Petroleum news

page 5 Bear rule stays: Salazar decides not to revoke Bush-era special ESA rule

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Drilling at Point Thomson

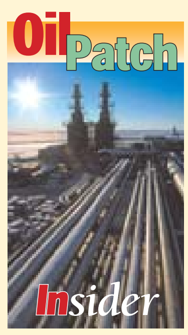
COURTESY EXXONMOBIL

The Point Thomson pad in early May, with drilling progressing on the PTU 15 well; ExxonMobil will drill to 5,000 feet, then drill PTU 16 to the same depth. Drilling into hydrocarbon-bearing zones on the coast is limited to Nov. 1 through April 15; drilling will resume in December-January. See story page 10.

Alberta cleans up royalty house; Alyeska wins operator award; JPO moving; Foothills road studies this summer

WHATEVER ALBERTA'S OIL AND GAS PRODUCERS think of the province's new royalty scheme — and the displeasure is close to universal — Alberta Auditor-General Fred Dunn isn't about to give them a break.

Following earlier criticism that the old royalty regime did not collect what Alberta was entitled to and failed for six straight years to meet the bottom end of the government's targets, he has promised a report by October that will show whether the pieces are in place to ensure that what is due is paid.



Dunn said he will also conduct a review next year to identify whether the regime is properly in tune with changing prices for conventional crude, oil sands crude and natural gas.

He told the Alberta legislature's public accounts committee that the royalty system has historically contained structural flaws that combined the three separate commodities under a single "blurred" performance measure.

It was "very hard to understand what it was that was being received on behalf of Albertans," Dunn said.

He also said the Conservative party government — which has been in power for 38 years — missed its own royalty collection target of 20-25 percent of industry net revenue for six years.

While unable to estimate the lost royalties, he had previously reported that billions of dollars were potentially left uncollected.

Complicating matters is the fact that the government reports its royalty data on a three-year rolling average, Dunn said.

He has asked the Energy Department to create three separate performance measures for the commodities and start reporting annually instead of on a rolling basis.

Dunn said the regime review is needed because the old sys-

see **INSIDER** *page 17*

B R E A K I N G N E W S

NATURAL GAS

Chugach contract

Following nearly five years of looking, Chugach Electric gets a gas supply

By ERIC LIDJI
Petroleum News

Chugach Electric Association filed a supply contract with state regulators on May 12 to buy some 66 billion cubic feet of gas from ConocoPhillips over the next seven years.

The contract is the result of nearly five years of solicitations and negotiations, and is the first long-term gas supply agreement filed by the electric utility in more than 20 years.

Under the proposed contract, ConocoPhillips would provide 100 percent of Chugach's unmet gas needs through April 2011, about half of its unmet gas needs between June 2011 and December 2015, and about 25 percent of its unmet gas needs in 2016.

The proposed contract gives Chugach all the gas it needs through 2010, but leaves the utility with about one-third of its 2011 needs and half of its 2012 needs unaccounted for.

Chugach supplies electricity directly to most of Anchorage, and indirectly to homes and businesses throughout the Railbelt region that runs from Homer to Fairbanks.

About 90 percent of the new gas volumes will be priced using a "Production Area Composite

see **CONTRACT** *page 19*

NATURAL GAS

More than expected

RCA decides wider scope for Cook Inlet utility gas supply investigation

By ALAN BAILEY
Petroleum News

Regulatory approval of utility tariffs may not be the kind of topic to raise an average person's adrenalin level, but the multiyear regulatory impasse over pricing and other terms for utility gas supplies from the Cook Inlet basin has and will impact the pocketbooks of Southcentral Alaska residents, as well as raising some important questions over future energy supplies in the region.

In the latest twist in this particular regulatory saga the Regulatory Commission of Alaska decided at its May 8 public meeting to open a regulations docket that will address a number of questions relating to the commission's role in protecting the interests of gas and electricity consumers, who depend on ever-tightening gas supplies from the Cook Inlet basin, delivered by gas producers to gas and electricity utilities.

"My recollection is that Enstar itself, on its own initiative, proposed a tariff provision back, I think, in circa 1981 or 1982, asking the commission to approve its gas supply agreements in advance of their becoming effective."

—Alaska Senior Assistant Attorney General Robert Stoller

see **RCA** *page 18*

FINANCE & ECONOMY

Winning the war is next

Canada's industry turns to next growth cycle; CNQ calls for unified approach

By GARY PARK
For Petroleum News

A concerted push-back by Canada's petroleum industry against out-of-control costs from contractors, suppliers and labor is starting to yield results, along with a warning that the gains could easily be wiped out unless companies prepare for the next boom by forming a united front.

The message was delivered in the clearest terms May 8 by Steve Laut, chief executive officer of Canadian Natural Resources (better known as CNQ), who said "it's just a matter of organizing ourselves so we don't (compete) head on head (and) ensure that while projects proceed concurrently, they are timed to avoid a simultaneous demand on specific contracting and labor components."

"You don't want everyone to do civil (engineering) work at the same time, or electrical work at the same time. You need to stagger projects, even though they're concurrent."

—Canadian Natural Resources CEO Steve Laut

"You don't want everyone to do civil (engineering) work at the same time, or electrical work at the same time. You need to stagger projects, even though they're concurrent," Laut said.

He told analysts that the current group of major players in the oil sands is a "fairly well-disciplined

see **WINNING** *page 19*

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Petroleum News | *A weekly oil & gas newspaper based in Anchorage, Alaska*

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Alaska - Mackenzie Rig Report

The Alaska - Mackenzie Rig Report as of May 17, 2009. Active drilling companies only listed.

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

This rig report was prepared by Marti Reeve

Alaska Rig Status

North Slope - Onshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Doyon Drilling			
Dreco 1250 UE	14 (SCR/TD)	Prudhoe Bay 12-07A	BP
Sky Top Brewster NE-12	15 (SCR/TD)	Stacked at Deadhorse	Available
Dreco 1000 UE	16 (SCR/TD)	Prudhoe Bay Y-16	BP
Dreco D2000 UEBD	19 (SCR/TD)	Alpine CD4-26	ConocoPhillips
OIME 2000	141 (SCR/TD)	Stacked at Deadhorse	Available
TSM 7000	Arctic Fox #1	Mobilizing	ConocoPhillips
	Arctic Wolf #2	Mobilizing	Rampart Energy
Nabors Alaska Drilling			
Trans-ocean rig	CDR-1 (CT)	Stacked, Prudhoe Bay	Available
AC Coil Hybrid	CDR-2	Kuparuk Rigging Up	ConocoPhillips
Dreco 1000 UE	2-ES	Prudhoe Bay DS 12-23i	BP
Mid-Continental U36A	3-S	Milne Point MPU F-86	BP
Oilwell 700 E	4-ES (SCR)	Prudhoe Bay J-20B	BP
Dreco 1000 UE	7-ES (SCR/TD)	Prudhoe Bay DS15-29B	BP
Dreco 1000 UE	9-ES (SCR/TD)	DS 14-23A	BP
Oilwell 2000 Hercules	14-E (SCR)	Stacked	Available
Oilwell 2000 Hercules	16-E (SCR/TD)		Available
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)	Chandler #1	Anadarko
Academy AC electric Heli-Rig	106-E (SCR/TD)	Demobilization rig shut down	Chevron
Nordic Calista Services			
Superior 700 UE	1 (SCR/CTD)	Prudhoe Bay Drill Site 4-35a	BP
Superior 700 UE	2 (SCR/CTD)	Prudhoe Bay Well Drill SiteR-21a	BP
Ideco 900	3 (SCR/TD)	Kuparuk Well 2V-08	ConocoPhillips

North Slope - Offshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Nabors Alaska Drilling			
OIME 1000	19-E (SCR)	Oooguruk ODSN-32i	Pioneer Natural Resources
OIME 2000	245-E	Oliktok Point OP04-P07	ENI
Oilwell 2000	33-E	Northstar NS-33A	BP

Cook Inlet Basin – Onshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Aurora Well Service			
Franks 300 Srs. Explorer III	AWS 1	Rigging up on Kaloa 3	Aurora Gas
Marathon Oil Co. (Inlet Drilling Alaska labor contractor)			
Taylor	Glacier 1	KBU 42-6x	Marathon
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)	Stacked, Kenai	Pioneer Natural Resources

Cook Inlet Basin – Offshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Chevron (Nabors Alaska Drilling labor contract)			
	428	Rig shut down by operator request	Chevron
XTO Energy			
National 1320	A	Platform A no drilling or workovers at present	XTO
National 110	C (TD)	Idle	XTO
Kuukpik	5	Tyonek platform A-16 recompletion	ConocoPhillips

Mackenzie Rig Status

Canadian Beaufort Sea

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

Mackenzie Delta-Onshore

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

Central Mackenzie Valley

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

JUDY PATRICK

Baker Hughes North America rotary rig counts*

	May 8	May 1	Year Ago
US	928	945	1,846
Canada	63	67	122
Gulf	52	50	66

Highest/Lowest

US/Highest	4530	December 1981
US/Lowest	488	April 1999
Canada/Highest	558	January 2000
Canada/Lowest	29	April 1992

*Issued by Baker Hughes since 1944

The Alaska - Mackenzie Rig Report is sponsored by:

XTO ENERGY

● EXPLORATION & PRODUCTION

DGGS gearing up for summer field work

Investigations continue on North Slope, along the Alaska Highway corridor, around the Cook Inlet basin and near Slate Creek

By ALAN BAILEY

Petroleum News

Geoscientists from Alaska's Division of Geological and Geophysical Services are getting ready to pull out their boots, hammers and notebooks for another busy summer field season, progressing work programs in several areas of economic interest in different parts of the state. Sponsored by industry and the state, the DGGS research results in geologic data that can act as a framework for investigations by individual companies, and that can help businesses evaluate the economic potential of a region using public-domain information.

In April the division issued proposals, seeking industry sponsors for this year's work.

North Slope program

ROBERT SWENSON

One DGGS-led team will head out in July for an area north of the Brooks Range, east of the Dalton Highway, continuing an investigation of a wide range of stratigraphic units in a region noted for oil seeps and other evidence of a petroleum system, and where some companies have been considering the possibility of drilling for natural gas, Robert Swenson, director of DGGS, told Petroleum News May 4. This year the DGGS team is moving north of what they refer to as the fold belt, along the northern side of the Brooks Range.

"They're going to be focusing in on the Echooka and Ivishak Rivers, east of the Dalton Highway. … We're moving to the north and away from the fold belt outcrop," Swenson said.

The team will work in territory with excellent surface rock exposures where rivers have cut through the terrain. However, because of a lack of continuity of exposed rock between river valleys, the team will use seismic data to link together and make sense of the geology observed in the various isolated exposed rock sections.

In fact, the use of available seismic data to tie the surface geology into subsurface structures inferred from the seismic has become a major focus of the DGGS North Slope research. And the seismic data is enabling the geologists to link the geology observed at the surface to data from exploration wells drilled in the region.

"We're … incorporating a significant amount of subsurface data that we've got access to now, including the wells," Swenson said. "… That's been really important to us to firm up some of our surface interpretations."

New insights

One result of this work will be a new geologic map of the Sagavanirktok River area that DGGS hopes to publish by the end of the summer, while the linking of surface and subsurface geologic data is providing new insights into the regional geology.

And, following what has become something of an annual tradition for the DGGS North Slope program, the division is organizing an industry show-and-tell, to be held on July 8 and 9. At this event, open to anyone who can arrange their own helicopter transportation, the North Slope team will take people on a tour of rock exposures that are important in piecing together the petroleum geology of the region.

"That's something we've done every year now and that's turned out to be a real learning experience for everybody, including us," Swenson said. "Lots of people working a lot of different issues on the slope come, and there's a lot of open discussion about the geologic interpretations that we're seeing."

Cook Inlet

The Cook Inlet region forms another major focus for DGGS energy-related investigations.

In the latter half of May a Cook Inlet project team will head for the central west coast of the Inlet to examine what is termed the Mesozoic stratigraphy, the older of the two major rock sequences associated with oil and gas in the region. Although all of the existing Cook Inlet oil and gas fields have reservoirs in the Tertiary, the younger of the two rock sequences, the Cook Inlet oil originated from the older sequence — some geologists think that there is significant potential for a new oil find within the Mesozoic.

But people do not have a good handle on the subsurface distribution of the Mesozoic rocks, including potential reservoir rocks. That lack of information coupled with the high cost of drilling a deep well to penetrate the Mesozoic in the more central parts of the basin ups the ante on drilling risks.

So understanding the distribution of Mesozoic rock types will be a key to further oil and gas exploration in the Cook Inlet region, Swenson said.

"The long-term viability of exploration in the Cook Inlet certainly will revolve around the Mesozoic. (There is) short-term (interest), no question, in the Tertiary and the gas issues, but I think in the long term we're going to have to have a better understanding of that Mesozoic than we do presently," Swenson said. "… Any exploration effort that's going to go on is going to benefit from having both an oil-leg part of it … as well as the shallow gas target."

Iniskin Peninsula

The DGGS team on the west side of Cook Inlet will be working in the area of the Iniskin Peninsula, where oil seeps were first discovered in the 19th century.

"Hopefully (they'll) get in to see some of the (oil) source rocks and do some measured sections through that," Swenson said.

The geologists also want to investigate the ways in which the rocks have become chemically altered, an issue of primary concern for the Mesozoic petroleum geology, since this alteration can result in the formation of minerals that clog the pores in rocks that would otherwise form good oil and gas reservoirs.

But, given the limited surface exposures of the rocks, DGGS wants to extract as much data as possible from the surface outcrops and then put the data into a geologic framework and a basin analysis, to extrapolate the data into the subsurface.

"Up to date it's just been piecemeal here and there at getting the data, and there's not a lot of real super-detailed data available, in the public realm anyway," Swenson said.

Tertiary rocks

The other component of the DGGS Cook Inlet research, an investigation of the Tertiary rocks of the Cook Inlet basin, began in 2006 with a primary objective of assembling information that will help explorers find subtle hydrocarbon traps, known as stratigraphic traps, that have generally been disregarded in the past but which the division thinks may contain much of the remaining undiscovered gas resources in the Cook Inlet basin. Gas deliverability issues from the Cook Inlet fields have been causing significant public concern.

"There is a lot of gas left in that basin, yet to be found," Swenson said. "… This is our contribution to that effort to make sure that there's gas in the Southcentral region for a number of years to come."

see DGGS page 12

Petroleum news

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● SAFETY & ENVIRONMENT

Salazar keeps ESA rule for polar bears

Says that revoking the rule would cause confusion without improving conservation; U.S. Fish and Wildlife will monitor situation

By ALAN BAILEY
Petroleum News

Secretary of the Interior Ken Salazar announced May 8 that he is retaining the Endangered Species Act special rule for polar bears, the rule introduced in May 2008 when the polar bear was listed under the ESA, a listing that primarily resulted from the contraction of the extent of Arctic sea ice, the creatures' primary habitat.

Scientists have linked the downward trend in the Arctic sea ice cover to global warming, a climatic trend largely attributed to greenhouse gases such as carbon dioxide in the atmosphere.

The special polar bear rule, finally published under the Bush administration in December, eliminates the possibility of greenhouse gas emissions outside the range of the bears being considered as a take of the bears under the ESA, and also allows the bears to be conserved under the terms of the Marine Mammals Protections Act and the Convention on International Trade in Endangered Species of Wild Fauna and Flora.

Without this special rule anyone creating carbon dioxide emissions could potentially be viewed as violating the ESA.

Appropriations rider

In February, Congress introduced a rider to the 2009 omnibus appropriations bill to allow the withdrawal of the special polar bear rule and the withdrawal of another regulation change published at the same time relaxing the terms under which government agencies had to consult over the potential impact of activities on a listed species. The appropriations bill rider enabled withdrawal of both regulation changes without public comment, with a deadline of May 9 for withdrawal.

On April 28 Salazar and Secretary of Commerce Gary Locke announced that they were revoking the ESA consultation regulation change, but the May 8 announcement by Salazar indicates that the polar bear special rule will remain in place.

"To see the polar bear's habitat melting and an iconic species threatened is an environmental tragedy of the modern age," Salazar said in announcing his decision on the polar bear rule. "This administration is fully committed to the protection and recovery of the polar bear. I have reviewed the current rule, received the recommendations of the Fish and Wildlife Service, and concluded that the best course of action for protecting the polar bear under the Endangered Species Act is to wisely implement the current rule, monitor its effectiveness, and evaluate our options for improving the recovery of the species."


ALAN BAILEY
KEN SALAZAR

No additional protection

Revoking the special rule would offer no additional protection to the polar bear, but would result in uncertainty and confusion about the management of the species, Salazar said. With the current polar bear protections in place, scientists will closely monitor the status of the polar bear's recovery and determine if any new rule needs to be put in place.

"In addition we will continue to reach out and listen to the public and a wide range of stakeholders," Salazar said.

The Endangered Species Act is not an appropriate vehicle for the control of carbon emissions, Salazar said.

"Instead we need a comprehensive energy and climate change strategy that curbs climate change and its impacts," Salazar said. "… Both President Obama and I are committed to achieving this climate change and renewable energy strategy. And both President Obama and I are committed to do everything we can to protect the polar bear and its habitat."

Earlier rule version

Rowan Gould, acting director of the U.S. Fish and Wildlife Service, also commented that, were the final special polar bear rule published in December to be revoked, an earlier version of the rule, published in May 2008 when the polar bear was listed, would come into effect. That earlier version is almost identical to the final rule, but would consider greenhouse gas emissions throughout Alaska as potential polar bears "takes," thus creating significant confusion.

In addition, even if there were no limitations placed on considering greenhouse gas emissions as takes under the ESA, it would not be possible in practice to directly link an individual greenhouse gas emission to the impact on a specific bear, bear population or bear habitat, Gould said.

"This direct 'connect the dots' standard that is part of the Endangered Species Act … is integral to the operation of our activities and it's been upheld in court rulings," Gould said.

But, with the final rule remaining in place, Fish and Wildlife will not only monitor the continuing condition of the polar bear population and its habitat, but will also "monitor potential impacts of actions such as oil and gas development that might impact the bear habitat," Gould said.

Monitoring will enable scientists to determine any necessary changes to the special rule, he said.

Continued conservation

However, Gould said that Fish and Wildlife anticipates continuing the present polar bear conservation measures, closely working with the oil and gas industry and other Arctic offshore operators to preclude any negative impacts on the bears.

Gould also said that President Obama's fiscal year 2010 budget request includes significant funding in support of polar bears.

"The budget request includes an increase of $7.4 million for polar bear conservation, of which $3.2 million will be invested directly in the Fish and Wildlife Service," Gould said. "This new commitment includes a $1.5 million increase for the Endangered Species program, specifically to address new and re-initiated interagency consultations on oil and gas projects, to provide for a range-wide polar bear conservation plan to guide U.S. and international work to conserve and improve the status of the species." ●

FINANCE & ECONOMY

BP Prudhoe Bay enters $29.5M settlement

BP Prudhoe Bay Royalty Trust said May 12 it entered into a $29.5 million settlement agreement with BP Exploration (Alaska) Inc., a unit of British oil company BP PLC.

BP Exploration will pay the $29.5 million to the trust.

The settlement, signed May 8, is related to the temporary shutdown of the Prudhoe Bay oil field in Alaska following oil spills on March 2, 2006, and Aug. 6, 2006, BP Prudhoe Bay said.

Shares of BP Prudhoe Bay rose 68 cents to $70.50 in after-hours trading following the announcement of the settlement. The stock had closed up 45 cents at $69.82 in the regular session before the announcement

—THE ASSOCIATED PRESS

Editor's note: The state and federal governments are seeking multimillion-dollar fines from BP related to these 2006 spills (see story in April 5, 2009, issue of Petroleum News at www.petroleumnews.com/pnads/212773290.shtml).

EXPLORATION & PRODUCTION

Forget and forgive in Newfoundland

Hebron partners file regulatory application for region's 4th commercial offshore project, leaving rifts with government in the past

By GARY PARK
For Petroleum News

It will be 12 years behind the original startup date, but Newfoundland's fourth commercial offshore oil field will come onstream in 2017, contingent on the usual regulatory and corporate sanctioning.

In a filing with the Canada-Newfoundland and Labrador Offshore Petroleum Board, the ExxonMobil-led consortium estimates the Hebron-Ben Nevis field will yield 120,000-176,000 barrels per day over 30 years, initially drawing on an estimated 566 million barrels of heavy crude reserves.

The application does not provide an updated cost projection which was pegged by Chevron Canada nine months ago at C$5 billion-C$7 billion.

ExxonMobil is operator with a 36 percent interest, Chevron Canada has 26.7 percent, Petro-Canada 22.7 percent, StatoilHydro Canada 9.7 percent and the remaining 4.9 percent is held by Nalcor Energy, created by the Newfoundland government to take equity positions in all future offshore projects. The government paid C$110 million for its stake as part of a royalty agreement with the companies.

The project description targets regulatory approval in early 2011 and final approval by the partners by mid-2012.

Rocky road

Hebron has traveled a rocky road to reach this milestone, including a bitter parting of the ways three years ago between the government and the consortium, with each side accusing the other of making unreasonable demands, culminating with Newfoundland Premier Danny Williams blaming ExxonMobil for the collapse of talks over royalties and his government's demand for an equity stake.

Soaring world oil prices last summer raised projected revenues for both government and industry, resulting in an agreement in principle.

At an oil price of $87 per barrel with a 2 percent inflation allowance, provincial revenues were estimated last August at C$20 billion over a 20-year operating life, with an additional C$8 billion destined for the Canadian government.

The deal also extended the existing generic royalty of 1 percent of gross revenues until project costs are recovered to include a super royalty of 6.5 percent after net royalty payout when the price of WTI crude exceeds an average $50 per barrel per month, translating onto a royalty rate of 36.5 percent above the $50 threshold.

The Hebron offshore area is 205 miles offshore from the Newfoundland capital of St. John's and about six miles north of the existing Terra Nova project and 20 miles southeast of Hibernia.

Three discovered fields

It contains three discovered fields — Hebron with three discovery wells, Ben Nevis with two and West Ben Nevis with one, in water depths of 290-335 feet.

For the base development, ExxonMobil said it anticipates drilling 35 to 45 wells, with about 13 likely to be pre-drilled to assist with the ramp-up of production.

The project provides for water injection as the primary-drive mechanism to improve overall oil recovery.

At the core of the project, the Ben Nevis pool is expected to account for 80 percent of total oil from the project, although ExxonMobil concedes the reservoir is of a lower quality than that of the producing Hibernia and terra Nova projects.

It said the "medium 20 degree API crude in this pool presents production challenges as the viscosity can be 10 to 20 times higher than that of water."

The application said the Jeanne d'Arc and Hibernia pools within the Hebron field are also part of the Hebron project, but compared to the Hebron-Ben Nevis pool they have high oil quality, poorer reservoir quality, lower recovery factors and higher development costs.

ExxonMobil said further development of resources within Hebron's four Significant Discovery Licenses is expected over the longer term.

Gravity-based structure

Development will involve a standalone concrete gravity-based structure like that used at Hibernia, with reinforced concrete to withstand the North Atlantic challenges of sea ice, icebergs and wild storms.

Current plans point to a total liquid production rate of 190,000-284,000 bpd to accommodate the high volumes of produced water for disposal overboard or possibly re-injection into the subsurface, if that is feasible.

Gas compression will be required to accommodate the re-injection of 56.5 million to 71 million cubic feet per day of produced gas and provide about 102 million to 173 million cubic feet per day of lift capacity, but ExxonMobil said those rates may change over time as a reservoir depletion strategy and plan is completed.

The production platform will have several storage compartments with capacity of 1.13 million to 1.45 million barrels each and an offshore loading system with a looped pipeline and two separate loading points for tankers to deliver crude to the Newfoundland Transshipment Terminal or directly to market.

The operator said that although the Hebron field fluids have a relatively low gas-to-oil ratio, it expects there will be more than enough gas to facilitate oil production.

The gas plan will also allow for the injection of excess produced gas into secondary project-area reservoirs and into primary producing intervals to improve oil recovery. ●

LAND & LEASING

Q&A on Beaufort proposed sale

The Alaska Department of Natural Resources, Division of Oil and Gas, will hold an informal question and answer session on the proposed Beaufort Sea areawide oil and gas lease sale preliminary finding of the director in Anchorage May 21.

Staff from the division will be available to answer questions from noon to 1 p.m. in Room 1270 of the Atwood Building.

The preliminary finding is available on the division's Web site at www.dog.dnr.state.ak.us.

CDs and hardcopies of the preliminary finding will be available at the session.

The division scheduled hearings in Barrow, Nuiqsut and Kaktovik the weeks of May 11 and May 18 (see "Hearings for Beaufort Sea areawide sales," in May 10 issue at www.petroleumnews.com/pnads/478693099.shtml).

—PETROLEUM NEWS

● EXPLORATION & PRODUCTION

Royalty-in-kind notice standardized

By KRISTEN NELSON
Petroleum News

At the request of the State of Alaska unit agreements have been amended at the Milne Point and Kuparuk River units on the North Slope to allow for a 90-day notice for the state to take its royalty in kind, replacing a 180-day notice.

Kevin Banks, the director of the Alaska Division of Oil and Gas, said in April 29 decisions and findings on the amendments that the state may take its royalty in kind rather than in money if taking the royalty in kind would be in the best interest of the state. Alaska statutes require that the state take its royalty in kind unless taking the royalty in value would be in the best interest of the state.

Banks said that during 2008 the state took royalty in kind from five North Slope units: Prudhoe Bay, Kuparuk River, Milne Point, Colville River and Duck Island.

Assessment of RIK volumes 90 days in advance rather than 180 days in advance allows the state to use more current production volumes in its nominations.

The Colville River and Prudhoe Bay unit agreements already require a 90-day RIK notice.

An amendment is also under consideration to the Duck Island unit agreement to require 90-day notice.

More efficient

Banks said amending the unit agreements to require 90-day notice would be more efficient because the division could evaluate RIK from all units simultaneously instead of looking at "piecemeal nomination at different times from different units."

He said volumes available for RIK nominations from each unit fluctuate — increasing due to new developments, enhanced recovery projects or improved well performance and decreasing "due to field decline rates or facilities maintenance programs which shut-in producing wells for a time."

Assessment of RIK volumes 90 days in advance rather than 180 days in advance allows the state to use more current production volumes in its nominations. Once all units have a 90-day notice, the state will be able "to more accurately analyze the value of taking in kind versus taking in value," Banks said.

The Kuparuk River field is the second-largest producer on the North Slope, following Prudhoe Bay, averaging about 150,000 barrels per day. Milne Point production averages about 30,000 bpd, while the Duck Island unit, better known as the Endicott field, averages less than 15,000 bpd. ●

● LAND & LEASING

State extends Nikolaevsk unit terms

State gives Unocal additional time to drill another Red well, releases flow test results from previous wells drilled in 2004

By ERIC LIDJI
Petroleum News

The state has agreed to extend the terms of the Nikolaevsk unit by more than two years.

The unit was set to expire on Jan. 30, 2009, but will now run through March 31, 2011.

Unocal, a subsidiary of Chevron, formed the unit on Jan. 29, 2004. The unit has since contracted twice and now covers some 5,766 acres over four state and two Cook Inlet Region Inc. leases.

The unit is in the southern Kenai Peninsula, about 12 miles north of Homer.

The state said wells at Nikolaevsk "clearly demonstrate the presence of hydrocarbons."

Unocal drilled two wells at the Nikolaevsk unit in late summer 2004.

The company tested Red No. 1 for some 26 hours in August 2004, yielding flow rates between 3.2 million to 6.8 million cubic feet of natural gas per day.

Unocal tested the well at three depths: between 8,768 and 8,777 feet; between 8,795 and 8,820 feet; and between 9,056 and 9,075 feet. The results indicated "resource potential in the area," but "the size of the accumulation has yet to be delineated," the state said.

Around the same time, Unocal drilled and tested Red No. 2, but found "no measurable hydrocarbons," the state said, citing drilling reports filed with the Alaska Oil and Gas Conservation Commission. The company tested the well at three depths: between 6,732 and 6,792 feet; between 8,038 and 8,088 feet; and between 9,298 and 9,344 feet.

Nikolaevsk is part of a regional puzzle to increase natural gas supplies in the Cook Inlet and also to extend the existing infrastructure grid past its southern end in Happy Valley.

The two Red wells were the first drilled in the area in nearly 35 years, since Standard Oil of California drilled the North Fork Unit 11-04 well to 12,462 feet in March 1970.

Socal did not test the well, according to the state.

Gas plays in Southern Kenai

Nikolaevsk is part of a regional puzzle to increase natural gas supplies in the Cook Inlet and also to extend the existing infrastructure grid past its southern end in Happy Valley.

The Nikolaevsk unit is a few miles north of the North Fork unit, where Armstrong Cook Inlet found natural gas this past summer and is considering developing in the future.

Nikolaevsk is to the east of the Cosmopolitan unit, an oil prospect that operator Pioneer Natural Resources said may have enough gas to justify an extension of the pipeline grid.

Unocal's first plan of exploration for Nikolaevsk involved drilling several wells by Jan. 31, 2007. Unocal drilled two and acquired a package of seismic data shot over the area, allowing it to keep part of the unit, and let the rest contract out of the unit in March 2006.

The second plan of exploration, which ran from March 2007 to March 2008, required Unocal to study fields similar to Nikolaevsk to get a sense of how to develop the unit.

Unocal said it compared Nikolaevsk to the Ninilchik and Happy Valley fields to the north.

The first plan of development for Nikolaevsk required Unocal to drill a well in the Red prospect by March 31, 2009, and another in the nearby Blue prospect by March 31, 2010.

On Jan. 12, 2009, Unocal submitted a second plan of development, which the state approved in early February. The new plan gave Unocal another year to drill the Red well.

According to the state, Unocal "planned to re-schedule Cook Inlet exploration efforts and not drill the Red well" in 2009, citing market conditions and the lack of pipelines connecting the southern Kenai Peninsula with the Cook Inlet transmission system.

Marketing gas from the southern Kenai Peninsula would require either an extension of the Kenai Kachemak Pipeline or a transmission line to and a distribution grid in Homer.

The state said Unocal "described efforts to farm out the drilling of the Red well before the drilling deadline," but ultimately the company "neither drilled nor caused the Red well to be drilled." The state contracted the Blue prospect from the unit this past March. ●

OIL COMPANY EARNINGS

Earnings from Petroleum News top companies

Earnings first quarter 2009 • Change from first quarter 2008
Liquids production first quarter 2009 • Change from first quarter 2008
Natural gas production first quarter 2009 • Change from first quarter 2008

Company	symbol	earnings	%	liquids	%	gas	%
ExxonMobil	XOM	$4,550	-58	2,475,000	-0-	10,195	-0-
BP	BP	$2,562	-74	2,504,000	+2	8,767	+4
Shell	RDS-A	$3,488	-62	1,639,000	–7	9,751	-0-
Chevron	CVX	$1,837	-74	1,826,000	+8	5,021	-8
Total	TOT	$3,048	-36	1,413,000	–6	4,957	-1
ConocoPhillips	COP	$840	-80	1,087,000*	+11	5,087*	+4
Eni	E	$2,556	-48	1,013,000	-0-	4,398	-2
StatoilHydro	STO	$623	-75	1,132,000	+8	4,992	+5
Occidental	OXY	$368	-80	506,000	+8	897	+6
EnCana	ECA	$962	+934	134,000	-2	3,869	+4
Can. Natural	CNQ.TO	C$305	-58	330,017	+1	1,369	-11
Anadarko	APC	-$338	—	214,000	-7	2,315	+8
Devon	DVN	-$3,959	—	231,600	-0-	2,720	+11
Marathon	MRO	$282	-61	224,000	+20	829	-4
Husky	HSE.TO	CS328	-63	250,100	-0-	551	-7
Talisman	TLM	C$455	-2	234,876	+8	1,291	+6
Apache	APA	-$1,757	—	277,547	+2	1,624	-5
Imperial	IMO	C$289	-58	251,000	-3	307	-5
Suncor	SU.TO	-C$189	—	278,000	+12	219	-4
Petro-Canada	PCZ	-C$47	—	294,000	-4	693	-3
Nexen	NXY.TO	C$135	-79	217,600	-3	205	-21
XTO	XTO	$486	+5	83,932	+24	2,228	+30
Chesapeake	CHK	-$5,746	—	31,930	+5	2,174	+4
Pioneer	PXD	-$11	—	56,749	+19	422	+12
EOG	EOG	$159	-33	74,000	+36	1,702	+10
Swift	SFY	-$59	—	15,720	-18	63	+14

Liquids production in barrels per day, including oil sands.
Natural gas production in millions of cubic feet per day.
For companies using European currencies, conversion to dollars at current rate, percentage change in local currency.
**Includes Lukoil investment*
Top companies chosen based on exploration spending and commitment to Alaska and Canada

● PIPELINES & DOWNSTREAM

No easy route to Asia for oil sands

Enbridge Northern Gateway project from northern Alberta to Kitimat, B.C., draws opposition from First Nations, conservationists

By GARY PARK
For Petroleum News

The closer Enbridge moves to placing an application for an Alberta-to-Asia link for oil sands production before Canadian regulators, the more resistance to the project seems to build.

Its Northern Gateway project, involving a pipeline link from northern Alberta to northern British Columbia's deepwater port at Kitimat for tanker delivery to several possible Asian markets, is high on Enbridge's "areas-of-opportunity" shopping list beyond 2012.

With forecast capital spending of C$12.5 billion over the 2008-12 period, the company is looking for ways to continue steady and sustained growth post-2012.

"Make no mistake, the oil sands resource will be developed," Chief Executive Officer Pat Daniel told shareholders at Enbridge's annual meeting.

"North America needs the energy. It's as simple as that and North America places a high value on a reliable, secure supply of energy and there are no better, more responsible people in the world than Canadians to develop that resource."

With that conviction in mind, Daniel has a list of pipeline ventures he hopes Enbridge can "win" against competition from pipeline companies such as TransCanada and Kinder Morgan.

The race features shipping rights from Fort McMurray to Edmonton for Imperial Oil's C$8 billion-plus, 300,000-barrels-per-day Kearl oil sands project, which is designed for startup volumes of 100,000 bpd and is likely to get corporate approval by mid-2009; the 200,000 bpd pipeline from the Sunrise project, a joint-venture by Husky Energy and BP; a combination of debottlenecking at Cushing, Okla., and the prospect of building new capacity to the Gulf Coast; and an opportunity in the U.S. Midwest to satisfy refinery expansions Marathon Oil and Husky have under way.

NEB application expected

At the outer edge of this next phase of Enbridge's dreams is Northern Gateway, which Daniel expects to result in an application to Canada's National Energy Board this year for the 525,000 bpd export leg and a twin pipeline to import 193,000 bpd of condensate to improve the pipeline flow of oil sands production, with an in-service date of 2014-15.

The project has lurched from highs to lows since it was first mooted, making a sharp descent when PetroChina scrapped its efforts to aggregate 200,000 bpd of Alberta production, then making a strong reappearance last year.

Western Canadian producers and Pacific Rim refiners have now signaled their confidence in the project by committing C$100 million to obtain equity approval and will probably be ready to front up even more money, if it's needed.

Northern Gateway, seen by some as a chance to buy insurance for producers should the U.S. restrict oil sands-related imports, is described by Daniel as "more and more a pricing play and optionality play for producers."

Resistance grows

But the support of industry for the concept is also being accompanied by growing resistance from several interest groups, notably aboriginals, environmentalists and landowners.

In an effort to win over some of those opponents, Enbridge has indicated it is ready to offer equity stakes in the pipeline for First Nations and communities along the route.

At Enbridge's annual meeting, a number of British Columbia First Nations voiced their concerns about the aboriginal consultation process and the risks to river and water course crossing from potential leaks.

Daniel told the speakers Enbridge "does not want to be involved in a project that is opposed by and of concern to others. I want to be able to work with you along with my management team to make sure we can design a project that meets your needs and ours."

But he challenged one speaker to "consider the broader importance of delivering energy to people who need it, whether they are here or in Southeast Asia or Africa. Energy is absolutely critical to our survival and our way of life."

Shareholders defeated two resolutions relating to Northern Gateway that also lacked support from Enbridge's board.

One from Ethical Funds asked directors to assess the costs and benefits of a policy requiring the consent of affected aboriginal communities before proceeding with construction of projects.

Board Chairman David Arledge said Enbridge believed it was up to regulators to decide whether projects should proceed.

He said those decisions were "based on a determination of whether a project is in the Canadian public interest, which requires a balancing of all the costs and benefits of all segments of society, with none having a veto."

The second resolution wanted the board to report by Sept. 1 on the chances and liability of product spills associated with Northern Gateway pipelines, facilities and tankers.

Arledge argued that information should be part of the regulatory process under the National Energy Board and other regulators. ●

● PIPELINES & DOWNSTREAM

ARRC willing, hesitant to operate FHR

Top executive says Alaska Railroad would be in 'serious trouble' without an oil refinery in the Interior part of the state

By ERIC LIDJI
Petroleum News

The top executive of the Alaska Railroad Corp. said the company doesn't want to operate an economically troubled oil refinery in the Interior, but might do so if asked by the state.

"Do we want to own a refinery? That's not my first choice. That is not a core business of the railroad. I don't know the first thing about operating a refinery," Pat Gamble, president and chief executive officer of Alaska Railroad Corp., told the Anchorage Chamber of Commerce May 11. "But I'll tell you this: If the State of Alaska makes a determination that (Alaska is) going to own this refinery and that the best entity to figure that will be the railroad — because it's profitable and it earns its way — then I'm going to do my darnedest to try to figure out what that value chain looks like for the state."

The state first floated the idea of the Alaska Railroad taking over the Flint Hills Refinery toward the end of last year. At the time, the Alaska Railroad said it didn't want to own the refinery, but saw a need for having a refinery in the Interior. Gamble said he wasn't speaking for Flint Hills, but was addressing general issues facing an Interior refinery.

The Alaska Railroad hauls jet fuel every day from the North Pole refinery to Ted Stevens Anchorage International Airport, deliveries that represent a major piece of the railroad's business. Those shipments have declined recently due to a drop in cargo flights. "If they shut that refinery down, the little Alaska Railroad is in serious trouble," Gamble said.

The problems at the Flint Hills Refinery began as the price of crude oil began to rise in recent years. The company also blamed new federal environmental standards for challenging its economics. Last year, Flint Hills put the refinery up for sale while it weighed its options.

One such option is to re-negotiate a supply contract with the state. Currently, the Flint Hills Refinery exclusively processes state royalty oil based on a contract from 2004. But Gamble said the contract is "pretty solid" and would be legally difficult to change.

'A very, very tough decision'

Gamble said the state asked the Railroad if it could "build a value chain for the State of Alaska that's equal to or better than the one that Flint Hills can build for themselves, and if so, explain convincingly, to the right people, what that might be before we would go forward and think about owning it as a state entity, or spinning it off in a model like the Alaska Railroad or something like that. We're in the process of doing that right now."

In addition to selling the refinery and having the state take it over, another option discussed publicly is converting the refinery into solely a distribution terminal.

Gamble said the drop in oil prices toward the end of last year improved the economics of the refinery, making it profitable in the short term. Continued stability in prices, Gamble said, would give the state and the railroad more time to find and implement a solution.

Gamble noted the Legislature would have final constitutional authority over any proposal involving the value of state resources, which he called "a very, very tough decision." ●

Contact Eric Lidji at 907-522-9469 or elidji@petroleumnews.com

FINANCE & ECONOMY

Liberty rig to cost $215 million to build

A specialty rig designed to drill eight-mile-long wells on the North Slope is expected to cost about $215 million to construct, according to the drilling company working on the rig.

Parker Drilling Co. released the figure in first-quarter financial documents on May 11.

The Houston-based drilling company is building an ultraextended-reach drilling rig for BP Exploration (Alaska) Inc. The rig, expected to be among the most powerful in the world when completed, will be used to drill the Liberty project in the Beaufort Sea from a drill site at Endicott.

Parker is building two rigs for BP in Alaska under a five-year contract signed last July.

—ERIC LIDJI

PIPELINES & DOWNSTREAM

Tesoro completes turnaround at Nikiski

Tesoro Corp. has completed its turnaround at the Nikiski refinery.

The company said in February that it planned a full turnaround at its Kenai Peninsula refinery, beginning in April or May and lasting less than a month.

Bruce Smith, Tesoro chairman, president and CEO, said in a May 7 analysts' call that a full turnaround at the company's Alaska refinery began April 21 and was expected to take about 20 days.

"All maintenance work at the refinery has been completed and it is expected to resume full operation early this week," Lynn Westfall, Tesoro senior vice president and chief economist, told Petroleum News in a May 11 e-mail.

In response to a question about how the refinery would replace the Cook Inlet crude oil which it previously obtained from the west side of Cook Inlet — currently shut-in due to the shutdown of the Drift River Terminal following volcanic activity at Mount Redoubt — Westfall said the Cook Inlet crude would be replaced from the company's supply system that feeds its other four refineries on the Pacific Rim "and we do not expect any impact from the production declines (in Cook Inlet). Crudes will be sourced from various worldwide markets," he said.

Westfall told the Alaska Legislature in March that the refinery, originally designed for Cook Inlet crude oil, was — before the Redoubt volcanic activity — obtaining 25 percent of its crude oil from Cook Inlet, 50 percent from the North Slope and 25 percent from elsewhere in the world.

—KRISTEN NELSON

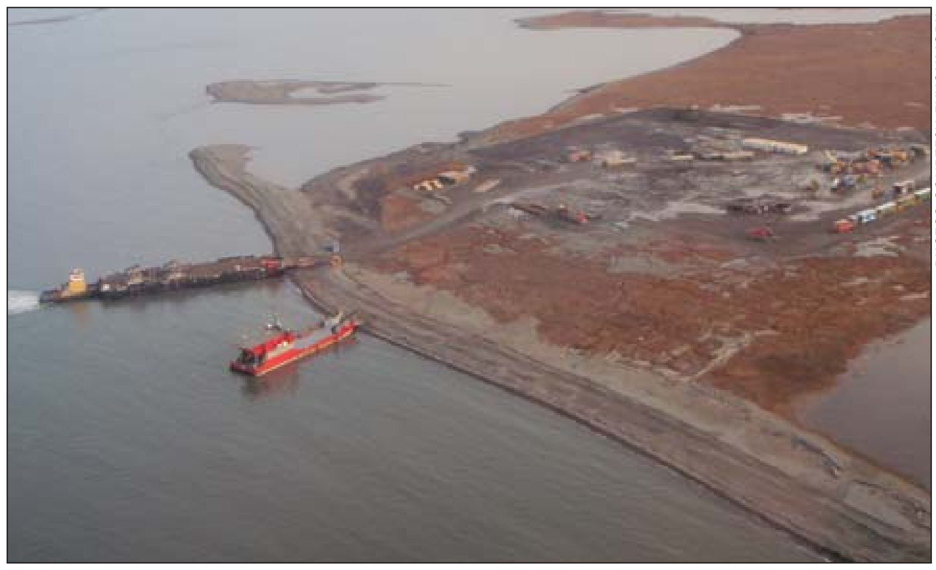
● EXPLORATION & PRODUCTION

ExxonMobil spuds well at Point Thomson

While this season's work under way, settlement needed with state says Exxon's Craig Haymes, so 2014 production won't be delayed

By KRISTEN NELSON

Petroleum News



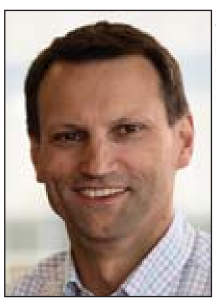
PHOTOS COURTESY EXXONMOBIL

These photographs contrast the appearance of the drilling pad at Point Thomson in August of last year, above — as equipment was beginning to be mobilized to the site — and early May, below, with drilling under way at the first of two wells permitted on the pad.

Actual drilling has begun at Point Thomson.

"ExxonMobil informed my administration that, at 2:30 a.m. today, drilling operations began," Alaska Gov. Sarah Palin said in a May 8 statement.

Craig Haymes, ExxonMobil's Alaska production manager, said May 13 at the Alaska Oil and Gas Association's annual luncheon that the first well, PTU 15, had been drilled to 3,600 feet as of that morning. This is an injector well, Haymes said, and in a pair with PTU 16, a production well, will provide cycling for production of liquids and re-injection of gas at the high-pressure condensate field.



JUDY PATRICK

CRAIG HAYMES

The other three wells in the initial five-well plan are oil delineation wells.

Haymes said after the luncheon that settlement talks with the State of Alaska continue and that the state and the companies are working well together in those settlement discussions.

But he said settlement of all issues is needed for the project to move forward.

These issues revolve around the state's refusal, beginning under the previous administration, to accept a plan of development for the Point Thomson unit which did not lead to production; the state ultimately terminated the unit and later took back all but one of the leases because they were being held beyond their original term by virtue of inclusion in the unit.

Haymes said issues include the state's termination of the Point Thomson unit which is in Alaska Superior Court; the state's termination of the leases at Point Thomson which is under administrative appeal to the commissioner of the Department of Natural Resources; damages and permit applications' issues, in Superior Court; and ExxonMobil's application to the Alaska Oil and Gas Conservation Commission for a mandatory unit at Point Thomson — Haymes said the commission has denied reconsideration of an earlier denial of the application.

Conditional decision

Drilling of PTU 15 and PTU 16 is taking place on two leases at Point Thomson which DNR Commissioner Tom Irwin allowed the companies to continue to hold under a conditional decision issued in late January — based on a commitment by ExxonMobil and the other Point Thomson owners to drill and complete two wells by the end of 2010 and begin production by the end of 2014.

Haymes said settlement needs to be reached or it will hold up permitting and impact the beginning of production. He said the company will begin applying for federal permits in June for the production facilities.

Permitting also will begin soon for the remaining three wells in the initial five-well drilling program. One issue there is drill sites: Only one of those wells is on the central pad from which Exxon is drilling this year. The other two of the three — all oil delineation wells — will be drilled from pads to the east and west. There is gravel on the east pad site, Haymes said, but none on the west pad site.

As to when Exxon would have to start applying for permits for that drilling activity, Haymes noted it had taken two years to get to this point. Sites were staked for the present wells in March 2007, he said.

What's next?

Work began at the Point Thomson pad in August with arrival of the first barges carrying 700 tons of equipment. Haymes said one advantage of the Point Thomson site was that the barges could pull up to the gravel and lower their ramps, allowing equipment to be driven off onto shore.

In addition to the ice road, a mile-long ice airstrip was built on the water, large enough to accommodate a C130 Hercules with a 130-foot wingspan.

Winter mobilization to Point Thomson began using rolligons; 30 percent of the equipment was mobilized that way while the ice road was under construction, he said.

There wasn't enough gravel at the existing Point Thomson pad, Haymes said, so they needed to bring in 10,000 insulated pads to protect the tundra over a 13-acre area; 1,760 large rig mats were put down on top of the insulated pads to protect them.

The drilling rig reached the pad in early April, and on May 8 drilling began from the surface conductor set in August.

Exxon can only drill to 5,000 feet at PTU 15 and PTU 16 this season because they are adjacent to the coast and drilling into hydrocarbon reservoirs there is limited to Nov. 1 through April 15.

Total depth will be 16,500 feet, but that won't be reached until next year.

Additional equipment and supplies will be barged in this summer and in late December or January drilling will begin on the intermediate portion of the wells, Haymes said.

He said the first two wells combined are estimated to cost almost half a billion dollars — a cost which includes pad work and the rig.

The weather

Companies working on the North Slope routinely say plans are subject to permitting and the weather — both were illustrated by this winter's activity at Point Thomson.

Because the state had terminated the unit and taken back the leases, Exxon didn't receive its ice road permits until after Irwin issued his interim conditional decision in late January; the company got the ice road permits in early February.

During the eight weeks it took to build the ice road, 35 days were lost to weather, Haymes said.

In addition to general weather delays, a storm surge in the Beaufort Sea required a portion of the ice road to be rebuilt, and then unusually warm weather in late April produced a quick thaw. State-owned North Slope coastal lands were closed for off-road winter travel effective noon April 28, giving companies 72 hours to complete off-road travel.

Haymes also said at the luncheon that he would be leaving Alaska.

He is returning to Australia in June where he will manage ExxonMobil's interests on that continent.

Dale Pittman, currently operations manager for Exxon Neftegas Limited at Sakhalin, will be ExxonMobil's new Alaska production manager. ●

LAND & LEASING

DOI seeks clarity on court OCS ruling

By ALAN BAILEY

Petroleum News

Since April 17, when the United States Court of Appeals for the District of Columbia upheld an appeal by the Native Village of Point Hope and several environmental organizations against the U.S. Minerals Management Service's 2007 to 2012 outer continental shelf lease sale program, the U.S. Department of Justice, working on behalf of the U.S. Department of Interior, has been trying to determine the ramifications of the court's decision.

And on May 11 Secretary of the Interior Ken Salazar asked Justice to seek clarification from the court regarding the status of leases already issued under the lease sale program, and regarding a Justice view of how the program might be salvaged to comply with the court order.

The 2007 to 2012 lease sale program, published by the U.S. Minerals Management Service during the Bush administration, includes the February 2008 Chukchi Sea lease sale that attracted $2.6 billion in high bonus bids, as well as three lease sales in the Gulf of Mexico.

Inadequate environmental analysis

The court had ordered Interior to withdraw the lease sale program because, the court said, Interior had not done an adequate analysis of the environmental sensitivity of areas impacted by planned lease sales — MMS had used a NOAA analysis of the impact of oil spills on coastlines, rather than an analysis of entire lease sale areas.

"The previous administration's failure to apply the law has resulted in widespread uncertainty in the oil and gas industry and put reliable conventional energy production from offshore areas at risk," Salazar said in announcing the Justice request for court clarification. "We must fix the problems the court identified and put oil and gas leasing decisions back on a firm scientific footing."

Justice has interpreted the court decision as not invalidating leases that have already been issued, and the department is seeking court confirmation of that position. And Justice wants the court to confirm that MMS can reinstate the lease sale program by fixing the shortcomings in the environmental analysis, rather than having to develop an entirely new five-year program.

"Interior has already begun addressing the court's remand instructions and is acting to preserve the environmental status quo in Alaskan waters during reconsideration," Justice said in its petition filed with the court. "The government submits, however,

see RULING *page 17*

INTERNATIONAL

MMS, Norwegians sign nonbinding MOU

The U.S. Minerals Management Service has signed a memorandum of understanding with the Norwegian Petroleum Directorate. The nonbinding MOU, signed May 6, is a cooperative agreement to exchange resource management information addressing issues of mutual interest related to offshore oil, gas and mineral resources, MMS said in a statement.

"We are happy to enter this agreement with our Norwegian counterparts," MMS Acting Director Walter Cruickshank said in a statement. He said the information exchange would "enhance our efforts to develop the outer continental shelf resources in a safe and responsible manner, as well as strengthen our and Norway's practices and procedures."

"During the years, the NPD and MMS have had a very fruitful cooperation," said NPD Director General Bente Nyland, adding that he was pleased to have the formal agreement.

Nyland said he thought the agreement would be "beneficial to both parties as we both have a substantial offshore petroleum industry," and the MOU provides "an even better platform for exchanging views and learning from one another."

Objectives of the agreement are to establish and build relationships; promote cooperative resource management activities in exploration and production; promote the sharing of scientific and technical information, exploration and production strategies and technical solutions; and conduct cooperative research studies.

MMS said this MOU complements an existing MOU between MMS and Norway's Petroleum Safety Authority, "helping both countries to improve all aspects of our oil and gas programs."

—PETROLEUM NEWS

FINANCE & ECONOMY

Conoco promotes Lance, Meyers, Mitchell

ConocoPhillips said May 14 that with the retirement of Jim Gallogly, executive vice president of exploration and production, Ryan Lance will become senior vice president, exploration and production — international; and Kevin Meyers will become senior vice president, exploration and production — Americas; Kevin Mitchell will become vice president, exploration and production — strategy, administration and technical services.

All three, along with Larry Archibald, vice president, exploration and production — exploration, will report to John Carrig, the company's president and chief operating officer.

Lance is currently president, exploration and production — Asia, Africa, Middle East and Russia/Caspian. Meyers is president, Canada, exploration and production. Mitchell is general manager, finance, strategy and planning, exploration and production.

Gallogly is retiring from ConocoPhillips to become chief executive officer of LyondellBasell.

—PETROLEUM NEWS

continued from page 4

DGGS

DGGS has carried out detailed mapping, measuring and sampling of Tertiary rocks that outcrop along the shore and in sea inlets, in and around Kachemak Bay, towards the southern end of the Kenai Peninsula. The geologists are now trying to extrapolate the results of this work into the subsurface using seismic and well data, in a similar manner to what DGGS is doing on the North Slope.

"That's really going to be the key for the east side (of the Inlet) and the stratigraphic traps that may be played there," Swenson said.

Capps Glacier

Later this summer a DGGS team will return to the Capps Glacier area, on the northwest side of the inlet, to continue an investigation of Tertiary rocks there, an investigation which began in the summer of 2008 but which was disrupted by bad weather.

The team is investigating the history and geometry of the Tertiary rocks deposited right on the northwest edge of the Cook Inlet basin, and determining the ways in which these rocks were deposited. In fact the Capps Glacier area has become a major focus for both DGGS and the U.S. Geological Survey, as part of the Statemap program, a program for developing detailed geologic maps with assistance from federal funds.

In addition, the geologists are looking for evidence for movement on the Castle Mountain fault that delineates the western margin of the Cook Inlet basin. An understanding of the history of fault movements can help with an analysis of the geologic hazards in the area and is especially important since the Castle Mountain fault extends east into the populated Wasilla and Willow areas, Swenson said.

"We've certainly seen some indication of recent (fault) activity," he said.

An understanding of the fault history and fault system will also be of help to people exploring for geothermal resources in the nearby Mount Spurr geothermal leases, Swenson said.

Gasline corridor

DGGS is also entering its final field season of a four-year program, mapping along the potential North Slope gas line corridor between Delta Junction and the Canadian border, primarily identifying geologic hazards, such as active faults and permafrost areas, and locating sites where construction gravel might be obtained. This summer's project will involve mapping the corridor east of Tok, Swenson said.

"That'll be the final leg of that 16-mile-wide corridor that we've been mapping," Swenson said. "That's been an incredibly fruitful effort for us. … We've identified some pretty major fault systems running through there that are currently active."

By combining the fieldwork results with data from geophysical surveys, the division will be able to publish a detailed geologic map of the entire corridor, something that has not been done before. The data that DGGS has obtained will help determine design criteria for the pipeline, as well as provide information about where it may be possible to obtain construction materials, Swenson said.

DGGS staff is also involved in fieldwork associated with the eruption of the Redoubt Volcano on the west side of Cook Inlet. And a DGGS team plans to do some geologic field mapping northeast of Paxson in the Alaska Interior this summer, as part of a mineral investigation in that region. ●

ALASKA DNR, DIVISION OF GEOLOGICAL AND GEOPHYSICAL SERVICES

A geologist examines tightly folded strata of the Hue shale, a North Slope oil source rock, where the shale is exposed near the Kavik River, east of the Dalton Highway.

ALASKA DNR, DIVISION OF GEOLOGICAL AND GEOPHYSICAL SERVICES

Strata of the Tertiary Sterling formation exposed along a bluff in Kachemak Bay, in the southern Kenai Peninsula

● NATURAL GAS

Denali updates legislators on gas line

Responding to request from Ramras, Johnston, BP-ConocoPhillips project outlines expenditures, 2008 accomplishments, 2009 plans

By KRISTEN NELSON

Petroleum News

The administration of Alaska Gov. Sarah Palin provided an update April 30 on the TransCanada Alaska gas pipeline project licensed last year under the Alaska Gasline Inducement Act.

Reps. Jay Ramras, R-Fairbanks, and Craig Johnson, R-Anchorage, negotiated the biannual report from the administration and also asked Denali — The Alaska Gas Pipeline, the BP-ConocoPhillips gas pipeline project, for a comparable report.

Denali President Bud Fackrell provided a project update to the Legislature May 8.

"The Alaska Gas Pipeline project will be the largest private sector construction project in North American history and is unrivaled in scale, cost and complexity," the company told legislators in the report, and said that in spite of recent economic turmoil, "Denali remains focused on the long-term prospects of the project."

On the Web

See previous Petroleum News coverage:

"Administration provides first biannual AGIA report," in May 10, 2009, issue at www.petroleumnews.com/pnads/303829545.shtml

"AGIA funding, reports an issue in Juneau," in April 26, 2009, issue at www.petroleumnews.com/pnads/659461307.shtml

Gas market issues

Denali said in an update on market and cost expectations that the most recent annual report from the U.S. Department of Energy's Energy Information Administration "indicates that there is space in the North American gas market for Alaska North Slope gas."

The report also says, however, that with new sources of nonconventional gas emerging, such as shale gas, and the potential for large volumes of liquefied natural gas imports, "an Alaska gas pipeline must be competitive and will need to provide a cost efficient means to move Alaska natural gas to market."

The report went on to say that potential natural gas shippers on the line are the ones "who will assess the economic viability of the pipeline as they determine whether or not they are willing to make the commitments that will be required to finance and construct the pipeline."

Denali acknowledged that the Legislature has spent time reviewing factors affecting the short-term price for natural gas and did not review those factors in the report, but said: "Denali is not aware of any significant changes in the long-range market price forecast for North American natural gas."

2009 plans

Denali said its work in 2009 will be focused on positioning itself for a successful open season in 2010. The company said key highlights of work this year include:

- Working with Fluor WorleyParsons Arctic Solutions and CH2MHill to update the cost estimate and the schedule for the gas treatment plant;
- Working with Bechtel on updating the cost estimate and the schedule for the mainline;
- Working with the Federal Energy Regulatory Commission, the Bureau of Land Management, the Office of the Federal Coordinator, and other federal and state agencies on regulatory requirements;
- Continuing work with Canadian regulatory agencies and government departments;
- Continuing to engage with Alaska Natives, Canadian First Nations and other aboriginal groups in Canada, and with other key stakeholders;
- Field work required to support the open season;
- Workforce development;
- Working with the Alaska Department of Transportation and Public Facilities on infrastructure upgrade planning; and
- Progressing commercial work for the 2010 open season. ●

● GOVERNMENT

Campbell cruises to victory in B.C. election

By GARY PARK

For Petroleum News

For a solid month, the refrain from Gordon Campbell was unchanged.

"Ask yourself: Who is best able to lead us through troubled economic times?" said the premier of British Columbia.

The voters of the province, or the 41 percent who bothered to cast ballots May 12, apparently bought the message.

GORDON CAMPBELL

In what is described as the "status quo" election, Campbell's Liberals are expected to occupy 49 of 85 seats in the provincial legislature and the New Democratic Party under leader Carole James will claim the balance of 36, almost a mirror image of the 2005 results.

Campbell, whose theme also hammered at James's lack of business experience, clearly persuaded voters that he was best suited to pilot British Columbia through whatever storms lie ahead.

As a result, he became the first premier in 26 years to win three straight elections and will now lead British Columbia into the 2010 Winter Olympic Games in Vancouver.

With the province's economic mainstays (forests, mines and fisheries) in such trouble Campbell desperately needs the energy industry, despite criticism from some that his government has offered too many incentives to the industry.

But any thoughts of reveling in the international spotlight will be secondary to the economic battles of trying to save — forget about turning around — a forestry industry, where thousands of jobs are disappearing in a wave of mill closures.

With the province's economic mainstays (forests, mines and fisheries) in such trouble Campbell desperately needs the energy industry, despite criticism from some that his government has offered too many incentives to the industry.

Mandate for carbon tax

The win also gives him a mandate to push ahead with his carbon tax on transportation and home heating fuels, which the NDP had pledged to eliminate, viewing the levy as an unfair penalty on more remote rural areas.

The Liberals also managed to fend off attacks on energy policies that have been portrayed as a sellout of publicly owned rivers and creeks to operators of private-sector electricity generation.

They rejected the NDP demand for a moratorium on Independent Power Projects, which BC Hydro has estimated could result in 1,144 micro-hydro projects on small streams around the province — a target some view as wildly ambitious, given that only 47 IPPs exist today.

Some citizens' groups will continue their efforts to make a case that IPP power costs are substantially higher than if government-owned BC Hydro were to develop new generation, making a case that the profits will be widely dispersed to shareholders outside British Columbia.

Gas policies won't change

What almost certainly won't change are the policies for development of northeastern British Columbia's shale and tight gas plays, which analysts suggest could see the province overtake Alberta within 10 years as Canada's leading gas-producing province.

The election campaign failed to stir any debate over environmentally related petroleum issues, such as the prospect of tankers carrying crude oil from the port of Kitimat to Asia and the Lower 48 states, or the mothballed plans to explore and develop offshore oil and gas resources, or the future of pipeline projects across First Nations' and ecologically sensitive lands. ●

● SAFETY & ENVIRONMENT

State takes comments on risk assessment

Citizen watchdog groups question scope and method of project to measure the risk to oil and gas infrastructure across Alaska

By ERIC LIDJI
Petroleum News

As the state works to create a model for measuring the risks threatening oil and gas infrastructure in Alaska, some are worried the scope of the project isn't broad enough.

A contractor with the Department of Environmental Conservation presented an early draft of the mathematical model on May 5 in Anchorage. The model is designed to gauge the type, likelihood and intensity of events that could harm oil and gas infrastructure, causing significant environmental damage, safety problems or losses in state revenues.

The draft of the model follows months of meetings across the state, where contractor Emerald/ABS met with stakeholders from industry, local government, and the public.

The May 5 presentation in Anchorage, the first of several to be held around the state, was formatted as a workshop where the public could learn about and comment on a draft of the methodology. The comments will go toward revising the methodology this summer.

Watchdogs challenge state

Several citizen watchdog groups attended the meeting and challenged the state on the progress of the risk assessment, saying the methodology still contained gaps.

"The name of the study right now is misleading," Lois Epstein, an engineer and watchdog of the oil industry, said in reference to material calling the study "comprehensive."

The assessment covers wells, pipelines, processing centers, storage tanks and marine loading facilities on the North Slope, in the Cook Inlet basin and along the corridor of the trans-Alaska oil pipeline, some 4,000 separate pieces of infrastructure. It doesn't cover refineries, marine traffic, distribution grids, exploration work or future developments.

> *"My concern is that this study is going to illustrate those risks as 'zeros.'"*
> **—Gabe Scott, Cascadia Wildlands Project**

Some, like Gabe Scott with the Cascadia Wildlands Project, said the scope should be broadened to include "secondary impacts," like problems associated with an oil spill.

"My concern is that this study is going to illustrate those risks as 'zeros,'" Scott said.

The "zero" refers to a complex ranking system within the model designed to guide policymakers' decisions about where to direct attention when it comes to infrastructure.

This "matrix" sets up a way to feed in information about the consequences of various reliability issues, such as the loss in state revenue associated with a loss of production.

Inlet shutdown wouldn't register

Under the terms of the matrix, the entire Cook Inlet oil production could be shut down — at an approximate cost about $45,000 a day — without registering on the scale.

"It won't capture reliability issues in Cook Inlet because of the small production," said Vinnie Catalano with the Cook Inlet Regional Citizens Advisory Council.

The purpose of the meetings is to "take the pulse" of the stakeholders, according to Ira Rosen, project manager with the state Department of Environmental Conservation.

The team hosting the workshop also planned meetings in Kenai, Valdez and Fairbanks.

Rosen said the state was forced to limit the scope of the project because of funding, but that any information gathered for this study can be used on future or related studies.

One issue that remains outstanding is the level of involvement from industry.

The state and the Alaska Oil and Gas Association, which is representing the oil and gas industry for this project, are still trying to come to terms on ways the industry can share confidential information with the state, without having that information become public.

Rosen noted the unusual nature of the state, as a major land and resource owner, performing a risk assessment on equipment built, owned and managed by industry.

"The state is doing a risk assessment of someone else's property," Rosen said.

Assessment dates back to 2006

The risk assessment can be traced to high-profile oil spills at Prudhoe Bay in 2006 caused by corrosion in gathering lines at the North Slope field. Gov. Sarah Palin announced the program in May 2007, a few weeks after forming the Petroleum Systems Integrity Office.

The Department of Environmental Conservation, as the lead agency on the multiagency project, hired Emerald/ABS in June 2008. The contractor is a joint venture between the local company Doyon Emerald and the international firm ABS Consulting.

The contract is for some $5 million and will run through summer 2010.

Emerald/ABS is currently finishing the first phase of the program. The second phase involves implementing the methodology. The third phase involves data analysis.

The company said it expects to have a final methodology complete around August.

The National Academy of Sciences will conduct a peer review of the model. Although members of the group attended the May 5 meeting, they did not comment on the model. ●

Contact Eric Lidji at 907-522-9469 or elidji@petroleumnews.com

NATURAL GAS

State puts out contract for bullet line work

The Department of Natural Resources is planning to spend up to $3 million on "environmental support services" to progress a gas pipeline to markets within Alaska.

The contract is the second put to bid since the Legislature appropriated $7 million for a project to bring new natural gas supplies to communities from Fairbanks to Anchorage.

The contract, put to bid on May 12, will run from June 19, 2009, to June 30, 2011.

The contract involves collecting information about wetlands and plants, fish and wildlife, and cultural resources, as well as going through existing literature to look for gaps.

According to the state, the existing studies will come not only from state agencies, but also from Enstar Natural Gas, a private utility pursuing an in-state gas pipeline in Alaska.

DNR put out a $6 million contract in April for a contractor to gather information needed to put together a draft Environmental Impact Statement for the gas pipeline.

Alaska In-State Gas Line

The state is calling the project the Alaska In-State Gas Line. The state describes the project as a "bullet line," a term used to describe a pipeline from northern Alaska into Anchorage and meant to distinguish the project from a larger pipeline to Outside markets.

However, the draft EIS proposal also requires the contractor to look at using a spur off that larger line as a way to deliver natural gas supplies to markets within the state.

The Alaska Natural Gas Development Authority is planning to spend up to $50,000 to evaluate the Ahtna 1-19 well drilled to explore a gas prospect near Glennallen.

ANGDA wants a sense of the size, life and commerciality of the prospect.

ANGDA is pursuing a pipeline or spur line project running through Glennallen.

—ERIC LIDJI

● EXPLORATION & PRODUCTION

‘Greening’ oil sands costly, but possible

Report from Canadian Energy Research Institute says most likely outcome requirement by U.S., Canada for carbon capture, storage

By GARY PARK
For Petroleum News

Shedding the “dirty oil” label for a “green bitumen” uniform will be costly for the Alberta oil sands business, but likely not an option as the United States and Canadian governments move towards low carbon fuel standards, the Canadian Energy Research Institute says in a new report.

Because the U.S. is currently the only export market for Canadian crude, in whatever form, the producing sector should, like it or not, expect to be pushed down the path to carbon capture and storage.

But CERI’s research director David McColl said it would be too soon for the Alberta government to raise the price of carbon above its current levy of C$15 per metric ton until the U.S. and Canada reach an agreement on environmental policy and the Canadian government sets its own targets this year for large carbon emitters.

He said “going green is a challenge that can be met,” even if the industry realizes that it will cost more to emit greenhouse gas emissions than to adopt the carbon capture and storage solution.

Rise in prices needed

At the same time, McColl said it will need a sharp rise in crude prices to cover those costs and government backing for carbon capture and storage technology if compliance costs in Alberta rise to C$65 per metric ton from C$15 per metric ton.

The “plausible scenario” used by CERI estimates West Texas Intermediate crude oil prices would have to regain a level of about C$100 per barrel for oil sands facilities to “withstand higher emissions compliance costs.”

However, if the inflationary cycle that hit oil sands construction in the 2005-08 period became the norm moving forward, benchmark crude would have to be close to US$110 per barrel “for new oil sands projects to go green.”

Assuming future oil prices are in that range, CERI said “there will be an incentive for ongoing oil sands development” through the deployment of nuclear power and gasification along with CCS that “could see project emissions dramatically decrease once new technologies are adopted.”

The institute, jointly funded by governments, the University of Calgary and private companies, said there is currently no silver bullet solution, although a “host of potential measures are being considered to produce a green barrel.”

Nuclear power a possibility

It said large nuclear power plants could be harnessed for mining operations to produce hot water, steam and electricity and for in-situ facilities.

By 2030, CERI projects Alberta could have four large nuclear plants in operation and about two dozen smaller nuclear energy facilities such as those developed by Japan’s Toshiba.

Always a source of controversy in Alberta, because of safety and security issues, nuclear power was identified in March by an Alberta government panel as a safe energy alternative.

Panel Chairman Harvie Andre, a former federal cabinet minister, said the debate over whether Alberta should open its doors to nuclear power plants has been influenced by the economic downturn that may reduce the demand for electricity over the shorter term.

The “plausible scenario” used by CERI estimates West Texas Intermediate crude oil prices would have to regain a level of about C$100 per barrel for oil sands facilities to “withstand higher emissions compliance costs.”

Energy Minister Mel Knight said that whatever policy his government develops will “reflect Albertans’ opinions” and answer their questions and concerns.

Andre said the report offers a “firm foundation for what will be a reasonable debate.”

Gasification an option

Gasification technology also offers an option for utilizing coal and petroleum coke to produce heat and steam and is getting a full-scale commercial workout at the recently started Long Lake oil sands project, a joint venture of Nexen and OPTI Canada.

CERI estimates CCS would be the cheapest route, adding US$2.25 to produce a barrel of bitumen; would need oil prices of US$85 per barrel to be economic; and would also have the greatest impact on emissions levels.

McColl said it would require industry and government cooperation to invest “very aggressively” in a new pipeline network.

Widespread implementation would take about 20 years and the complexities of making such a move may persuade oil sands developers to pursue other new technologies.

Gasification would add US$13.50 a barrel and would need oil prices of US$95 per barrel to be economic, while nuclear power would add US$19 per barrel to operating costs and need oil prices of US$105 to be economic when using smaller nuclear plants and add US$10 per barrel if large nuclear plants were involved.

CERI said a 100,000-barrel-per-day upgrader sourcing mined bitumen now emits 65 kilograms of GHGs per barrel of synthetic crude. That could drop to 15 kilograms using a combination of gasification and CCS and to zero with nuclear power.

A 30,000 bpd in-situ project could cut emissions to 22 kilograms per barrel from 83 kilograms by using gasification and CCS and to zero with nuclear power. ●

Petroleum news Business Spotlight

North Slope Telecom Inc.

FORREST CRANE

Sarah Meyer, Accounting Supervisor

North Slope Telecom Inc. is uniquely suited to perform telecommunications design and installation projects in the state of Alaska, as well as other extreme remote locations and climates. Providing big-company results with small-company service, NSTI is proud to have a long-standing relationship with its clients. Talent and experience allow the company to offer a full line of telecommunications and installation services.

A life-long Alaskan, Sarah Meyer worked a variety of jobs before coming to NSTI four years ago to find a career that she loves and now enjoys going to work every day. A self-professed closet karaoke superstar, Sarah also enjoys camping, fishing and four wheeling. She and her husband Clint are expecting their first child, Naomi, in August.

—MARTI REEVE

Arctic Slope Telephone Association Cooperative Inc.

COURTESY PHOTO

Steve Merriam, CEO and General Manager

ASTAC was formed more than 30 years ago, bringing the first reliable, modern telecommunications services to the communities of the North Slope. As a cooperative its mission is to improve the quality of life for all the people it serves, providing, voice, data and wireless service to the North Slope.

Steve Merriam has 29 years of management experience beginning with an Alaska tour of duty as a regular army officer. His telecommunications career began in 1995. In 2005 he earned a master's in business administration in telecommunications management from Alaska Pacific University. Steve enjoys bow hunting for elk and is currently working on a book with his brother and nephew about shared hunting misadventures. He is married with two children.

—MARTI REEVE

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

Oil Patch Bits

CH2M Hill receives apprenticeship award

CH2M Hill said April 30 that it received one of six awards presented by Labor Commissioner Click Bishop at the Department of Labor and Workforce Development's second annual Apprenticeship Conference and Awards Celebration. CH2M Hill was recognized for training a rural workforce based on industry's current needs.

The company's electrical apprenticeship training program, held at the decommissioned King Salmon Air Force Base, increased employment opportunities for Alaskans in the Bristol Bay and Aleutian regions. All of the graduates were offered work on a rotational work schedule, which enables them to continue to reside in their communities.

CH2M Hill has also trained and certified 15 Alaskans in King Salmon as scaffold builders. Company leaders say their long-term goal is to develop a transferable workforce to meet the need of the company and its clients.

MACTEC awarded airport contract

MACTEC said May 7 that it has been awarded a two-year contract with the Alaska Department of Transportation and Public Facilities, to provide environmental services at Ted Stevens International Airport. The airport, about four miles southwest of downtown Anchorage, was constructed in 1951 and renamed by the Alaska legislature in 2000 to honor former U.S. Senator Ted Stevens. Anchorage ranks as the world's fifth-busiest airport by cargo traffic.

"MACTEC will provide groundwater monitoring and soil testing at remediation land spread areas, fire training facilities, and other locations, such as storm water outfalls and soil storage areas," said Sean P. Thomas, Alaska office manager of MACTEC. "Additional services and task orders may be issued during the term of the contract to provide additional testing and environmental services as needed."

MACTEC is a leading infrastructure engineering firm based in Alpharetta, Georgia.

For more information visit www.mactec.com.

Carlile relocates John Langham to Hawaii

Carlile said May 11 that it is relocating Account Manager John Langham from Alaska to Hawaii. For the past six years, Langham held the position as the Carlile account manager for the Kenai Peninsula.

"Carlile has been offering Hawaii services to customers for several years through our Port of Tacoma terminal and other West Coast ports," said Carlile President Linda Leary, "and now with John in Hawaii fulltime, we can provide our customers the enhanced personal commitment to customer service we've become known for, daily, throughout the islands."

Langham, an Alaska resident for 35 years is best known for his photo on the cover of Alaska Magazine in 2008, surfing in Cook Inlet.

Carlile Transportation Systems is based in Anchorage, Alaska, and has 675 employees, including 110 at the Tacoma, Wash., location.

Rain for Rent AOD pump offers advantages

Rain for Rent said May 12 that its air-operated pump offers a number of advantages that make it perfect for a variety of uses, easily and efficiently handling a wide variety of fluids from water to heavy solids. The pumps have the ability to run dry without damage, are self-priming and can also be fitted for 100 percent submergence making the unit an air-operated submersible pump. Other key benefits are: leakless operation, the ability to operate in areas where concerns about explosive vapors may be present; true solids-handling designs; portability; and the ability to be pressure controlled by system parameters for automatic operation.


COURTESY RAIN FOR RENT

For more information visit www.rainforrent.com.

ABB AS in Norway signs contract with Saab

ABB AS in Norway said May 11 that it has signed a contract with Saab in Denmark that will enable ABB to offer a unique critical communication infrastructure to future customers. The contract consists of the delivery of a TactiCall communication solution to BP Norge AS.

ABB is the leading supplier of power, automation and telecom solutions to the onshore and offshore oil and gas industry. Saab's TactiCall will account for the critical communication infrastructure as part of a fully integrated power, automation and telecom solution delivered by ABB to BP on the Valhall redevelopment project in Norway.

TactiCall enables operators in the control room to manage all communication from one single operator console. The system collects all communication media and thereby simplifies the task in daily operations as well as in critical situations.

For more information visit www.abb.com.

Schlumberger service operation lauded

Schlumberger said May 7 that Schlumberger Information Solutions has received the Service and Support Professionals Association's Excellence in Service Operation certification. This prestigious certification applies to SIS global support operations. SSPA, in partnership with J.D. Power and Associates, confirmed that SIS meets the requirements of the Certified Technology Service and Support program for the audit phase.

"Our dedication to quality to all our clients around the globe is one of the differentiating factors for SIS," said Nana Kontchou, vice president of services for SIS. "Achieving this level of certification is a symbol of our commitment to delivering the highest degree of customer satisfaction."

SIS support quality was evaluated based on compliance with more than 120 criteria and standards outlined in the SSPA Certified Technology Service and Support audit document. The organization surpassed the requirement to meet 80 percent of the standards.

Editor's note: Expanded versions of these news items will appear in the next Arctic Oil & Gas Directory, which will be released in September.

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INSIDER

tem set rate caps that were outdated by six or seven years.

Energy Minister Mel Knight said his department expects to deal with the problems by Sept. 30 and is working with Dunn to "set up the proper targets and markets."

—GARY PARK

Alyeska wins API Operator Award

ALYESKA PIPELINE SERVICE CO. has received the American Petroleum Institute's 2008 Distinguished Award for Outstanding Safety and Environmental Performance in the large pipeline operator category. The award was presented in April at API's 60th annual Pipeline Conference in Fort Worth, Texas.

Alyeska operates the trans-Alaska oil pipeline from Alaska's North Slope to the Valdez Marine Terminal, moving some 750,000 barrels per day of crude oil.

"This is among the industry's highest honors and it is not awarded lightly," Alyeska President and CEO Kevin Hostler said in a statement. "API sets rigorous minimum criteria to just apply, and simply meeting those targets does not guarantee a company will receive the Distinguished Operator Award. The fact that Alyeska has been honored with this speaks to the pride and teamwork of TAPS employees who are committed to safety, the environment and the integrity of the pipeline," Hostler said.

Alyeska previously won the Distinguished Operator Award in 2005, the company said.

Alyeska has received five API environmental awards in the past and API said the company "has made a step-change improvement in safety performance."

API cited Alyeska's "initiatives in preventing soft tissue injuries, its outstanding mainline integrity program (zero pipeline releases due to corrosion), its significant engagement with external stakeholders, and taking an all-hazards approach to business continuity."

Alyeska also won the API Large Operator Environmental Performance Award, API said, and reported zero employee Occupational Safety and Health Administration lost-time and-or restricted work-injuries (zero fatalities; zero days away from work cases; and zero job transfer or restriction cases).

—PETROLEUM NEWS

188 Northern Lights new home to JPO

PETROLEUM NEWS REPORTED in its May 10 issue that the Alaska Office of the Federal Coordinator for Alaska Natural Gas Transportation Projects would be moving to the 188 Northern Lights Building in Anchorage in the fall. The 188 Northern Lights Building is the new Midtown building where Denali — The Alaska Gas Pipeline has its offices.

The OFC Alaska office currently rents space from the Joint Pipeline Office at 411 W. 4th Avenue in Anchorage.

It turns out that all of the federal personnel at JPO are moving — and probably state JPO personnel as well.

JPO said in its May 8 newsletter that a general services agreement has been signed formally authorizing the move of federal personnel associated with JPO. JPO-associated personnel from the Bureau of Land Management, U.S. Department of Transportation PHMSA and OFC will be moving to 188 Northern Lights, with the move expected to begin in July.

JPO said the Alaska Department of Natural Resources is working to reach an agreement to co-locate JPO's state personnel in the same building.

JPO is an umbrella organization of the state and federal agencies with regulatory and oversight responsibilities for the trans-Alaska oil pipeline and other non-in-field oil and gas pipelines in Alaska.

—PETROLEUM NEWS

Engineering, environmental studies for Foothills road

THE JOINT PIPELINE OFFICE PROVIDED an update on the proposed state road to Umiat in its May 8 newsletter.

JPO said the Alaska Department of Transportation and Public Facilities is preparing for engineering and environmental field studies on potential road corridors within the project study area this summer field season.

The proposed all-season road from the Dalton Highway to Umiat, the Foothills West Transportation Access Project, would allow access to potential oil and gas resources in the northern foothills of the Brooks Range, as well as access to the National Petroleum Reserve-Alaska from Umiat.

Two phases are anticipated for the proposed project: An 80-mile road from the Dalton Highway to the Gubik oil and gas fields east of the Colville River and a second phase extending the road 15 miles to the Colville River and potentially providing access to the state airport at Umiat by bridge. The studies planned for this summer are in advance of developing permit applications.

JPO said specific engineering field studies anticipated for this summer include imagery acquisition; topographic mapping; hydrology investigations; geotechnical investigations; and road alignment evaluations.

Anticipated environmental field studies include wetlands mapping; fish and wildlife evaluation; subsistence evaluation; and cultural resource identification.

—PETROLEUM NEWS

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RULING

that vacating the entire 2007-2012 program pending reconsideration will cause broader disruptions that would be both severe and unnecessary. In particular, (vacating) might require interruption of exploration and production activity in the Gulf of Mexico and could call into question the validity of 487 leases already issued in the Chukchi Sea and 1,854 more issued in the Gulf of Mexico. … The government therefore asks the court to clarify the intended scope of its order and/or to amend the order to remand the program without vacating it."

As an alternative, the court could defer its order to withdraw the lease sale program until MMS has reconsidered its environmental analysis and submitted its findings to the court for legal review, Justice said.

API petition

In a parallel filing, the American Petroleum Institute has asked the court to remand the lease sale program without requiring the program to be withdrawn.

"The court's decision should not stand as an impediment to continued production of oil and natural gas from leases already issued in the outer continental shelf and to leasing in the future under the five-year program," said API President Jack Gerard May 12. "Offshore oil and gas leasing under the program is responsible for thousands of well-paying American jobs, over $10 billion in much-needed revenue for federal, state and local governments. The nation's energy security depends upon these resources."

The court has said that it will respond to the Interior and API petitions by May 28. ●

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RCA

Contract approval

Although the commission does not regulate the producers, RCA regulation of utility tariffs, with the gas price paid to producers as a major component of energy rates, has led to a situation in which it has become de rigueur to seek commission approval of each new utility gas supply contract as a perquisite for approval of the associated tariff change. And that has led to a situation in which, if the commission rejects a contract, the utility has to go through the time consuming and expensive procedure of negotiating further contracts, and then seeking RCA approval of those.

In recent years the commission has rejected all new gas supply contracts negotiated between the Cook Inlet gas producers and Enstar Natural Gas Co., the main Southcentral gas utility, with the price of the gas being the main stumbling block. And on April 2 the commission asked for public comments on a proposal to develop a standard gas supply contract, to provide a level of clarity in what contract terms the commission would accept.

But, although in their responses to the RCA request two electric utilities expressed general support for RCA's proposal, Enstar and the gas producers questioned the workability of the standard contract concept and instead suggested looking at the broader issues of RCA jurisdiction over gas prices and the shortcomings of the current RCA procedures for utility tariff approval.

Broaden scope

And in its May 8 meeting the commission took the various comments to heart.

"We started with a scoping document that dealt with primarily pricing interests of public utility gas sales contracts and trying to establish some certainty about the pricing terms of those contracts," said Commissioner Janis Wilson. "But … the comments were much broader. … I believe that my initial approach was probably not broad enough and that there are questions we need to look at either before or along with the narrow question that we asked."

Wilson proposed opening a regulations docket that would encompass questions such as RCA jurisdiction over gas prices, the effectiveness of RCA procedures for reviewing utility tariff changes and whether a gas-price docket is required.

Commissioner Kate Giard concurred with Wilson's approach.

"I think the comments that we received … were terrific because they … emphasized for me the very, very difficult position our regulated public utilities are in," Giard said.

There's a "tremendous amount of opinion" as to whether formulating RCA pricing provisions will even help the situation — the commission has a lot of work to do and the commissioners need to decide what work will prove effective, she said.

Historic perspective

State of Alaska Senior Assistant Attorney General Robert Stoller commented on the historic background to the procedure whereby RCA reviews utility gas supply contracts. Stoller said that he was not aware of anything in the Alaska public utility statute that explicitly gives the commission authority to pre-approve the contracts.

"My recollection is that Enstar itself, on its own initiative, proposed a tariff provision back, I think, in circa 1981 or 1982, asking the commission to approve its gas supply agreements in advance of their becoming effective," Stoller said. That provision has become part of subsequent tariffs.

Stoller emphasized that he wanted to do some research into this issue, but said that he thought that Enstar, in the interests of defensive protection, had probably wished to avoid a retrospective rate challenge after a new supply contract had gone into effect. The statutes and regulations do not require a utility to include its gas supply contracts in its tariff, but no utility will risk second-guessing a retroactive challenge to a contract, he said.

But when a utility such as Enstar files a new or revised tariff, the commission has to review that tariff, a requirement that triggers a need to review the utility's gas supply contracts because of the impact of those contracts on the utility's rates, Giard said. The commission must, by law, review those contracts, she said.

The real issue is how the commission exercises its authority, and whether the approval process can be streamlined, Stoller responded.

"There is reason to believe that the commission has shifted its standards upon which it decides whether and how to approve contracts," Stoller said. And there's reason to believe that the process has been dysfunctional, he said.

Timing

Commissioner Anthony Price said that the commission needs to obtain a legal opinion on its jurisdiction before opening a regulations docket and he expressed concern about the amount of time a commission investigation might take, given the urgency of resolving the issues surrounding utility gas supply contracts.

"We could … use much of our two-year timeframe for our docket, flushing out and getting comments … on our jurisdiction … without benefit of actually crafting or trying to craft regulations," Price said.

But a review of RCA procedures could be done concurrently with the assessment of RCA jurisdiction, Wilson said.

Commission Chairman Robert Pickett also voiced concerns about timing.

"We don't have two years of time for the commission to make sure that adequate gas-supply agreements are in place for utilities," Pickett said. "… I do believe there are very serious questions concerning the commission's standard of review. … As utilities have business dealings with non-regulated entities, just how far down the food chain does the commission's reach go? Where is the line past which the commission defers to the management of that utility? And where does the public interest demand that commission walk down the food chain?"

Regulations docket

The commissioners, with the exception of Price, eventually voted to open a regulations docket. That docket will start with a notice of enquiry and will involve drafting regulations that clarify RCA jurisdiction over gas supply contracts; reviewing the effectiveness and consequences of the existing gas supply contract review procedures; determining whether the commission should continue with its practice of prior approval of utility gas supply contracts and whether there are workable alternatives; and determining whether the commission should play a role in creating incentives for the Cook Inlet gas supply market.

"The environment that we're in today is dramatically different from the one that existed 12 months ago when Enstar brought new contracts into the commission," Pickett said. "… Time is of the essence." ●

RCA backs off gas storage regulation

Faced with some significant unknowns regarding its jurisdiction over natural gas storage facilities that are not operated by a public utility, the Regulatory Commission of Alaska decided in its May 8 public meeting not to open a docket for developing RCA gas storage regulations. Instead the commission will continue to collect material in an information docket that the commission had already opened as a preliminary step of an investigation into the gas storage regulation question.

On April 2, following a presentation by the Alaska Department of Law on potential RCA gas storage jurisdiction, the commission had asked for public comments on the points made in the presentation, a presentation that had indicated that storage operated by a public utility would likely come under regulation, but that the regulatory status of other storage facilities would depend on the specific operational situation for each facility.

Raised questions

The public comments that the commission subsequently received continued to raise questions about the limits of the commission's jurisdiction, said Commissioner Anthony Price at the May 8 meeting. Without legislative action that clearly specifies the commission's authority over gas storage, a project to develop regulations would be unwise, he said.

"It's evident from nearly all the responses that we received, that there's a question as to the limits for our jurisdiction," Price said. "… I am reluctant to launch into a very long program … for developing regulations for an uncertain number of storage facilities and providers, without clarity as far as jurisdiction. … What we would have in the end is probably a massive amount of litigation that would go on for years and years and years."

Moreover, opening a regulations docket might dampen enthusiasm for investment in new Cook Inlet gas storage facilities that will be needed over the next few years. Meantime, the material collected in the information docket would create a record that the commission can use in the event of legislative clarity over gas storage jurisdiction being eventually achieved, Price said.

Commissioner Kate Giard, while supporting a motion not to open a docket for the regulation of non-utility gas storage operations at present, did express some concern that regulated utilities negotiating for unregulated gas storage use could face similar regulatory problems to those encountered when negotiating for gas supplies from unregulated producers.

—ALAN BAILEY

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WINNING

group," but also warned that "when certainty in commodity prices returns, players are likely to start construction on a cost-plus basis, with the ultimate concern that poor productivity and inflation will all reignite and we will all be back in the same unfavorable position" that saw prices for major projects overrun budgets by 50 percent and more.

"It will take a considerable effort from the industry to ensure we don't return to a minimal focus on cost control that we have seen in the past from owners, contractors, regulators and labor," he said.

Horizon C$3B over estimates

CNQ, despite its efforts to get a grip on costs as it entered the oil sands by proceeding with the Horizon project in stages and by building an airstrip to fly workers and contractors in and out, still ran about C$3 billion over initial estimates with its C$9.7 billion first phase coming on-stream in February and now pumping 75,000 barrels per day into sales tanks as it ramps up to capacity of 110,000 bpd.

Laut describes the results as a "successful execution strategy," but acknowledges that there are lessons to be learned from the experience, which included design flaws for some components and incorrect metallurgy for fabrication.

Although work on Tranche 2 is already under way, Tranches 3 and 4 will only go ahead when CNQ is certain it can implement its lessons even more rigorously.

Laut said contractors' capacity has increased significantly during the downturn and the recent consolidation of operators (the planned merger of Suncor Energy and Petro-Canada) should allow for a more orderly and effective scheduling of construction projects and major turnarounds.

Greg Stringham, a vice president of the Canadian Association of Petroleum Producers, commenting on the indications from some companies that future projects can be profitable at oil prices of US$60-$70 per barrel ($80-$100 was previously viewed as the threshold), told the Globe and Mail that re-designed projects will focus on building projects in "bite-size" stages and outsourcing fabrication jobs to Eastern Canada.

The new focus will also be on seeking fixed-price contracts to avoid the inflation that accompanied cost-plus agreements.

Laut conceded that coordinating industry efforts will be "hard to do in reality," although it could happen by default.

Paul Verhesen, president of Clark Builders, which provides construction services across Western Canada, doubts companies will be eager to defer to competitors when "they all want to be first."

However, he thinks the operators will have success in proceeding on a "more sustainable, cost-effective" basis.

Recent cost reductions

What has happened over recent months has been a sharp scaling back of costs, according to CNQ, Suncor, Petro-Canada, Royal Dutch Shell and Husky Energy.

Laut said conventional drilling and completion costs, especially for deep gas drilling, are 10-15 percent below 2005 levels, largely because of improved productivity and technological innovation, with a smaller contribution from lower service and supply costs.

He rates those gains as "impressive," given that steel prices, which account for 28 percent of drilling costs, are up 48 percent since 2005 and regulatory costs, which account for 6 percent of spending, are up 35 percent.

Petro-Canada believes it could shrink the costs of its proposed Fort Hill oil sands mine by 30 percent to under C$10 billion, and the price tag for the joint Sunrise project by Husky and BP has been slashed by 44 percent to C$2.5 billion.

Suncor's Chief Operating Officer Steve Williams said the cycle has turned through a "systematic, broad-fronted attack on costs. … We're making real and substantial progress."

Imperial Oil Chief Executive Officer Bruce March said that although the cost estimate for the Kearl oil sands project has climbed above its original target of C$8 billion there has been enough headway on costs that "we should have something exciting to share with you in the next several weeks."

He suggested that Imperial's snail-like pace in recent years could "win the day, at least in the next four or five years."

Suncor has shrunk the cost of producing a barrel from C$41 in the final quarter of 2008 to C$33 currently and is chasing a further cut of 10-15 percent.

Shell is taking a hard line with vendors "around cost and cost performance" as it moves towards a late 2010 deadline for completion of a C$13.7 billion expansion of its Athabasca oil sands development.

Enbridge Chief Executive Officer Pat Daniel predicted "some notable decreases in costs (are on the horizon), but it is hard to quantify because it's an early stage. We're seeing far more competitive bidding from contractors for new projects." ●

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CONTRACT

Index" averaging five production areas in Texas, Oklahoma and Louisiana.

The Regulatory Commission of Alaska proposed such an index during an Enstar Natural Gas supply contract case last year. The index, or price basket, was meant to approximate a spot market for Cook Inlet gas by comparing it to gas prices in other producing regions.

ConocoPhillips and fellow Cook Inlet producer Marathon, the two companies looking to supply Enstar, refused to accept the RCA-proposed price cap under the basket approach.

Chugach said gas prices under its index averaged 9 percent below the Henry Hub price of gas over the past four years. Henry Hub is currently $4.42 per thousand cubic feet.

The remaining gas under contract, some 10 percent, covers peak loads, or times of increased electric demand. These peaks are less common with electricity than natural gas use in Alaska. Chugach said proposed renewable energy sources could cover these peaks.

Through March 2011, the price for these peak loads will be 95 percent of the average monthly price of Kenai liquefied natural gas shipped to Japan. From March 2011 through the end of 2013, the peak load will be priced at 120 percent of the national average.

Chugach said both of these prices have historically been below Henry Hub.

The contract requires the approval of the Regulatory Commission of Alaska. Chugach asked the commission to cut the public notice period to 30 days from 45 days.

The utility hopes to start buying gas under the contract as soon as Jan. 1, 2010.

Chugach still needs gas

The proposed contract gives Chugach all the gas it needs through 2010, but leaves the utility with about one-third of its 2011 needs and half of its 2012 needs unaccounted for.

But while regional demand for electricity, and by extension gas, could grow in the coming years, Chugach expects its gas needs to ease starting in 2013, as a more efficient power plant comes online, and two regional utilities stop buying wholesale power.

Chugach currently uses some 27 billion cubic feet of natural gas per year. It expects that need to drop to about 17 bcf in 2014 and 11 bcf in 2015.

Chugach is the largest electricity producer in Alaska, supplying its own customers in Anchorage as well as selling power to other utilities across the Railbelt. Chugach is extremely dependent on natural gas, using the fuel to make 93 percent of its electricity.

Contract eases export debate

With the contract, ConocoPhillips fulfilled the final term of a 2008 agreement to get state support for an extension of the export license at the Nikiski liquefied natural gas plant.

Chugach originally appealed the U.S. Department of Energy's decision to extend that license to 2011 from 2009, but is now withdrawing that appeal because of the contract.

On May 8, three Anchorage-area senators —Bill Wielechowski, Johnny Ellis and Bettye Davis, all Democrats — publicly asked the Palin administration to require Cook Inlet producers to sell their gas to utilities in Alaska first before shipping it to Asia, citing the Chugach appeal. ●