from a December average of 145,167 bpd. Kuparuk, the second-largest field on the North Slope, includes production from satellites at Tabasco, Tarn and Meltwater; West Sak viscous oil — the formation analogous to Schrader Bluff; and production from the Pioneer Natural Resources Alaska-operated Oooguruk field. The most recent month for which Oooguruk production figures are available is December, when Oooguruk production averaged more than 9,100 bpd.

The BP-operated Northstar field averaged 22,301 bpd in January, down 0.9 percent from a December average of 22,500 bpd.

Only two North Slope fields had increased January over December production, Alpine and Endicott.

The BP-operated Endicott field averaged 13,608 bpd in January, up 4 percent from a December average of 13,084 bpd.

The ConocoPhillips-operated Alpine field averaged 93,357 bpd in January, up 1.45 percent from a December average of 92,026 bpd. Alpine includes satellite production from Fiord, Nanuq and Qannik. The majority of Alpine oil comes from the main Alpine formation; the second-largest producer is Fiord, which accounted for 22 percent of oil processed at Alpine in December, the most recent month for which such details are available.

The temperature at Pump Station 1 averaged minus 14.8 degrees F in January, compared to minus 0.5 F in December.

Cook Inlet production averaged 9,564 bpd in January, about flat from a December volume of 9,512 bpd.

ANS crude oil production peaked in 1988 at some 2 million bpd; Cook Inlet crude oil production peaked in 1970 at more than 227,000 bpd. ●

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FINANCE & ECONOMY

Revenue responds to ACES tax concerns

By ALAN BAILEY
Petroleum News

Both oil industry investment and employment have increased since the introduction of both the state's ACES production tax and the preceding form of the tax, known as PPT, said Alaska Commissioner of Revenue Patrick Galvin in a letter dated Jan. 21 to several members of the Alaska Legislature. Galvin was responding to a Dec. 4 letter from the lawmakers to Gov. Parnell, expressing concern about evidence of a decline in Alaska oil industry activity and questioning whether excessive taxation of the industry was causing that decline.

PAT GALVIN

"However, the data also reveals that the period from 2005 to the present experienced less drilling activity than the previous five-year period," Galvin said.

PPT was enacted in 2006 and ACES in 2007.

It is also important to recognize that an evaluation of Alaska's appeal as a target for oil and gas investment cannot be limited to just the fiscal system, Galvin said. Other factors impacting investment decisions include the state's geology, infrastructure, support service costs, the regulato-

"However, the data also reveals that the period from 2005 to the present experienced less drilling activity than the previous five-year period."
—Commissioner of Revenue Pat Galvin

ry environment and global economic considerations, he said.

Response to questions

In response to a series of questions posed by the legislators in their December letter, staff from the departments of Revenue, Natural Resources and Labor and Workforce Development and the Alaska Oil and Gas Conservation Commission prepared a series of tables and graphs showing leasing activity, employment levels and drilling activity over the past few years.

In summary, the staff concluded that:

- There has been no clear trend in leasing activity in recent years.
- Oil industry employment has reached peak levels in the past couple of years.
- A slight downturn in the number of wells permitted, and in the number of wells completed, occurred prior to the enactment of the new taxes, although the count of active drilling rigs fluctuated quite a bit during the same period.
- The permitting of exploration wells shows no obvious trend in relation to the enactment of the new taxes.
- Oil industry capital and revenue expenditures have both increased steadily since the new taxes came into operation.
- A big run-up in applications for exploration credits in 2008 may have related to especially high oil prices in that year, with credit applications dropping in 2009 as oil prices fell.

No pipeline shutdown

Claims that the trans-Alaska oil pipeline may have to shut down as early as 2018 are "without technical merit" and, based on "more reasonable estimates," operation of the pipeline is likely to continue beyond the 2040s, the staff said.

And the staff commented on the state administration's recent proposals for changes to the ACES exploration credit program. Those proposals consist of an extension of the 30 percent capital credit to all well-related activity, improved access to capital credits for new explorers, accelerated usage of capital credits and the waiving of interest on taxes overdue because of ACES regulation changes. ●

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NATURAL GAS

FERC gives Alaska requested gas waiver

State can obtain prearranged capacity releases for transporting royalty gas, facilitating switching from in-value to in-kind

By KRISTEN NELSON
Petroleum News

The State of Alaska has gotten FERC approval for a fix to an issue which could have caused it problems in shipping royalty gas on a proposed natural gas pipeline and could also, the state feared, have caused uncertainty in open seasons for the line.

Over objections by Denali and ConocoPhillips, the Federal Energy Regulatory Commission has granted the state a limited waiver, allowing it to obtain prearranged capacity releases for transporting its royalty gas.

Because Alaska oil and gas leases allow the state to take its royalties in-value or in-kind, the state would need shipping capacity when it took its gas in-kind — but the producer would need that capacity when the state took the gas in-value.

The state's petition for the waiver, filed Nov. 12, requested linking shipping capacity for the state's royalty gas to the gas, so if the state changed from in-value to in-kind, the shipping capacity would remain with the gas, rather than reverting to the shipper.

The state applied for a waiver because FERC requires that any spare shipping capacity on a gas pipeline be put out for bid, which could have theoretically left a producer-shipper with stranded capacity in the line.

The state sought "permission to obtain prearranged capacity releases for transporting its royalty gas without posting the releases for bidding," FERC said in a Jan. 28 order.

On the Web

See previous Petroleum News coverage:

"State of Alaska applies for FERC waiver," in Nov. 22, 2009, issue at www.petroleumnews.com/pnads/427331955.shtml

The commission granted the request subject to conditions.

Conditions from shippers

FERC said BP Exploration (Alaska) Inc., ExxonMobil Gas & Power Marketing Co., TransCanada and Anadarko Petroleum Co. in general supported the waiver, although ExxonMobil and Anadarko conditioned their support.

Denali — The Alaska Pipeline Co., ConocoPhillips Alaska Inc. and ConocoPhillips Co. filed adverse comments or protests.

ExxonMobil asked FERC to limit the state's request by requiring that the producer-shipper accept a capacity release from the state "at the corresponding contract rate," a condition which would also apply if the state made a sale of in-kind gas at the wellhead.

Anadarko requested that FERC not limit the state's waiver to only those producer-shippers acquiring capacity in the initial open season. The company told the commission the risk of stranded capacity applied to all producer-shippers, not just to those participating in the initial open season. Anadarko also said limiting the waiver to producer-shippers participating in an initial open season "would create an uneven playing field and undermine the goal of promoting future exploration, development and production of Alaskan natural gas."

Protests from Denali

The commission said comments filed by Denali and a protest from ConocoPhillips had some overlapping concerns, including a contention that the state's request for a waiver was premature and that the state's petition was inconsistent with FERC's capacity release rules and its policy respecting waivers.

Denali also requested that, if FERC granted a waiver, it attach a number of conditions, including making the waiver applicable only to gas used in Alaska, requiring the state to waive its sovereign immunity and setting a minimum timeframe for any switching by the state between taking its royalty gas in-kind and in-value.

Conoco requested that the commission deny the waiver, telling FERC the state would use the waiver to address fiscal and royalty matters in commercial negotiations with producers.

State accepts some conditions

FERC said the state accepted the condition from ExxonMobil "and will accept capacity releases from the releasing producer-shipper at the corresponding contract transportation rate."

The state accepted "Anadarko's suggestion that the waiver apply to any capacity on any Alaska Gas Pipeline Project, including expansions to such systems."

The state opposed Denali's request to narrow the waiver to gas solely transported within Alaska, but told FERC the predominant use of the waiver would be to address in-state demand and storage fluctuations. It also opposed Denali's request for limits on the frequency of switching and rejected the suggestion that it should waive sovereign immunity.

The state requested the commission reject ConocoPhillips' protest and said the waiver is not premature. The state said the request would provide clarity before the open seasons begin and said it depended on the waiver to transport its in-kind volumes.

The state told FERC ConocoPhillips failed to prove its claim that the waiver would confer any commercial advantage to the state and told FERC that if commission granted the waiver request it would remove the ability of any party to gain potential leverage in commercial negotiations regarding capacity associated with royalty gas.

The state also said FERC could assure any waiver would be neutral by requiring the state to apply the terms of the waiver equally to shippers participating in any open season on any Alaska gas pipeline project.

Commission conditions

FERC granted the state's waiver request but said if the state uses the waiver to take capacity release from one producer it must offer to do the same with similarly situated producers on any Alaska gas pipeline project and "the waiver must apply to all firm capacity held by producer-shippers and is not limited to firm capacity acquired by a producer-shipper during the initial open season."

FERC said holding the state to its agreement that the waiver would apply to either pipeline project "should alleviate the concerns of certain parties, such as Conoco and Denali, concerning potential discrimination."

The commission said it found the conditions requested by Denali are not necessary and rejected them. The waiver will not be limited to gas for in-state use, FERC said, because the state indicated that "out-of-state uses will be incidental" and no party will be harmed because the state will pay for released capacity at the contract rate. ●

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● EXPLORATION & PRODUCTION

Upstream hope dampened by labor shortage

By GARY PARK

For Petroleum News

The forecasts span a broad range, but they all point in the same positive direction — toward a stronger year in the Canadian upstream than has originally been forecast.

Bolstered by strengthening natural gas prices and a growing belief that the Alberta government is on the verge of rolling back its controversial royalty increases, forecasters are raising their sights for 2010 even though their revised numbers lag far behind the 2006-08 peak years.

The Petroleum Services Association of Canada has hiked its well-completion target by 12 percent from its November forecast to 9,000, with all of the 1,000 new wells assigned to Alberta; investment dealer Peters & Co. has hiked its 2010 Western Canada well-count forecast by 22 percent to 11,000 wells and expanded its capital spending estimate by 28 percent to C$15.8 billion; FirstEnergy Capital expects 12,900 well completions, up almost 4,400 from 2009, with capital spending rising by C$3.3 billion to C$24.4 billion; and BMO Capital Markets analyst Michael Mazar is forecasting 10,675 wells, compared with the 2006 record of 22,127 completions.

Although breakdowns are not provided, gas-targeted prospects usually account for about 60 percent of Canada's total drilling.

Most of the forecasters agree that shallow gas drilling in Alberta and Saskatchewan will still be out of favor, but Mazar sees 2010 as the year the industry will start to "turn the corner" on a recovery.

Labor shortage a concern

Petroleum Services Association of Canada President Roger Soucy said a drilling spurt in December and expectations of strengthening commodity prices this year are generating feelings of "cautious optimism that will continue to impact drilling levels as we move through 2010."

But some of the hopes could be eroded by a labor shortage in Canada's service sector.

"We're turning jobs down that we have equipment for because we can't hire qualified people," said Duane Mather, president of Nabors Canada, one of the largest drilling contractors.

He said all workers who were laid off over the past two years are being called back, but the best Nabors can promise is a job for the next six to eight weeks until the spring thaw forces rigs to shut down.

Soucy said "virtually all" of his member companies have customers they are unable to satisfy.

"In most cases, they're also hesitant to go through any major hiring because their customers are not sure this activity will continue past the spring break-up."

What puts a more positive spin on the well counts is the increase in horizontal drilling, which extends the average time needed to complete a well from 6.5 to seven days three years ago to 11.

Mather is hopeful that trend will make 2010 the year that the industry starts to "turn the corner" on a recovery. ●

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● EXPLORATION & PRODUCTION

COST pays the cost

Oil sands trust writes down C$148M of High Arctic gas purchase, conceding it's been overtaken by shale gas, delays in other Arctic projects

By GARY PARK

For Petroleum News

A long-shot bet by one of Alberta's biggest oil sands producers to lock up natural gas resources in the farthest reaches of the Canadian Arctic has turned sour.

In 2006, Canadian Oil Sands Trust emerged victorious from a heated bidding contest for Canada Southern Petroleum, whose primary asset was about 1 trillion cubic feet of High Arctic natural gas discoveries.

COST, hopeful that the Mackenzie Gas Project might proceed and serve as a stepping stone to develop those discoveries and anxious to secure gas as a hedge against its long-term oil sands needs, paid C$198 million for little-known Canada Southern.

Now, less than four years later, it has been forced to write off C$148 million of that purchase.

COST Chief Executive Officer Marcel Coutu conceded in a news release that the emergence of shale gas and stalled progress on Arctic projects have extended the assumed timetable for development of gas that is well beyond the geographical limits of the Mackenzie Gas Project.

The Canada Southern holdings covered 184 square miles, embracing seven Significant Discovery Licenses, one Production License and an estimated 927 billion cubic feet equivalent of marketable gas and 13.7 billion cubic feet equivalent of proved and probable reserves.

Operator now an unknown

It was thought at the time of purchase that Petro-Canada, also a major player in the Arctic Islands, was the logical choice to operate any commercial venture, but that, too, is an unknown following Suncor Energy's takeover of Petro-Canada.

COST, the biggest shareholder in the Syncrude Canada oil sands consortium — the world's largest producer of synthetic crude — took the Arctic plunge in the hopes of securing 25 years' worth of gas production to fuel its 36.74 percent stake in Syncrude Canada, using the Arctic gas as a price hedge.

The writedown contributed to a drop in COST's fourth-quarter earnings to C$96 million, or C20 cents a share, from C$124 million, or C26 cents a share, a year earlier.

COST said it expects production this quarter will be "impacted by unplanned outages" at the Syncrude upgrader, but is counting on those lost volumes being recaptured later in 2010.

The upgrader work includes plans to advance work on modifying the upgrader to break down bitumen by adding hydrogen in the presence of a catalyst to produce a cracked light gas oil.

2010 production to rise

The trust has forecast Syncrude's 2010 production will be about 315,000 barrels per day, giving it a net 116,000 bpd, compared with 103,000 bpd in 2009 and 106,000 bpd in 2008. Final-quarter output last year was 327,000 bpd, up 19,000 bpd from the same quarter of 2008.

Syncrude sold synthetic crude in the fourth quarter for an average C$78.67 per barrel, up from C$69.40 a year earlier, but the annual average dropped to C$69.47 from C$106.91 in 2008. Operating costs for the final quarter were C$30.18 per barrel, down from C$32.10, and C$35.29 for all of 2009 compared with C$35.26 per barrel in 2008.

Coutu said that although 2009 production was 12 percent short of guidance, "we once again demonstrated that the plant can run at robust rates," given the December output of 360,000 bpd.

"Syncrude's priority is to improve operational reliability to achieve design capacity rates more consistently," he said.

The other partners in Syncrude are Imperial Oil 25 percent, Suncor 12 percent, ConocoPhillips 9.03 percent, Nexen 7.23 percent, Murphy Oil 5 percent and Mocal Energy 5 percent. ●

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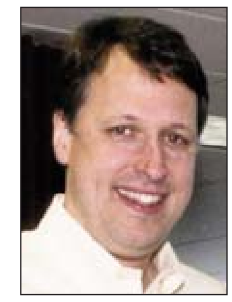
Oil Patch Bits

ExxonMobil and the Harris Foundation in San Diego

COURTESY EXXONMOBIL

ExxonMobil said Jan. 29 that former U.S. astronaut Bernard Harris gave students and teachers in San Diego a first-hand experience with the wonders of science, technology, engineering and mathematics when "The Dream Tour, presented by ExxonMobil" made its first stop of 2010 at Abraham Lincoln High School, speaking to 650 students from Millennial Middle School, Innovation Middle School and Memorial Preparatory School. The tour is designed to encourage today's middle school students to realize their potentials and strive to acquire strong math and science skills. The program included an interactive and inspirational program by Harris, a demonstration on space and engaging dialogue about achieving goals. This year the dream tour will visit Anchorage, Baton Rouge, Billings, Cleveland, Denver, Nashville, Philadelphia, Phoenix, San Diego and San Francisco as Dr. Harris continues to motivate and inspire students to pursue math and science. For more information visit www.daring2dream.org.

Crowley restructuring its Alaska operations


COURTESY CROWLEY

CRAIG TORNGA

Crowley Maritime Corp. said Jan. 28 that it has restructured it petroleum distribution and contract services group, consolidating all Alaska operations under Craig Tornga, vice president. Tornga will remain in Anchorage, will continue reporting to Rocky Smith, senior vice president and general manager, will continue to manage Alaska's petroleum distribution and fuel sales but will now also manage tanker assist and escort services in Valdez and Prince William Sound, Alaska, and energy support services on Alaska's North Slope. "The realignment of our Alaska management team is in line with our statewide business strategies," said Smith. "We are leveraging our management talents across all lines of business in Alaska in order to promote a one Crowley vision and presence in our Alaska markets." For more information visit www.crowley.com.

AAL provides medical oxygen to rescue teams in Haiti

American Air Liquide, a division of Air Liquide said Jan. 27 that it has been helping coor-

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

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

● NATURAL GAS

Persily to 'deal in reality' on gas line

Obama nominee for position of federal coordinator awaits Senate confirmation as competing projects gear up for open seasons

By WESLEY LOY

For Petroleum News

Larry Persily, the Obama administration's pick to become the new federal coordinator for Alaska natural gas transportation projects, said during a Feb. 2 confirmation hearing he'd do whatever he could to enhance chances for a gas pipeline.

"I pledge to devote my energy, my knowledge and ingenuity to the prospect of a very large and very long steel pipe to bring North Slope natural gas to America's consumers," Persily told the Senate Energy and Natural Resources Committee.

TOM KEARNEY

LARRY PERSILY

Persily, of Juneau, currently works as a legislative aide to state Rep. Mike Hawker, an Anchorage Republican. He's held such government jobs as deputy state revenue commissioner, and his extensive journalism background includes working as a writer for Petroleum News.

Only four of the Energy Committee's 23 members attended the confirmation hearing, including the chairman, Democratic Sen. Jeff Bingaman of New Mexico, and the top-ranking Republican, Sen. Lisa Murkowski of Alaska. Others present were Sen. Robert Menendez, D-N.J., and Sen. James Risch, R-Idaho.

Murkowski told the panel she felt Persily "will bring some refreshing candor" to the long-running quest for a gas line.

Persily flashed a bit of that candor during his committee testimony.

"I just deal in reality," he said, as reported on the Alaska Public Radio Network. "We have to look at the reality of the numbers, the risk, the problems involved in this. Just because we want it isn't gonna make it happen."

Among points Persily made at the hearing: Alaska gas will carry higher transportation costs compared to the blossoming shale gas projects in the Lower 48, but North Slope gas will be cheaper to produce.

Next steps

President Obama nominated Persily to replace Drue Pearce, who was the first federal coordinator after Congress created the office with the Alaska Natural Gas Pipeline Act of 2004. Pearce resigned at the president's request effective Jan. 3.

Her deputy, Thomas Barrett, is now serving as acting federal coordinator. Barrett is a retired vice admiral who formerly headed the U.S. Coast Guard in Alaska. He also ran the federal Pipeline and Hazardous Materials Safety Administration.

The coordinator's job is to expedite permitting for construction of a pipeline, working with some 20 federal agencies, the Canadian government, the State of Alaska, tribal governments and other stakeholders.

This promises to be a big year for gas line hopefuls, as two competing pipeline projects plan to hold open seasons this year to recruit customers. One is a partnership of ExxonMobil and TransCanada, and the other teams BP and ConocoPhillips.

On Jan. 29, TransCanada announced it had filed documents with the Federal Energy Regulatory Commission estimating a 1,700-mile pipeline from the North Slope to Alberta would cost $32 billion to $41 billion.

Persily also enjoys the support of Alaska's Democratic senator, Mark Begich.

The Energy Committee is scheduled to meet again Feb. 10 to further consider presidential nominees, including Persily.

If he passes the committee, Persily would then need full Senate confirmation. Because the nomination isn't considered politically controversial, Persily conceivably could start the job by late February or early March. ●

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● PIPELINES & DOWNSTREAM

CIPL to RCA: We're nearly 'non-profit'

Operator of oil pipeline along Alaska's Cook Inlet tries to quell protest against its volcano-related 259 percent rate hike

By WESLEY LOY

For Petroleum News

Answering criticism of its steep tariff increase, Cook Inlet Pipe Line Co. is telling Alaska regulators its crude oil pipeline is "very small" and is operated on "nearly a non-profit basis."

Those arguments might not wash with oil shippers, who have lodged objections to the carrier's 259 percent rate hike with the Regulatory Commission of Alaska.

The RCA is allowing the pipeline operator to collect the higher rate for now, but subject to refunds if commissioners determine CIPL is overcharging.

The higher rate of $14.57 per barrel, up $4.06 per barrel, kicked in beginning Jan. 1.

Texas-based CIPL operates a 20-inch pipeline that runs 42 miles from Granite Point southwest along the western bank of Cook Inlet to the Drift River Oil Terminal, which also belongs to CIPL. The pipeline was installed in 1966.

At least three industry players with an interest in Cook Inlet oil production have lodged objections with regulators: Cook Inlet Energy LLC, ExxonMobil and Dan Donkel.

Bad timing for new producer

Anchorage-based Cook Inlet Energy has lodged the most extensive protest of CIPL's higher rate.

The firm's lawyer has argued the rate hike couldn't have come at a worse time, as the newly formed company is just now ramping up production from oil and gas assets it bought out of bankruptcy court from troubled Pacific Energy Resources Ltd. of California.

Cook Inlet Energy's parent company, Miller Energy Resources, on Feb. 1 announced those assets are now producing more than 300 barrels of oil equivalent a day with production expected to reach 1,100 barrels within eight weeks.

Cook Inlet Energy argues the tariff hike is excessive and unreasonable.

Further, it argues that CIPL can't justify the increase simply by saying it followed a methodology established in a 2001 settlement between CIPL and the state.

Although the commission accepted that settlement, Cook Inlet Energy argues it wasn't a signatory and so the settlement is "legally irrelevant" to the company's right to challenge rates.

CIPL's defense

Chevron subsidiary Unocal owns half of CIPL, while Pacific Energy holds the other half.

On Feb. 1, CIPL filed a 10-page answer to Cook Inlet Energy's Jan. 14 formal complaint, arguing it disagrees that the settlement is legally irrelevant.

It argues Cook Inlet Energy and other shippers invite an even higher tariff should they press for a calculation under "a more traditional rate-making approach."

CIPL also urged the commission to consider a Jan. 13 ruling from the U.S. Supreme Court that deals with rate challenges brought by non-signatories to a settlement. The case is NRG Power Marketing v. Maine Public Utilities Commission. It can be found at www.scotusblog.com.

CIPL has blamed its rate hike largely on damage and disruption from last year's series of Mount Redoubt volcanic eruptions. The eruptions forced an extended shut-in of oil production, as well as the pipeline, along the west side of Cook Inlet.

CIPL also made another argument to the RCA — that it's essentially doing west Cook Inlet oil producers a favor.

"The Commission should recognize … that CIPL is a very small pipeline that is operated on nearly a non-profit basis, with very limited throughput, and a short expected remaining life," the company's lawyers wrote in the Feb. 1 filing.

The RCA should either approve the higher rate as final or, at most, "designate a settlement judge to hold a conference to explore the issues raised in this proceeding," the CIPL filing concluded. ●

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continued from page 16

OIL PATCH BITS

dinate emergency assistance efforts with the United Nations Center for International Disaster to provide much-needed medical oxygen to the rescue teams in Haiti. Due to Air Liquide's footprint and logistics structure, it was able to establish its first medical filling system in Haiti on Jan. 16 and a second system on Jan. 18, providing medical oxygen needs for a number of hospitals in the area and all of the temporary medical facilities and tents that are in operation at the U.N. compound. While support services are needed, monetary donations are also critical to recovery efforts. Air Liquide has coordinated with the American Red Cross to develop a microsite for employee donations, which will be matched dollar for dollar by the company until Feb. 28.

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

FINANCE & ECONOMY

State adopts ACES regs for lease expenses

The Alaska Department of Revenue has announced that it is adopting new regulations for the state's ACES oil production tax, under title 15 chapter 55 of the Alaska administrative code. The new regulations, part of a series associated with the introduction of ACES, apply specifically to the standards for allowable lease expenditures in calculating a company's ACES tax liabilities.

"The regulations have been reviewed and approved by the Department of Law, signed and filed by the lieutenant governor on Jan. 28, 2010, and will go into effect on Feb. 28, 2010," Revenue said in a Feb. 2 public notice.

The Department of Revenue has been working on the regulations for ACES, Alaska's Clear and Equitable Share, since the new tax passed into law in November 2007. And in January Revenue Commissioner Patrick Galvin explained that the lengthy time taken to develop the regulations has resulted from the state using a regulation development process that is highly interactive with industry, to ensure practical, understandable and usable regulations. Gov. Parnell has asked the state Legislature to pass a bill that would exempt companies from paying interest on any taxes paid in arrears, as a consequence of the retroactive application of the new regulations.

—ALAN BAILEY

continued from page 12

PATHFINDER

Crowley estimated 6,410 gallons of diesel spilled into Prince William Sound, prompting a sizable cleanup effort.

The reef is well-marked and lighted. Crowley relieved the captain and second mate pending the outcome of the investigation.

The status of the probe was still unknown as Crowley, the U.S. Coast Guard and the Alaska Department of Environmental Conservation remained silent on whether they've reached any conclusions on how the accident happened.

To ready the Pathfinder for the long, slow tow to Seattle, Crowley removed all the remaining fuel and lubricants from the vessel.

Some temporary repairs also were made to the hull.

The company had to obtain Coast Guard approval for its plan to tow the tug away, Miller said.

Crowley and Coast Guard personnel did a final walk-through on the Pathfinder, and "everybody was comfortable and signed off on the plan," Miller said.

With the temporary repairs that were made in Valdez, he said, "she's completely seaworthy."

—WESLEY LOY

continued from page 1

GREENING OF OIL

KITCHEN REMODELS MAY GLOW IN THE DARK … Among the concerns about drilling in the Marcellus Shale is the possibility that drill cuttings bring radioactive material to the surface. Drill cuttings are mostly small rocks brought up during drilling.

During a summit on the "Science of Marcellus Shale" at Lycoming College in Williamsport, Pa., on Jan. 29, someone in the audience asked, "Is there any regulation on that or is it just so low that you don't have to worry about it?"

Michael Beattie, a senior geological advisor for Anadarko Petroleum Corp., said the cuttings are radioactive, but he also offered some context: "We sample it routinely," Beattie said. "I wanted to know myself, because I know it does have a uranium content. Every rock, every natural material, actually has a radioactive content. It is higher than some rocks but lower than others. I actually found, when we tested, that the granite countertop I had in my kitchen is more radioactive."

HOW ABOUT THOSE HAPPY COWS … Contrary to other reports, California's plan to measure methane emissions involves more than just cows. The state is actually installing a network of computerized monitors to measure methane emissions from regions that are home to dairy ranches, farms, landfills and other sources. It will be the first network of its kind in the United States and will help California move closer to reducing emissions of gases related to global warming. By May, seven PC-size devices developed by California-based Picarro Inc. will be placed across the state where methane emissions are believed to be the highest, including the farm fields of the Sacramento and San Joaquin valleys and landfills in the Los Angeles basin.

Stanley Young of the California Air Resources Board told Mac Ackers that the goal of the network is to measure methane from all sources, not just the cows, with very high accuracy and precision at high frequency, which will provide researchers with important data expected to inform state regulators charged with implementing the state's landmark global warming law. Known as AB32, the law requires the state to cut its greenhouse gas emissions by about 25 percent over the next 10 years.

IT'S ABOUT MORE THAN COWS… The international Methane to Markets Partnership is putting the finishing touches on plans for a second Partnership Expo. The event is to be held in New Delhi, India, March 2-5. The first expo, held in Beijing, China, in 2007, attracted 750 attendees from 34 countries and showcased 91 methane recovery projects from 11 countries. India, with the world's second-largest population, is the second-largest emitter of anthropogenic, or human-related, methane. Methane to Markets said India's rapid economic growth, increased urbanization, and rising energy consumption create a perfect balance of opportunity and demand for methane recovery and use. ●

Editor's note: Mac Ackers is Greening of Oil's social net worker. Her weekly column is posted in both Petroleum News and www.greeningofoil.com's Buzz page.

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OPEN SEASON

but also the construction of the modules and the equipment needed for them.

The "time-critical factor is not the pipeline; it's the gas treatment plant at the moment," he said.

When Palmer presented the open season information to the Alaska Legislature's Senate Resources Committee Feb. 1, he was asked why tariffs for in-state transportation of gas, about a third of the distance to Alberta, were not a third of cost of the Alberta tariff.

Palmer said that primarily it was because there was a "very large" GTP common to all customers and that number doesn't change. He said that when you look at the pipeline the tariff is relatively related to mileage, but the GTP is approximately a third of the cost on the Alberta option in round numbers.

Conditional bids

Palmer said it is typical in large pipeline projects that customers have conditions when they respond in an open season. It is difficult to predict what the conditions may be, but some of those may be outside the control of the pipeline company.

The desire of potential shippers to resolve fiscal issues with the State of Alaska, for example, would be outside the control of the Alaska Pipeline Project, he said.

The pipeline company will work with potential customers through the end of the year on conditions that the company can address, Palmer said.

Denali

Denali, the competing BP-ConocoPhillips gas pipeline project, has said it will submit its open season plan to FERC in April, so that information will probably become available just after the FERC concludes its 60-day review of the TransCanada-ExxonMobil open season plan.

Bud Fackrell, president of Denali, said in e-mail comments that the TransCanada-ExxonMobil open season filing does not affect Denali's plans.

"Everything we are doing is focused on Denali's open season process, which will start in April of this year," he said.

"We've been working hard on developing an updated cost estimate for the project, and have spent $130 million on that effort so far.

"I am confident that we will have an attractive commercial offer for our potential customers," Fackrell said.

As to the success of a Denali open season, Fackrell said Denali is "concerned that shippers may hesitate to make the financial commitments needed to support the project due to issues outside of Denali's control."

He listed increased gas supply in the Lower 48, legal issues around the status of Point Thomson leases and "the lack of a long-term fiscal regime for North Slope gas production."

Fackrell said potential shippers on Denali "have publicly indicated that resolution of these issues will be important in their decision to make the multibillion dollar commitments necessary to move the project forward." ●

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SANCTUARY NOISE

cal knowledge and proven implementation."

It said the JRP's suggested noise level had already proved impossible to meet and argued it was not needed to protect birds in the sanctuary from adverse effects.

It said that enforcing the recommendation would prevent development of two of the three anchor natural gas fields, which contain established reserves of 5.8 trillion cubic feet.

Threat to development

"To make this condition for any approvals for facilities in the Kendall Island Bird Sanctuary would have the potential effect of preventing development of the Taglu and Niglintgak anchor fields, and therefore, the entire Mackenzie Gas Project."

Taglu, with 3 tcf of discovered gas, is 100 percent owned by Imperial, and Niglintgak, wholly owned by Shell Canada has 1 tcf. The third field is Parsons Lake, owned 75 percent by ConocoPhillips Canada and 25 percent by ExxonMobil Canada, and has an estimated 1.8 tcf.

Imperial urged the NEB to reject several of the JRP's recommendations, targeting measures the partners believe would be inappropriate and time-consuming.

The JRP urged the NEB to withhold approvals for any future applications for projects or activities until some measures were completed.

Imperial argued against any blanket rejection, calling for applications to be handled on a case-by-case basis.

It also said a recommendation requiring the proponents to complete certain tasks before any construction begins would be a problem because work would take place at various locations over four years.

"It is not practical to expect that all plans, manuals and specifications for all construction activities at all locations will be made available before the first right-of-way or site preparation activity begins," Imperial told the NEB.

Recommendations 'far-reaching'

The company said about half of the JRP recommendations are "far-reaching and apply to activities that are not associated with the Mackenzie Gas Project," urging the governments involved to avoid taking any steps that could discourage development of Canada's North.

It said recommendations to block facility applications that have yet to be filed were "tantamount to fettering the board's discretion to determine the outcome of future proceedings."

The proponents also said the NEB should not require them to establish greenhouse gas emissions targets in collaboration with the Canadian and Northwest territories governments before construction starts.

They said those targets should be developed by governments and applied to industry as a whole to ensure that all project developers and facilities are treated equitably, rather than being handled on a case-by-case basis.

The NEB is scheduled to hear final arguments on the MGP April 12-24 in the Northwest Territories before releasing a verdict in September for a final decision by the Canadian government. ●

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GRETC

member utility able to choose which mix of power generation to buy its power from.

Transition

If GRETC comes into being it would face the daunting task of transitioning from the existing power supply arrangement, with the power entities and transmission infrastructure owned by various utilities and the state, into the new ownership and operation arrangements. But, rather than trying to spell out the transition arrangements, as was done in the original version of the GRETC bill, the crafters of the latest version of the bill have finessed the transition question by allowing a flexible business arrangement that would enable the existing infrastructure arrangements to evolve into the future structure.

"We're looking at GRETC (initially) like the frame of a building — it doesn't necessarily have the plywood on it," Strandberg said. The plywood would be added later through financing.

ML&P concerns

Anchorage Municipal Manager George Vakalis said that, while Municipal Light and Power wants to find a solution that is beneficial to all, there are three remaining major stumbling blocks for ML&P in the proposed legislation:

• GRETC would not be regulated by the Regulatory Commission of Alaska.

• As a public entity, the transactions of ML&P have to be transparent to the public, while as a private entity GRETC would be "operating outside the bounds of transparency."

• Unlike ML&P, which has to seek approval from the Anchorage Assembly for any land acquisitions, GRETC would have the power of eminent domain.

Moreover, Vakalis said, ML&P has its own power generation infrastructure upgrade route, with the ability to take care of its own capital needs for its upgrades. ●

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COURTESY SAVANT ALASKA

Doyon rig 15 at the Red Wolf prospect at Badami

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BADAMI

ed and preparations are being made on the drilling rig to run a production liner over the prospective pay zones.

"As such, additional diagnostic work on both prospective pay zones will come in the form of production testing. The timing of this work is yet to be determined."

Vigil also wrote, "The 5-1/2 inch liner is on bottom and to be cemented shortly."

A rare piece of good news

Savant, an Alaska subsidiary of Denver independent Savant Resources, is drilling wells at Badami through an arrangement with unit operator BP. BP hopes improved recovery rates can jump-start the field, which has been shut down since the fall of 2007.

Savant began the B1-38 well in early 2009, but cut its drilling program short last April because of poor weather conditions on the North Slope. The company returned this winter, building a new ice road to the site and completed drilling the well using Doyon rig 15.

Red Wolf is an oil prospect in the Ellesmerian Kekiktuk formation, a rock unit equivalent to the oil reservoir in BP's Endicott field. Savant also plans to drill a horizontal sidetrack into younger and shallower Brookian rocks from the Badami B1-18 well, to see if horizontal wells can better produce from the challenging Brookian reservoir at Badami.

BP started production at Badami is 1998, hoping for 30,000 barrels per day from the field, but tricky geology led to production rates less than a tenth of that goal.

The company suspended production for four months in 1999, and mothballed the field again in 2003 after production dropped further. BP kept the field off-line until 2005, when it planned to use horizontal drilling techniques to improve field production. However, low production rates ultimately led BP to take the field off-line again in September 2007.

The company hoped that leaving the field fallow would increase reservoir pressure, making it easier for oil to move through rocks, into wellbores and up to the surface. In August 2009, though, BP told the state that the reservoirs failed to recharge as hoped and asked to continue suspending Badami operations for another year, until Aug. 31, 2010. ●

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REVIEW

duction under the agreement. But the director can exercise that power only after the unit operator 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."

The state's lawyers had argued unsuccessfully that ExxonMobil didn't deserve such a hearing in a situation where a field's production rate is zero.

And that's really the crux of the conflict between the state and ExxonMobil.

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.

Supreme Court petition

In her ruling, Judge Gleason gave the two sides 30 days to file arguments on whether she should turn the matter over to DNR for the Section 21 hearing, or preside herself over what's known as a trial de novo.

Neither side had filed such arguments by the time Petroleum News went to press.

But the state did, on Jan. 29, make a different sort of filing — a "motion for stay of proceedings" pending the state's petition to the Alaska Supreme Court for a review of the Section 21 issue.

"A central premise of the Petition will be that this court erred in concluding that a Section 21 proceeding was necessary," the state's filing said.

The state also indicated it would challenge Gleason's finding that DNR had deprived the oil companies of their constitutional rights to procedural due process.

State lawyers asked the Supreme Court for extra time to file the petition, promising to submit it by Feb. 5.

Field's significance

The remote Point Thomson field straddles the Beaufort Sea coastline about 60 miles east of Prudhoe Bay.

While the field contains some oil, it is especially prized for its estimated 8 trillion cubic feet of gas — about a quarter of all the known gas reserves on the North Slope.

Many consider the field a vital component for supporting a proposed multibillion-dollar pipeline to market Alaska's long-stranded gas.

It was during the administration of former Gov. Frank Murkowski that state officials first made moves to reclaim Point Thomson due to lack of production from the field. Two subsequent governors, Sarah Palin and Parnell, have pressed on with what Murkowski started.

Under pressure from the state, which not only has tried to terminate the unit but has also declared the underlying leases expired, ExxonMobil last year began drilling a pair of wells on two leases Irwin allowed the company to retain even as the court battle rages.

ExxonMobil has said it intends to produce 10,000 barrels a day of gas condensate from Point Thomson by year-end 2014, an output lawyers for the state have characterized as "a minimal trickle of production."

What does it mean?

Aside from ExxonMobil, other major leaseholders at Point Thomson include BP, Chevron and ConocoPhillips.

Kevin Banks, the state's oil and gas director, said the Supreme Court petition isn't a sign that settlement talks with ExxonMobil are off.

"Not at all," Banks told Petroleum News on Feb. 3.

"The state is smarter about the unit now, and we have had many opportunities to talk with the owners and we're still doing that," he said.

Banks declined to discuss the forthcoming petition in detail, but he said state officials feel significant questions — including some that "go beyond Point Thomson" — warrant the high court's review. ●

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INSIDER

But the sale of additional interest in the leases did not come as a surprise. The hydrocarbon potential in the Chukchi Sea is considered high, but so is the financial and political risk.

And ConocoPhillips is not in a position to take on a lot of risk.

The Houston-based major has faced some tough challenges in the past year, including $34 billion in write-downs on its 20 percent stake in Russia's Lukoil and its 2005 acquisition of U.S. gas producer Burlington Resources.

To "improve its financial position and increase returns on capital" ConocoPhillips said last fall that during the next two years it would sell about $10 billion of its assets and significantly reduce its worldwide 2010 capital budget.

Proceeds from the sales of its assets, it said, would be used to pay off debt and accelerate the company's return to its target debt-to-capital ratio of 20-to-25 percent.

Statoil a natural choice

Statoil, the world's largest offshore operator, was a natural choice as a partner as it already holds 16 leases in the Chukchi Sea, which Tony Dore, chief of the company's exploration in North America, described as a "new frontier area for all operators."

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The company, which is two-thirds owned by the Norwegian government, also has extensive offshore Arctic experience.

Following the announcement of the deal with Statoil, Larry Archibald, Conoco's senior vice president of exploration and development, said "Statoil's decision to acquire an interest in these leases substantiates ConocoPhillips' view that world-class hydrocarbon potential exists in the Chukchi Sea of Alaska."

He also said that Conoco "has had a long-term business relationship with Statoil in many ventures around the world, particularly in Norway, and welcomes its expertise in this harsh operating climate."

Eni, Statoil frequent partners

A frequent partner with Statoil in offshore Arctic and subarctic plays outside Alaska, and soon to be a producer in Alaska's Beaufort Sea, is Italian major Eni Petroleum.

Moreover, Eni was a minority bidding partner with Statoil in the February 2008 Alaska Chukchi lease sale.

Eni picked up four leases of its own at the sale and was outbid on nearly 60 other tracts.

But Eni is knee-deep in major investments elsewhere in the world, including its recent commitment to invest $13 billion in Uganda oil and $18 billion in Venezuela oil fields and build a refinery in the petroleum-rich Orinoco region.

And then there is Shell, the major player in the Chukchi, and Spain's Repsol YPF, which entered Alaska in September 2007, when it joined a Shell-Eni partnership in a block of 64 contiguous outer continental shelf leases in the Beaufort Sea, adjacent to the Chukchi.

At the time, Repsol said "exploration activities" could start in 2009-10, but exploration has been held up by related lawsuits against Shell, the company that has taken the exploration lead in both the Beaufort and Chukchi.

Madrid-based Repsol's acquisitions did not stop with the Beaufort Sea partnership.

In February 2008, Repsol also bid in the Chukchi Sea oil and gas lease sale, bidding $15.6 million on 104 blocks and was the high bidder on 93 blocks for $14.4 million.

Repsol has not said if it was looking at operating its Chukchi leases, but the company was not partnered with other bidders in the lease sale. Rumors of a potential partnership with Shell, Eni and/or Statoil have made their way to Petroleum News, but none have been confirmed by any of the companies.

—KAY CASHMAN

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