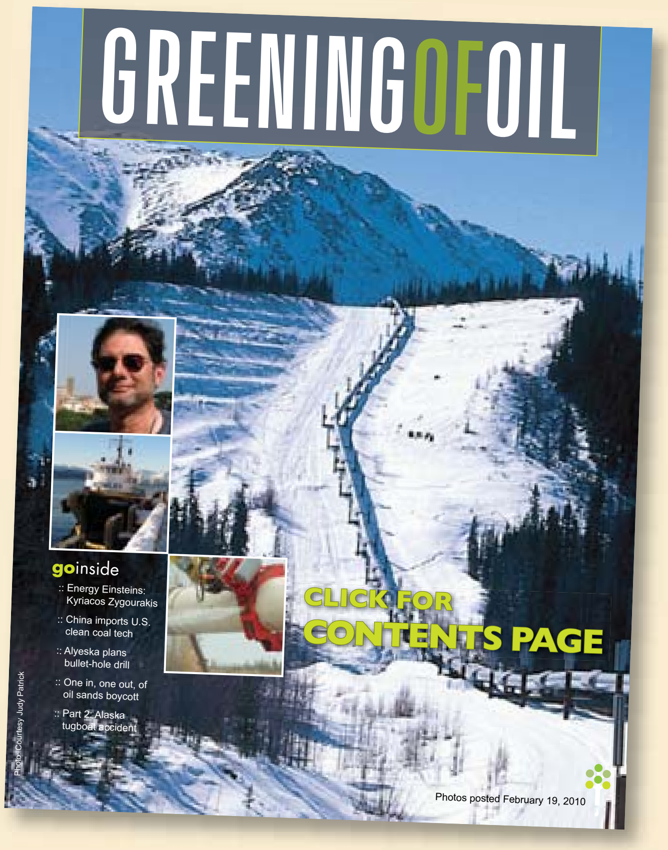
Petroleum news

Vol. 15, No. 8 • www.PetroleumNews.com | A weekly oil & gas newspaper based in Anchorage, Alaska | Week of February 21, 2010 • $2

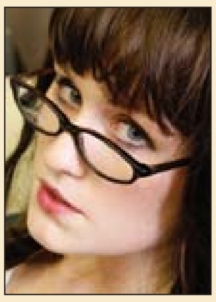
page 6 Jim Bowles, ConocoPhillips Alaska president, dies in Kenai avalanche

TAPS makes Greening of Oil



Petroleum News' sister publication, the online magazine Greening of Oil, posts new cover photos once a week — on Fridays, the day it sends out an email to subscribers about the most recent stories. This week the main photo is of the trans-Alaska oil pipeline. Check out Greening of Oil at www.greeningofoil.com.

Greening of Oil: Latest from Mac Ackers



MAC ACKERS

CALLING ALASKA JOB HUNTERS … The North Slope Insider report from Alaska Pipeline Job Info., says there is good news and bad news for job hunters.

First the report's bad news: The U.S. Corps of Engineers denied a permit for ConocoPhillips to expand in the National Petroleum Reserve-Alaska, eradicating 400 new jobs. The project is now on hold pending ConocoPhillips' appeal.

Now the report's good news: ExxonMobil's eastern North Slope Point Thomson project is on schedule, expecting the current workforce to expand from 200 to 600 (mostly con-

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

No Barrow hydrate research funds; wells will be drilled

The U.S. Department of Energy is no longer funding research into possible methane hydrate deposits in the Barrow gas fields on Alaska's North Slope, Petroleum News has learned. As a consequence, a North Slope Borough research team involving Petrotechnical Resources of Alaska is no longer proceeding with phase two of the research.

"We're going ahead as a development project and just cutting out the (methane hydrate) science," Tom Walsh, a managing partner of PRA, told Petroleum News Feb. 17.

The team had planned to drill two methane hydrate test wells and four horizontal development wells in the gas fields but will instead drill six horizontal development wells, Walsh said. The concept behind the previously planned test wells was to verify the presence of methane hydrate in the fields and

see **BARROW RESEARCH** *page 17*

EXPLORATION & PRODUCTION

Beaufort air permit

EPA issues proposed air quality permit for Shell's Beaufort Sea drilling

By ALAN BAILEY
Petroleum News

On Feb. 17 the U.S. Environmental Protection Agency issued a proposed air quality permit for Shell's planned drilling program in the Beaufort Sea. Shell plans to use the drillship Frontier Discoverer to drill one well in its Beaufort Sea Torpedo prospect and another well in its Sivulliq prospect during the 2010 open water drilling season — both prospects are on the outer continental shelf, on the west side of Camden Bay, east of Prudhoe Bay.

The EPA permit, allowing exhaust emissions up to prescribed annual limits for the drilling program, is a critical piece of the required permitting for Shell's exploration plan.

"We are pleased this permit is now out for pub-

SHELL EXPLORATION & PRODUCTION

Shell plans to use the drillship Frontier Discoverer to drill two wells in the Beaufort Sea in 2010

lic comment," Shell spokesman Curtis Smith told Petroleum News Feb. 17. "This permit is the result of a year-plus effort on behalf of Shell and the EPA to ensure the minimization of air emissions from

see **PERMIT** *page 20*

NATURAL GAS

Arctic gas by 2017

Ziff sees Mackenzie online first, Alaska North Slope following in 3-4 years

By GARY PARK
For Petroleum News

Canada's Mackenzie Gas Project could be onstream as early as 2017 and Alaska's North Slope project could be delivering gas to Lower 48 markets three or four years later, predicts consultant Ziff Energy Group.

And, regardless of the enormous capital costs to develop Arctic gas and compete with abundant shale gas supplies, the two projects are tied to expectations for gas prices in the 20 years after they are completed, not what happens over the next decade, the Calgary-based firm said.

But getting the Mackenzie Gas Project, or MGP, out of the starting gate will require a key contribution from the Canadian government in sharing the cost of building basic infrastructure, said Ziff Vice President Bill Gwozd, suggesting that all-weather roads in the Northwest Territories would be better than using barges to deliver materials and equipment along the Mackenzie River.

Ziff's big picture forecast for gas supply through the current decade is strongly linked to the growth of shale production and the chances of industrial demand rebounding.

Shale to grow to 33 percent

The study forecasts shale gas will account for about 33 percent of North American production of

see **ARCTIC GAS** *page 20*

LAND & LEASING

Point Thomson case on ice

Judge grants state's call for timeout as it appeals ruling to Alaska Supreme Court

By WESLEY LOY
For Petroleum News

A judge has ordered a temporary halt to the Point Thomson case pending the state's appeal of a recent unfavorable ruling to the Alaska Supreme Court.

The one-page order from state Superior Court Judge Sharon Gleason of Anchorage, issued Feb. 11, came over the objections of ExxonMobil and other oil companies with a stake in the rich Point Thomson oil and gas field on Alaska's eastern North Slope.

Fresh off a significant victory in Gleason's court, the companies had opposed the State of Alaska's request for a timeout in a case that's not yet run its course.

EXXONMOBIL

Gleason granted the state's motion to stay the Superior Court proceedings until the Supreme Court either rejects the state's petition, or accepts and acts upon it.

see **POINT THOMSON** *page 18*

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Alaska - Mackenzie Rig Report

The Alaska - Mackenzie Rig Report as of February 18, 2010.
Active drilling companies only listed.

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

This rig report was prepared by Marti Reeve

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

Alaska Rig Status

North Slope - Onshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Doyon Drilling			
Dreco 1250 UE	14 (SCR/TD)	Prudhoe Bay P2-31A	BP
Sky Top Brewster NE-12	15 (SCR/TD)	Badami B1-38	Savant Alaska
Dreco 1000 UE	16 (SCR/TD)	Prudhoe Bay 16-01	BP
Dreco D2000 UEBD	19 (SCR/TD)	Alpine CD3-124	ConocoPhillips
OIME 2000	141 (SCR/TD)	Alpine CD3-106	ConocoPhillips
TSM 7000	Arctic Wolf #2	Stacked at Prudhoe Bay	FEX/Available
Nabors Alaska Drilling			
Trans-ocean rig	CDR-1 (CT)	Stacked, Prudhoe Bay	Available
AC Coil Hybrid	CDR-2	Kuparuk 1E-12	ConocoPhillips
Dreco 1000 UE	2-ES	Prudhoe Bay, Stacked out	BP
Mid-Continental U36A	3-S	Stacked, Milne Point	BP
Oilwell 700 E	4-ES (SCR)	Milne Point MPF-94	BP
Dreco 1000 UE	7-ES (SCR/TD)	Prudhoe Bay DS 17-09	BP
Dreco 1000 UE	9-ES (SCR/TD)	Prudhoe Bay DS 03-37	BP
Oilwell 2000 Hercules	14-E (SCR)	Kuparuk 2A-27	ConocoPhillips
Oilwell 2000 Hercules	16-E (SCR/TD)	Sak River #1	Brooks Range Petroleum
Oilwell 2000	17-E (SCR/TD)	Stacked, Point McIntyre	Available
Emsco Electro-hoist -2	18-E (SCR)	Stacked, Deadhorse	Available
Emsco Electro-hoist Varco TDS3	22-E (SCR/TD)	Stacked, Milne Point	Available
Emsco Electro-hoist	28-E (SCR)	Stacked, Deadhorse	Available
Emsco Electro-hoist Canrig 1050E	27-E (SCR-TD)	Point Thompson PTU-16	ExxonMobil
Academy AC electric Canrig	105-E (SCR/TD)	Stacked at Deadhorse	Available
Academy AC electric Heli-Rig	106-E (SCR/TD)	Stacked at Deadhorse	Available
OIME 2000	245-E	Shut down, plan to recommence drilling at OPP in January	ENI
Nordic Calista Services			
Superior 700 UE	1 (SCR/CTD)	Prudhoe Bay Drill Site 18, well #30	BP
Superior 700 UE	2 (SCR/CTD)	Milne Point Drill Site L, well #02	BP
Ideco 900	3 (SCR/TD)	Kuparuk Drill Site 1J, well #162	ConocoPhillips

North Slope - Offshore

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

Cook Inlet Basin – Onshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Aurora Well Service			
Franks 300 Srs. Explorer III	AWS 1	Workover at West Mac #5	Cook Inlet Energy
Doyon Drilling			
TSM 7000	Arctic Fox #1	Stacked at Beluga	Available
Marathon Oil Co. (Inlet Drilling Alaska labor contractor)			
Taylor	Glacier 1	Sunrise Lake #2	Marathon Oil
Nabors Alaska Drilling			
Continental Emsco E3000	273	Stacked, Kenai	Available
Franks	26	Stacked	Available
IDECO 2100 E	429E (SCR)	Stacked, removed from Osprey platform	Available
Rigmaster 850	129	Kenai SLU 41-33RD	Chevron
Rowan Companies			
AC Electric	68AC (SCR/TD)	Stacked Kenai, Cosmopolitan	Pioneer Natural Resources

Cook Inlet Basin – Offshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Chevron (Nabors Alaska Drilling labor contract)			
	428	M-20 Steelhead Platform Kenai	Chevron
XTO Energy			
National 1320	A	Platform A no drilling or workovers at present	XTO
National 110	C (TD)	Idle	XTO
Kuukpik	5	Stacked in Kenai	Available

Mackenzie Rig Status

Canadian Beaufort Sea

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

Mackenzie Delta-Onshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
AKITA Equtak			
Modified National 370	64 (TD)	On the move to Nisku, AB	Available

Central Mackenzie Valley

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


JUDY PATRICK

Baker Hughes North America rotary rig counts*

	Feb. 12	Feb. 5	Year Ago
US	1,346	1,335	1,339
Canada	551	557	421
Gulf	43	42	57

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

*Issued by Baker Hughes since 1944

The Alaska - Mackenzie Rig Report is sponsored by:

XTO ENERGY

● GOVERNMENT

Moratoria may cost U.S. $2.36 trillion

New study assesses the impact on U.S. economy of keeping closed federal land off limits for O&G exploration and development

COURTESY FEX

NPR-A exploration drilling in winter of 2006-07. Drilling to the roadless NPR-A is only allowed in the winter when the tundra is frozen.

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By ALAN BAILEY
Petroleum News

In 2008, faced with energy security issues and soaring oil prices, President Bush and the U.S. Congress eliminated some decades-long moratoria on oil and gas development in huge tracts of federal offshore and onshore territory. But in a continuing debate over whether oil and gas exploration should in fact be sanctioned in any of this erstwhile closed land, just what is the nature of the trade-off between the economic benefits of oil and gas production and the environmental impacts of oil and gas development?

In an attempt to attach some solid data to the development side of the trade-off balancing act, the National Association of Regulatory Utility Commissioners instituted a study, funded by a wide variety of government and private entities, to model the economic impacts of continued land closures.

Possible cumulative loss of $2.36 trillion

And that study, conducted by Science Applications International Corp. and the Gas Technology Institute, has come up with some fairly eye-popping numbers, including a possible cumulative loss of $2.36 trillion from the U.S. gross domestic product over the period 2009 to 2030, if the previously off-limits lands continue closed to the oil and gas industry. That loss amounts to shaving an average annual 0.52 percent from the GDP.

Other key findings include the loss of a potential 9.9 billion barrels of U.S. domestic oil production across that same 2009 to 2030 time frame, with a corresponding increase of 4.1 billion barrels in oil imports from OPEC countries; a loss of 46 trillion cubic feet of domestic natural gas production, with an increase of 15.7 tcf of natural gas imports; and a loss of nearly 13 million jobs in energy-intensive industries.

Reduced economic activity as a consequence of issues with the energy supplies could result in 200,000 fewer housing starts than might otherwise occur, the study found.

The reduced availability of domestic oil and gas would possibly trigger an annual average increase of more than 1.4 percent in the use of renewable energy for power generation, although energy consumption would also increase by an average of 1 percent per year, the study found.

The study predicted a total cumulative loss of $2.34 trillion in people's real, disposable income, together with a consequent reduction in the U.S. consumption of goods and services. Total consumer energy costs would increase by a cumulative $2.35 trillion; the cost of the shipment of industrial products would increase by $1.68 trillion; and there would be a cumulative increase of $1.6 trillion in the bill for the import of foreign crude oil and natural gas.

If U.S. lands were opened for oil and gas development, environmental impacts of that development would obviously occur. On the other hand, keeping the lands closed would trigger the environmental impacts of producing and transporting imported oil and gas resources, the study said. However, the study did not attempt to model the environmental impact of foreign oil and gas production.

Economic model

The study team conducted its assessment by plugging estimated volumes of domestic oil and natural gas available with and without the land closures into separate runs of an adapted version of the NEMS model, a publicly available model of the U.S. economy used by the Energy Information Administration for energy market forecasts, and by White House policy advisors, the U.S. Congress and several government agencies for the analysis of energy and environmental policy, according to the study's draft report.

"The model is the most robust model of the U.S. economy for energy forecasting, producing a general equilibrium solution for energy supply and demand in the U.S. energy markets on an annual basis," the report said.

By finding the difference between the economic model outputs when all land is assumed open for development, and the corresponding outputs if the previously off-limits land remains closed, the team could calculate the direct impact of continued land closures and hence derive data such as the projected loss in gross domestic product.

The study team obtained its estimates for recoverable oil and gas in potentially closed lands using U.S. Minerals Management Service resource assessments for offshore oil and gas resources, and primarily using U.S. Geological Survey data for onshore resources. However, the Gas Technology Institute increased the MMS offshore estimates, to reflect the use of new development technologies in the offshore and to reflect a tendency for reserves estimates to increase as oil and gas provinces mature. And in Alaska the team included USGS estimates for oil and gas resources in the Arctic National Wildlife Refuge within its resource totals for lands subject to closure.

Two resource estimates

The baseline technically recoverable oil and gas resource estimates used in the model for all U.S. federal land, whether open or closed, came from the Energy Information Administration and amounted to 186 billion barrels of oil and 1,748 trillion cubic feet of natural gas. But, by considering the potential impact of new technologies and anticipated shale gas development, the Gas Technology

see **MORATORIA** *page 6*

● FINANCE & ECONOMY

Jury still out on EnCana split

Analysts struggle to put initial financial reports in context; companies say they are positioned to achieve output growth goals

By GARY PARK
For Petroleum News

Caught in the credit squeeze of late 2008 when it needed an estimated US$5 billion in debt to break itself into separate natural gas and oil sands units, the big Canadian independent EnCana put breakup plans on hold because funds were not available at reasonable interest rates.

But the re-creation of EnCana and the creation of Cenovus Energy formally moved forward on Dec. 1 and now the new entities have delivered their first report cards, covering the final quarter of 2009.

Yet the impact of the strategic reorganization, designed to give the market a fairer chance to assign value, is far from clear.

In the view of Lanny Pendill, an analyst at Edward Jones, "it was a pretty messy quarter and hard to draw comparisons."

Knowing that the split would create difficult accounting and several one-time items that would make a straight comparison difficult, to arrive at bottom line numbers EnCana and Cenovus developed pro-forma numbers, which were based on the assumption that the split had occurred at the start of 2008 — thus comparing apples with apples on both an annual and final-quarter basis.

However, analysts are still wrestling with the comparisons and offered widely divergent estimates of the results as they tried to get a better fix on how the two companies would perform as separate businesses.

Andrew Potter, an analyst with UBS Securities, wrote that the "considerable variance" had generated a "tremendous noise" over the corporate restructuring.

Company has rosier view

The company leaders had a much rosier view.

EnCana Chief Executive Officer Randy Eresman said the transformation into "two highly focused energy producers" had positioned EnCana to "achieve even greater success through significant, low-cost organic natural gas production growth for many years ahead."

Cenovus Chief Executive Officer Brian Ferguson said his company was being launched "from a position of strength — a vast resource base, a solid financial foundation and a track record of superior operational performance."

On the pro-forma basis (with both companies reporting in U.S. dollars), EnCana reported final-quarter operating earnings of $373 million, down 32 percent from a year earlier, and cash flow of $930 million, down 38 percent. For the full year, earnings were $1.77 billion, down 32 percent, and cash flow was $5.02 billion, down 21 percent. Total production for the fourth quarter was 2.83 billion cubic feet equivalent per day, a drop of 11 percent, and for the full year 3 bcf equivalent, a dip of 4 percent.

Cenovus, which took a one-time tax cost of $400 million related to the split, reported cash flow for the fourth quarter of $225 million, compared with a loss of $174 million in the same quarter of 2008; operating earnings were $152 million, compared with a loss of $123 million. For the full year, Cenovus reported a 20 percent decline in cash flow to $2.47 billion and a 19 percent drop on operating earnings to $1.31 billion.

Oil and liquids production for the quarter was 114,500 barrels per day compared with 103,317 bpd in the fourth quarter of 2008, but natural gas dipped to 765 million cubic feet per day from 879 million.

EnCana Chief Executive Officer Randy Eresman

The 2009 total was 109,784 bpd for oil and liquids compared with 100,250 bpd and for gas, 824 million cubic feet compared with 905 million.

Basis for future comparison

Whatever the value of the comparisons, the fourth quarter numbers provide the basis for future comparison.

Pendill said the "key metrics show that EnCana is definitely off to a good start."

> *Cenovus Chief Executive Officer Brian Ferguson said his company was being launched "from a position of strength — a vast resource base, a solid financial foundation and a track record of superior operational performance."*

Mark Friesen, with Versant Partners, said the comments EnCana made about the North American gas market "give me pause."

In response to market weakness, EnCana shut-in 300 million cubic feet per day of gas last year, but expects most of that will be back onstream by the end of this quarter as it targets average output of 3 bcf per day in 2010 — a crucial element of its goal of 10 percent average annual growth over the long term.

Eresman said the biggest issue that impacted the gas industry last year was the "lowest average commodity price in seven years," adding EnCana believes the abundance of new North American supplies from unconventional sources such as shale gas "likely herald a future of low and less volatile gas prices" that are "here to stay."

He said the rapid evolution of horizontal drilling and well fracturing means "supply can meet demand at a much lower price than historically."

Keeping ahead of price curve

To keep ahead of the price curve, EnCana has hedged about 2 bcf per day, or two-thirds of its projected 2010 production at a Nymex price of $6.04 per thousand

see SPLIT page 7

● EXPLORATION & PRODUCTION

ConocoPhillips Alaska's Jim Bowles dies

Company president leaves legacy of community involvement; Bowles, Alan Gage of Conoco killed in avalanche while snowmachining

PETROLEUM NEWS

Jim Bowles, 57, president of ConocoPhillips Alaska, died Feb. 13 in an avalanche. Also killed was Alan Gage, 40, a member of the company's capital projects organization.

The men were part of a group of about a dozen who were snowmachining on the Kenai Peninsula.

Bowles was retired — after a career with ConocoPhillips' predecessor Phillips Petroleum Co. — when he was named president of ConocoPhillips Alaska in 2004.

He told the Anchorage Daily News in an interview after he arrived in Anchorage that the opportunity to hunt and fish in Alaska were "draws to me" in coming out of retirement to accept the Alaska job. Bowles replaced Kevin Meyers, who left Alaska to head up ConocoPhillips' operations in Russia and the Caspian Sea region.

Bowles had retired from Phillips in 2002 after 28 years. In his Phillips' career he held drilling and production assignments, was vice president of the company's gas gathering and processing subsidiary, deputy managing director of the Norway division and president of Phillips' Americas division, which included the company's Alaska operations prior to Phillips' acquisition of ARCO Alaska's assets.

State's largest producer

ConocoPhillips Alaska is the state's largest oil and gas producer. The company operates the Kuparuk River and Alpine fields on the North Slope, is a major owner at Prudhoe Bay and has interests from Point Thomson in the east to the National Petroleum Reserve-Alaska in the west. Conoco also has interests in Cook Inlet, operating the Beluga River field, the North Cook Inlet field and the Nikiski liquefied natural gas plant.

Bowles was involved in negotiations with former Gov. Frank Murkowski over a gas pipeline. After the Alaska Legislature failed to approve state partnership in a gas pipeline, and Gov. Sarah Palin won approval for the Alaska Gasline Inducement Act, ConocoPhillips joined BP in establishing the Denali gas pipeline project, a competitor with the AGIA-licensed TransCanada-ExxonMobil gas pipeline proposal.


JUDY PATRICK

ConocoPhillips Alaska President Jim Bowles

ConocoPhillips also won a renewal of its export license for the Nikiski LNG plant under Bowles in a deal that guaranteed more gas drilling in Cook Inlet in exchange for the state's support of the export license.

Bowles was caught up in the corruption trials of Alaska legislators when the FBI taped a phone conversation between Bowles and Bill Allen, then president of VECO Corp. Allen was convicted of bribing legislators.

As the Anchorage Daily News reported the incident in a story on Bowles' years in Alaska, "Nothing in the conversation indicated Bowles knew Allen had bribed legislators."

The Daily News also quoted a statement Bowles sent to company employees after the taped conversation came out that said VECO had "cast a pall on the image of our company and our industry in Alaska."

Legacy in state

Statements after Bowles' death reflect his legacy in the state.

Anchorage Mayor Dan Sullivan said: "Jim's generosity in giving back to our community set a high standard for Alaska business leaders. His legacy of investment in our community and commitment to the people of our state was an example to all of us." Sullivan said he had toured the ConocoPhillips Integrated Science Building at the University of Alaska Anchorage which, he said, "became reality under Jim's leadership."

"Jim brought so much to our state," said Gov. Sean Parnell, "his love of the great outdoors, his leadership of ConocoPhillips Alaska and his dedication to making Alaska a better place for all of us to call home."

The members of Alaska's congressional delegation all issued statements.

U.S. Rep. Don Young said Bowles "was a true Alaskan, and a great man, and he will be dearly missed."

U.S. Sen. Lisa Murkowski called Bowles "a great partner in the responsible development of Alaska's natural resources. He truly loved Alaska and spending time outdoors," she said.

"During his nearly six years as president of ConocoPhillips Alaska, Jim Bowles left a legacy of solid corporate leadership and excellent community leadership," said U.S. Sen. Mark Begich. He said that last year alone ConocoPhillips contributed $13 million to hundreds of Alaska nonprofits, from environmental causes to health care.

"Jim set the bar high for the 900 employees of his company in Alaska, volunteering his time to make the community and state better," Begich said. ●

—The Anchorage Daily News contributed to this story

continued from page 4

MORATORIA

Institute upped those estimates to 229 billion barrels and 2,034 trillion cubic feet.

The study team did separate model runs using the original EIA estimates and the increased estimates. The study's headline data, including the $2.36 trillion loss in GDP, then came from a comparison between two economic scenarios: the economics of closing land and developing amounts of oil and gas equivalent to the original EIA resource estimates, and the economics of opening of all land, using the revised, increased estimates.

Other model runs with the increased resource estimates applied to the scenarios for both closed and open lands resulted in economic impact data that simply reflected the effect of land closures, rather than also incorporating some impact from resource estimate revisions. And although the estimated impacts from comparing these model runs still appeared very large, the numbers were somewhat lower than those of the headline data, with a projected loss in GDP of $1.25 trillion and a cumulative increase of $1 trillion paid for imported crude oil and natural gas, for example. ●

Contact Alan Bailey at abailey@petroleumnews.com

● NATURAL GAS

Imperial mum on Mac gas project numbers

By GARY PARK

For Petroleum News

Partners in the Mackenzie Gas Project haven't put a price tag on the venture since their C$16.2 billion estimate three years ago — at that time a C$8.7 billion hike from when they filed an application with regulators in October 2004.

Since then, in the absence of anything firm from lead participant Imperial Oil, no guides have been provided, other than a September 2007 statement by ExxonMobil Chief Executive Officer Rex Tillerson in a conference call who said updated costs could result in a higher price tag for the project.

"There is no question the cost has gone up, but we don't have a number that I have high confidence in," he said.

But don't hold your breath in hopes of some new estimates from Imperial.

It has sharply rebuffed demands by Alternatives North, a social justice coalition in the Northwest Territories, to provide new indications of the economic feasibility of the Arctic gas venture.

The Yellowknife-based organization has asked Canada's National Energy Board to force the proponents' hand, allowing everyone to decide whether the MGP makes sense based on the outlook for natural gas markets and the economic feasibility of the pipeline.

Group says public at risk

A spokesman for Alternatives North said Imperial stands to make money from the MGP, "but the public is also at risk from this project in terms of the environmental and socioeconomic effects."

"We know that the proponents are also attempting to get subsidies from the (Canadian) government, so that's why there is a need for an independent regulator to look at all of these factors," he said.

The spokesman said the MGP partners are required to provide up-to-date information about their proposal and the NEB must consider the gas markets in deciding whether to approve the project.

Proponents not worried about gas prices, impact of shale

Imperial spokesman Pius Rolheiser was reported by the Canadian Broadcasting Corp. as questioning whether Alternatives North "has provided any valid reason for the NEB to require us to file an updated market demand report" when the MGP's gas price forecasts are confidential.

He said the proponents are not worried about changes in the gas market since 2007, particularly the impact of shale gas in North America and the prospect of an Arctic gas pipeline from Alaska.

Regardless of that competition, there would still be room in the market for the Mackenzie Valley pipeline, Rolheiser said.

He said decisions on whether the project is economically feasible should ultimately be made by the partners. ●

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SPLIT

cubic feet, comfortably ahead of Versant's forecast US$5.25 per bcf, which the firm is rethinking. It has also hedged 935 million cubic feet per day of 2011 output at $6.52 per mcf and 870 million cubic feet per day of 2012 volumes at $6.47 per mcf.

There was nothing in Eresman's comments or in the current uncertain prices to indicate that gas has any chance in the foreseeable future of regaining its mid-2008 level of $13 per million British thermal units.

Even Eresman conceded that had the current price outlook existed in 2007 when EnCana approved construction of its Deep Panuke project offshore Nova Scotia, a sanctioning decision would have been more challenging.

He said the board of directors decided in 2007 that Deep Panuke would only be economic at gas prices of $6.50 per mcf.

A delay in delivering a production field center from Abu Dhabi could stall the startup of Deep Panuke by six months to the second quarter of 2011, while capital costs have edged up to C$800 million from C$760 million.

The most optimistic view Eresman could offer was that the "economics are pretty good going forward and that's really the only way we can think about it."

Cost efficiencies a priority

A greater priority for the company is to continue working on cost efficiencies, which resulted last year in a lowering of average well costs by 25 percent to $10 million-$12 million in British Columbia's Horn River shale play and by 40 percent for completion and tie-in costs to $9 million per well in the Haynesville play of Texas and Louisiana.

EnCana was also able to report a sharp cut in its finding and development costs for 2009 to $1.62 per mcf equivalent, down 30 cents per mcf equivalent from the 2007-09 average.

Although there is much still to be learned about the Haynesville play, Eresman said it "has the potential to become" the company's leading resource performer as the company aims to more than double current production to 400 million cubic feet per day at the end of 2010.

Horn River is also expected to make rapid gains from 20 million cubic feet per day currently to average 50 million this year and end 2011 at 200 million.

Mike Graham, president of EnCana's Canadian division, said a well pad can now have up to 20 long horizontal wells and the number of well fractures per well is increasing.

But two other British Columbia plays posted sharp declines in the fourth quarter — Greater Sierra averaged 178 million cubic feet per day, off 22 percent from a year earlier, and Cutbank Ridge was 254 million cubic feet per day, down 18 percent.

Cenovus enthusiastic

Cenovus painted an enthusiastic picture of its near-term outlook, especially for its kingpin Foster Creek and Christina Lake thermal-recovery projects, which are expected to yield 10-15 percent annual production growth over the next five years.

The company said it hopes to accelerate the startup of its fourth phase at Christina Lake, adding 40,000 bpd by mid-2013, six months earlier than scheduled.

Foster Creek is currently delivering 52,000 bpd and destined for 210,000 bpd within seven years and Christina Lake is on track for growth from 7,500 bpd to 218,000 bpd.

In addition, Cenovus said a regulatory application should be filed by this summer for its Narrows Lake, expected to be developed in two or three stages, each of 40,000 bpd, while its Borealis steam-injection project is before regulators and is expected to come onstream at 35,000 bpd.

Total proved reserves were estimated at 1.4 billion barrels of oil equivalent entering 2010, up 8 percent from a year earlier, with bitumen reserves increasing 24 percent to 866 million barrels, but natural gas — a vital fuel source for the oil sands operations — slipped 24 percent to 1.53 tcf.

Ferguson said there was no need for Cenovus to acquire more oil sands assets to achieve the growth targets, noting the company is "literally only scratching the surface" of Foster Creek and Christina Lake. ●

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● FINANCE & ECONOMY

Foreign rivals bid for oil sands

By GARY PARK

For Petroleum News

BP and India's Reliance Industries seem locked in a bidding war for control of privately held Value Creation, which controls extensive oil sands leases and a proposed upgrader to turn bitumen into synthetic crude.

Reliance opened the round Feb. 5 with a US$2 billion offer to take over Value, then BP surfaced — according to a British newspaper report — with a US$1.2 billion offer for a 50-50 joint venture with Value.

In a financial squeeze for the past year, Value has 186,000 acres of oil sands leases in northern Alberta, where it plans a 10,000 barrel-per-day demonstration project, followed by a 40,000 bpd commercial operation.

The Terre de Grace development was originally expected to deliver its first oil by early 2009, but the economic downturn has pushed that target date out to 2011.

Value is also the outright owner of BA Energy, which was forced in late 2008 to stop work on its Edmonton-area Heartland upgrader, designed to process 163,200 bpd of bitumen, while it hunted for partners in help finance the project.

An estimated C$500 million had been spent on the planned C$2.9 billion facility before inflationary pressures brought progress to a halt.

First Indian oil sands foray

A Reliance spokesman said his company has just identified what it views as a "new area of interest," marking the first foray into the oil sands by an Indian company.

BP, which is in a joint oil sands production venture with Husky Energy to develop the 200,000 bpd Sunrise project has declined to confirm its interest in Value.

But observers say any further moves by BP into the oil sands would likely anger environmentalists and some BP shareholders who strongly oppose the oil sands business.

Fair Pensions, an activist British investor group, has tabled a resolution for BP's annual meeting in April questioning the financial rationale for the oil giant's role in oil sands development and the "unthinkable" environmental consequences.

However, BP met earlier in February with several institutional investors to make its case for a presence in the oil sands, claiming the new generation of steam-extraction methods is far less destructive than open-pit mining of the bitumen resource.

Value has refused to say what, if any negotiations are taking place. ●

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● FINANCE & ECONOMY

Precision Drilling to leave income trust fold

By GARY PARK

For Petroleum News

Calgary-based Precision Drilling Trust, one of North America's largest land drilling contractors, is joining the exodus from the income trust sector to the ranks of traditional corporations.

It is one of the largest entities to make the switch in response to the Canadian government's decision in 2006 to start taxing trusts like corporations, starting in 2011.

Precision said the move will remove limitations on non-Canadian ownership, expand its investor base and give it greater freedom to make acquisitions.

"The clarity and administrative simplification of a corporate structure is expected to reduce administrative costs and make capital markets more accessible," said Chief Financial Officer Doug Strong.

But Precision did not indicate whether it intends to pay dividends to shareholders, which are similar to the monthly cash distributions by trusts that Precision halted a year ago pending a sustained recovery in cash flow.

High-performance rigs

Precision said indications of a recovery in land drilling markets have prompted it to enter negotiations with E&P companies about building new high-performance rigs.

Chief Executive Officer Kevin Neveu said deals are in sight for new Tier 1 rigs, likely starting in Canada, to drill shale and other new unconventional oil and natural gas plays.

Precision is looking for contract terms of two to four years for rigs that would cost $18 million to $20 million each to build.

Neveu said all of Precision's Tier 1 rigs are utilized, while Tier 2 rigs are 60 percent utilized for horizontal wells in shale plays such as the Barnett in north Texas, the Haynesville in east Texas and northwest Louisiana and the Marcellus in Pennsylvania.

He said converting Tier 2 rigs could cost up to $4 million per rig, a course Precision intends to follow if the market stays where it is today.

Rig count ahead of forecast

Neveu said the company is currently running 130 to 140 rigs in Canada, ahead of its December forecast of 110, and 70 rigs at work in the United States, eight more than forecast two months ago.

Precision is looking for contract terms of two to four years for rigs that would cost $18 million to $20 million each to build.

He said Precision underestimated the desire by E&P companies to get back to the drill bit, but he cautioned that the recovery is "fragile and fraught with risk" because of the potential for a "dramatic" reversal in gas storage levels, commodity prices and shifts in the global economy.

Alberta royalty structure

Neveu said that if the Alberta government does make effective changes to its royalty structure and stimulates gas drilling "we could see some very good leverage in our completions production business, not to mention our drilling operations."

Revenue in the fourth quarter of 2009 fell 15 percent to C$286 million, net earnings dropped 47 percent to C$161.7 million and cash flow dipped 8 percent to $123.7 million.

During the quarter, Precision decommissioned 38 drilling rigs and 30 well servicing rigs. ●

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● FINANCE & ECONOMY

Oil sands underpin Alberta's finances

Conventional oil, gas edged out by sands, with production in both forecast to decline as production, revenues from oil sands rise

By GARY PARK
For Petroleum News

The reasons for the Alberta government's refusal to cave in to demands and slow the pace of oil sands development are now coming into sharper focus.

The province's budget for the fiscal year 2010-11 estimates that oil sands royalties are edging out the traditional keystone revenue sources of conventional oil and natural gas.

Stronger oil prices, higher production and the maturing of the sector show that synthetic crude and bitumen revenues will recover in the upcoming budget year to C$3.2 billion from C$1.9 billion in 2009-10.

Conventional crude will yield C$2.1 billion, up C$300 million from the fiscal year that ends March 31, and gas royalties are forecast to reach C$1.9 billion in the upcoming fiscal year compared with C$1.7 billion in 2009-10, but a far cry from C$5.8 billion in 2008-09.

Government land auctions are expected to generate C$630 million, down about one-quarter from the last budget year.

Overall, nonrenewable resource revenue is projected at C$6 billion in 2009-10, about half the previous fiscal year, and is expected to grow by C$1.3 billion in the new budget year.

Natural gas prices are forecast to average C$3.40 per gigajoule at the AECO trading hub in the 2009-10 budget and C$4.25 in 2010-11, while West Texas Intermediate oil prices are set at US$78.75 per barrel, up US$8.80 from 2009-10, and bitumen prices are pegged at C$56.38 per barrel in 2010-11, an increase of C$7.02.

For 2010-11, the government anticipates raw bitumen production of 1.7 million barrels per day, 200,000 bpd more than the previous year, rising to 1.9 million bpd in 2011-12 and 2.1 million bpd in 2012-13, a more optimistic outlook than the Canadian Association of Petroleum Producers, which does not expect 2 million bpd before 2015.

Conventional crude is forecast to continue its decline to 419,000 bpd in 2012-13 from 454,000 bpd in 2009-10 and gas production is on a similar path, dropping to 4.3 trillion cubic feet in 2010-11, a loss of 200 billion cubic feet in a year, then declining another notch to 3.9 tcf in 2012-13.

Importance of oil sands

Against that background, the importance of the oil sands to Alberta's economic well-being is evident in the financial year that is just winding down, with royalties from the bitumen deposits expected to edge ahead of conventional crude by C$35 million as the first step toward 2012-13 when they will make up 53 percent of the province's royalty stream, or about 25 percent of the government's total revenues.

Aside from the declining role of conventional oil and gas, the oil sands royalty structure is just starting to yield results.

Under the Alberta structure, the government collects only 1 percent of profits until the capital costs of projects are paid off, when royalties rise to 25 percent. That threshold is being crossed as a number of projects reach maturity by covering the multibillion-dollar upfront costs of their development.

Gary Leach, executive director of the Small Explorers and Producers Association of Canada, said it is now time to pass the crown to the "massive resource endowment in the oil sands."


COURTESY SUNCOR

Oil sand is a mixture of bitumen (a thick, stick form of crude oil,) sand, water and clay.

He said the arrival of the oil sands as the leading resource contributor to Alberta coffers is likely permanent and also illustrates why it is important to improve the investment climate for the conventional sectors.

No details on royalty plan

Finance Minister Ted Morton, during a conference call to discuss the budget, indicated that a change maybe in store when details of the government's review of its competitive standing in North America is released in early March.

However, he would not confirm what most industry leaders and analysts expect — that royalties will be reduced.

"The purpose of the competitiveness report, which will include the royalty review, is to stimulate and increase investment in our oil and gas sector.

"In other words, it's to grow the (revenue) pie. If the pie grows and we take a smaller slice, our revenue situation still should be good. And I'm confident that will be the case."

Whatever emerges from the review "obviously could swing things" by bringing in new investment that in turn would result in greater personal and corporate income tax revenues, he said.

Leach said the collapse of gas royalties is the major reason the government reopened royalty discussions with the industry.

He said Alberta is not so far behind that it can't catch up to British Columbia and the United States by deploying its large resource endowment.

Under the Alberta structure, the government collects only 1 percent of profits until the capital costs of projects are paid off, when royalties rise to 25 percent. That threshold is being crossed as a number of projects reach maturity by covering the multibillion-dollar upfront costs of their development.

Evolution to shale

Greg Stringham, vice president of the Canadian Association of Petroleum Producers, agreed the gas evolution to shale deposits over the past year has shown how important it is to Alberta's revenue and employment and the need to be more competitive in the marketplace.

Shale gas discoveries have drastically changed the gas supply dynamic and that has an impact on Alberta's ability to attract investment, he said.

In the meantime, Alberta faces an overall budget shortfall of C$3.6 billion in 2009-10, then C$4.7 billion and C$1.1 billion in the next two years before regaining a surplus of C$505 million in 2012-13.

To avoid breaching its own anti-deficit legislation, the government will draw on a sustainability fund, which will shrink to C$2.8 billion at the end of 2012-13 from a peak C$16.8 billion in 2008-09. ●

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● SAFETY & ENVIRONMENT

Continuing challenge to Arctic OCS drilling

Speakers pitch in on the debate about the appropriate level of environmental assurance for offshore oil and gas leasing and drilling

By ALAN BAILEY
Petroleum News

To drill or not to drill is the core question in the current controversy surrounding oil exploration in the outer continental shelf off northern Alaska. Shell is chomping at the bit, preparing to drill in its federal leases in the Arctic Ocean's Beaufort and Chukchi seas during this year's summer open water season, while ConocoPhillips is laying plans to drill in the Chukchi Sea in 2012. In the Chukchi Sea, both companies are targeting prospects in federal leases they purchased in a U.S. Minerals Management Service 2008 lease sale that has been challenged in the courts.

The federal government, in this case MMS, has jurisdiction over the outer continental shelf's submerged lands, subsoil and seabed which lie between state waters — 3 nautical miles from shore — and international waters.


JUDY PATRICK

John Goll, regional director for the U.S. Minerals Management Service, emphasized his agency's obligation under the Outer Continental Shelf Lands Act to realize the value of U.S. offshore resources while also maintaining high standards of environmental protection.

At stake are potentially huge offshore oil and gas resources that could knock a significant dent in U.S. oil imports, boost natural gas supplies for a future North Slope gas pipeline and bring continuing financial wellbeing for many Alaskans.

But while the oil companies stress the steps they are taking to understand and protect the environment, and while regulating agencies explain the rigor of their permitting requirements, a vigorous debate continues regarding whether there has been adequate consideration of potential environmental damage as a consequence of industrial activities in the outer continental shelf, or OCS, off northern Alaska.

And at the Alaska Forum for the Environment in Anchorage on Feb. 8 people from government agencies, oil companies, North Slope communities and an environmental organization presented their perspectives on Alaska OCS oil exploration opportunities and risks.

Responsible development

John Goll, regional director for the U.S. Minerals Management Service, emphasized his agency's obligation under the Outer Continental Shelf Lands Act to realize the value of U.S. offshore resources while also maintaining high standards of environmental protection.

Goll characterized the MMS procedures for permitting offshore exploration and development as a winnowing process, starting with the big picture when planning an oil and gas lease sale schedule, and progressively narrowing the focus as companies move from broad exploration, to drilling at specific sites and then on to field development. Company plans, as they progressively home in on specific developments, have to move through a series of environmental reviews and permitting thresholds, with repeated opportunities for public comment on what is proposed.


JUDY PATRICK

BP's Northstar oil field sits partly in federal waters off Alaska in the Beaufort Sea. It is the only field in Alaska's outer continental shelf that is currently in production.

"During this process we do overview what is going on from the industry standpoint and inspect their activities," Goll said.

And, in addition to putting company plans under an increasingly powerful microscope, as those plans take shape, MMS has regulations designed to prevent offshore accidents and pollution, he said. Those regulations spell out, for example, the need to survey for drilling hazards before any drilling is commenced and they require an agency review of well designs, platform designs and other aspects of oil company operations.

Goll also commented that MMS sponsors a great deal of research on the offshore environment and on offshore technologies. The agency has funded more than $300 million of Alaska environmental research since 1970, with $43 million allocated to research that is in progress or planned to begin in 2010 in the Chukchi Sea. The agency has also been funding research into offshore oil spill prevention and research, Goll said.

"We at MMS do and have had a robust oil spill research program with regard to both looking at preventing spills from occurring and also spill response," Goll said.

Importance of science

Michael Macrander, Shell's science lead in Alaska, picked up on the benefits of scientific research in the offshore.

"To me one of the benefits of offshore oil and gas activity is the investment in science that it brings," Macrander said. "… Historically there has been a strong relationship between oil and gas interest in the offshore and the number of dollars that are spent on science."

Oil companies have joined the effort spearheaded by MMS to understand the offshore ecosystem. For example in 2009 MMS, Shell, ConocoPhillips and other organizations funded the deployment of more than 40 scientists to do research on the Chukchi Sea, Macrander said.

"That was the beginning of a program that we anticipate certainly getting larger and larger, as we move forward," he said.

Scientists have gained a new mechanistic understanding of how the Chukchi Sea works, in terms of the interaction of ocean currents and subsea topography, and the resulting ice patterns and impacts on marine organisms, Macrander said. And in 2007 an industry-funded overflight program first detected major coastal haulouts of walrus, when ice departed the Chukchi Sea, he said.

Shell and ConocoPhillips have deployed more than 40 seafloor acoustic recorders in the Chukchi Sea, recording background sounds and animal calls, Macrander said.

Focus on Chukchi

Bruce St. Pierre, senior environmental coordinator for ConocoPhillips, said that his company has shifted its exploration focus from the National Petroleum Reserve-Alaska to the Chukchi Sea, following some disappointment in its search for new, large oil reserves in NPR-A.

"With the purchase of our leases out in the Chukchi we really want to spend some effort and some energy trying to get out there and drill a well in 2012," St. Pierre said.

So far ConocoPhillips has conducted some seismic surveys and environmental studies in the Chukchi Sea. In 2008 the company did some site clearance work and conducted comprehensive research, establishing baseline environmental data at its Devil's Paw prospect, with that work program continuing and including some seafloor coring in 2009, St. Pierre said.

"We're trying to find a blend between regional (environmental) studies and some local, specific studies," St. Pierre said. "When you put in exploration plans, a lot of the information that goes in there needs to key in on those areas where you want to go out and do your drilling."

And in its offshore operations, the company has taken steps to avoid conflicts with subsistence hunting and has worked with Shell to minimize the number of vessels working concurrently on industrial activities, St. Pierre said.

"We want to be able to do it right, work with the local

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CHALLENGE

communities, work with the science portion of it, and get out there and see if we can find a resource that all of us could benefit from," St. Pierre said.

NSB wants balance

Tom Lohman, an environmental specialist with the North Slope Borough, said that the borough is not opposed to oil and gas development, but is concerned about achieving a balance between environmental protection and the desire for jobs and revenues. The borough depends on oil and gas revenues for the funding of basic borough services, including schools, health programs, search and rescue, and police, Lohman said.

But, although the borough has on the whole enjoyed good relations with the oil industry, its relationships with some government agencies have been less harmonious, Lohman said.

"Our concerns over the years have been in that balancing act between going forward with leasing, going forward with operations and going forward with development, or taking a step back and taking a harder look at the potential impacts," Lohman said.

In particular, disagreements between the borough and agencies have revolved around what the borough considers to be a lack of sufficient environmental information to decide when to move forward on development and around what the borough feels is inadequate agency consideration of the borough's interests.

And Lohman pointed out what he sees as a flaw in the step-wise, winnowing permitting process that Goll had outlined: The commitment of huge sums of money by industry into an exploration and development program may make it difficult to face critical environmental issues once companies are some way down the exploration and development road.

"Our sense has been that with each one of those successive steps, important decisions, the real hard look that we'd like to see, get put off to a point where hundreds of millions of dollars (have been) invested and decisions to maybe slow things down become more difficult," Lohman said.

Necessary environmental information should be assembled before making decisions on expensive exploration and development, he said.

Out of the loop

And Lohman slammed changes made to the Alaska coastal management program in 2003, saying that the new state program had left the borough out of the coastal management loop.

"We have no mechanism to formally be at the table and influence what goes on in the OCS," Lohman said. "We'd like to have that back."

People should not view this borough position as anti-development: Projects went forward prior to 2003 and would continue to move forward if the borough regains its influence over what goes on, Lohman said.

Local people on the North Slope know what's best for the North Slope communities — permitting delays have cost revenue and jobs, but some delays could be avoided if local people had an opportunity to help shape projects, Lohman said.

On the other hand, agencies need to realize that, in a culture in part dependent on subsistence hunting, many people in North Slope communities have to hunt to put food on the table, as well as hold a full-time job — layering on to that the time required to participate in a multiplicity of public processes meetings for oil and gas development, as well as meetings associated with local government, becomes impossible.

Bruce St. Pierre, senior environmental coordinator for ConocoPhillips, said that his company has shifted its exploration focus from the National Petroleum Reserve-Alaska to the Chukchi Sea, following some disappointment in its search for new, large oil reserves in NPR-A.

"Something's got to change. … The system is broken. … We have great respect for the oil companies and the agencies … but we've got to find a better way of working more efficiently," Lohman said.

ASRC concurs

Teresa Imm, director of resource development for Arctic Slope Regional Corp., the Alaska Native regional corporation for the North Slope and a major provider of services to the oil industry, concurred with the North Slope Borough's position.

"There are a lot of issues that the communities in our region have to face with respect to resource development," Imm said, "and trying to get the information out there in a manner that people can tangibly use and understand, to be able to make intelligent and informed decisions is really, really important."

Development is not a foregone conclusion and communities do have a role to play in development decisions, she said.

ASRC is concerned about the long-term sustainability of the North Slope communities, with part of that concern centered on the future of the infrastructure that supports those communities, as oil production declines. At the same time companies are having to start to search offshore for significant new oil and gas resources.

"How can development in the Arctic occur in a safe, environmentally friendly manner … that will take into account our shareholders, their lifestyles and incorporate traditional knowledge?" Imm asked, adding that ASRC has been taking steps to better understand what offshore development might look like, what the implications are and what would be the safety measures.

"Without knowledge we can't help be part of shaping what that future looks like," Imm said.

OCS development appropriate?

Whit Sheard, Alaska program director for Pacific Environment, questioned whether offshore oil and gas development is appropriate in Arctic waters or the Bering Sea, given what he characterized as unanswered questions about environmental risks coupled with a shortage of information about the offshore Arctic environment.

Sheard echoed Lohman's concerns about the phased OCS permitting process, saying there was a series of critical environmental questions that have remained unanswered through the initial, broad phases of Alaska OCS oil and gas permitting.

"During the broader planning process … there was a series of fundamental questions that were either ignored or completely went unanswered, and as this process moved along we were forced to go back to the courts to say 'here's some fundamental issues that haven't been addressed,'" Sheard said. "And we've been victorious on several of those cases. Several are still pending."

see CHALLENGE page 13

NATURAL GAS

Aurora wants Nicolai Creek gas storage

Proposing injection into upper Carya sands of Tyonek formation, nearing approval of Nicolai Creek expansion and West PA formation

By ERIC LIDJI
For Petroleum News

Aurora Gas hopes to increase the amount of hydrocarbons moving through the Nicolai Creek unit, both the amount coming out of the field and also the amount going back in.

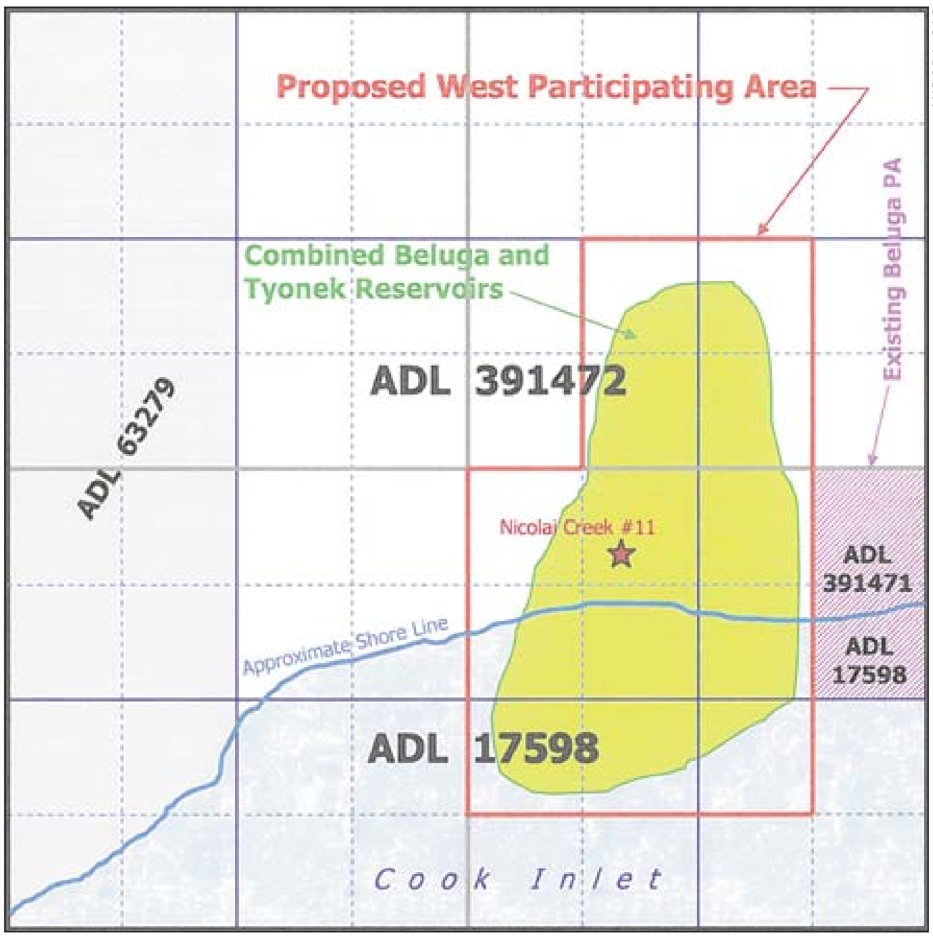
The Anchorage-based independent, which operates five natural gas fields on the west side of Cook Inlet, is asking state officials to expand the Nicolai Creek unit and is also asking for permission to start natural gas storage operations at a reservoir in the unit.

Aurora wants to add 75 acres to Nicolai Creek, which sits along the shoreline 50 miles west of Anchorage and 12 miles southwest of the village of Tyonek. The expansion would bring the unit to 486 acres by adding segments of ADL 391472 and ADL 17598.

Aurora requested the expansion late last year. The Division of Oil and Gas deemed the application complete on Feb. 10 and is accepting comments through March 22.

The expansion acreage would form a new West participating area. There are currently three participating areas at Nicolai Creek: South (A), North (B) and Beluga. The West PA would, appropriately, be contiguous with the western boundary of the Beluga PA.

The West PA would include the Nicolai Creek No. 11 well that Aurora brought online in November 2009. The well is currently producing only from Tyonek Carya sands in the region, but is also capable of producing from Beluga Tsuga sands, Aurora said.



The proposed West participating area sits along the western boundary of the existing Beluga participating area and would include the Nicolai Creek No. 11 well.

The company is simultaneously asking the Alaska Oil and Gas Conservation Commission for permission to comingle natural gas from different sands within the same wellbore.

Although NCU 11 has been part of previous plans of development, Aurora said plans for the West PA would be in the 37th Nicolai Creek unit POD due by Oct. 10, 2010.

Storage in the Carya sands

The storage application, made to AOGCC, would allow Aurora to pump modest amounts of natural gas into a now nearly depleted reservoir at the Nicolai Creek unit, increasing the amount of natural gas available when Southcentral demand spikes.

Natural gas storage involves converting a depleted reservoir into an underground holding tank. Storage improves deliverability, or the amount of natural gas available at any given instant, allowing producers to develop fields at a more even keel throughout the year.

Aurora pitched the idea of third-party storage last April, seeing a business opportunity in repeated claims that Southcentral lacks sufficient storage opportunities for natural gas.

Currently, Marathon Oil operates private storage at the Kenai gas field, and Chevron operates private storage at Swanson River and Pretty Creek, but third-party storage isn't available. In addition to Aurora, Cook Inlet Natural Gas Storage LLC, owned by a subsidiary of TransCanada Corp., is pursuing third-party storage in the Cook Inlet.

Chevron, through its subsidiary Union Oil Company of California, is also currently asking AOGCC for permission to store natural gas at the Ivan River unit using the IRU 44-36 well.

Next step for an old field

Nicolai Creek is a legacy field brought back to life in the last decade.

Texaco formed the unit and participating areas A and B in 1968, drilling the Nicolai Creek State No. 1-A well, but did not build the infrastructure required for production.

The company tested a Nicolai Creek No. 2 well in PA A for nine months in 1968 and 1969, and finally brought the field online with the Nicolai Creek No. 3 well in PA B.

Nicolai Creek No. 3 produced from 1969 to 1977. Unit production peaked in 1968 with 387 million cubic feet, and declined annually except for bumps in 1975 and 1976.

The state contracted out discontiguous acreage from PA A and PA B in 1973.

In 1988, Unocal and Marathon took over Nicolai Creek, each taking a 50 percent share with Unocal serving as operator. Those companies, though, never brought the unit back into production and eventually transferred complete ownership to Aurora in late 2000.

Aurora brought the unit back online in 2001, but production levels have been inconsistent over the past decade, tripling one year only to fall 80 percent the next and then rise after that. In 2004, production peaked at 983 million cubic feet. In 2008, the unit produced 250 million cubic feet.

The field produces from sands in both the Beluga and Tyonek formations, which allows Aurora to continue producing from one pool while it begins storage in another.

Using decades-old well

If approved, the Nicolai Creek Gas Storage Facility would use the NCU 2 well.

Texaco drilled NCU 2 in 1966 but shut-in the well in December 1969. Unocal suspended the well in 1991. Aurora took over the unit in June 2000, re-entered the well

see GAS STORAGE page 13

● GOVERNMENT

B.C.-Montana reach 'peace in our time'

By GARY PARK

For Petroleum News

In the ancient Olympic Games it was the Greek tradition to lay down arms for the duration of the event.

Three days before the Vancouver Winter Olympics got under way, the British Columbia government offered its own olive branch to Montana.

In a speech to open a new session of the legislature, B.C. promised to impose a ban on oil and gas development, coalbed gas extraction and mining in the Flathead River basin that extends over the international boundary into the United States.

It was the clearest gesture yet of a peaceful end to an often contentious debate between B.C. and Montana that edged close to a showdown two years ago.

But B.C. Premier Gordon Campbell and Montana Gov. Brian Schweitzer have established a strong personal relationship in recent times that a B.C. government spokesman said has led to "far broader issues of cooperation."

The legislative speech said a "new partnership with Montana will sustain the environmental values in the Flathead River basin in a manner consistent with current forestry, recreation, guide outfitting and trapping uses."

It said B.C. and Montana are already working on a formal agreement to "identify permissible land uses and establish new collaborative approaches to transboundary issues."

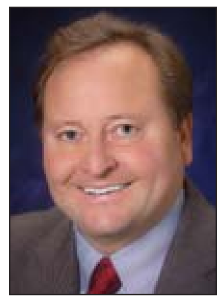
Promise for federal lands

Montana's Democratic U.S. Senators, Max Baucus and Jon Tester, wasted no time pledging to take the same action on Montana's federal lands.

Baucus said "we need to show the Canadians we're working in good faith on our side of the border, as well."

"Canadians and Americans — especially Montanans — are forever linked by the

GORDON CAMPBELL



BRIAN SCHWEITZER

beautiful Flathead Valley. We must step up and protect this gem — and our outdoor heritage — for future generations, no matter which side of the border we live on," he said.

Tester said Canada has "stepped up to be a good neighbor and now we'll do our part to safeguard this area."

Baucus said a few existing, though dormant, mineral leases in Montana will be swapped or bought out.

Pending actual legislation in B.C., it is assumed the province will move in a similar direction, with Max Resource, which has been exploring for gold in the region, insisting it will seek "adequate compensation."

John Bergenske, executive director of the Canadian conservation group Wildsight, applauded the B.C. government, while cautioning that any future government could overturn the bans.

"But in reality this is a done deal," he said. "I don't have any reason to believe that this is not a permanent solution."

The move to a peaceful solution gathered pace when BP Canada Energy and Cline Mining advanced their plans for coalbed methane and coal development, respectively, although BP backed away from exploring its 80,000 acres and possibly launching a C$3 billion capital investment as the cross-border controversy started to boil over. ●

Contact Gary Park through publisher@petroleumnews.com

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GAS STORAGE

in July 2002 and began producing 3.5 million cubic feet per day in December 2003.

Deliverability is now down significantly, with production at 200,000 cubic feet per day in December 2009, according to Aurora. According to February 2009 estimates, the company expects final recovery from the well to be around 947 million cubic feet of gas.

NCU 2 is in the South PA. Aurora wants to store up to 1 billion cubic feet of natural gas in three upper Carya sands of the Tyonek formation (known as Carya 2-1.1, Carya 2-1.2 and Carya 2-2.2) in the Nicolai Creek Undefined Gas Pool present under that PA.

Those sands range in depth from about 2,100 feet to 2,900 feet below the surface.

Aurora told the state these sands are separated from the deeper Beluga Tsuga sands by more than 150 feet of tight rocks. Aurora believes there is "full zonal isolation" in the NCU 2 well, which the company said is "sufficient" for natural gas injection and storage.

Aurora also believes the reservoir is well suited for storage because of its history of limited water production. In six years, the well produced only 25 barrels of water.

The pressure in a depleted reservoir is less than in a full one, and pumping millions of cubic feet of compressed natural gas into Nicolai Creek will increase the pressure.

Aurora said this would not create underground fractures that could theoretically allow natural gas to contaminate underground freshwater aquifers, telling regulators that the expected injection pressure is below the "fracture gradient" measured in the reservoir.

The company also said it plans to test the well for "mechanical integrity."

Supplier as yet unknown

Once the storage facility is operational, Aurora plans to produce between 10 million to 12 million cubic feet per day on average, with daily production not exceeding 20 million cubic feet.

Aurora doesn't list a supplier in its application, saying it would store excess natural gas "either owned by Aurora or purchased from another producer or utility." Despite not knowing the source of its gas, Aurora expects to store only "dry" gas, mostly methane.

While the current plan only calls for converting NCU 2 into an injection well, Aurora told the state it might drill future wells into the reservoir to increase the deliverability of the storage facility. The company previously told Petroleum News that a second phase of the project would involve drilling a horizontal well into the top three gas producing zones.

Pricing uncertainties remain

Regulation remains an uncertainty for any gas storage operation in Cook Inlet.

The Regulatory Commission of Alaska is at an impasse on the extent of its authority over third-party storage and wants lawmakers to remove ambiguities in state statutes.

Aurora is mostly concerned about pricing. On numerous occasions, the company has publically advocated for any storage to be based on market pricing, not prices set by regulators.

Aurora could get a different boost this legislative session, though.

Senate Bill 203, currently before the Senate Resources Committee, would provide tax credits for storage development costs, exempt pressure maintaining "cushion gas" from taxation and also exempt storage facilities and equipment from state property taxes. ●

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CHALLENGE

Moving forward through the permitting process while leaving open some fundamental environmental questions, forecloses the opportunity to address those questions because of the increasing level of commitment to development, he said.

The issue of possible offshore oil spills is a major concern, as is the potential impact of industrial noise, he said. And then there is the question of the impacts of climate change in the region.

Ecological chaos

"There's ecological chaos occurring," Sheard said. For example, the biological changes impacting the walrus are pushing them towards extinction and it's vital to understand that situation before adding another stressor to that environment, he said.

Sheard particularly criticized the MMS 2007-12 OCS lease sale plan that included the 2008 Chukchi Sea lease sale and which the United States Court of Appeals for the District of Columbia has vacated, pending a revised MMS environmental analysis for the Alaska OCS. MMS understated the environmental sensitivity of the Chukchi Sea and understated the potential impact of a Chukchi Sea oil spill, he said.

"The (permitting) process is absolutely broken," Sheard said. "… We need to revisit the Arctic. We need to do baseline studies. We need to talk about reasonable and rational development."

Earl Kingik, a resident of the Chukchi Sea village of Point Hope, the village at the center of challenges to Chukchi Sea offshore development, questioned what would happen to the Chukchi Sea animal life, were there to be an offshore oil spill.

"I'm a hunter. I hunt bowhead whales. I hunt walrus. I hunt seals. I hunt polar bears," Kingik said. "I hunt all species of animal in my garden … the garden that keeps my people together. Now our garden is being invaded."

As the oldest settled community on the North American continent, Point Hope has for thousands for years depended on marine animals, he said.

"The animals come to us," Kingik said. "The animals give themselves to us so we can feed our community."

The community does not have cows, sheep, goats or horses; the community cannot grow crops; the community needs the marine animals to come to it, he said. ●

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OIL COMPANY EARNINGS

Earnings from Petroleum News top companies

Earnings fourth quarter 2009 • Change from third fourth 2008
Liquids production fourth quarter 2009 • Change from fourth quarter 2008
Natural gas production fourth quarter 2009 • Change from fourth quarter 2008

Company	symbol	earnings	%	liquids	%	gas	%
ExxonMobil	XOM	$6,050	-23	2,393,000	-3	10,717	+9
BP	BP	$4,295	—	2,577,000	+5	8,568	-1
Shell	RDS-A	$1,177	-75	1,701,000	-4	9,452	-1
Chevron	CVX	$3,070	-37	1,911,000	+12	5,054	+5
Total	TOT	$3,052	—	1,404,000	-2	5,320	+4
ConocoPhillips	COP	$1,246	—	1,056,000*	+1	4,632	-5
Eni	E	$869	—	1,073,000	-1	4,668	+5
StatoilHydro	STO	$1,200	+247	1,068,000	-2	784	+3
Occidental	OXY	$938	+112	493,000	+4	944	+8
EnCana ***	ECA	$373	-32	24,000	-27	2,687	-10
Can. Natural	CNQ.TO						
Anadarko	APC	$229	-71	237,000	+17	2,076	-6
Devon	DVN	$667	—	200,500	+3	2,454	-8
Marathon	MRO	$355	—	259,000	+6	929	-2
Husky	HSE.TO	C$320	+39	291,500	-19	529	-7
Talisman	TLM	-C$111	—	203,000	-11	1,320	+7
Apache	APA	$583	—	292,515	+12	1,783	+16
Imperial	IMO	C$543	-19	240,000	-4	298	-0-
Suncor	SU.TO	C$457**	—	510,800	+110	764	+259
Nexen	NXY.TO	C$259	—	220,700	+11	265	+13
XTO	XTO	$537	+53	85,800	+9	2,367	+22
Chesapeake	CHK	-$530	—	30,400	-4	2,494	+15
Pioneer	PXD	$57	—	50,094	-2	350	-82
EOG	EOG	$462	-13	60,900	+9	1,607	-3
Swift	SFY	$15	—	15,800	-14	53	-2

**Does not include Lukoil investment*
***Comparable quarters do not include former Petro-Canada profits or production*
****EnCana results are pro forma numbers representing components of the company retained after Cenovus Energy was spun off*

Liquids production in barrels per day. Natural gas production in millions of cubic feet per day. Top companies chosen based on exploration spending and commitment to Alaska and Canada

● FINANCE & ECONOMY

EIA expects stronger spring crude market

Oil prices still fluctuating; $81 per barrel average expected in second half of 2010, $84 in 2011; forecast good for natural gas

PETROLEUM NEWS

While crude oil prices continue to fluctuate, the U.S. Energy Information Administration expects the crude oil market to strengthen this spring, with West Texas Intermediate crude oil prices averaging about $81 per barrel in the second half of the year and $84 in 2011.

In its Feb. 10 short-term energy outlook EIA noted that from Dec. 14 to Jan. 6 the WTI price increased from $69.48 per barrel to $83.12, and then fell to $72.85 on Jan. 29.

EIA's crude oil forecast is unchanged from January based on a growth in U.S. real gross domestic product of 2.3 percent this year and 2.5 percent in 2010.

The world oil-consumption-weighted real GDP is expected to grow by 2.7 percent this year and 3.6 percent in 2011.

The annual average price for regular-grade gasoline is expected to increase from $2.35 per gallon in 2009 to $2.84 in 2010 and $2.97 in 2011 "because of the rising average crude oil price forecast," EIA said, adding that pump prices may exceed $3 per gallon at times this spring and summer.

The Henry Hub spot price for natural gas is expected to average $5.37 per million Btu this year, up $1.42 per million Btu over the 2009 average of $3.95, with an increase in 2011 to $5.86. EIA said working gas inventories are expected to end the first quarter at some 1.644 trillion cubic feet, compared to the 1.734 tcf forecast in January, because weather in January was colder than normal.

Oil market projected to tighten

EIA said it expects the world oil market to "gradually tighten in 2010 and 2011, as the global economic recovery continues and world oil demand begins to grow again."

While continuation of Organization of the Petroleum Exporting Countries' production targets and lower overall non-OPEC supply growth in 2010-11 would also contribute to a firming of crude oil prices to above $80 this summer, EIA said a tendency toward any large upward swing in prices will be dampened by high inventories among Organization for Economic Cooperation and Development countries and by ample OPEC surplus production capacity.

The agency has revised its outlook for global liquid fuels consumption upward to a growth of 1.2 million barrels per day this year and a growth of 1.6 million bpd in 2011 after declines in 2008 and 2009, with non-OECD countries expected to account for the majority of the growth in both 2010 and 2011.

In 2009 supply from non-OPEC countries increased by 560,000 bpd, "the largest annual increase since 2004," EIA said. The 2010 non-OPEC projected increase is 430,000 bpd, with the largest source in 2010 the United States followed by Brazil and Azerbaijan. Production is forecast to decline in Mexico, the United Kingdom and Norway, with non-OPEC supply falling by 120,000 bpd in 2011, "as declining production in mature areas overwhelms any new production growth."

Spare capacity way up

One reason WTI prices stabilized between $70 and $80 per barrel in the middle of last year is that OPEC cut its crude oil production by 2.2 million bpd in 2009, EIA said. OPEC's spare production capacity, most of it concentrated in Saudi Arabia, stands at some 5 million bpd and could grow to 6 million bpd, EIA said. Between 1999 and 2009, OPEC surplus capacity averaged 2.8 million bpd.

EIA said it expects annual OPEC production to increase by an average of 400,000 bpd this year and again in 2011 as global oil demand recovers. OPEC non-crude petroleum liquids, which are not subject to production targets, are expected to grow by 600,000 to 700,000 bpd each year through 2011, for a total of up to 2.2 million bpd of increased OPEC liquids production over the next two years.

OECD commercial oil inventories were 2.69 billion barrels at the end of 2009, some 90 million barrels more than the five-year average for that time of year.

Natural gas consumption expected to grow

U.S. natural gas consumption is expected to increase 0.4 percent to 62.5 billion cubic feet per day this year and by the same percentage in 2011, EIA said, while total U.S. marketed natural gas production is forecast to decline 2.6 percent to 58.7 bcf per day in 2010 and to increase by 1.3 percent in 2011.

Working natural gas rigs were at a low of 665 in mid-July last year and the agency expects that lower drilling activity will contribute to the 2010 production decline. The number of working natural gas rigs increased by about 100 in January and totaled 861 rigs at the end of that month, still about 25 percent below the year-ago level.

EIA said current futures market prices between $5.50 and $6.70 per million Btu "appear to provide the necessary economic incentive to expand drilling programs even further," and as a result the agency expects monthly production to begin to increase slowly later this year and continue on an upward trend through the end of next year. ●

● FINANCE & ECONOMY

Tax holiday for new oil floated in House

Senate Finance hearing reviews ACES impact; Labor Department data shows recent drop in employment, more nonresident workers

By KRISTEN NELSON
Petroleum News

The Alaska Legislature is focusing a fair amount of attention on oil taxation, with companion bills being heard in the House and Senate which would offer incentives for hiring Alaskans and also reduce the tax rate established in the 2007 production tax bill, Alaska's Clear and Equitable Share, known as ACES.

Other production tax bills have been introduced. The most recent, by Rep. Mike Kelly, R-Fairbanks, would offer tax credits for new oil going into the trans-Alaska oil pipeline.

Senate Finance has embarked on an extensive review of the impact of ACES, with a presentation from the Alaska Department of Labor and Workforce Development providing numbers for employment in the sector — projected to drop by 3 percent this year — as well as the percentage of resident and nonresident workers in the industry.

Tax credit for new oil

Kelly's bill, House Bill 351, is aimed at increasing throughput in the trans-Alaska oil pipeline.

In a Feb. 15 House Majority press availability Kelly called it an aggressive tax bill with a relatively modest risk.

He said in a statement that the bill retains the current 25 percent severance tax, including the current progressivity rate, for the easier oil which has been discovered and is under development and production.

For the first 10 years that it flows through the line, new oil producers pay only royalties — and whatever local property taxes and income taxes apply — but no production tax.

Kelly said the tax break, along with oil exploration credits already available, should take off the table the argument that high taxes are shutting down drilling.

"The beauty of this bill is that it should give oil companies exactly what they need for new oil, while avoiding a shock to state revenue by cutting tax on all oil," Kelly said in a statement.

Unemployment claims up

Senate Finance Co-Chair Bert Stedman, R-Sitka, has the committee working through a series of presentations designed to identify production tax impact.

On Feb. 16 the committee heard from the Department of Labor and Workforce Development on oil industry employment, unemployment and resident hire.

Unemployment claims in the oil and gas industry rose sharply last year and the department is projecting a 3 percent decline in sector jobs this year.

Jeff Hadland, a department economist and the research program supervisor for Labor's Research and Analysis Section, told the committee that while 2009 oil and gas employment in the state was slightly higher than 2008 levels, the last half of the year showed a decline, a trend which is projected to continue this year.

Major oil and gas company employment was stable over the year, he said, but unemployment in service and supply companies was dragging down the numbers.

"So in terms of a forecast, we're looking at from 2009 to 2010 a 0.4 percent decline in jobs overall … and a 3 percent decline in oil industry employment from 2009 to 2010."

Nonresident numbers up

The other number that is down is the percent of resident workers in the oil and gas industry — a chart from the department showed a drop from some 83 percent resident workers in the oil and gas industry in 1988 to 70 percent in 2008.

In recent years the percent of resident workers peaked in 2002 at about 74 percent, and has dropped since.

"A lot of that is in conjunction with the increased reliance on oilfield service companies to do a lot of work," Hadland said. "The major oil company resident hire statistics have been fairly stable but the oilfield service sector tends to be a little bit higher, something more comparable to the construction industry in terms of their resident-hire performance," so as the number of workers in the oilfield service sector of the industry as increased, so has the nonresident hire percentage.

The number of unemployment insurance claimants for all oil and gas industry related employment bottomed out in 2006 at 906. The chart Hadland showed the committee covered 2003 through 2009. In 2003 there were 2,827 individuals from oil and gas related industries claiming unemployment insurance (a footnote indicates that individuals are only counted once in a year), a number which dropped off steadily to 2006 and then began to rise again: 1,084 in 2007, 1,362 in 2008 and more than doubled to 2,844 in 2009.

For all industries the number of unemployment insurance claimants for 2003-09 bottomed out in 2008 and rose by just 40 percent in 2009, from 45,343 to 63,630. ●

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LAND & LEASING

Potential Alaska state and federal oil and gas lease sales

Agency	Sale and Area	Proposed Date
DNR	Beaufort Sea Areawide	Feb. 24, 2010
DNR	Alaska Peninsula Areawide	May 19, 2010
DNR	Cook Inlet Areawide	May 19, 2010
BLM	NPR-A	Aug. 11, 2010
DNR	Beaufort Sea Areawide	October 2010
DNR	North Slope Areawide	October 2010
DNR	North Slope Foothills Areawide	October 2010
MMS	Sale 209 Beaufort Sea	2010*
MMS	Sale 211 Cook Inlet	2010*
MMS	Sale 212 Chukchi Sea	2010*
MMS	Sale 217 Beaufort Sea	2011*
MMS	Sale 214 North Aleutian basin	2011*
MMS	Sale 219 Cook Inlet	2011*
MMS	Sale 221 Chukchi Sea	2012*

Agency key: BLM, U.S. Department of the Interior's Bureau of Land Management, manages leasing in the National Petroleum Reserve-Alaska; DNR, Alaska Department of Natural Resources, Division of Oil and Gas, manages state oil and gas lease sales onshore and in state waters; MHT, Alaska Mental Health Trust Land Office, manages sales on trust lands; MMS, U.S. Department of the Interior's Minerals Management Service, Alaska region outer continental shelf office, manages sales in federal waters offshore Alaska.

**On April 17, 2009, the U.S. Court of Appeals for the District of Columbia issued an opinion requiring Interior to withdraw and reconsider the MMS 2007-12 oil and gas lease sale program for the outer continental shelf.*

This week's lease sale chart sponsored by:

PGS Onshore, Inc.

Petroleum news

Business Spotlight

North Slope Telecom Inc.

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

Retiring proudly from the Marines after 20 years of service in the communications field, Steve Washam joined North Slope Telecom Inc. eight years ago. His career with NSTI began as shop manager and has progressed to his current position as operations manager. Washam has been married for 22 years to his wife Janet and has two children.

FORREST CRANE

Steve Washam, Field Operations Manager and Project Manager

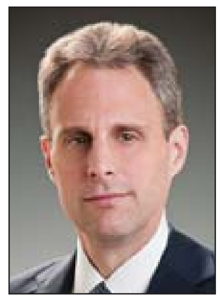
Companies involved in Alaska and northern Canada's oil and gas industry

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

Oil Patch Bits

UIC announces new chief financial officer

Ukpeavik Iñupiat Corp. said Feb. 9 it has named Chris Morgan chief financial officer. UIC said Morgan has worked in accounting and finance in Alaska for more than 20 years, and has demonstrated expertise in financial reporting, external audit management, government contract compliance and board communication. His previous positions include vice president of finance for Harbor Enterprises, Alaska's largest independent petroleum marketing and distribution company; owner of A&F Solutions, a consulting company; and chief financial officer for Arctic Slope World Services, a subsidiary of Arctic Slope Regional Corp. UIC is the village corporation for Barrow, Alaska.



CHRIS MORGAN

With more than 1,500 employees, UIC is consistently ranked among the top 10 Alaskan-owned businesses by Alaska Business Monthly's annual Top 49ers. UIC provides services to clients in a range of industry sectors worldwide, including energy development, construction and engineering, marine operations and government contracting.

Rain for Rent's HH-150 superior fuel efficiency

Rain for Rent said Feb. 9 that its 6-inch HH-150 stainless steel Power Prime pump is specifically designed to produce high discharge heads for mining and dewatering projects. The company said that superior fuel efficiency enables this pump to move more gallons of water at a lower cost. The impellers and shaft are stainless steel for added durability in mine and quarry applications. The HH-150 can handle solids up to 1.5-inches in diameter, flow up to 2,250 GPM and head up to 320-feet.

Customers can combine this 6-inch pump with other Rain for Rent products for a complete system to solve their unique liquid-handling problems, the company said.

For over 75 years, and now through 60 locations, Rain for Rent has been providing turnkey liquid-handling solution with specialized pumps, tanks, pipe, filtration and automation.

For additional information, please visit www.rainforrent.com.

Crowley begins ocean class tug building program

Crowley said Feb. 16 that it has signed a contract with Bollinger Shipyards to build two newly designed ocean-going tugboats, with options for additional vessels.

COURTESY CROWLEY

The 10,880-horsepower tugs are the beginning of a new-build program at Crowley to further enhance its ocean towing, salvage and offshore support capabilities. Crowley said the new tugs will be ideally suited to work with Crowley's new 455 series heavy lift deck barges, which measure 400 feet by 105 feet and offer increased stability for load up to 4,200 pounds per-square-foot.

Additionally, the tugs will be outfitted for, and capable of, rig moves, platform and floating production, storage and offloading unit tows, emergency response and firefighting.

The new tugs will be designated the Ocean Class, with the first two named Ocean Wave and Ocean Wind.

For more information visit www.crowley.com.

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.

EXPLORATION & PRODUCTION

BRPC to case, test Sak River 1-A well

Brooks Range Petroleum Corp. is planning a production flow test on a North Slope exploration well after encountering hydrocarbons, the company announced on Feb. 17.

BRPC, which is operating a multiwell program this winter on behalf of several partners, drilled the Sak River No. 1-A sidetrack to a measured depth of 12,726 feet and a total depth of 9,350 feet, "stopping within the Miluveach formation." In a statement, BRPC said, "Porous sandstones with hydrocarbon shows were encountered in sandstones of the Kuparuk formation at a depth of approximately 8,900 feet subsea (total vertical depth)."

Sak River No. 1-A is in the onshore-offshore Beechey Point unit in the Gwydyr Bay area. BRPC drilled the well from an onshore ice pad to bottomhole location more than a mile and half offshore beneath Gwydyr Bay. BRPC drilled the well using Nabors rig 16 E.

Sidetrack spud in January

The company spud Sak River No. 1-A on Jan. 26.

BRPC said it decided to case the well and begin testing because a Modular Formation Dynamics Tester — a wireline tool used to measure pressure and permeability and to take fluid samples — "failed to recover a reservoir sample due to a tool failure."

The company said it plans to release results after completing testing operations.

Sak River No. 1-A is a sidetrack of a well BRPC drilled in 2007 to a total depth of 11,348 feet and a measured depth of 13,110 feet. That well did not encounter any hydrocarbons.

BRPC is an affiliate of the Alaska Venture Capital Group, and operates on behalf of the BRPC Group, which includes TG World Energy Inc. and Ramshorn Investments Inc.

—ERIC LIDJI

SAFETY & ENVIRONMENT

BP, Conoco drop out of USCAP; Shell stays

BP and ConocoPhillips, along with Caterpillar, have opted not to renew their memberships in the U.S. Climate Action Partnership, the partnership said in a statement Feb. 16.

In the partnership, better known as USCAP, some 30 businesses and leading environmental organizations joined forces to urge the U.S. government to quickly enact strong national legislation to require significant reductions of greenhouse gas emissions.

By withdrawing from the group, ConocoPhillips said it will be able to better focus its efforts on ensuring fair and equitable treatment of the transportation sector and its consumers and on expanding opportunities for greater near-term greenhouse gas reductions through increased use of natural gas.

In a separate statement, ConocoPhillips Chairman and Chief Executive Jim Mulva said climate legislation in the U.S. Congress has placed the transportation sector and its consumers at a disadvantage, left domestic refineries unfairly penalized vs. international competition, and ignored the critical role that natural gas can play in reducing GHG emissions.

"We believe greater attention and resources need to be dedicated to reversing these missed opportunities, and our actions today are part of that effort. Addressing these issues will save thousands of American jobs, as well as create new ones," Mulva said.

Shell stays in

A CEO-led organization that has seen periodic membership changes, USCAP also has added three new corporate members — AES, Alstom and Honeywell — during the past seven months.

"We believe that U.S. action on energy and climate legislation in 2010 will preserve and create American jobs, secure our energy future and generate new investment in the global clean energy economy," the partnership said Feb. 16.

In response to BP, ConocoPhillips and Caterpillar leaving USCAP, Marvin Odum, president of Shell Oil Co., had this to say in a Feb. 16 e-mail to Petroleum News: "Shell has long supported a market-based approach to addressing energy supply and CO2 emissions. We are pleased to continue our association with USCAP and will remain engaged in advocating for federal legislation that will protect existing jobs, create new jobs via development of domestic oil and gas resources allowing the U.S. to be more self-reliant, incentivize the development of lower carbon energies, and reduce greenhouse gas emissions."

Houston-based Shell Oil Company is a subsidiary of Royal Dutch Shell.

—ROSE RAGSDALE

continued from page 1

BARROW RESEARCH

to try out a methane hydrate production technique.

Robert Dillon from Sen. Lisa Murkowski's office confirmed the cancellation of DOE funding for the Barrow gas fields project. As a consequence of DOE budget cuts the agency did not have the money for the second phase of the project, Dillon told Petroleum News Feb. 17.

"We've been asking them to reconsider but so far haven't been successful in that," Dillon said.

But there is still DOE funding for two other North Slope methane hydrate projects, one led by BP and the other led by ConocoPhillips, he said.

As reported in the Feb. 14 issue of Petroleum News, a report on the DOE methane hydrate program, published by the National Research Council Jan. 29, had indicated that the Barrow gas field's methane hydrate project was continuing. However, it now appears that the information in that report was out of date.

The huge volumes of methane locked up in methane hydrate deposits under the North Slope could become a major source of natural gas for export through a future North Slope gas pipeline, and the close proximity of an existing oilfield infrastructure to these deposits has made the deposits a prime focus of methane hydrate research. The U.S. Geological Survey estimates there are between 25.2 trillion and 157.8 trillion cubic feet of technically recoverable natural gas in these deposits.

Jocelyn Grozic, a hydrate researcher and engineering professor at the University of Calgary, has said this source of energy "could provide energy to North America for the next 64,000 years."

—PETROLEUM NEWS

continued from page 1

POINT THOMSON

Issues for the high court

Lawyers for the state want the Supreme Court to review Gleason's Jan. 11 ruling that reversed state Department of Natural Resources Commissioner Tom Irwin's 2008 termination of the Point Thomson unit.

Gleason held that the state did two things wrong.

First, the major Point Thomson leaseholders — BP, Chevron, ConocoPhillips and the operator, ExxonMobil — were wrongly denied an administrative hearing under Section 21 of the Point Thomson unit agreement, the judge ruled.

Second, in a prior administrative hearing before Irwin, the commissioner improperly relied on the same attorneys and a staff member who previously had acted as state "advocates" against the oil companies in court. This created the appearance of a lack of impartiality and deprived the leaseholders of their constitutional right to due process, Gleason held.

Although the Superior Court case has yet to go to trial and no final judgment has been rendered, the state took the unusual step of appealing Gleason's ruling to the Supreme Court.

The state's attorneys argue Gleason incorrectly found that the Point Thomson leaseholders deserve a Section 21 hearing — a hearing the state contends would be enormously complex and expensive, potentially adding years to the Point Thomson conflict for no good reason.

The state also refutes the judge's finding that the oil companies were denied proper due process.

A monumental case

As Petroleum News went to press, the Supreme Court had not yet ruled on the state's petition for a review of the Gleason ruling.

Lawyers for ExxonMobil are expected to file papers by March 1 opposing the state's petition.

For five years now, the state has been trying to reclaim the remote Point Thomson field on state land along the Beaufort Sea coastline east of Prudhoe Bay.

Frustrated state officials have said the oil companies have failed to develop the field 30 years after its discovery, choosing instead to "warehouse" the asset.

ExxonMobil has cited the lack of a North Slope natural gas pipeline, along with the extremely high reservoir pressure at Point Thomson, as big reasons for the development delay.

Even as the oil companies fight, both in court and through the DNR administrative appeals process, to keep the state from dissolving the unit and voiding the underlying leases, ExxonMobil this winter is mounting a limited drilling campaign at Point Thomson with Irwin's blessing.

While it's unclear how the conflict ultimately will play out, one thing is clear: Alaska might never have seen a court case involving so fabulous a prize.

Point Thomson's estimated 8 trillion cubic feet of gas, plus hundreds of millions of barrels of petroleum liquids, are worth tens of billions of dollars.

The 'taint' in DNR

After her January ruling, Gleason asked both sides to submit arguments about how to proceed with a hearing under Section 21 of the Point Thomson unit agreement.

Section 21 says the state can alter or modify the rate of production, provided the unit operator has the opportunity for a hearing to consider whether a required production increase would violate "good and diligent oil and gas engineering and production practices."

The state's lawyers argued unsuccessfully in Gleason's court that because Point Thomson has no production, Section 21 doesn't apply.

Not surprisingly, lawyers for the state and for the Point Thomson leaseholders disagree on how to proceed with a Section 21 hearing.

Lawyers for the oil companies, in a 10-page argument filed on Feb. 10 in Superior Court, urged Gleason herself to preside over the Section 21 hearing on grounds that DNR's administrative handling of the Point Thomson matter is now "tainted."

That's because DNR, in misusing its lawyers and staff, failed to keep its decision making and advocacy functions separate, wrote ExxonMobil attorney Doug Serdahely.

He suggested the taint disqualifies all the senior people at DNR, including the commissioner, from presiding over the Section 21 hearing.

Serdahely held out the possibility no hearing will be necessary if DNR is now "satisfied with the current rate of development" at Point Thomson, where ExxonMobil has vowed to begin 10,000 barrels a day of gas condensate production by year-end 2014.

If DNR is unhappy, then it must, under Section 21, tell the oil companies what changes to the current development would be satisfactory, within the bounds of "good and diligent" practices, Serdahely argued.

"No one's interests have been served by DNR's unwillingness to say straightforwardly what it wants" from the companies, he wrote.

State looks to keep control

State attorneys don't like ExxonMobil's idea of putting the judge in charge of a Section 21 hearing.

Rather, they argue the administrative hearing should stay in DNR's court. And they contend the department is fully capable of acting as an impartial decision maker.

Under state law, DNR has the authority to "balance complex economic issues and the public interest in formulating state oil and gas leasing policy," Senior Assistant Attorney General Richard Todd wrote in a 14-page argument filed Feb. 10 in the Superior Court.

Turning over to anyone else a resource management decision "of this magnitude" is inconsistent with Alaska law, Todd wrote.

He continued: "The Section 21 hearing goes to the essence of the state interest in oil and gas leases and DNR's land management responsibilities. The DNR Commissioner is the person who under Alaska law is entitled to make the initial Section 21 decision," a decision that could then be appealed to the Superior Court.

DNR would not allow any attorneys working as advocates for the department to advise Irwin this time around, Todd added. Ditto for any DNR staffers who have, or will, function as DNR advocates.

The state filing names the attorneys who would stay clear of Irwin in a Section 21 proceeding. They include Todd and fellow state attorneys Jonathan Katchen and Jeff Landry, plus lawyers with the private firm of Ashburn & Mason.

As far as what should happen going into a Section 21 hearing, the state laid out a different roadmap from what ExxonMobil argued.

The way the state sees it, the oil companies would first say what rate of development and production they propose for the Point Thomson unit.

The commissioner would determine whether their proposal was consistent with "good and diligent oil and gas engineering and production practices."

And if he did not agree with the proposal, "the matter would then proceed to hearing" with the commissioner ultimately deciding the "proper rate of development for the unit."

Whether the arguments over Section 21 procedure are very important — at least for now — is debatable given Gleason's order staying the Superior Court case. ●

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GREENING OF OIL

tract employees) in 2010-11.

A member of ExxonMobil's management team told Mary, who runs Alaska Pipeline Job Info., that "this is only the beginning." ExxonMobil has big plans for Alaska.

SNAKE OIL SCIENCE … If you're interested in reading a response to Sarah Palin and others who raised a ruckus about "snake oil science" when referring to climate change, here's a response from one of the people in charge of the Intergovernmental Panel on Climate Change's fourth assessment — the report that contained the error about the amount of melting anticipated for Himalayan glaciers: Setting the climate record straight http://www.nature.com/news/2010/100217/full/news.2010.77.html Not offering an opinion. Just some alternative reading. Let me know what you think.

FINALLY, ANOTHER ENERGY EINSTEIN … In its six-week existence, Greening of Oil has posted only one story in its Energy Einsteins' section. Sometime today a second one will be posted. This one features Rice University's Kyriacos Zygourakis. He's the guy on this week's cover. Youngish looking, but he started his career studying coal gasification during the OPEC embargo in the 1970s. Yep. The headline of the Energy Einsteins' piece is something like, "Zygourakis: think small for biofuels success". If you know someone who should be featured let me know!

FACTS NEVER GET IN THE WAY OF OPINIONS … This time my least favorite reader comment came from someone on the Far Left (last week I picked on the Far Right): "You can't tell me oil companies are reducing the environmental footprint of their operations out of the goodness of their hearts!" (I say, where does one begin?) "The last time I checked oil companies were for-profit companies, not religious institutions," I quipped, taking a line from our publisher and a similar comment she received. Motives didn't matter, I explained, as long as their environmental impact was negligible. Turns out her retirement fund includes ExxonMobil stock. The conversation got a whole lot more realistic.

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 page. My email address is mac@greeningofoil.com

● EXPLORATION & PRODUCTION

Pioneer tests its Cosmopolitan sidetrack

Independent conducts workover of Hansen well in Alaska's Cook Inlet, plans fracturing, possibly another Cosmo appraisal well by '12

By WESLEY LOY
For Petroleum News

Pioneer Natural Resources recently completed a flow test on an appraisal well tapping its offshore Cosmopolitan unit in Alaska's lower Cook Inlet.

The well, known as the Hansen 1A-L1, is a sidetrack to an earlier well drilled on Cosmopolitan, which takes in both federal and state leases off the coast of the Kenai Peninsula near the Anchor Point community.

Pioneer drilled the sidetrack in late 2007 and tested it at that time at a rate of 400 to 500 barrels of oil per day, Pioneer's Anchorage spokesman, Tadd Owns, told Petroleum News.

Subsequently, a steep decline in oil prices and a weak economy prompted Pioneer to essentially shelve its Cosmopolitan project and defer the drilling of another appraisal well.

When oil prices improved late last year activity around Cosmo came back to life.

Test follows workover

In early November, Pioneer sought permission from Alaska regulators to re-enter the Hansen 1A-L1 to conduct a workover. The job included locating and repairing a suspected casing leak.

The workover proceeded over several weeks, ending Jan. 16, Owens said.

Then came the flow test from Jan. 23-29, he said.

The test wasn't expected to produce a different result from the 400-500 barrels yielded earlier, Owens said. Rather, he said, it was to see if the workover was successful.

Pioneer is now evaluating the results with an eye toward possibly going back in to fracture the well, with another production test to follow, Owens said.

Development decision pending

Pioneer has not yet decided whether to develop Cosmopolitan, which has significant potential. The unit contains an estimated 30 million to 50 million barrels of oil, and a modest amount of natural gas.

Pennzoil discovered the oil accumulation in 1967 when it drilled two wells in the prospect — the discovery well, Starichkof State No. 1, penetrated a hydrocarbon-bearing section, and Starichkof State Unit No. 1, which was about 2.5 miles north of the first well. The reservoir was wet in the second well and the project was abandoned. The discovery well was suspended and was subsequently certified by the state as capable of production in paying quantities.

In 2001, ConocoPhillips' predecessor in Alaska and its partner Forest Oil formed the Cosmopolitan unit.

ConocoPhillips operated the unit and drilled the original Hansen well prior to Pioneer's takeover in 2006.

If developed, Pioneer most likely would use trucks to haul the crude about 60 miles north to the Tesoro refinery at Nikiski.

The Hansen 1A-L1 lateral was drilled from an onshore pad with Rowan rig 68. It was a significant achievement — the longest extended reach drilling or ERD well in the Cook Inlet basin.

In November, the Alaska Division of Oil and Gas approved changes to Pioneer's fourth plan of exploration for the Cosmopolitan unit. As part of that approval, Pioneer committed to the Hansen 1A-L1 workover, and must progress toward an addition appraisal well with drilling to start by April 30, 2012.

Pioneer is a large independent exploration and production company based in Irving, Texas, with operations in the Lower 48 states, Tunisia and South Africa.

It operates the small Oooguruk field in the shallow waters of the Beaufort Sea off Alaska's North Slope. ●

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PERMIT

our program in the Beaufort Sea."

Comment period

EPA is inviting public comments on the proposed permit until March 22 and the agency has scheduled public hearings in the Beaufort Sea coastal communities of Barrow, Nuiqsut and Kaktovik. Following the public comment period the agency will decide whether to issue the permit.

Feb. 17 was also the closing day of the public comment period for a similar EPA air quality permit for Shell's planned drilling operations in the Chukchi Sea — the company proposes drilling up to three wells in its Chukchi Sea leases in 2010.

Following a multiyear, unresolved courtroom tussle over previously approved minor air quality permits for its planned drilling in the Beaufort Sea, Shell elected to apply for major prevention of significant deterioration air quality permits, rather than minor permits, for its latest Beaufort Sea and Chukchi Sea exploration plans. The company is also making a $25 million modification to the Frontier Discoverer, to install catalytic reducers to scrub the engine exhaust and thus reduce the emission of pollutants by more than 90 percent. And the company has committed to the use of low-sulfur fuel in the diesel engines of the Frontier Discoverer and other vessels in its drilling fleet.

In both the Beaufort Sea and the Chukchi Sea permits, EPA is inviting public comment on a couple of options for the definition of an "OCS source," for the purposes of determining the periods during which Shell's drilling fleet comes under the terms of the air emissions permit. The question of what constitutes an OCS emissions source, a critical factor in determining the total emissions from an offshore drilling program, became a major bone of contention in the court battles over Shell's earlier Beaufort Sea minor air quality permit.

Fixed position?

Essentially, determining when a drillship becomes an OCS emissions source, as distinct from a regular ship plying the ocean, becomes a question of defining each period during which the drilling vessel is in a fixed position, working at a drill site.

The Frontier Discoverer has a drilling turret that is anchored at a fixed position over a well location during a drilling operation, with the turret moored by set of eight anchors and the ship's hull able to rotate around the turret to face the wind or sea ice.

In one proposed definition the vessel would become an OCS source during the entire period that the vessel is attached to the seafloor by at least one anchor at a drill site. According to the other proposed definition the vessel would be an OCS source only during the period when the vessel is deemed sufficiently secure and stable for drilling operations, a situation that would presumably require multiple anchors to be deployed but which EPA says does not necessarily require all of the vessel's eight anchors to be in place.

In addition, the supply vessel used for resupply of the drillship would become part of the OCS source during periods when the supply vessel is attached to the drillship, EPA says. And, when calculating the total emissions anticipated from a drilling operation, EPA is taking into account the estimated emissions from any vessels supporting the operation, when those vessels are within 25 miles of the drill site when the drillship is in place as an OCS source. ●

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ARCTIC GAS

76 billion cubic feet per day in 2020, compared with about 10 percent of current output of 70 bcf per day.

Supply growth will be determined by future industrial demand, which has plunged from 27 bcf per day in 1973 to 19 bcf per day currently because North American gas prices have driven new fertilizer and chemical plants to overseas jurisdictions, which have access to abundant feedstocks of cheap gas, Ziff said.

Gwozd is counting on lower gas prices through 2020 whetting the North American industrial gas appetite.

The impact of technological gains, which have brought shale to the forefront over recent years, have contributed to significant changes in the flow of shale gas, with Barnett wells in Texas which yielded an initial 500,000 cubic feet per day a decade ago now coming on at 2 million cubic feet per day and likely to generate higher productivity in the future, the study said.

Although Barnett drilling is likely to decline to 1,000 wells a year by 2020 from 3,000 completions two years ago, there is not likely to be any significant decline in Barnett production, Ziff said.

The same technologies should increase supply in Western Canada to almost 14 bcf per day in 2020 — almost 1 bcf per day better than Ziff's previous forecast, but still down from the current 15 bcf per day.

If this new output forecast is attained, volumes on the toll-regulated Alliance and TransCanada pipeline systems will allow costs to be spread over a larger base, thus lowering per-unit shipping costs for producers.

Drop in 2011 prices predicted

Ziff expects gas prices to average US$6-$6.50 per million British thermal units on the New York Mercantile Exchange this year, and to drop to under US$6 in 2011, putting pressure on Western Canadian producers to cut costs.

Despite the distance from key United States markets for Western Canadian producers, there is some upside, notably access to the Alberta oil sands where producers currently consume more than 1 bcf per day of gas (excluding power generation) and are expected to need 3 bcf per day in 2020, Ziff said.

A second boost could come from plans by Apache and Kitimat LNG to build a gas liquefaction plant on the British Columbia coast which could create demand in overseas markets for 500 million cubic feet to 1 bcf per day of LNG, which would fetch much higher prices than gas in North America.

A third plus involves the province of Ontario, which is phasing out coal-fired power plants in favor of gas-fired electrical generation.

Also a boon to Western Canada is a decline in the Gulf of Mexico Shelf, where well completions are forecast to drop to 100-200 a year in 2020 from 1,000 wells at the turn of the century, thus reopening some of the U.S. Northeast market for Western Canadian gas, Ziff said. ●

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