Petroleum news

page 3 Conoco to spend more on E&P, while cutting costs in the short term

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Liberty rig mast up

BP EXPLORATION (ALASKA)

The mast is up on BP Exploration (Alaska)'s Liberty rig at the drill site at the Endicott secondary drilling island on Alaska's North Slope. The mast was raised March 18 and pinned into place April 1, company spokesman Steve Rinehart told Petroleum News in an e-mail. Rinehart said the rig stands 240 feet tall — compared to BP's Anchorage headquarters at about 190 feet. Assembly and testing will continue, he said, with the schedule for Liberty calling for drilling to begin this year and oil production to begin in 2011. Liberty is a 100-million-barrel offshore prospect in federal waters east of Endicott that will be reached by record-length extended reach wells drilled from the Endicott SDI. Rinehart said several contractors including Parker Drilling and CH2MHill are working on the installation and assembly. BP commissioned Parker to build the rig, which arrived on the North Slope on two barges at the end of July 2009.

In dispute over pipeline's value, judge deals the owners a setback

Does federal tariff regulation somehow "preempt" the state's ability to appraise the trans-Alaska oil pipeline for property tax purposes?

No, an Alaska Superior Court judge ruled recently.

The decision from Judge Sharon Gleason of Anchorage knocks down an attempt by the pipeline owners — BP, ExxonMobil, ConocoPhillips, Chevron and Koch Industries — to invalidate the state's method of valuing the pipeline.

The owners feel overtaxed on an asset that carries crude oil 800 miles from the North Slope of Alaska to the tanker port at Valdez.

see DISPUTE page 19

Greening of Oil: Latest from Mac Ackers

WHY 'UNDERCOVER BOSS' MATTERS … Reihan Salam, co-author of "Grand New Party: How Republicans Can Win the Working Class and Save the American Dream," wrote a thought-provoking piece in his April 5 weekly column for Forbes about the new reality TV series, "Undercover Boss," calling it "a remarkable educational tool." The CBS program, which has 13 million to 17 million viewers per episode, features top executives from major American firms such as Waste Management, Hooters and 7-11 going undercover to work

MAC ACKERS

see MAC ACKERS page 21

NATURAL GAS

Denali line at $35B

If shippers don't commit to 85% of capacity, LNG, smaller line possible

By KRISTEN NELSON

Petroleum News

Denali—The Alaska Gas Pipeline, filed its open season plan with the Federal Energy Regulatory Commission April 7, and has tagged the price of a gas treatment plant and the gas pipeline from the North Slope to market at $35 billion in 2009 dollars.

BUD FACKRELL

Denali President Bud Fackrell said in a press briefing that the company expects FERC approval of the plan; with that approval Denali would begin an open season July 6 and conclude it in early October.

TransCanada and ExxonMobil have received FERC approval for an open season for their competing pipeline which will run May through July.

Fackrell said Denali believes "we have a really high-quality design and project execution plan," underpinned by an investment of $140 million and more than 600,000 hours of work.

"Backing that up are decades of Arctic and mega-project and pipeline experience," he said.

"This is an enormous undertaking with significant risk" in both the marketplace and in the project execution; Fackrell said Denali has "constructed our commercial offering such that we're not asking the shippers to take on unreasonable risk."

The project will terminate at Blueberry Hill in Alberta, he said, providing shippers with the

see DENALI page 22

EXPLORATION & PRODUCTION

Shifting the OCS season

Ion wants to use under-ice techniques to do seismic survey late in the year

By ALAN BAILEY

Petroleum News

As the days lengthen and the short Arctic summer looms on the horizon, an annual ritual has been taking place to sort out who does what in the seas around Alaska's northern coastline during upcoming brief period when sea ice retreats towards the northern horizon.

But this year, in the interests of avoiding conflicts with other open-water activities, and in particular to avoid the annual subsistence bowhead whale hunts, one of the would-be offshore operators, Ion Geophysical, has proposed a novel solution to conflict avoidance: Shoot a seismic survey in the Beaufort Sea late in the year, after the sea ice

> *"We're talking about an icebreaker in front and seismic boat behind. … They're not independent. They have to operate together. There is no timeframe in which the icebreaker will actually operate independently from the seismic vessel."*
>
> **—Joe Gagliardi, Ion Geophysical**

has formed, using special equipment that can function under the ice.

Joe Gagliardi of Ion Geophysical presented his company's concept at the National Marine

see OCS SEASON page 23

EXPLORATION & PRODUCTION

Blow-out rules outdated

Imperial, BP, CAPP want same-season relief well requirement changed

By GARY PARK

For Petroleum News

The combined weight of Imperial Oil, BP and the Canadian Association of Petroleum Producers is being applied to seek changes to relief well policies for the Canadian Beaufort as the industry starts to eye prospects more distant from the shoreline.

In submissions to Canada's National Energy Board, the three parties want an end to a 34-year-old policy requiring operators to, if necessary, be able to drill a relief well, kill an original well and safely suspend both wells during a single Arctic drilling season.

The review process was started last fall after the NEB turned down a request from joint partners

> *The review process was started last fall after the NEB turned down a request from joint partners Imperial and ExxonMobil Canada for an advance ruling on the adequacy of well control provisions for a proposed deepwater exploration well about 75 miles north of the outermost edge of the Mackenzie Delta.*

Imperial and ExxonMobil Canada for an advance ruling on the adequacy of well control provisions for a proposed deepwater exploration well about 75 miles north of the outermost edge of the Mackenzie Delta.

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FINANCE & ECONOMY

ConocoPhillips: Lean, legacy-focused in 2010

Company plans to spend more on E&P, while cutting costs in the short term, planning $340 million program on Western North Slope; exploitation dollars on infield, peripheral drilling

By ERIC LIDJI

For Petroleum News

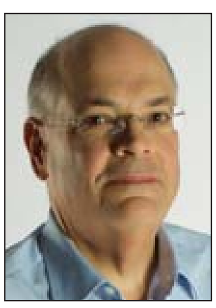
Everyone always wants to know where Alaska fits in ConocoPhillips' global strategy, and the company gave some clues in presentations and documents in late March.

In short: ConocoPhillips plans to focus on "legacy assets" in the developed world, company Chairman and Chief Executive Officer Jim Mulva said during an analyst meeting in New York on March 24.

JIM MULVA

That bodes well for Alaska.

In its 2009 annual report, a publication for investors that is distinct from year-end financial filings, ConocoPhillips includes the North Slope among its "core oil-producing assets," alongside the Lower 48, the Canadian oil sands and the North Sea.



KEVIN MEYERS

Alaska accounted for 15 percent of the 1.85 billion barrels of oil equivalent ConocoPhillips produced worldwide in 2009 and 20 percent of its 10.3 billion BOE of proved reserves. Those figures put Alaska behind Canada, the Lower 48 and Europe.

Generally speaking, ConocoPhillips wants to convert an estimated 10 billion barrel global resource base into proven reserves over the next 10 years, Mulva said.

Mulva said ConocoPhillips would hit those numbers by increasing exploration and development spending, and selling assets. While the company is not announcing sales, Mulva named U.S. downstream marketing, the Rockies Express pipeline, its stake in Syncrude and 10 percent of its Lower 48 and Western Canada portfolio as potential sales.

The increase in E&P spending will comes by shifting dollars to upstream operations.

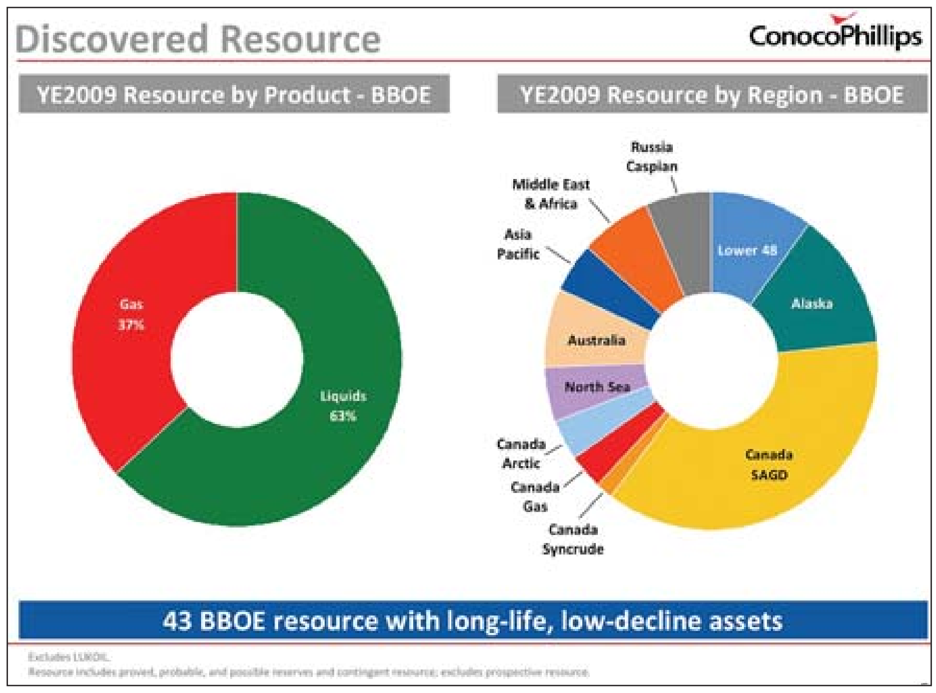
Currently, between 65 and 70 percent of ConocoPhillips' assets are connected with upstream operations. The company wants that to be closer to 85 percent, Mulva said.

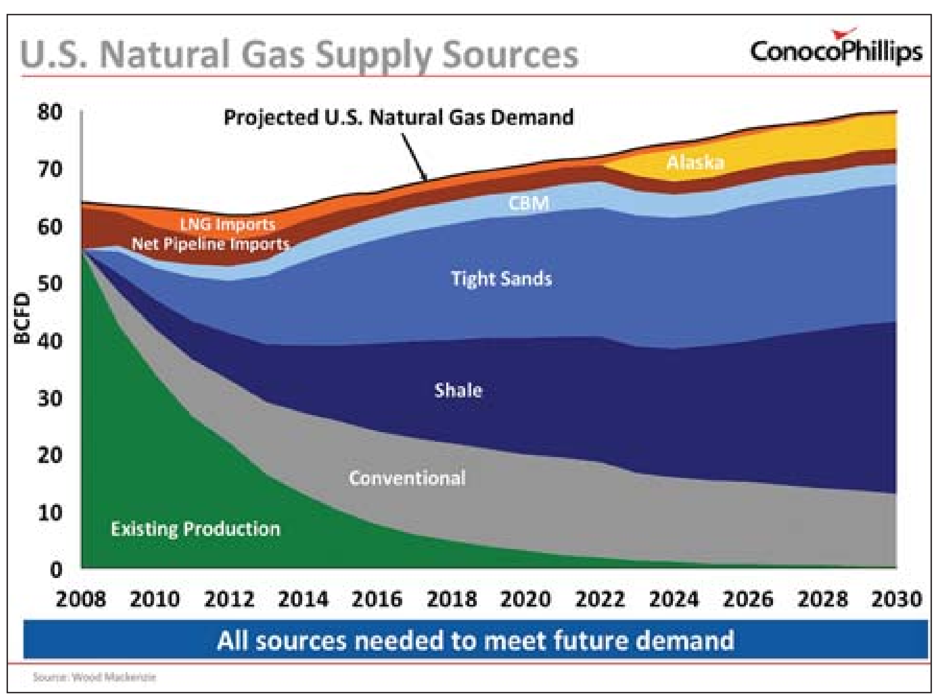
$340 million to North Slope

That falls in line with ConocoPhillips' stated desire to be a leaner company.

The company decreased operational costs by 7 percent in 2009 and wants to cut them another 5 percent this year, according to President and Chief Operating Officer John Carrig. The overall goal is to get back to the spending levels of 2005 and 2006 (a time, incidentally, of roughly $60-a-barrel oil prices, compared with $80 oil today.)

see CONOCO page 22





● EXPLORATION & PRODUCTION

Pioneer lays out plans for Cosmopolitan

Production from Cook Inlet unit could begin in 2014, fill up to 40 trucks daily with peak at 8,000 bpd; project not yet sanctioned

By WESLEY LOY
For Petroleum News

Pioneer Natural Resources Co. says daily oil production from its proposed Cosmopolitan development on Alaska's Cook Inlet could peak at 8,000 barrels, enough for 40 tanker truckloads bound for Tesoro's refinery at Nikiski.

Pioneer laid out these and many more details about the Cosmo project in documents submitted recently to state and federal regulators.

An Alaska spokesman for the Irving, Texas-based independent stresses the company has made no decision yet on sanctioning, or moving forward, with the development.

But based on the level of detail in the plan documents, Pioneer would seem close to green-lighting Cosmo. And presumably, recent oil prices in excess of $80 a barrel are providing encouragement.

"Vertically, up to three laterals may be drilled from each trunk wellbore to access the sand prone Hemlock and Starichkof intervals. Additionally, hydraulic fracturing of the reservoirs may be necessary" to reach commercial production rates, the company said.

The 23,516-acre Cosmopolitan unit takes in eight state leases and two federal leases in Cook Inlet offshore the west bank of the Kenai Peninsula.

In plans submitted to the Alaska Department of Natural Resources and the U.S. Minerals Management Service, Pioneer proposes to tap Cosmo from a drill site on land about 500 feet back from the Cook Inlet beach. The wells will angle out to the unit two to three miles offshore.

If the project goes, first oil is scheduled for 2014, Pioneer said.

Old discovery

Pioneer didn't find Cosmo.

Pennzoil did, in 1967, drilling the Starichkof State No. 1 and the Starichkof State Unit No. 1 wells.

The first well "was drilled on the eastern flank of the structure," encountering oil in the Starichkof interval and water in the Hemlock interval, Pioneer said. The second well was drilled on the northeastern flank and hit water.

The early drilling didn't result in a commercial development.

In 2001, ConocoPhillips formed the Cosmopolitan unit and the next year drilled the Hansen well up dip of the Starichkof State No. 1, encountering oil in both the Starichkof and Hemlock intervals, Pioneer said.

In 2003, ConocoPhillips drilled a sidetrack, the Hansen 1A, across both the Starichkof and Hemlock sands, and a 50-day flow test averaged 550 barrels per day of 24-27 API gravity crude.

A 3-D seismic survey was completed over Cosmo in 2005, and the next year Pioneer took over the unit.

In 2007, Pioneer drilled a lateral, the Hansel 1A-L1, from the Hansen 1A wellbore, targeting the upper Starichkof interval. In recent months, Pioneer re-entered and flow tested the lateral.

The Cosmo reservoir "is lower quality than most other producing oil fields of the Upper Cook Inlet," Pioneer wrote in its plan of operations submitted to the DNR.

Drilling plans

To develop Cosmo, Pioneer intends to use the Rowan rig 68 for extended-reach, undulating, horizontal wellbores "drilled from the east to the west across the entire structure," Pioneer said.

"Vertically, up to three laterals may be drilled from each trunk wellbore to access the sand prone Hemlock and Starichkof intervals. Additionally, hydraulic fracturing of the reservoirs may be necessary" to reach commercial production rates, the company said.

Although all the drilling will be done from land, Pioneer has applied to the U.S. Army Corps of Engineers for permission to pipe in Cook Inlet seawater for a flooding program to maintain field pressure and boost oil recovery.

Pioneer proposes to begin development drilling in the fourth quarter of this year and drill through 2014.

The five-acre drill site is on leased, private land between the Sterling Highway and the inlet, 5.5 miles north of the Anchor Point community. It's the same site both Pioneer and ConocoPhillips used for their exploratory drilling.

Pioneer is proposing to drill 11 to 28 development wells, with half to be producer wells and the other half waterflood injectors.

While most of the wells will be aimed at Cosmo's state leases, some are planned to extend three miles offshore into the federal leases, Pioneer said. To date, no wells have reached the federal leases.

Production facilities

To accommodate equipment for processing the oil, natural gas and water from the wells, Pioneer proposes expanding the drill site by 15 acres for a total development footprint of 20 acres.

It's a good site, says Pioneer, previously developed as a gravel pit with only limited residential development nearby.

Prefabricated, truckable modules set on piles or blocks will contain equipment for processing the oil.

Power for the site and possibly the drilling rig will be purchased from Homer Electric Association — a cleaner and quieter option than generating power onsite from diesel, Pioneer said.

The production site will have a control room staffed 24 hours a day, but no permanent overnight housing.

The site also will feature a loading rack with three to five stations for oil tanker trucks.

As for natural gas from the field, Pioneer said it "plans to come to an agreement with a third party to construct and operate a gas pipeline extension to the site." The third party would run a gas line 16 miles south to Anchor Point from the existing distribution network at Ninilchik. Pioneer aims to sell Cosmo gas into this line.

Pioneer anticipates up to a 30-year life for the Cosmo field, with production starting in 2014.

"Peak production is estimated at 8,000 barrels of oil per day," Pioneer said. "Average production over the life of the field is estimated to be 3,000 BOPD."

Pioneer previously has said Cosmo could contain 30 million to 50 million barrels of oil.

Cosmo likely would generate $1 million to $2 million in property taxes annually for the Kenai Peninsula Borough, and the state and federal governments would collect royalties, Pioneer said.

Transportation options

Pioneer said it considered various options for delivering Cosmo oil to market, including a pipeline, marine tankers and trucks.

"Oil trucking 75 miles to the Tesoro Refinery was selected based on risk and cost factors," Pioneer said.

Trucking eliminates the need for loading oil for a sea voyage, and is most appropriate for the size of the Cosmo oil resource, the company said. What's more, trucking will reduce the Tesoro refinery's reliance on oil deliveries by sea.

After loading at the Cosmo production

see COSMOPOLITAN page 19

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● FINANCE & ECONOMY

Unleashing record public offering

AOSC beats industry record, raises C$1.35B; PetroChina senior partner in first 2 projects; analysts say shows oil sands appetite

By GARY PARK
For Petroleum News

The verdict is in and it's decisive: The Alberta oil sands are back in favor with investors.

Athabasca Oil Sands Corp., which has PetroChina as the majority partner in two of its planned commercial projects, planned to raise C$750 million in an initial public offering that was viewed as a test of both the strength of Canadian capital markets and the level of interest in the oil sands.

On both counts, AOSC posted a resounding victory.

An offering of 75 million shares raised C$1.35 billion at C$18 per share (a net C$1.269 billion after underwriters were paid) and could result in C$1.55 billion if the 11-company underwriting syndicate exercises its option to buy an additional 11.25 million shares within 30 days after the offering closes April 8.

And all that for a company that has yet to produce a single commercial barrel of oil.

The IPO is thus the largest in the Canadian petroleum industry and almost as large as the entire Canadian IPO market in 2009.

AOSC has received conditional approval to list its common shares on the Toronto Stock Exchange on or before June 17.

Mark Friesen, an analyst with Versant Partners, said the response demonstrates that "investors have an appetite for the oil sands," which he said has lagged behind the recovery of other shares over the past year.

The interest in AOSC is "not being reflected across other publicly traded companies at the moment ... so I would hope this is a sign of things to come," he told the Calgary Herald.

Tom Pavic, vice president of Sayer Energy Advisors, said the offering is a "good sign for the oil sands, which has been on the back burner."

Six oil sands properties

Net proceeds from the IPO are dedicated to commercial development of AOSC's six oil sands properties.

First on the list are recovery projects at the MacKay River and Dover leases, targeting ultimate planned capacity of 150,000 barrels per day and 200,000-270,000 bpd, respectively.

To achieve that goal, AOSC said in a regulatory filing it will need an additional cash infusion over the next five years to raise the C$2.39 billion it expects to spend developing commercial production at MacKay River in 2014 and Dover in 2015.

The next project is AOSC's 100 percent-owned Dover West play, forecast to produce its first bitumen in 2016 and grow to 165,000 bpd.

"During the five-year period from 2015 to 2019, the company plans to undertake substantial capital expenditures to continue development of its projects," the AOSC filing said.

PetroChina, having paid C$1.9 billion to enter the oil sands upstream, is ready to participate in other financing arrangements, according to AOSC's prospectus.

"The terms of the PetroChina loans require that 90 percent of the cash flow derived from commercial production of the MacKay and Dover oil sands projects be used for repayment of outstanding balances under the PetroChina loans," it said.

PetroChina has loaned AOSC C$430 million to retire its senior secured debt and is expected to contribute C$660 million over the next four years to fund AOSC's 40 percent of the initial oil sands phases, starting with 35,000 bpd at MacKay River.

Estimates of 140 million barrels

An independent evaluation estimates AOSC has 140 million barrels of proved plus probable reserves and 7.1 billion barrels of contingent resources on its net 1.57 million acres.

"Management believes that the large scale of the company's assets may also attract interest from other potential joint venture partners should the company choose to pursue that strategy," AOSC said.

"Most of the company's leases are located in proximity to Suncor (Energy's) producing MacKay River (steam-assisted gravity drainage) project as well as other planned oil sands projects. As a large-scale leader in the area, Athabasca intends to opportunistically pursue acquisitions to complement its existing portfolio."

Nexen testing interest

Hot on AOSC's heels is Nexen, the fifth largest Canadian-based independent, which is testing industry interest in the Alberta heavy oil region by offering 18,000 barrels of oil equivalent per day and 1.25 million gross acres for bids.

A part of the company's strategy of streamlining its operations and tightening its focus on other core areas, Nexen is hoping to fetch C$1 billion in asset sales over the next two years, with the heavy oil holdings expected to generate C$600 million-$800 million.

Chief Executive Officer Marvin Romanow said earlier this year Nexen wants to concentrate on ramping up production at its Long Lake oil sands project and further developing that resource; building on its success in British Columbia's shale gas play; exploring and producing in the Gulf of Mexico; and working on international operations in the North Sea, Nigeria's offshore Usan project and Yemen.

A Nexen spokeswoman said the company hopes it can take advantage of the current enhanced value of heavy oil, which currently generates about C$73.40 per barrel for Imperial Bow River heavy crude and C$80 per barrel for Edmonton Par.

The Scotia Waterhouse Web site said the properties for sale are primarily close to Lloydminster, which straddles the Alberta-Saskatchewan border.

Terry Peters, an analyst with Canaccord Adams, said in a note that Nexen has more desirable places to reinvest its capital, whether it is Long Lake, owned 65 percent by Nexen and 35 percent by OPTI Canada, the Horn River shale play in British Columbia and the Gulf of Mexico.

Waterous said declining heavy crude production in Mexico and Venezuela should raise interest in Canadian heavy crude in major refining centers such as the U.S. Gulf Coast, where coking capacity is being expanded to handle increasing Canadian supplies.

Identified as possible bidders are Canadian Natural Resources and Husky Energy, both leading heavy oil producers near Lloydminster, and Baytex Energy Trust. ●

Contact Gary Park through publisher@petroleumnews.com

● NATURAL GAS

Enstar buying ANR Pipeline out of CINGS

Local gas distribution firm couldn't reach commercial agreement with TransCanada subsidiary; will go it alone on gas storage

By KRISTEN NELSON
Petroleum News

Enstar Natural Gas Co. began working with Houston-based ANR Pipeline Co. last year to develop gas storage in Cook Inlet. Enstar and ANR, a subsidiary of TransCanada, were to make a final decision by the end of last year on whether to proceed with construction of a storage facility.

By early April, however, the companies had been unable to reach commercial agreement and Enstar exercised its option to buy the assets and work product developed under CINGS, Cook Inlet Natural Gas Storage LLC. CINGS was the entity formed by ANR for the Southcentral storage project.

Some gas storage exists in Cook Inlet, but it is proprietary storage, owned and operated by natural gas producers and used by them to manage gas deliverability between low-volume needs for heating and electricity in the summer, and high-volume needs in the winter.

John Sims, corporate communications and customer service manager for Enstar, told the Senate Resources Committee April 5 that Enstar has "notified TransCanada that we would like to exercise our option to purchase the asset and work product" of Cook Inlet Natural Gas Storage.

He said Enstar wasn't "able to reach an agreement on commercial terms" with TransCanada, "but it is our job and we're going to move forward with the project and hopefully have storage here in the near term."

Sims said 2012 is the target date to have storage under way. He said 2012 has been identified as the earliest date that the project could be under way.

Sims told Finance Resources Co-Chair Bill Wielechowski, D-Anchorage, that he couldn't speak to any specifics such as the size of the facility because while Enstar has "notified TransCanada we would like to exercise our option to purchase the assets and work product, we haven't actually seen those documents yet, so I can't get into specifics as to their project until that transition takes place."

Sims told Petroleum News that he couldn't talk about why the companies couldn't reach commercial agreement but said Enstar exercised its option to purchase the assets and work product the week ending April 2.

He said TransCanada is going to work to ensure a smooth transition and Enstar will be moving forward and completing the storage project.

When Enstar discussed the project with Petroleum News in August the company said ANR would fund, build and operate the facility and Enstar would pay for storage space. At that time the company discussed an underground gas storage facility with an eventual capacity of up to 15 billion cubic feet. ●

Contact Kristen Nelson at knelson@petroleumnews.com

UTILITIES

No appeal planned for Enstar error

Enstar says it won't be appealing the Regulatory Commission of Alaska's decision to deny its request to recoup a $5.7 million billing error.

The commission had ruled that the natural gas company's proposal to raise rates to absorb the cost of the error was unreasonable.

Enstar overcharged Fort Richardson for 10 times as much gas as was used at its laundry between 2002 and 2007. Enstar later repaid the Department of Defense.

The company said the higher gas volume resulted in lower prices to consumers and that they should pay because the gas was used in its system and left unpaid.

The commission ordered Enstar to refund the extra charges.

—THE ASSOCIATED PRESS

ASSOCIATIONS

Geological Society technical conference

The Alaska Geological Society is holding its 2010 AGS Annual Technical Conference April 16 at the ConocoPhillips Science Building at the University of Alaska Anchorage.

Presentations begin at 8:30 a.m. and run to 2:30 p.m. in the CPSB auditorium; the poster session will be from 8:30 a.m. to 4:40 p.m. in the CPSB atrium.

Cost is $20 for Alaska Geological Society members and $25 for non-members. There is no charge for AGS student members; the cost for non-member students is $5.

The conference theme is "New Insights in Alaska Geoscience" and Dr. Richard Koehler from the Alaska Division of Geological & Geophysical Surveys will give the keynote talk, "Reconnaissance study of the 2010 Port-au-Prince Haiti earthquake and implications for seismic hazards in Alaska." Koehler was invited to participate in geological investigations on the ground in Haiti after the earthquake.

Register online by April 12 by e-mail to: ken.helmold@alaska.gov or at the door.

Presentations will be by a variety of academic, industry and government speakers and will include a presentation on the recent assessment of Cook Inlet gas supply by Petrotechnical Resources of Alaska.

—PETROLEUM NEWS

● EXPLORATION & PRODUCTION

Canadian outpost stirs into action

New Brunswick draws interest from two US-based gas producers; LNG import terminal delivers first gas; refinery upgrade completed

By GARY PARK
For Petroleum News

New Brunswick sits on the doorstep of New England and New York, one of the world's largest natural gas consuming regions.

Until now, the Canadian province has been little more than a long-shot prospect to help meet the energy needs of its giant neighbors.

But two U.S.-based gas producers have started nudging the Atlantic Canada jurisdiction into the spotlight by acquiring stakes in a basin estimated to hold median in-place potential of 41 trillion cubic feet of gas and 2.5 billion barrels of oil.

Apache is set to start drilling farm-in lands in June and Southwestern Energy, which currently produces 1 billion cubic feet per day of gas equivalent in the United States, is making its first foray outside the U.S.

Apache's Canadian unit, under an agreement with Corridor Resources, hopes to appraise and potentially develop oil and shale gas resources in southern New Brunswick and is expected to undertake various operations to evaluate the commercial potential of the properties.

Independent gas report

An independent resource study by GLJ Consultants of Calgary has estimated the shale gas resource-in-place potential of the Sussex-Elgin area of New Brunswick at 60 trillion cubic feet.

Apache has committed to spend C$25 million by June 2011 and then decide whether to spend a further C$100 million to earn 50 percent of Corridor's interest in 116,000 acres.

Because of weak commodity prices, Corridor stopped drilling from April 2009 to March this year, trimming its 2009 budget to C$41.5 million from C$47.5 million, while waiting for better market conditions.

It has set a 2010 capital spending program of C$28.6 million and is counting on gas sales revenues from a gross average production of 22.3 million cubic feet per day this year based on a forecast average Henry Hub price of US$5.50 per million British thermal units.

Southwestern plans exploration

Southwestern Energy, which is active in several U.S. shale plays, including

The Canaport LNG terminal imported its first cargo of Qatari LNG in December, the first from the Middle Eastern state to land at an East Coast North American terminal, representing 4.6 billion cubic feet of regasified natural gas.

Fayetteville and Marcellus, said March 29 it has been awarded a three-year exploration license, committing it to spend about C$47 million on exploration.

New Brunswick government officials said the company has made a cash bonus payment of C$2.3 million and will pay a land rental fee of C$150,000 a year.

Natural Resources Minister Wally Stiles said the tender call indicates the "strong level of interest in oil and natural gas exploration that we are currently experiencing."

Southwestern Chief Executive Officer Steve Mueller said his company has identified a "large area which we believe is prospective for oil and natural gas."

"There is a significant amount of data yet to be collected in order to confirm its economic merit. But if our testing yields positive results, we expect that our activity in the area could increase substantially over the next several years."

Contact spots well locations

Of the juniors active in New Brunswick, Contact Exploration, which produces small volumes of oil from its Stoney Creek field, said it has identified up to 19 well locations that can be drilled from pads in the field and is re-evaluating well data and seismic that could open up 25,000 acres of thick shale gas potential.

PetroWorth Resources announced March 30 it has signed a letter of intent with Enbridge Gas New Brunswick to build a 15-mile pipeline to deliver gas to the City of Moncton for the first time in more than 60 years.

PetroWorth President Neal Mednick said the current interest in New Brunswick by Apache and Southwestern Energy "reinforces our belief that onshore Eastern Canada is on the verge of becoming a new frontier for oil and gas exploration and development."

Altius Minerals said it is making progress on oil shale exploration and evaluation activities at its 26,000-acre oil shale license in southeastern New Brunswick, having completed a 23-well core drilling program and is now seeking a partner with extraction technology research capabilities.

Downstream rollercoaster

At the downstream end, New Brunswick has experienced a rollercoaster ride over the past year.

A partnership of Spain's Repsol (75 percent) and privately held Irving Oil (25 percent) made an LNG breakthrough, while other ventures in Atlantic and Eastern Canada remained bogged down.

The Canaport LNG terminal imported its first cargo of Qatari LNG in December, the first from the Middle Eastern state to land at an East Coast North American terminal, representing 4.6 billion cubic feet of regasified natural gas.

The terminal has the capacity to send out up to 1 billion cubic feet per day of gas, although this year's average is expected to average only 700 million cubic feet per day for shipment to New England and the Atlantic Canada region.

Separately, Irving has just completed a C$220 million upgrade of its 300,000 barrel-per-day Saint John refinery, which exports more than 80 percent of its fuels to the U.S. and accounts for 75 percent of Canada's gasoline shipments to the U.S. ●

Contact Gary Park through publisher@petroleumnews.com

● EXPLORATION & PRODUCTION

Statoil and TGS plan Chukchi surveys

Statoil wants modern 3-D seismic data to assess its Chukchi Sea leases while TGS plans a more regional scale 2-D survey on spec

By ALAN BAILEY
Petroleum News

Since the $2.6 billion Chukchi Sea outer continental shelf lease sale in 2008, Shell and ConocoPhillips have led the charge to determine whether this remote region of the Arctic offshore holds the huge oil and gas resources that many people think exist beneath its often ice-covered waters. Now Norwegian oil major Statoil wants to conduct a seismic survey during the summer and fall of 2010, to start testing its 16 leases purchased in the sale — Statoil owns most of these leases in partnership with Italian major ENI, with Statoil as operator.

"We're planning a 3-D seismic survey over those leases in this open water season," Martin Cohen, exploration manager for Statoil, told the National Marine Fisheries open-water meeting on March 22.

And, at around the same time, geophysical company TGS wants to shoot a 2-D survey across a broad area of the Chukchi Sea, with the intention of subsequently licensing this regional-scale data to entities interested in the regional geology, Michaele Cerf, TGS acquisition and quality control project manager, told the open-water meeting.

3D survey

A 3-D marine survey involves bouncing air-gun sounds off subsurface rocks and then gathering the resulting echoes using water-borne microphones known as hydrophones, towed in a grid configuration. The recorded echoes enable the construction of detailed three-dimensional images of the subsurface rocks, so that oil and gas explorers can pinpoint underground oil and gas prospects as targets for exploration drilling.

In fact, the planning and design of a modern exploration well typically depends on detailed information gleaned from a 3-D survey.

Cohen said that Statoil expects its 3-D survey to cover a total of about 915 square miles, with almost all of that area lying more than 100 miles from the coast.

In a 2-D, or two-dimensional, survey the hydrophones are strung on a single, long line, rather than across a grid, thus enabling relatively large areas of territory to be covered quite quickly. However, the resulting seismic images are not as detailed as those from a 3-D survey and are more appropriate to gaining an understanding of broad geologic features than necessarily to the planning of specific wells.

Cohen said that Statoil expects its 3-D survey to cover a total of about 915 square miles, with almost all of that area lying more than 100 miles from the coast. If time permits, and depending on ice and weather conditions, the seismic crew may follow the 3-D survey with a broader 2-D survey across the locations of some exploration wells drilled in the 1980s, Cohen said.

"One neat thing about such a regional survey is that, as we collect this data on (wildlife) distribution and abundance, we're collecting it over a very large area in the Chukchi Sea."
—Michaele Cerf, TGS acquisition and quality control project manager

"The existing seismic data in the area are quite old — they're quite sparse and widely separated and they're of inadequate quality to carry out modern exploration," Cohen said.

Fugro-Geoteam will conduct the survey work, planned for early August to early October, using survey vessel Geo-Celtic supported by two smaller vessels for marine mammal monitoring and for conducting crew changes, he said. All three vessels involved in the survey will carry marine mammal observers — air-gun operations would shut down if the seismic vessel comes too close to a marine mammal.

"The vessels will arrive in Dutch Harbor towards the end of July and we'll then have a safety program on board the vessels for both crews that we plan to use," Cohen said, adding that Statoil anticipates just a single crew change through Nome around early- to mid-September.

The seismic vessel will tow six arrays of air guns and 12 lines, or "streamers," of hydrophones. This configuration involves more streamers than have been used to date in Chukchi Sea 3-D surveys but will somewhat reduce the total time required for the survey operation, Cohen said.

Acoustic monitoring

Statoil anticipates participating in a subsea acoustic monitoring program already established by Shell and ConocoPhillips. This program involves the placement of arrays of acoustic recording devices on the seafloor to monitor the sounds of marine mammals and hence track their movements — Statoil plans to install a grid of acoustic recorders in the area of its leases.

The company hopes to improve the accuracy of future marine mammal monitoring by cross-referencing the results of vessel-based observations with the results of the acoustic monitoring, Cohen said.

Cohen said that since October Statoil has been discussing its plans with various Chukchi Sea stakeholders, including the North Slope Borough wildlife department and community leaders from North Slope villages. The company submitted applications for necessary approvals and permits in December. And earlier in 2009 Statoil hosted a visit to Norway by people from the North Slope Borough, giving people an opportunity to meet with Norwegian government officials and fishermen from northern Norway, to discuss how the Norwegians approach offshore oil and gas exploration and development.

Statoil is still considering its response to a subsistence hunting conflict avoidance agreement revised by the Alaska Eskimo Whaling Commission, Cohen said.

TGS survey

The TGS survey will involve towing a single streamer, three to four miles in length, along about 3,100 line-miles of 2-D seismic lines across a broad swath of the Chukchi Sea. Some of the longer lines extending north-south through the region may take as long as two days to transit, Cerf said.

"We will have one seismic vessel that will tow one source (air-gun) array and one (hydrophone) streamer," Cerf said.

TGS is using feedback from coastal communities to refine the exact positions of the lines that it expects to follow. As currently envisaged, all lines will be at least 50 miles offshore, but that minimum distance may prove to be too close to land and require adjustment, Cerf said.

The company has already reduced the planned strength of the air-gun array that will be used, and may yet decide to change that strength further.

And, although in a perfect world it might be possible to complete the survey in 30 to 35 days, factors such as ice conditions, the presence of marine mammals and the need to coordinate with other offshore operators will likely extend that timeframe. With Shell planning to drill in the Chukchi at around the same time and Statoil planning its seismic survey, TGS will meet with these two companies to make sure that their operations do not clash, Cerf said.

Five to seven weeks

"We will start no earlier than July 22. More than likely it's going to be around Aug. 1," Cerf said. "… We have planned a five- to seven-week duration. That takes us from August to about mid-September. … We would like to be in and out as quick as possible but we are permitting to the end of October."

In addition to the seismic vessel, the TGS operation will involve two scout vessels, with one of these vessels assisting the seismic vessel and monitoring the area relatively closed to the air guns, while the other scout vessel will be stationed further out, watching for wildlife. All vessels will have marine mammal observers on board.

"One neat thing about such a regional survey is that, as we collect this data on (wildlife) distribution and abundance, we're collecting it over a very large area in the Chukchi Sea," Cerf said.

And TGS plans to do refueling, resupply and crew changes through Nome — the vessels will not conduct refueling at sea. TGS has been discussing its plans with North Slope communities and has just received for review a draft subsistence hunting conflict avoidance agreement, Cerf said. ●

Contact Alan Bailey at abailey@petroleumnews.com

● PIPELINES & DOWNSTREAM

Enbridge wins one, loses one in toll dispute

By GARY PARK

For Petroleum News

Enbridge took the first round in a toll dispute with Canadian shippers to the United States, but victory was fleeting and only partial.

The U.S. Federal Energy Regulatory Commission gave the green light for Enbridge to impose higher tolls on the U.S. segment of its 450,000 barrel per day Alberta Clipper system from the Alberta oil sands to Wisconsin.

Within hours, however, Canada's National Energy Board issued a ruling March 31, ordering the Calgary-based pipeline company to refile a toll application it made in 2007.

For now, Enbridge said it needs time to determine what the NEB decision means, but the shippers were quick to proclaim success.

The spat started in February when Suncor Energy, Imperial Oil (which submitted 500 pages of legal documents) and a host of other shippers made a case to FERC that Enbridge had been "imprudent" in building the 1,000-mile, $3.7 billion Clipper system at a time when demand was falling.

They asked for a deferral of toll increases until Enbridge could prove Clipper is needed.

Analyst estimates 41% surplus

Chad Friess, an analyst with UBS Securities, had estimated the pipeline would have 41 percent surplus capacity until 2013 because of a spate of cancellations and delays of oil sands production projects.

But FERC sided decisively with Enbridge, opening the way for a toll increase of 97 cents per barrel, or 33 percent over 2009 levels, about three-quarters of the increase tied to Clipper costs.

Friess said the hike would not significantly affect producers' profits, but had Enbridge lost it would have been a "negative" for the pipeline company's earnings.

However, shippers face the prospect of a further increase as TransCanada builds even more cross-border pipeline capacity which is expected to divert volumes from the Enbridge system

"At some point Clipper is going to be used, but that may take 10 years," Friess said.

An Enbridge spokesman said the FERC ruling "further supports the common carrier system, which we believe benefits the producing community as a whole."

Other interveners were Marathon Petroleum, Total E&P Canada, Canadian Oil Sands Trust, Husky Gas Marketing, Nova Chemicals (Canada) and Flint Hills Resources Canada.

FERC had approved a tolling structure between Enbridge and the Canadian Association of petroleum Producers in 2004 and updated one to include Clipper costs in 2008.

"The protesters' speculative arguments concerning the benefits (of Clipper) are not sufficient to abrogate the settlement or find that the proposed rates are unjust and unreasonable," it said.

A Suncor spokeswoman said the NEB's request for Suncor to refile its 2007 trolling application, which contains the tolling calculation provided for Clipper, shows the regulator "listened to the arguments and concerns put forward by a number of companies."

Imperial argued the situation has changed from the time CAPP negotiated the tolls in 2004 until the tolls were actually introduced.

An Imperial spokesman said Imperial believes FERC failed to reflect those changed circumstances.

The NEB accepted a proposal from Imperial and Suncor that interim tolls for the Canadian portion of Clipper should be no higher than the per unit toll levels forecast by Enbridge in the 2007 regulatory proceeding.

It said that was a reasonable argument given that the determination of final tolls might result in tolls that were either higher or lower than the interim tolls. ●

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● NATURAL GAS

From the NEB: Canada's new gas reality

By GARY PARK

For Petroleum News

Canadian natural gas production will decline 14 percent over the next two years to 13 billion cubic feet per day, down a dramatic 14 percent from this year's expected volumes and a dramatic slide of about 23 percent from average output over the past decade, the National Energy Board has forecast.

The only cushioning affect will come from British Columbia's tight and shale gas plays, which will raise that province's short-term output by 1 billion cubic feet per day to 3.7 bcf per day.

The federal regulator said the trends point to a "new reality" for Canadian gas, driven by new plays, new technology and new gas types.

NEB Chairman Gaeten Caron said in a statement that Canada's gas focus is "shifting not only in location, but also in type, which can translate into opportunities for many in the industry."

However, he said Canadians have no cause to worry about insufficient supplies to meet domestic needs.

The study made no allowance for the latest announced changes in the Alberta government's conventional and unconventional gas in predicting that the traditional mainstay province will see its production slide to 8.5 bcf per day in 2012 from 12.7 bcf per day in 2009.

The federal regulator said the trends point to a "new reality" for Canadian gas, driven by new plays, new technology and new gas types.

The NEB said it expects about 210 wells to be drilled this year in the British Columbia Montney play and 70 in the Horn River basin.

The agency said capital spending on gas projects will stabilize then rise over the two-year period, while drilling days will increase about 11 percent to 50,512 days from 45,659 days in 2010, noting that extracting tight gas and unconventional gas takes more time, thus boosting the number of drilling days per well, although Canada's drilling levels made a rapid descent to 5,100 wells last year from a record 15,300 in 2006.

It said the rise in oil prices, while gas flounders, poses a challenge to gas producers, adding that some of the new technology designed to extract shale gas is being used for oil extraction in Alberta and Saskatchewan.

With oil drilling more profitable than gas, some capital investment is being drawn away from gas, the NEB said.

Mid-price estimate

The targets are based on the NEB's mid-price estimate, which would see the Henry Hub average increase from US$5.50 per million British thermal units in 2010 to US$6.75 in 2012.

Under that case, conventional production would decline to 6.68 bcf per day from 10.14 bcf per day in 2008 and coalbed methane would slip to 587 million cubic feet per day from 762 million.

Shale gas, all of it in British Columbia, would rise to 462 million cubic feet per day from just 10 million and tight gas would ease to 4.82 bcf per day from 4.89 bcf per day.

The NEB said that Western Canada's producers have been able to raise capital to increase production, mainly in the Montney and Horn River plays, and service costs have dropped as much as 20 percent under 2008 levels.

It does not expect that quickening interest in Quebec and New Brunswick gas development will have any impact on output over the short term.

Under a low-price case, with average prices rising to US$5.25 from US$4.25 over the two years, the NEB projects deliverability would slide to 11.6 bcf per day by 2012.

Bill Gwozd, a gas supply analyst with Calgary-based Ziff Energy Group, does not share the NEB's Alberta forecast, predicting a decline that would be flat to slight because of the new drilling technology, which results in greater gas volumes from fewer wells. His firm is releasing its own supply predictions later in April.

He said British Columbia benefits from lower gas prices because its initial production rates from new wells are about ten-fold higher than Alberta. ●

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● EXPLORATION & PRODUCTION

ANS crude production nudges up in March

By KRISTEN NELSON

Petroleum News

Alaska North Slope crude oil production nudged up in March, averaging 678,810 barrels per day, an increase of 1.29 percent (an average of 8,666 bpd) over a February average of 670,144 bpd.

The largest per-barrel increase was at the BP Exploration (Alaska)-operated Prudhoe Bay field, up an average of 6,054 bpd to 352,571 bpd, an increase of 1.75 percent over a February average of 346,517 bpd. Prudhoe Bay production includes satellites at Aurora, Borealis, Midnight Sun, Orion and Polaris.

The largest month-over-month percent increase was 12.13 percent at the BP-operated Lisburne field, which averaged 33,539 bpd in March, up 3,629 bpd from a February average of 29,910 bpd. Lisburne, part of greater Prudhoe Bay, includes production from Point McIntyre and Niakuk.

BP's Milne Point was up 8.47 percent, averaging 28,781 bpd in March compared to 26,534 bpd in February, a difference of an average 2,247 bpd. Milne Point production includes Sag River and Schrader Bluff.

The ConocoPhillips Alaska-operated Alpine field averaged 90,480 bpd in March, up 1.46 percent (1,301 bpd) from an average of 89,179 bpd in February. Alpine includes satellite production from Fiord, Nanuq and Qannik.

Production down at other fields

Other North Slope fields had month-over-month drops in production.

The BP-operated Northstar field averaged 20,298 bpd in March, down 8.53 percent (1,892 bpd) from February production of 22,190 bpd.

The BP-operated Endicott field averaged 13,201 bpd in March, down 5.02 percent (698 bpd) from a February average of 13,899 bpd.

The ConocoPhillips-operated Kuparuk field averaged 139,940 bpd in March, down 1.39 percent (1,975 bpd) from a February average of 141,915 bpd. Kuparuk includes satellite production from Tabasco, Tarn, Meltwater and West Sak, as well as production from the Pioneer Natural Resources Alaska-operated Oooguruk field. The most recent production figures for Oooguruk (from the Alaska Oil and Gas Conservation Commission) are for February, when the field averaged 9,453 bpd.

The average March temperature at Pump Station No. 1 on the North Slope was minus 9.39 degrees F.

Cook Inlet production averaged 8,986 bpd in March, down 17.54 percent from a February average of 10,897 bpd.

ANS crude oil production peaked in 1988 at 2.1 million bpd; Cook Inlet crude oil production peaked in 1970 at more than 227,000 bpd. ●

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● GOVERNMENT

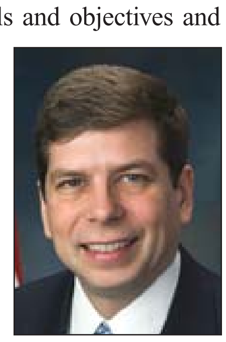
Fish and Wildlife begins ANWR plan update

Plan to consider new wilderness designations draws protests from Gov. Parnell, Sen. Begich; would require congressional approval

By KRISTEN NELSON

Petroleum News

The U.S. Fish and Wildlife Service said April 6 that it is beginning an update of the 22-year-old comprehensive conservation plan for the Arctic National Wildlife Refuge. The plan will establish goals and objectives and include wilderness and wild and scenic river reviews, the agency said.

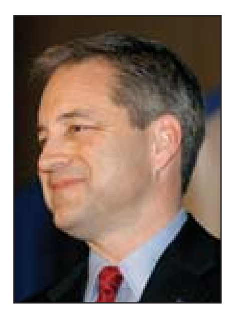


MARK BEGICH

Alaska objections to consideration of new wilderness designations within ANWR were immediate and bipartisan, with protests from U.S. Sen. Mark Begich, D-Alaska, and Alaska's Republican governor, Sean Parnell.

"The Obama administration is wrong to pursue new wilderness in the Arctic National Wildlife Refuge or anywhere else in Alaska," Begich said in a statement. "I'll fight any effort to block development of the enormous oil and gas likely beneath the Arctic Refuge. I'll work through my position on the Senate Budget Committee to cut any funding for this effort, and with the other members of Alaska's congressional delegation to short-circuit this unnecessary, money-wasting review," he said.

Parnell said the wilderness recommendations in ANWR would preclude oil and gas development in the region.



JUDY PATRICK

SEAN PARNELL

"The oil and gas, wilderness, and wildlife values of the coastal plain have already been studied and this study previously has been submitted to Congress," the governor said in a statement. "It is a mistake for the federal government to initiate yet another planning process in ANWR, the most promising unexplored petroleum region in North America."

The governor said the State of Alaska would participate "vigorously" in the public comment on the conservation plan and said oil development in ANWR would provide oil for the nation, tens of thousands of jobs throughout the country and ensure that the trans-Alaska oil pipeline continues to operate for years.

The planning process will begin with public meetings to discuss issues and future goals for stewardship of ANWR in April and May in Anchorage, Arctic Village, Fairbanks, Fort Yukon, Kaktovik and Venetie; dates and times will be announced later. There will also be a public meeting in Washington, D.C., on May 4.

A draft plan will be released for public review and comment in February 2011 and a final plan and record of decision will be issued in April 2012.

"I'll work through my position on the Senate Budget Committee to cut any funding for this effort, and with the other members of Alaska's congressional delegation to short-circuit this unnecessary, money-wasting review."

—U.S. Sen. Mark Begich, D-Alaska

As part of the planning process, Fish and Wildlife may inventory, study and possibly propose areas suitable for wilderness within the National Wilderness Preservation System. A wilderness area recommendation would be forwarded to the Secretary of the Interior for consideration and any new wilderness designation would require congressional approval.

Alaska Regional Fish and Wildlife Service Director Geoffrey Haskett said the current plan for ANWR "is more than 20 years old, and much has changed since then. New laws and policies have been enacted, climate change has emerged as a concern, the Dalton Highway has opened to the public and visitor patterns have changed."

Information about the planning process for ANWR is posted at http://arctic.fws.gov/ccp.htm. ●

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● GOVERNMENT

Hillary Clinton spreads Arctic chill

Rebukes Canada for leaving 3 countries off summit invitation list at time when 'we need all hands on deck'; ice return seen as blip

By GARY PARK

For Petroleum News

Arctic sea ice has returned to average 1979-2000 levels for the first time in a decade after years of alarming shrinkage, according to the National Snow and Ice Data Center in Boulder, Colo.

The expansion at a time of year when ice is normally melting was accompanied by a severe chill emanating from U.S. Secretary of State Hillary Clinton when she left a summit of Arctic coastal countries in Gatineau, Quebec.

She delivered what was characterized as a "smack-down" to Canada for not extending summit invitations to all of those with "legitimate interests in the region."

And she hammered home the rebuke by shunning a news conference that ended the one-day meeting of foreign ministers from the U.S., Canada, Russia, Norway and Denmark.

In Clinton's view, Sweden, Finland and Iceland — all members of the eight-nation Arctic Council along with Inuit indigenous groups — and the region's indigenous peoples should have participated in the discussions.

"I hope the Arctic will always showcase our ability to work together, not create new divisions," she said. "We need to have all hands on deck because there is a huge amount to do and not much time to do it.

"What happens in the Arctic will have broad consequences of the earth and its climate. The melting of sea ice, glaciers and permafrost will affect people and ecosystems around the world," Clinton said.

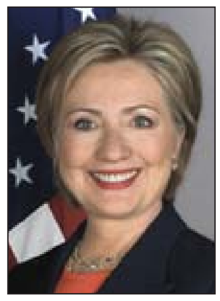
"Understanding how these changes fit together is a task that demands international cooperation."

Shoreline state solidarity

Canadian Foreign Minister Lawrence Cannon said the summit was intended to build solidarity among the five shoreline states and underscore their "unique" position as chief guardian's of the region's environment.

The tensions among the Group of Five were evident prior to the summit when Norway's Foreign Minister Jonas Gahr Store, who said Russia is "not yet a stable, reliable, predictable state," while stressing Norway's desire to build a trusting, cooperative relationship with Russia on Arctic issues.

He said it was "unhelpful" that Russian President Dmitry Medvedev recently declared it "absolutely inadmissible" for other countries to try to "limit Russia's access" to northern resources.



HILLARY CLINTON

Medvedev's remarks were interpreted as a poke at European Union efforts to become a bigger player in setting environmental regulations in Arctic waters as melting sea ice opened the way to increased northern shipping and petroleum exploration.

Store said that, unlike Canada's "well-managed" Arctic territorial disputes with Denmark and the United States, Norway was trying to resolve a boundary dispute in a potentially oil-rich portion of the Barents Sea with Russia, when that country was still grappling with its transition from a totalitarian state to a democratic nation.

He mused that some experts say Russia is "lost in transition."

But, like Clinton, Store acknowledged it was "not a good thing" to exclude Sweden, Finland and Iceland from the talks, although he argued the five participants have a special geographic status.

Protestors oppose drilling

Protesters from various organizations, including Greenpeace, urged participants in the summit to avoid a scramble to launch offshore drilling, arguing Arctic mineral resources should remain untouched.

Michael Byers, a professor of politics at the University of British Columbia, said the "three worst emitters of carbon dioxide on the planet — the United States, Canada and Russia — are around the table talking about a region of the world that is at the epicenter of climate change impact."

The summit reached no significant agreements, with participants confining themselves to discussing "issues that relate to the continental mapping that fall under the United Nations Convention Law of the Seas."

That extended to talk about creating mandatory shipping regulations, settling maritime boundaries, establishing search and rescue protocols and negotiating territorial disputes in the Beaufort Sea and Barents Sea.

Meanwhile, the Colorado snow and ice data center, which publishes monthly sea-ice updates, does not view the sea ice comeback as "the end of global warming," said spokesman Mark Serreze.

He said a few weeks of cold weather in one part of the Arctic had distorted the overall numbers.

The summit reached no significant agreements, with participants confining themselves to discussing "issues that relate to the continental mapping that fall under the United Nations Convention Law of the Seas."

Serreze said "all of the action is in the Bering Sea … (causing) a late spurt in ice growth," while the rest of the Arctic Ocean is experiencing "very warm" temperatures.

He also cautioned that satellite data used to develop the center's information offers no information on ice thickness, suggesting most of the recent Bering Sea ice is likely very thin and won't last. ●

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OUR ARCTIC NEIGHBORS

Arctic is Norway's foreign policy priority

The Arctic remains the most important strategic foreign policy area for Norway's center-left coalition government, which first took power in 2005 and was narrowly re-elected in September 2009, a government official said March 22. State Secretary Erik Lahnstein was speaking at the Arctic Dialogue conference in Bodo, Norway.

Norway has three main aims in the Arctic, Lahnstein said: enhancing knowledge in and about the north; increasing the country's activity and presence in the area; and laying the foundations for sustainable economic and social development in the years to come.

"Knowledge is at the core of our High North efforts," he said. "Knowledge is one of the most important building blocks in sustainable social and business development. It is essential that knowledge institutions in the region are competitive, both nationally and internationally. It is important to develop the knowledge infrastructure in the High North."

Climate change, new shipping routes and petroleum resources are the driving forces behind the world's increased interest in the Arctic region, Lahnstein told the conference.

"The Arctic is not where the consequences of climate change will be most severely felt, but it is where they are first seen," he said. "The region is therefore very important for climate change research. We encourage international cooperation in this field."

More than a dozen nations are engaged in climate change activities in Svalbard, and Norway is also developing an international center for climate and environmental research in Tromso, Lahnstein said.

"The melting of the ice is a severe challenge, but also creates new opportunities for commercial activities like shipping, extraction of oil and gas, fisheries and tourism," he said. "These activities create new technical, environmental and political challenges that will have to be dealt with. It is important that we develop appropriate regulations and guide the development."

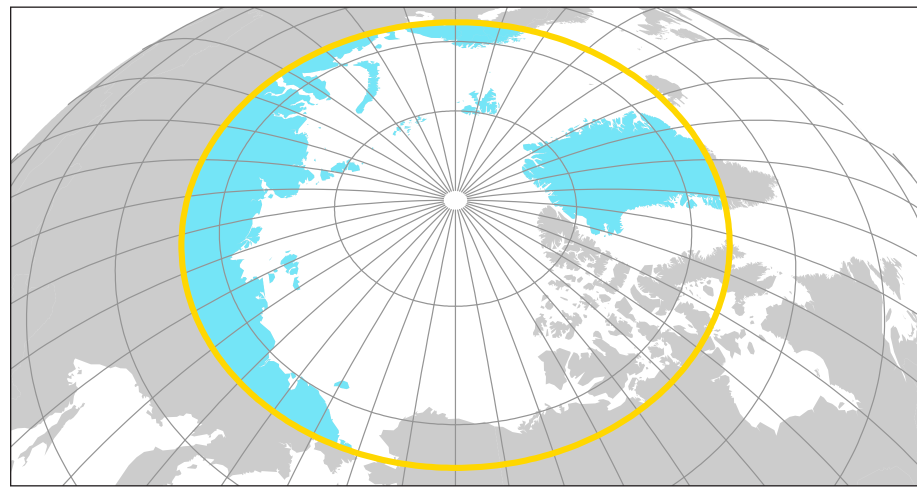
Lahnstein said that Norway is working actively through the International Maritime Organization to update the Polar Code and make the code mandatory for ships operating in the Arctic.

—SARAH HURST

Lukoil shows off multipurpose drilling rig

A new ERMAK-model drilling rig for Russia's Lukoil has been unveiled, the company said in a release March 25. The ceremony took place in Kaliningrad at the metal works plant of Lukoil-Kaliningradmorneft. The rig is equipped with a

see ARCTIC NEIGHBORS page 13



● OUR ARCTIC NEIGHBORS

Russia needs more offshore explorers

Russian law places too many burdens on the two major state-owned oil and gas companies and should be changed, deputy minister says

By SARAH HURST

For Petroleum News

More companies, including foreign ones, need to be involved in Russian offshore oil and gas activities, the country's deputy minister of natural resources, Sergey Donskoy, said recently. Donskoy was speaking at a meeting of the government's Marine Board, the Ministry of Natural Resources said in a release March 30.

"To activate the opening up of the shelf there is an urgent necessity to change our legislation and, above all, expand the list of entities that have the opportunity to work on the shelf by changing the requirements placed on potential developers," Donskoy said.

Under current Russian law, as amended in the summer of 2008, only state-owned giants Gazprom and Rosneft meet the criteria to be awarded offshore exploration and development licenses. The law says that such companies must have been established according to the laws of the Russian Federation, have more than a 50 percent share of state ownership and have at least five years' experience of Russian offshore activities.

For gas fields it would be beneficial to establish that besides Gazprom, developers of the resources could include its subsidiary companies and foreign partners brought in by it with less than a 50 percent share in the projects, Donskoy said. For oil, the developers could be Rosneft and its subsidiaries, other Russian oil companies with the requisite financial and technological potential and again foreign companies with less than a 50 percent share (as stipulated by Russian law), he said.

"On the one hand this approach will allow us to attract the necessary financial resources and technology to study and open up the shelf, and on the other hand it will ensure that we retain government control over the development of projects," Donskoy said. Another change in the law that needs to be made is to acknowledge geological exploration as an independent activity, he added.

"At the moment there is no such thing as an exploration license for the shelf — exploration activity can only be conducted within the framework of an exploration and development license, and only by state companies," Donskoy said. "We need to help our state companies share the risks of working on the shelf. The opportunity to obtain a license for this type of use of the resources should be offered to all interested parties, including foreign ones."

As an incentive there should be a government guarantee that any entity that discovers an oil or gas field gets either a non-controlling share in a consortium with a state company to develop the field, or fair compensation for its loss, Donskoy suggested.

Gazprom and Rosneft invested 56.4 billion rubles ($1.9 billion) in their Russian offshore activities in 2008, according to the ministry. Russia's Ministry of Economic Development has estimated that more than 9.3 trillion rubles ($318 billion) needs to be spent on this activity by 2040. In the most optimistic scenario it would take the state companies 165 years to develop Russia's offshore resources, the release said. ●

NATURAL GAS

Chugach has new contract with Marathon

Electric utility applies to REA for approval of gas supply contract to meet remaining natural gas needs from 2011 to 2014

By KRISTEN NELSON
Petroleum News

Chugach Electric Association has signed a gas supply contract with Marathon Alaska Production LLC, a contract which will help fill the gap in the utility's natural gas needs through 2014.

A gas supply contract CEA signed last year with ConocoPhillips Alaska was the first such contract the Regulatory Commission of Alaska had approved since 2001. In the interim RCA rejected contracts Enstar Natural Gas Co. negotiated with producers, objecting to prices indexed to "city gate" market prices.

Until CEA negotiated its contract with ConocoPhillips last year, the utility had spent several years seeking new supply contracts extending beyond 2011.

The new contract with Marathon Alaska Production involves, as did the ConocoPhillips contract, price floors and ceilings.

CEA told the commission it uses 27 billion cubic feet per year of natural gas in its power stations, all purchased from Cook Inlet gas fields.

CEA told the commission that the Marathon contract, submitted April 2, will meet the utility's gas supply requirements beginning at the end of the first quarter of 2011. The utility said that because Marathon needs lead time "to plan, drill, and develop wells to meet Chugach's gas requirements," it is requesting a commission ruling on the contract no later than Oct. 2.

CEA said Marathon needs to make capital investment commitments this October for drilling which would take place in 2011 and 2012.

On the Web

See previous Petroleum News coverage:

"RCA OKs Chugach natural gas supply contract; first since '01," in Aug. 30, 2009, issue at www.petroleumnews.com/pnarchpop/090830-04.html

"Gas supplies for CEA?," in Nov. 14, 2008, issue at www.petroleumnews.com/pnads/297191883.shtml

The utility said this contract, combined with expected Cook Inlet gas storage services, would "fill the balance of Chugach's unmet needs for natural gas from April 2011 through December 2014," and told the commission it believes the contract provides the needed gas volumes "at a reasonable price on terms that are fair, just and reasonable."

The utility said it has no other means to acquire gas necessary to produce electric power for wholesale and retain customers.

27 bcf per year

CEA told the commission it uses 27 billion cubic feet per year of natural gas in its power stations, all purchased from Cook Inlet gas fields. These needs have been met for more than 20 years under a series of long-term gas contracts, but "volumes available under these existing long-term contracts will run out in 2010 and 2011," CEA said.

The utility said it has been working for the past six years to obtain replacement gas supplies, and in May 2009 signed its first significant gas supply contract in 20 years with ConocoPhillips Alaska and ConocoPhillips, a contract which the commission approved in August. The contract with Conoco meets 100 percent of CEA's unmet needs until April 2011, some 50 percent of the utility's unmet needs from May 2011 through December 2014, some 60 percent of its unmet needs in 2015 and 29 percent of its unmet needs in 2016.

The utility said that because Marathon needs lead time "to plan, drill, and develop wells to meet Chugach's gas requirements," it is requesting a commission ruling on the contract no later than Oct. 2.

Price of contract gas

CEA told the commission that the Marathon contract price starts with a Nymex futures index price and varies due to the application of discounts and premiums according to the time period.

The utility said the key pricing feature is the price collar.

"The price collar bounds the price risk for both Chugach and MAP," the utility said. "From an energy consumer perspective, the price ceiling caps the market price, creates price certainty, and reduces price volatility. From a gas producer perspective, the price floor reduces the investment risk by ensuring that the price will be sufficient to warrant expansion and maintenance of its gas supplies."

CEA said the collar prices generally increase over time to reflect inflation, although a 5 percent discount is applied to the price of gas when storage is available to represent the shift in gas storage cost to CEA from Marathon.

The collar begins with a floor of $5.90 and a ceiling of $8.90 per thousand cubic feet and rises to $6.50 and $9.50.

Comparison with Conoco contract

CEA said different prices in its contract with ConocoPhillips and in its proposed contract with Marathon reflect the fact that prices in the ConocoPhillips contract were based on historical gas pricing data revised on a quarterly basis while the Marathon contract reflects futures prices averaged on a yearly basis.

"Chugach actively sought such pricing diversity in order to avoid concentration of price risk exposure on shorter or longer term markets, or past prices or future prices," the utility told the commission.

CEA also said the price color for the entire term of the Chugach-Marathon contract "has the benefit of less price volatility risk" compared to the ConocoPhillips pricing. Chugach said that even with different pricing methods, the contracts the utility has with ConocoPhillips and the proposed contract with Marathon "provide a similar range of gas prices."

RCA noticed the filing April 7 and is taking comments through May 7. ●

Contact Kristen Nelson at knelson@petroleumnews.com

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ARCTIC NEIGHBORS

hydraulic mobility system that enables it to move by steps in all directions and around its axis to achieve a 360-degree rotation, according to Lukoil.

"The unit can be used both for production and exploration drilling and this is one of its unique features," the release said. The rig's loading capacity is 450 metric tons and its drilling depth is 6,500 meters (21,320 feet); it is also equipped with a 1.5 megawatt drill winch, three 1 megawatt drill pumps, an upper power drive with a loading capacity of 500 metric tons and a 0.8 megawatt rotary table.

The drilling rig can be operated in vastly different climates, especially extreme climates such as the Arctic and in high temperatures.

—SARAH HURST

NATURAL GAS

ML&P buying extra gas for April, May

Anchorage Municipal Light & Power is buying a small amount of natural gas from an independent Cook Inlet producer this spring to meet a two-month supply shortfall.

Under a contract sent to state regulators on April 5, ML&P will buy 3 million cubic feet per day of base volume from Aurora Gas LLC between April 1 and May 31 with the option of buying 4 million to 5 million cubic feet of “additional volume” for up to 10 days during that period.

That base volume represents only about 6 to 8 percent of ML&P’s average daily needs, but is necessary because of a planned maintenance program at the Beluga River gas field.

ML&P owns a third of the production at Beluga River, which is usually enough to meet the 37 million to 45 million cubic feet per day the company needs to meet local demand.

“However, in April and May of this year, ML&P’s access to BRU production will be limited to some extent due to maintenance of the BRU’s compressor facilities, select wells, and select well site facilities,” the company wrote to state regulators.

Short-term premium

The short-term contract is priced at a premium.

ML&P will pay $6 per thousand cubic feet for the base volumes and $7.25 per mcf for the additional volumes. ML&P pays around $3.88 per mcf for its current gas supplies.

The utility said it plans to pay this additional cost using funds from an internal account, rather than collecting the difference through an increase to customer electricity rates.

“Given the relatively small volume of Contract gas that will be provided during this short, two-month period, the impact of this higher-priced supplemental gas on ML&P’s overall, long term gas costs will be minimal,” the utility said in a letter to regulators.

ML&P sent the contract to the Regulatory Commission of Alaska for informational purposes. Alaska doesn’t require approval for contracts lasting less than 12 months.

ML&P serves some 30,000 residential and commercial customers in the downtown Anchorage area. The utility is in the process of requesting a permanent rate increase.

Aurora Gas operates five fields on the west side of the Cook Inlet basin.

ConocoPhillips and Chevron, the other owners at Beluga River, will also presumably see lower production rates through the end of May as a result of the maintenance program.

Beluga River has produced more than 1 trillion cubic feet of gas since 1963.

—ERIC LIDJI

● ALTERNATIVE ENERGY

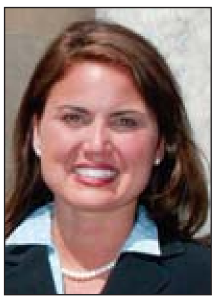
Alaska Senate passes geothermal bill

Royalty rate reduced to match federal level; drilling and safety issues moved to AOGCC; DNR retains leasing, unit authorities

By KRISTEN NELSON
Petroleum News

The Alaska Senate has passed and sent to the House a bill designed to fix some royalty and regulatory issues for geothermal development in the state. The need for fixes came to light when Naknek Electric Association began development drilling for geothermal on the Alaska Peninsula and when Ormat Technologies leased geothermal acreage at Mount Spurr and began assessing costs of producing electricity from that geothermal resource.

Senate Bill 243 originally addressed the royalty rate for geothermal developed on state land; the bill as passed by the Senate April 5 also addresses which agency has authority over drilling, resource waste and public safety issues associated with geothermal development.



LESIL MCGUIRE

Under current law, geothermal development is entirely under the Department of Natural Resources. The committee substitute adopted by Senate Finance April 2 transfers authority over drilling and inspection to the Alaska Oil and Gas Conservation Commission. DNR retains authority over geothermal land management and unitization.

The bill reduces the royalty rate on geothermal to correspond with the federal royalty rate — 1.75 percent of gross revenues from production, sale or use of geothermal resources on a state lease for the first 10 years of production and 3.5 percent after the first 10 years. The current royalty rate is 10 percent.

Since geothermal is not exported, but is used exclusively in the state, the royalty rate would simply transfer through to utilities and consumers.

“We can look to Iceland to see the power geothermal resources bring to a society,” said Sen. Lesil McGuire, R-Anchorage, the bill’s sponsor, in a statement April 5 after the bill passed the Senate.

“Geothermal power is a consistent, clean, renewable power that could transform the energy picture in Alaska,” she said.

Mount Spurr

Paul Thomsen, director of policy and business development for Ormat Technologies Inc., told the Senate Finance Committee in a March 29 hearing that Ormat believes reducing the royalty rate to the federal rate would make the company’s project at Mount Spurr commercial. Maintaining the royalty at the existing rate, Thomsen told the committee, would mean the company would need to get 14 cents per kilowatt hour to make the project profitable. He said Ormat does not think utilities or ratepayers in the area want to sign a long-term contract that that rate. The company thinks utilities are looking at 10-11 cents per kilowatt hour, Thomsen said.

At the federal royalty rate, Ormat estimates that the state would receive revenues from a Mount Spur geothermal development of $38 million over a 25-year period.

Regulatory issues

Regulation of geothermal drilling became an issue when Naknek Electric began plans to drill geothermal wells.

All authority over geothermal development is currently vested in DNR.

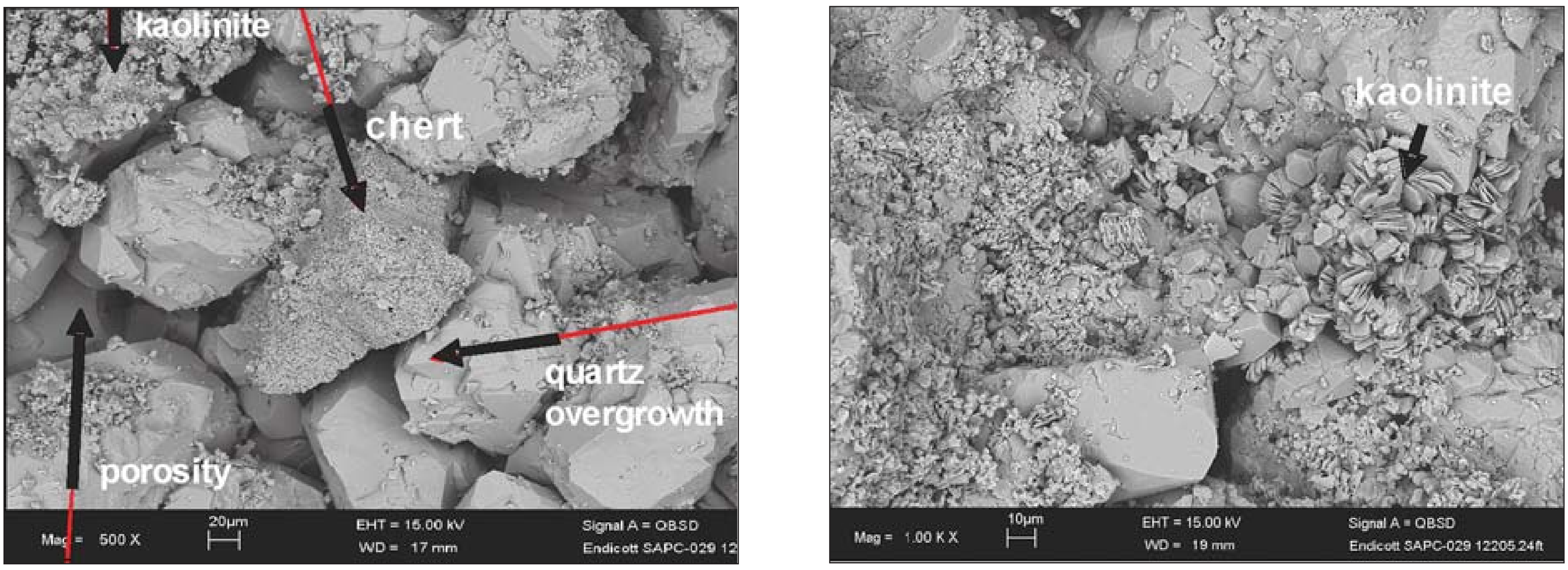
When the AOGCC discussed the issue at a public meeting in August, Commissioner Cathy Foerster said DNR’s drilling regulations are based on 1986 commission regulations. The DNR regulations have not been updated as AOGCC has updated its regulations through the years.

Commission staff said AOGCC had received requests from DNR to review geothermal drilling applications.

Solutions discussed by the commission included statutory amendments moving geothermal drilling authority to AOGCC or a requirement that DNR consult with the commission on geothermal drilling permits.

In September the commission held a hearing on a commission motion to require an AOGCC drilling permit for any well with a total vertical depth greater than

see GEOTHERMAL BILL page 15



COURTESY BP EXPLORATION (ALASKA) INC.

Scanning electron micrographs of Endicott reservoir rock showing sand grains and clay (labeled "kaolinite"). During initial production the oil occupying voids (labeled "porosity") between the grains is removed, but residual oil remains adhered to the clay. Low salinity water can detach the residual oil from the clay.

● EXPLORATION & PRODUCTION

BP's LoSal test at Endicott succeeds

The new enhanced oil recovery technique may deliver more than 700 million barrels of oil from the company's worldwide assets

By ALAN BAILEY
Petroleum News

BP's trademarked LoSal enhanced oil recovery test in the Endicott field on Alaska's North Slope has successfully demonstrated the possibility of recovering as much as 20 percent of the remaining oil in place in a field reservoir, BP spokesman Steve Rinehart told Petroleum News April 6.

The test, involving the injection into the reservoir of low salinity water rather than the saline water typically used to flush oil from an oil field, fully met the company's expectations.

"We came out of this feeling very good," Rinehart said. "We're looking at this as a pretty significant breakthrough."

Verify the technique

BP designed the test at Endicott to verify the viability of the LoSal technique and the company is now evaluating where best within its worldwide portfolio of oil fields to put the technology into full operation.

"We're looking for and assessing targets, but we're not at a point yet where we can say 'OK, we're going to do LoSal next in this location or that one,'" Rinehart said. "… We showed that it worked and now we want to put it to work."

BP has in the past said that the cost of implementing a full-scale LoSal operation in a specific field will depend on factors such as the availability of a suitable low-salinity water source at the field and the extent to which oil wells need to be reconfigured to support the operation. However, in a region such as the North Slope, even a small increase in field oil recovery can represent a large amount of new oil production.

Worldwide, the use of the technique could result in the recovery of more than 700 million barrels of oil from BP's oil fields, Rinehart said.

Trademarked in 2005

BP trademarked its LoSal technology in 2005 after laboratory testing had demonstrated that low-salinity water can be more efficient than saline water in sweeping oil from the pores of oilfield reservoir rocks. The technique works because low-salinity water is especially effective in severing the electric bonds that hold molecules of oil to the clay that typically coats sand grains in a reservoir rock — the oil attaches to the clay rather like Velcro, with the water disconnecting

see **LOSAL TEST** *page 16*

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GEOTHERMAL BILL

1,000 feet in specified townships and ranges within the Bristol Bay Borough, the area where Naknek Electric is drilling geothermal wells.

Under state statue, a well is subject to commission regulations if there is likelihood of "an unexpected encounter of oil, gas, or other hazardous substance as a result of well drilling."

In an October order the commission said it had determined that there was "sufficient likelihood" that wells drilled in designated townships in the Bristol Bay area would encounter oil, gas or hazardous substances, and ruled that wells in the designated area drilled to depths of greater than 1,000 feet would be subject to the commission's regulations and requirements. ●

Contact Kristen Nelson at knelson@petroleumnews.com

LAND & LEASING

BLM posts NPR-A maps for upcoming sale

The Bureau of Land Management in Alaska said April 2 that it has posted online maps detailing proposed oil and gas lease sale tracts in the National Petroleum Reserve-Alaska to be offered at its Aug. 11 lease sale in Anchorage.

BLM said proposed tract maps show 414 tracts, some 4,211,926 acres, with 269 tracts (2,513,750 acres) in Northeast NPR-A and 145 tracts (1,698,176 acres) in Northwest NPR-A.

BLM said there are currently 310 oil and gas leases, 3,026,633 acres, in the Northeast and Northwest planning areas.

The proposed lease maps can be found at BLM Alaska's home page at www.blm.gov/ak under "In the Spotlight."

—PETROLEUM NEWS

SAFETY & ENVIRONMENT

Arctic sea ice reaches maximum extent

The Arctic sea ice appeared to reach its maximum extent for the winter on March 31, despite a small, temporary decline in ice cover earlier in the month, the National Snow and Ice Data Center reported April 6. March 31 is the latest date for the winter maximum extent since satellite-based ice observations began in 1979, with the previous record of March 29 being set in 1999, NSIDC said.

Cold weather and northerly winds over the Bering and Barents Seas caused the unusual late-season spurt in ice growth, NSIDC said.

At 5.89 million square miles this year's maximum came close below the average maximum extent since 1979. However, the ice cover varies between different regions, being higher than average in the Bering and Baltic Seas, below average in the Atlantic and average elsewhere. And the long-term trend for the sea ice maximum, including the data for this year, shows a decline rate of 2.6 percent per decade, NSIDC said.

The lowest ever maximum sea ice extent occurred in 2006, with a total area of 5.6 million square miles.

However, NSIDC says that the ice that formed late in the season this year is thin and will melt quickly when temperatures rise, thus having little impact on the summer ice extent. On the other hand, with unusual patterns of atmospheric pressures and winds in the Arctic this winter, less sea ice than usual drifted out of the region, so that there has been some replenishment of the relatively thick multiyear ice that plays a key role in determining the extent of the summer ice melt.

—ALAN BAILEY

SAFETY & ENVIRONMENT

'Coots' Matthews, famed firefighter, dies

Edward "Coots" Matthews, a famed oil well firefighter and part of a trio who inspired the 1968 movie "Hellfighters" starring John Wayne, has died. He was 86.

Matthews and Asger "Boots" Hansen co-founded Houston-based Boots & Coots International Well Control Inc. in 1978, after a 20-year career fighting oil well fires alongside counterpart — and later rival — Red Adair. Boots & Coots said Matthews died March 31.

Matthews and Asger "Boots" Hansen co-founded Houston-based Boots & Coots International Well Control Inc. in 1978, after a 20-year career fighting oil well fires alongside counterpart — and later rival — Red Adair. Boots & Coots said Matthews died March 31.

"We owe a tremendous debt to Mr. Matthews for the vision he and Boots Hansen shared when they formed this company and the culture they developed that helped the company endure the hard times as well as the good," Jerry Winchester, the company's president and CEO, said in a statement April 1. "His imprint on this industry will live forever."

Matthews began his career with Halliburton in 1947 after serving as a U.S. Air Force tail gunner on a B-17 during World War II.

Matthews and Hansen then joined forces with Adair, fighting some of the best known oil well flares, including the "Devil's Cigarette Lighter" in Algeria in 1961. The geyser was so great, astronaut John Glenn reported seeing it from space as he passed over the Algerian desert.

After Iraq's 1991 invasion of Kuwait, Matthews was again called to service, flying to the Persian Gulf to help extinguish some 700 fires in Kuwaiti oil fields.

Matthews retired in 1994 and Boots & Coots was sold to employees.

—THE ASSOCIATED PRESS

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LOSAL TEST

the Velcro hooks.

However, because a lab test does not prove that a technique such as LoSal will work properly in a full-scale oilfield situation, BP decided to conduct a field test. And Endicott, as a mature oil field with a substantial volume of oil remaining in place, turned out to be an optimum test location.

The company sanctioned the Endicott test in 2006 and began by pumping water in and out of single wells, to test the effectiveness of low-salinity water in moving oil that lay close to a well.

In December 2007 BP began a major, conventional waterflood operation in the field, to establish baseline oil recovery data, to enable a later determination of how much additional oil the LoSal technique would remove, Rinehart said.

Started June 2008

Then in June 2008 the company started pumping low salinity water at a rate of about 5,000 barrels per day into a single injection well, to cause an expanding pool of this water to move through the reservoir towards a production well, gathering oil along the way. Careful positioning of the test within the Endicott reservoir ensured a geologic setting that would channel the water along a path towards that single production well.

"This was a well-to-well test," Rinehart said. "The bottom-hole locations were approximately 1,000 feet apart."

Three trucks continuously delivered fresh water from a gravel pit for the water injection operation, he said.

In May 2009 changes in the chemistry of water passing up the production well indicated that the leading edge of the package of low salinity water had crossed the oil reservoir between the injection and the production wells. It was then possible to start measuring the oil recovery associated with the low-salinity water and thus estimate how much oil recovery to attribute to the LoSal technique.

Completion of these measurements and subsequent analysis of the results has enabled BP to derive the figure of a potential 20 percent recovery of remaining oil in place from LoSal at Endicott.

"We've got a tool out of this that promises to be very useful," Rinehart said. ●

Contact Alan Bailey at abailey@petroleumnews.com

● EXPLORATION & PRODUCTION

Is Sunrise stalking something new?

Marathon exploration well is shallower than a previous well in the region, suggesting a different target at the CI prospect

By ERIC LIDJI

For Petroleum News

Marathon Oil Co. may be chasing something new at Sunrise.

Early completion data suggests the recent Cook Inlet exploration well is targeting a different prospect than the one encountered by a well drilled in the area 40 years ago.

Marathon drilled the Sunrise LK2 well about one mile west of the Sunrise Lake Unit No. 1 well, which Forest Oil drilled in 1970 to a depth of 14,500 feet. Forest encountered gas shows in the Tyonek formation below 11,000 feet, but not in commercial quantities.

In well logs at the time, Forest Oil reported a "small amount of gas" between 11,698 feet and 11,758 feet and some additional gas between 11,220 feet and 11,260 feet.

In a completion notice published by the Alaska Oil and Gas Conservation Commission the week of March 21, though, Marathon reported that it drilled Sunrise LK2 to a total depth of 9,918 feet and a total vertical depth of 9,798 feet, shallower than SLU No. 1.

Marathon drilled Sunrise LK2 relatively straight, angled slightly toward the northeast.

'Zone of interest'

After completing the exploration well, located on Cook Inlet Region Inc. land in the Kenai National Wildlife Refuge east of the Swanson River field, Marathon said it "encountered a zone of interest" and was "continuing to evaluate the results to determine commerciality."

The company also permitted a second well, Sunrise LK 2RD, with the same top hole location as Sunrise LK2, but a proposed bottom hole location just north of SLU No. 1.

Drilling reports suggest that Marathon is currently drilling a development well at the Ninilchik unit, rather than pursuing that second well location at the Sunrise prospect.

The company previously announced plans to drill three wells total this year.

Marathon has called Sunrise a "tight well." In mid-January, the Peninsula Clarion quoted Carri Lockhart, production manager for Marathon in Alaska, as saying, "We probably won't be saying a whole lot about it until we fully evaluate it, but cross your fingers."

Discontinuous sands common

Cook Inlet geology includes many laterally discontinuous sands, making it possible for one well to encounter a gas-bearing zone not encountered by another nearby well.

"While I do not know details of either well, it is possible that both wells encountered slightly different stratigraphy. In fact, given the fluvial depositional setting, I'd say there's a fairly high probability of that," said David LePain, chief of the Energy Resources Section of the Alaska Division of Geological and Geophysical Surveys.

In a December 2009 report, the Alaska Division of Oil and Gas included Sunrise among six potential onshore Cook Inlet prospects that "might yield between 40 and 120 (billion cubic feet) of recoverable gas" combined. It described Sunrise as a "lightly explored anticline trend." ●

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● PIPELINES & DOWNSTREAM

Settlement judge to hear pipeline dispute

Regulatory Commission of Alaska hopes for resolution of complaints about CIPL's rate hike; Cook Inlet oil producer reports growth

By WESLEY LOY

For Petroleum News

The Regulatory Commission of Alaska has taken action to try to settle protests over a Cook Inlet oil pipeline operator's recent 259 percent rate increase.

In a 12-page order issued March 22, the RCA appointed a settlement judge, Blythe Marston, to hear the controversy over Cook Inlet Pipe Line Co.'s new rate.

Three parties had asked to intervene in the matter of CIPL's tariff revision, and the RCA granted the petitions from Anchorage-based oil and gas producer Cook Inlet Energy LLC and overriding royalty interest owners Daniel K. Donkel and Donkel Oil & Gas LLC.

In its order, the RCA said it wants the parties to engage in "meaningful settlement discussions." Barring a resolution, the commission said the parties should identify those issues that can be resolved by mediation and those, if any, requiring commissioners to decide.

The RCA scheduled an initial settlement conference for April 21-22 at RCA offices in downtown Anchorage.

Volcanic rate hike

CIPL's rate hike took effect at the beginning of the year. The RCA is allowing the pipeline operator to collect the rate temporarily and subject to refunds.

The current transportation rate is \$14.57 per barrel of oil, a 259 percent increase from the previous rate of \$4.06.

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

Cook Inlet Energy, in its formal complaint filed in January, argued the rate hike was excessive and "could not have come at a worse time" for the fledgling company, which in late 2009 bought oil and gas assets on the west side of Cook Inlet from Pacific Energy Resources Ltd., a California firm undergoing bankruptcy liquidation. The assets include the West McArthur River oil field.

CIPL has attributed much of its rate increase to damage and disruption the erupting Redoubt volcano caused in 2009, idling west Cook Inlet oil production and the pipeline for months.

CIPL has attributed much of its rate increase to damage and disruption the erupting Redoubt volcano caused in 2009, idling west Cook Inlet oil production and the pipeline for months.

In filings with the RCA, the pipeline operator has defended its higher rate as "entirely reasonable," allowing for recovery of actual costs plus a reasonable return. CIPL added it "has no responsibility to subsidize the recent investment" Cook Inlet Energy made in the oil and gas properties.

Cook Inlet Energy's growth

Despite the rising transportation cost for moving its oil, Cook Inlet Energy is plowing ahead with efforts to grow its production from wells that previously were shut-in.

The company is a subsidiary of Tennessee-based Miller Energy Resources, which announced in an April 5 press release that its Cook Inlet produc-

see RCA page 21

● FINANCE & ECONOMY

BP changes North Slope management scheme

Organization around fields changed to surface, subsurface business units; some jobs lost, other shuffled in state, companywide

By ELIZABETH BLUEMINK
Anchorage Daily News

BP is quietly finalizing a major reorganization of its Alaska operations — some workers are losing their jobs and many others are getting new duties, the oil company said April 6.

BP Exploration (Alaska) Inc. had about 2,000 employees before the restructuring began several months ago and will have "about" the same number when it is finished, the company's spokesman Steve Rinehart said.

He declined to say exactly how many workers are losing their jobs and how many are getting reassigned. The numbers are still in flux, he said.

The biggest component of BP's reorganization has involved the dismantling of two major business units, one that managed the Prudhoe Bay oil fields and the other that managed all of the other BP oil fields on the Slope. BP runs most North Slope fields on behalf of itself and the other oil-company leaseholders.

BP has replaced those business units with two new ones based on function rather than geography: One runs BP's surface operations and the other is responsible for maintaining the underground oil reservoirs.

Job reduction not goal

Some Alaska employees are getting new responsibilities, others have lost their jobs, some have retired, and still others found new positions at BP, Rinehart said.

"We didn't go into this with a goal to reduce the head count," Rinehart said.

One BP hourly worker on the Slope said he has heard a lot of talk about the reorganization but hasn't seen many people losing their jobs. He works for a union and thus his job is not at risk, he said. He knows one person — a manager — who is no longer at BP, he said.

"We do this about every five to seven years, shuffling things around," said Mark Niver, the BP employee.

Niver said he and other BP workers at Prudhoe unionized years ago mostly because they "got tired of these reorganizations."

This year's reorganization has affected people from the top level of BP's Alaska operation to people who work on projects in the field, Rinehart said.

Two BP senior vice presidents in Alaska were given new job titles and revised responsibilities. Mike Utsler, who ran the Greater Prudhoe Bay production unit, is now in charge of all surface operations on the North Slope. Max Easley, who ran BP's other oil fields, such as North Star and Endicott, is now senior vice president for resources, meaning that he is in charge of maintaining BP's below-surface operations.

Similar reorganization is under way at other BP operations around the world, Rinehart said.

The state's Oil and Gas Division director, Kevin Banks, said April 6 that BP has not formally shared information about the reorganization with his office but he has heard "vague rumors" about it. ●

EXPLORATION & PRODUCTION

US rig count increases by 21 to 1,465

The number of rigs actively exploring for oil and natural gas in the U.S. increased by 21 the week ending April 2 to 1,465.

Alaska lost four rigs, Arkansas and New Mexico each lost two and North Dakota and Pennsylvania each lost one.

Baker Hughes Inc. said 949 rigs were exploring for natural gas and 502 for oil. Fourteen were listed as miscellaneous. A year ago this week, the rig count stood at 1,043.

Of the major oil- and gas-producing states, Texas gained 23 rigs, Louisiana gained five, Colorado gained two and California gained one. Alaska lost four rigs, Arkansas and New Mexico each lost two and North Dakota and Pennsylvania each lost one. Oklahoma, West Virginia and Wyoming were unchanged.

The rig count tally peaked at 4,530 in 1981 and fell to a record low of 488 in 1999.

Baker Hughes is based in Houston.

—THE ASSOCIATED PRESS

continued from page 4

COSMOPOLITAN

plant, tanker trucks would go north along the rural Sterling Highway to Kalifornsky Beach Road connecting to the Kenai Spur Highway.

A Golder Associates analysis done for Pioneer shows that the spill risk from trucking the oil "is comparable to pipeline transportation," Pioneer said.

Cosmo over its lifetime will average 14 truck trips per day, with each tanker likely hauling a maximum of 200 barrels or 8,400 gallons, the Golder analysis says. The trips rise to 40 per day when Cosmo production peaks about two years after startup.

"Note that during peak operations there will be a maximum of 6-7 crude oil tanker trucks traveling simultaneously along the route per day," the analysis says.

The biggest hazard from the trucking operation is a traffic collision, Golder says. The consultant estimates a frequency of one collision every 25 years involving an oil tanker truck. ●

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DISPUTE

They are fighting their property tax bills for a number of years beginning with 2006.

At stake is potentially tens of millions of dollars in property taxes — the difference between what the pipeline owners believe they owe and what the state as well as local governments believe is due.

Gleason's 10-page ruling, entered March 30, pertains only to 2006. The pipeline valuation for that year was $4.3 billion.

The ruling is the upshot from oral arguments held in Gleason's courtroom months ago, on Sept. 30, 2009.

The arguments centered on a motion for summary judgment the pipeline owners filed seeking to nullify the 2006 appraisal.

Lawyers for the owners argued federal law preempted the new method the state Department of Revenue adopted beginning in 2005 to value the pipeline.

Specifically, the owners said state officials violated the "filed rate doctrine" by failing to recognize income from tariffs filed with the Federal Energy Regulatory Commission as the basis for determining pipeline value. Instead, the state used an appraisal approach that resulted in a higher value and thus bigger property tax bills.

Gleason, however, ruled against the owners.

She noted that the state Assessment Review Board in 2006 determined that an appraisal based on declining tariff revenue "fails to capture the full and true economic value" of the pipeline system — an asset the energy companies would replace if necessary to continue producing their North Slope oil.

Because the Department of Revenue and the review board did not employ a tariff different from what the FERC set, their 2006 pipeline valuations for property tax purposes "are not preempted by the filed rate doctrine," Gleason held.

So, what's next in the already protracted fight over pipeline property taxes?

A big item to look for is another ruling from Gleason on whether the $4.3 billion assessment for 2006 was correct.

—WESLEY LOY

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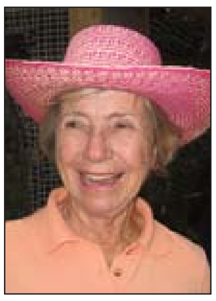
Oil Patch Bits

Crowley announces passing of Molly Murphy Crowley

Crowley Maritime Corp. said March 24 that board member Molly Murphy Crowley died March 21 surrounded by her family at her Indian Wells, Calif., vacation home. Born Nov. 27, 1938 in Portland, Crowley was a past Portland, Ore., real estate mogul, philanthropist and competitive amateur golfer. She met her late husband, Thomas Crowley Sr., chairman, president and CEO of Crowley Maritime Corp., on a ski vacation in Switzerland. The two claimed it was love at first sight and they were married for many years prior to his death in 1994. She was a long time member of Crowley's board of directors and oversaw the growth of the 118-year old maritime and logistics services company into a nearly $2 billion a year powerhouse. Her stepson, Tom Crowley Jr., is the chairman, president and CEO today.



MOLLY MURPHY CROWLEY

Schlumberger acquires Geoservices from Astorg

Schlumberger said March 24 that it has acquired Geoservices, a privately owned French oilfield services company specializing in mud logging, slickline and production surveillance operations. The total value of the transaction, including debt, is $1,070 million. Geoservices, founded in 1958, employs approximately 5,000 people and is active in more than 50 countries worldwide. The company is the leading mud logging company, and has invested heavily in the development of new technology for exploration and appraisal well activities, particularly in the emerging deepwater market. "The addition of mud logging technology to the Schlumberger portfolio is an important step in the development of higher-performance drilling systems," said Andrew Gould, chairman and CEO, Schlumberger Ltd. "The combination of Schlumberger real-time downhole formation sampling measurements with Geoservices' drilling mud analysis will help customers better identify and react to drilling hazards, while the combination of mud logging with Schlumberger formation evaluation measurements will bring more complete understanding of rock lithology and fluid content."

Rain for Rent Hoseguard for pipe spill containment

Rain for Rent said March 30 that its latest innovation in pipe and hose spill containment, the Hoseguard, is available to rent in 2-foot widths and in 10- and 20-foot lengths. The Hoseguard can be assembled to achieve any desired length or configuration, with cus-

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MAC ACKERS

alongside front-line employees. The show gives viewers a glimpse of the human beings behind America's corporate bosses, which Salam says helps "the audience move beyond the caricature of heartless, rapacious chief executives. Broadly speaking, one gets the impression that these men — and unfortunately all of the CEOs so far have been men — are hard-working, conscientious people who've devoted their lives to leading large, complex enterprises." As for the show's featured employees, often characterized as victims by fictional cinema and television, Undercover Boss doesn't just present "plucky, morally upright employees who invariably do the right thing out of the goodness of their hearts." Salam says we also get to see "incorrigible, incompetent and simply cruel employees, who test the patience of the undercover boss." Read Salam's column at http://bit.ly/9JTXfV.

NOT TO BE BLOWN OFF ... Nissan has announced the pricing on its 2011 all-electric LEAF. It's approximately $25,000; with additional rebates some can get it for only $20,000. The legit breakdown? Operating costs of a highly efficient internal combustion (normal) engine are 10 cents per mile; a pure electric vehicle's operating costs can be as low as 2.5 cents per mile. At current U.S. electricity rates, it should cost less than $3 to fully charge a 23-kilowatt hour battery, giving the first commercial electric vehicles a range of approximately 100 miles. It's being said that cities and regions with electrified transportation sectors won't be the only ones to benefit, that it will bring costs down for the entire nation. Can any automobile gurus verify or challenge these claims for me? You can read more about the value chain of the electrified transportation sector here: www.electrificationcoalition.org.

MISTAKES ENERGY COMPANIES MAKE … In designing new facilities energy companies should focus less on bells and whistles and more on nuts and bolts, Solomon Associates said April 5. In building new plants many refiners, chemical manufacturers and power generation firms fall into the common trap of assuming that by spending millions of dollars on the latest generation of equipment and technology they will automatically yield better operating performance. But research by Solomon Associates, a Dallas-based performance-improvement company for the energy industry, indicates that this is not the case. Solomon says operators cannot buy their way to prosperity. (Who knew!?) The four most common mistakes, per Solomon, are designing new facilities for throughput or capacity rather than overall performance; failing to include operations personnel in the project team; planning to run the new plant the same way as the old plant; and cutting corners on training. For more information: www.solomononline.com.

Twenty-five states are launching "Cash for Appliances" rebate programs just before Earth Day on April 22. You'll have to move quickly to cash in on the limited dollars for rebates on energy efficient appliances.

YOUR WALLET WILL THANK YOU ... But you can thank me for the reminder! Twenty-five states are launching "Cash for Appliances" rebate programs just before Earth Day on April 22. You'll have to move quickly to cash in on the limited dollars for rebates on energy efficient appliances. But figuring out when programs start, which appliances are included and who qualifies for different rebates is a pain. ApplianceRebate.com has put all currently available rebates online — including utility, municipality, manufacturer and retailer rebates. They also provide a tool that calculates the operating cost of a new appliance based on the consumer's actual gas and electric costs within their zip code. All of the site's tools are free. I've checked it out, it's pretty simple and it's legit. But I don't qualify. Bummer.

Contact me! I am Greening of Oil's social networker. My weekly column is posted in both Petroleum News and on Greening of Oil's Buzz and Latest news pages. My e-mail address is mac@greeningofoil.com. And remember to cast your vote about climate change in the "share your opinion poll" on Greening of Oil's latest news page at http://www.greeningofoil.com/latest.aspx

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OIL PATCH BITS

COURTESY RAIN FOR RENT

tom widths available. When used in conjunction with Rain for Rent's patented Spillguards and Hose Bridges, Hoseguards provide a total containment system that can be used with various applications including acids, caustics, and hydrocarbons. These spill containment systems can be used in refineries, power generation plants, oil fields, and environmentally sensitive worksites. Contact Rain for Rent for sales and rental enquiries at 800-742-7246 or visit www.rainforrent.com.

ExxonMobil cardholder's sweepstakes opportunity

ExxonMobil said March 31 that Exxon and Mobil retailers and Citi are giving cardholders the chance to win a 2010 smart fortwo coupe each week through the ExxonMobil personal card "Win a smart fortwo Sweepstakes". From April 1 through June 30, a new winner will be drawn every week. In addition to the weekly car giveaways, consumers will also have the chance to win one of thousands of ExxonMobil gift cards during the three-month promotion. To enter, cardholders simply make a purchase with an ExxonMobil personal card at any participating Exxon or Mobil station. Each purchase qualifies as one entry. If customers don't have a card, they can enter by applying for a new account at sweepstakes.exxonmobilcard.com or calling 866-379-1010.

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

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RCA

tion now exceeds 1,100 barrels of oil equivalent per day.

"This increase in production is the result of the successful rework of its West McArthur River Unit-6 well which tested at a flowing rate of 584 BOED," Miller said. "The rework included replacing tubing and adding new perforations targeting previously untapped oil-bearing sands."

Another well, the West McArthur River Unit-5, was successfully worked over earlier this year, Miller said.

Scott Boruff, Miller's chief executive, said the company originally thought it would take much longer, until the fourth quarter of this year, to reach its goal of 1,100 barrels per day. ●

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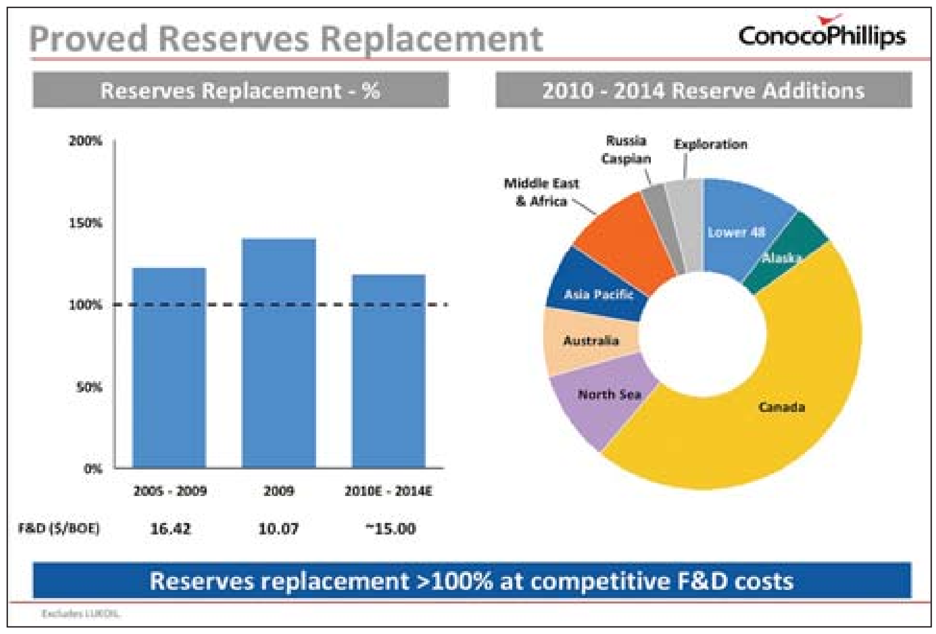
CONOCO

ConocoPhillips saved $500 million in operating and capital costs in 2009 and is looking to save more than $400 million this year, Carrig said. Some of those reductions will come from "overall maintenance programs," "procurement savings," "optimized turnarounds," "lower corporate overhead," "emphasis on unit costs" and "increased accountability."

ConocoPhillips budgeted an $11.2 billion capital program for 2010, about 87 percent of which is set aside for exploration and production projects. That won't necessarily mean an immediate increase in production, though. Instead, in the near term, ConocoPhillips expects a "production plateau" at 2008 levels while it focuses on integrity, planning and maintenance of existing assets followed by production growth in 2014 and beyond.

About half of the planned capital-spending program this year is for North American projects, Carrig said, including "about $1 billion in downstream, $1 billion for oil sands, $1 billion or so in Alaska, and the balance in Lower 48 and Western Canada gas."

In annual financial filings, ConocoPhillips projected spending $854 million on E&P work in Alaska this year. Because of permitting obstacles, though, ConocoPhillips deferred around $60 million of that spending directed at a planning Alpine satellite, bringing 2010 spending approximately in line with 2009 levels, the company has said.



"So, what are we doing here? If you look at the overall program, what we're doing is we are constraining capital. That's generating cash. We are disposing of assets. That's generating cash. We're maintaining our overall production level volumes consistent with 2008 volumes. We're taking the excess cash and we're buying shares back," Carrig said.

On a more detailed level, ConocoPhillips plans to spend about $340 million on North Slope development this year, focused on the Western North Slope, Prudhoe Bay satellites and a five-year program to improve Kuparuk recovery rates using a new coil-tubing rig.

"Whether it be Alaska or Australia or the North Sea, you see some common themes that emerge. We are spending our exploitation dollars on infield drilling opportunities, on peripheral drilling opportunities, and on technology — application of technology to improve recovery in these legacy assets," said Kevin Meyers, senior vice president for exploration and production in the Americas and former head of ConocoPhillips Alaska.

Kuparuk is one example of ConocoPhillips applying technology to legacy assets, Meyers said. The company is using its new "state-of-the-art" coil-tubing rig "in conjunction with 3-D seismic and multilateral sidetracks to go out and access literally hundreds of drill opportunities that wouldn't be economic otherwise without this technology."

If certainty, then certainly

ConocoPhillips executives also briefly touched on North Slope natural gas, positioning it as a longer-term investment in the goal of increasing production by the end of the decade.

"Are we moving that forward?" Ryan Lance, senior vice president for international exploration and production, said about Alaska North Slope natural gas. "We need some more fiscal certainty. We need more, probably, regulatory certainty. But certainly, that's in our plans to try to move that Alaskan resource forward as well."

Mulva said ConocoPhillips expects natural gas demand to rise in the coming decade, requiring all forms of conventional and unconventional production, from shale gas and tight sands, to coalbed methane, Canadian imports, liquefied natural gas and Alaska gas. ●

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DENALI

opportunity to move gas on to market on three major outlets out of Alberta — the Spectra, Nova and Alliance pipelines.

The estimated tariff from the gas treatment plant to Alberta is $2.67 per million Btu in 2009 dollars, and when the costs are escalated to reflect when the line will be built that comes out to roughly $3.25, Fackrell said. First gas is projected in 2020.

Mainline, GTP expandable

Kris Fuhr, Denali's vice president for the mainline, said the technical team includes experienced employees and contractors, and the plan is built on work the owner companies, BP and ConocoPhillips, have done in more than 30 years of looking at monetizing Alaska gas.

Fackrell said he thinks the biggest hurdle Denali faces going into open season is that "we know that there are several factors that shippers have talked about that aren't resolved."

"We have people that have managed and delivered projects on the Alaska North Slope; we have people that have worked in other Arctic regions around the world; and we have folks that have delivered mega projects in frontier basins globally," Fuhr said.

The project includes a one-mile 60-inch transmission line from Prudhoe Bay and a 62-mile, 36-inch line from Point Thomson to the GTP; these will be conventional aboveground lines, he said.

The mainline will be a buried 48-inch line designed to deliver an annual average of 4.5 billion cubic feet per day of gas and expandable with added compression to 5.6 bcf a day.

Roberto Reichard, Denali's vice president for the gas treatment plant, said the GTP will be a world-scale modularized plant, with four trains, designed to produce 4.5 bcf a day of sales gas into the mainline and expandable to 5.8 bcf per day "with the addition of one more train."

Distinctive commercial offering

Scott Jepsen, Denali's vice president for business services, said the company "has created a distinctive commercial offer that we believe will be attractive to potential customers." He said the open season "has been crafted to make it possible for a broad group to participate as foundation shippers."

Foundation shippers must meet Denali's creditworthiness standards, have a net worth commensurate with their commitment and commit for at least 20 years during the initial open season, Jepsen said, but "there is no minimum volume requirement to be a foundation shipper," which the company believes "will make it possible for smaller lease-holders, explorers, end users and possibly the state to participate as foundation shippers."

Denali will be "shouldering some of the project risk" by asking for a minimum term of 20 years but taking its depreciation over 25 years, "taking the risk that we can recover the remaining 20 percent of our capital from late-life shippers over the remainder of the project's life," Jepsen said.

And, "subject to FERC regulations, Denali will not propose that existing shippers subsidize expansion shippers," he said.

Options

Jepsen said that if Denali does not receive commitments of at least 85 percent of the design capacity at open season, the company has "provided a framework for customers and Denali to work together to consider a scaled-down project, a pipeline to an LNG facility at a location of interest to customers" or time to gather additional shipping commitments to allow the original project to proceed.

Fackrell said he thinks the biggest hurdle Denali faces going into open season is that "we know that there are several factors that shippers have talked about that aren't resolved."

Two are "in our own front yard," he said: State of Alaska taxes, which shippers have talked about "for many, many years;" and the fact that the Point Thomson field is in litigation and "we don't know if the shippers will bid that field or not bid that field."

The third issue, Fackrell said, is will Alaska gas be "able to complete in the gas market in the Lower 48 — what's the gas price going to be and how can we compete heads up?" ●

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RULES

The well was planned for an exploration lease which was one of two acquired by the partnership in 2007, carrying work commitments of C$585 million for rights to 508,000 acres on Exploration License 446.

Heated response to delay

The Imperial-ExxonMobil request was denied pending a generic policy review by the NEB that includes written submissions and a technical conference on June 3 and 4 to discuss the submissions.

The delay provoked a heated response from Imperial geosciences manager Michael Peacock, who replied on behalf of Imperial, telling the regulator that waiting for completion of a review would have "very serious implications" for EL 446 by eliminating an entire year from the nine-year license.

He said Imperial had spent C$150 million on developing well plans, acquiring 3-D seismic data and designing a drillship specifically to operate in the Beaufort.

Imperial warned the "continuing regulatory uncertainty" add to the risks associated with making these investments, would jeopardize its ability to procure an Arctic drillship, obtain permits, drill an exploration well and conduct a formal evaluation of the well results.

Peacock said the delay would add to the costs and the "already onerous inhibitions" to developing Canada's Arctic resources.

Imperial: Deepwater drilling precluded

In its latest submissions, Imperial said the existing same season relief well would "essentially preclude the drilling of deepwater wells such as (the proposed Ajurak) well which require multi-season operations."

The company said the probability of a blowout is one in 285,000 and should one occur "there are many better approaches than starting a relief well immediately. The best approach is preventive engineering."

Imperial told the NEB that 295 wells were drilled in the Beaufort and Mackenzie Delta in the 1965-2009 period and none required a relief well, adding it alone has accounted for 107 wells.

Imperial said the Ajurak well targets depths of 8,400 feet to 17,400 feet, in water depths of 2,100 feet and would need three drilling seasons to complete and test, with the drillship able to operate without limitation from April 1 to Dec. 1.

Two to four icebreakers would be available to clear ice from around the drillship and help it maintain its position during ice incursions, while two ice-class and supply boats would provide additional logistics and resupply support.

Imperial, BP (which plans a baseline survey this year on its offshore exploration block) and CAPP all pressed the NEB to eliminate the same season relief well requirement and introduce a relief well policy that can be applied to all geographical areas under its jurisdiction.

BP said continuation of the same season relief well provision might well "impede further exploration in the Beaufort Sea."

Instead, the NEB should establish goals and objectives to enhance safety and protection of the environment, leaving a same season relief well as "one of a suite of after-the-fact tactics to deal with a well control problem."

BP also said it was statistically unlikely that a relief well could be completed in the same season.

Inconsistent with modern goal-oriented regulations

CAPP said the current same season relief well policy is inconsistent with a modern goal-oriented regulatory regime, and recommended a revised policy, emphasizing safety, protection of the environment, conservation of the resource and a "prevention first" approach.

Chevron Canada suggested consideration of an alternative well kill system developed with Houston-based Cameron, a global supplier of oil and gas equipment, to replace a same season relief well with an enhanced blowout prevention system.

The two companies entered an agreement in 2007 to develop a well control system and practices, engaging the Inuvialuit Game Council throughout the process.

The council told the NEB that a same season relief well or equivalent system should be required for operations planning to drill in the Beaufort, while the Tuktoyaktuk Hunters and Trappers Committee said it was opposed to Imperial's proposed drilling program without a relief well in order to protect the region's "subsistence harvesting of different mammal species"

The committee said Imperial has made no mention of compensating people who might be affected by a blowout. ●

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OCS SEASON

Fisheries Service Arctic open-water meeting on March 23, a meeting that forms part of the public process for the authorization of offshore activities that might disturb marine mammals.

"What's unique about this program is that we actually intend … starting on Oct. 1 and concluding sometime in mid- or late-November," Gagliardi said. "Really the limiting factor for us becomes landfast ice in the Bering Straits … at the end of the season."

Complete rethink

In 2006 GX Technology, a division of Ion, conducted a regional seismic survey in the U.S. Chukchi Sea. The company planned to carry out a second Chukchi Sea survey in 2007 but during the open-water meeting of that year decided not to proceed with that survey, Gagliardi said.

Instead, the company decided to completely rethink its approach to shooting offshore seismic in the Arctic.

"Starting in 2007, when we decided to remove our permit application for our Chukchi No. 2 program, we really took a look at what it would take if we wanted to come back and work in Alaska," Gagliardi said.

In a marine seismic survey a vessel tows arrays of air guns that periodically blast sound through the ocean water and into the rocks beneath the seafloor. The vessel also tows what are referred to as "streamers," often several miles long, carrying special microphones called hydrophones that detect air-gun-blast echoes, reflected from rock strata deep below the sea. Computer processing of the sounds detected by the hydrophones enables the construction of detailed images of subsurface rock structures.

In a conventional marine operation, the seismic survey vessel tows the air guns and the hydrophone streamers close to the sea surface. But, to overcome the problem of conducting a survey in a near-continuous ice sheet, Ion came up with a streamer design that would ride deeper in the water, below the bottom of the ice pack.

Icebreaker in front

Ion completely redesigned its equipment configuration to enable operations in situations where ice covers nine-tenths of the sea, Gagliardi said. An icebreaker and a survey vessel would work in tandem, with the icebreaker moving just ahead of the survey vessel, clearing a path through the ice as the survey vessel proceeds along the desired survey route.

"We're talking about an icebreaker in front and seismic boat behind. … They're not independent. They have to operate together. There is no timeframe in which the icebreaker will actually operate independently from the seismic vessel," Gagliardi said.

And in 2009 Ion successfully demonstrated this concept in a marine survey off northeast Greenland, he said.

In October and November 2010 Ion wants to shoot 600 to 800 kilometers (375 to 500 miles) of 2-D seismic lines along much of the Beaufort Sea offshore the North Slope using its new survey technique. The survey would start at the eastern end of the U.S. Beaufort Sea, moving progressively west, starting as the last of the summers' bowhead whales head west toward the Chukchi Sea and avoiding the October whale hunt in the Barrow area, off the western end of the North Slope.

The survey should end by late November but could continue into December, Gagliardi said.

Marine mammal observers

Three marine mammal observers on the icebreaker and one observer on the survey vessel will watch for marine mammals, to ensure that the air guns are shut down if the vessels come too close to the animals. And although the observers would have powerful binoculars and the vessels would turn on floodlights at night, Ion is also considering the use of a forward-looking infrared camera for spotting wildlife in the dark, Gagliardi said.

Gagliardi said that in December Ion had introduced its concept to the North Slope Borough and had sought guidance from the borough's wildlife department. The company had also attended other meetings with North Slope communities and with the Alaska Eskimo Whaling Commission. And in April the company plans to meet with the people in Kaktovik, the village toward the eastern end of the U.S. Beaufort Sea coast.

Some participants in the open-water meeting questioned the practicalities of observing animals at a sufficient distance from two closely spaced vessels. There were also questions relating to possible interactions with any subsistence seal hunting that might be taking place at the time of the survey, and also regarding possible disturbance to the start of polar bear denning on the sea ice. And a resident of Kaktovik expressed concern about the possible impact on the formation of multiyear sea ice of offshore ice breaking operations. ●

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