Petroleum news

page 12 Burger gas prospect Shell's top priority for 3-well Chukchi program

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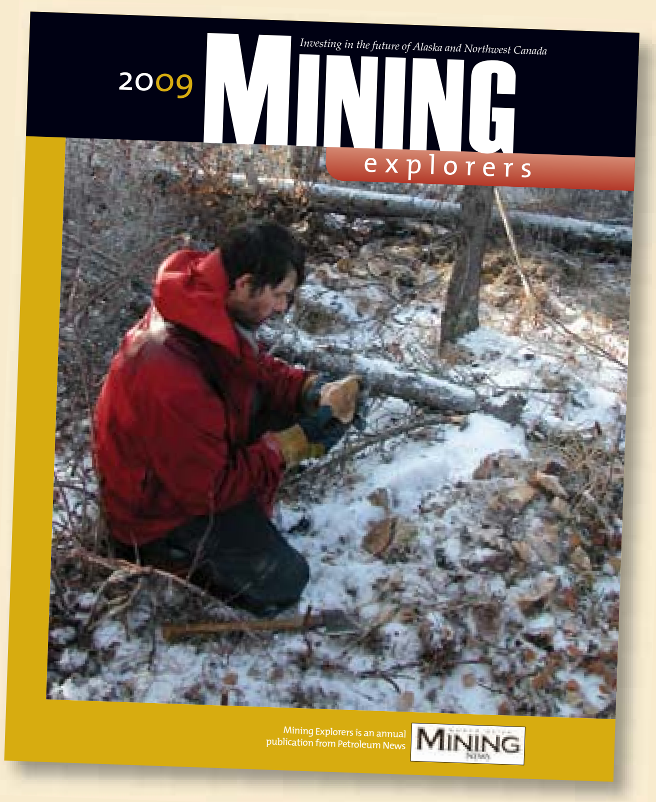
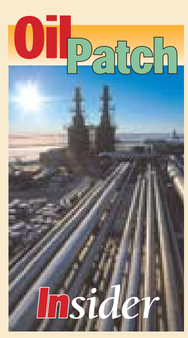
Debut: Mining Explorers



The first-ever edition of Mining Explorers magazine is in this issue of Petroleum News. The full color, glossy magazine features companies investing in Alaska and Northwest Canada. It was written by North of 60 Mining News editors Rose Ragsdale and Shane Lasley, and designed by Steven Merritt. For additional copies, details on the next edition of the magazine, or other information, contact PNA general manager Clint Lasley at clasley@petroleumnews.com.

More ACES trivia: Conoco's state tax jumps from $537 million in 2005 to $3.4 billion in 2008

PETROLEUM NEWS RECENTLY REPORTED that Alaska oil and gas production makes up about 12 percent of ConocoPhillips' worldwide output, but yielded more than 55 percent of the company's E&P profit in the second quarter.



In the first quarter, Alaska production yielded 29 percent of the company's total E&P profits of $840 million, but the $244 million that came from Alaska was, in part, due to more than $100 million in tax credits against the cost of exploration and development.

The State of Alaska's production tax, referred to as ACES, takes away much of the risk at relatively low oil prices, but as prices increase, ACES takes a bigger and bigger bite.

The highest tax rate possible under ACES is 75 percent of net profits, but this level can only be reached when the net profit per barrel of oil is $342.50.

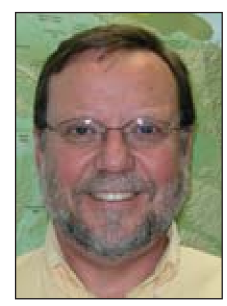
see **INSIDER** *page 21*

LAND & LEASING

70 & 148 top bidder

Armstrong affiliate puts down $7.8 million for 68 North Slope sale tracts

By KRISTEN NELSON
Petroleum News



KEVIN BANKS

It was déjà vu all over again as Alaska Division of Oil and Gas Director Kevin Banks read 93 bids for 80 tracts in the state's 2009 areawide North Slope oil and gas lease sale in Anchorage Oct. 28.

Armstrong Oil & Gas Inc. of Denver, bidding as 70 & 148 LLC, dominated the sale, with the apparent high bid on 68 of 80 tracts and 91.3 percent of the dollar value of the apparent high bids.

The same thing happened at the state's 2008 North Slope and Beaufort Sea areawide sales, when Armstrong, also bidding as 70 & 148 LLC, returned to Alaska's North Slope after an absence of several years and dominated those sales.

The $8.5 million in apparent high bids topped last year's $6.5 million as what could have been a low-dollar, low-interest sale, with a few companies picking up small numbers of tracts around known fields or prospects, boomed into the largest sale in several years. Armstrong affiliate 70 & 148 LLC took substantial acreage on the west and southwest side of the North Slope, extending a position the company established last year to the west and south of the Kuparuk River unit.

The company had apparent high bids of $7,791,654.40, adding 68 tracts to the 68 the com-

see **LEASE SALE** *page 22*

NATURAL GAS

Caught in political web

Canadian cabinet committee reported to have turned down fiscal package

By GARY PARK
For Petroleum News

Backers of the Mackenzie Gas Project now seem to be getting dragged deeper into a Canadian government quagmire.

Political insiders have told Petroleum News there could be growing differences over the project at the highest federal levels, compounding protracted delays in the regulatory process, unease over the long-term need for northern gas and uncertainty over the status of negotiations on a fiscal agreement.

The latest round of speculation was triggered Oct. 27 when the National Post, quoting unnamed sources, said a cabinet committee (believed to be Planning and Priorities) rejected a fiscal package brought forward by Environment Minister Jim Prentice, the cabinet point man for the MGP.

> *Prentice has consistently been touted as a leader-in-waiting for the governing Conservative Party if ever Harper resigns or is defeated and Harper is known to have little tolerance for rivals, real or imagined.*

Prentice's initial comment was that "no decision" had been made.

However, if the "sources" are right that the

see **WEB** *page 21*

FINANCE & ECONOMY

Alaska oil jobs peak

Field maintenance, new projects buoy payrolls; BP ignites competition for people

By WESLEY LOY
For Petroleum News

Employment in Alaska's oil patch is softening, but only very slightly as the industry continues to support near record payrolls.

"I'm surprised at the strength of the numbers," state labor economist Neal Fried told Petroleum News on Oct. 26.

According to Fried's latest estimates, the oil and gas industry employed 13,000 people in September, compared to 13,300 in September of last year. That's a small slippage of 2.3 percent.

But over the first three quarters of this year, the average monthly job count was 13,111, slightly higher than the 12,667 for the same period in 2008.

> *"Prices have been spectacular and they remain that way. We kind of look at oil at $70 or $80 a barrel and say, 'Big deal.' Well, it is a big deal. If oil was $20 or $30 a barrel, I think the employment story would be very different."*
> **—state labor economist Neal Fried**

The employment figures are for oil and gas producers such as BP and ConocoPhillips plus their major drilling and other services providers — companies such as Schlumberger, CH2M Hill and Doyon,

see **JOBS** *page 24*

BREAKING NEWS

contents

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

Alaska - Mackenzie Rig Report

The Alaska - Mackenzie Rig Report as of October 29, 2009.
Active drilling companies only listed.

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

This rig report was prepared by Marti Reeve

Alaska Rig Status

North Slope - Onshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Doyon Drilling			
Dreco 1250 UE	14 (SCR/TD)	Kuparuk 2A-27	ConocoPhillips
Sky Top Brewster NE-12	15 (SCR/TD)	Stacked at Kuparuk	Available
Dreco 1000 UE	16 (SCR/TD)	Prudhoe Bay R-28	BP
Dreco D2000 UEBD	19 (SCR/TD)	Alpine CD2-176	ConocoPhillips
OIME 2000	141 (SCR/TD)	Stacked at Kuparuk	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 3H-33A	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 MPI-04	BP
Dreco 1000 UE	7-ES (SCR/TD)	Orion L-223	BP
Dreco 1000 UE	9-ES (SCR/TD)	Orion V-227	BP
Oilwell 2000 Hercules	14-E (SCR)	Stacked	Available
Oilwell 2000 Hercules	16-E (SCR/TD)		Available
Oilwell 2000	17-E (SCR/TD)	Stacked, Point McIntyre	Available
Emsco Electro-hoist -2	18-E (SCR)	Stacked, Deadhorse	Available
Emsco Electro-hoist Varco TDS3	22-E (SCR/TD)	Stacked, Milne Point	Available
Emsco Electro-hoist	28-E (SCR)	Stacked, Deadhorse	Available
Emsco Electro-hoist Canrig 1050E	27-E (SCR-TD)	Point Thompson PTU-15	ExxonMobil
Academy AC electric Canrig	105-E (SCR/TD)	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 11A	BP
Superior 700 UE	2 (SCR/CTD)	Prudhoe Bay Well Drill Site Q well 4B	BP
Ideco 900	3 (SCR/TD)	Stacked out, Kuparuk	ConocoPhillips

North Slope - Offshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Nabors Alaska Drilling			
OIME 1000	19-E (SCR)	Oooguruk ODSN-45A	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	Stacked out West side of Cook Inlet for winter maintenance	Available
Doyon Drilling			
TSM 7000	Arctic Fox #1	Stacked at Beluga	Available
Marathon Oil Co. (Inlet Drilling Alaska labor contractor)			
Taylor	Glacier 1	Stacked, back to work on Dec. 2	Available
Nabors Alaska Drilling			
Continental Emsco E3000	273	Stacked, Kenai	Available
Franks	26	Stacked	Available
IDECO 2100 E	429E (SCR)	Stacked, removed from Osprey platform	Available
Rigmaster 850	129	Kenai SLU 41-33RD	Chevron
Rowan Companies			
AC Electric	68AC (SCR/TD)	Stacked, Kenai	Pioneer Natural Resources

Cook Inlet Basin – Offshore

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

Mackenzie Rig Status

Canadian Beaufort Sea

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

Mackenzie Delta-Onshore

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

Central Mackenzie Valley

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


JUDY PATRICK

Baker Hughes North America rotary rig counts*

	Oct. 23	Oct. 16	Year Ago
US	1,048	1,040	1,964
Canada	244	250	447
Gulf	33	32	70

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

● FINANCE & ECONOMY

Pacific Energy sale drama continues

Bidders jockey for Cook Inlet oil and gas assets as objections pour in ahead of Nov. 3 hearing in US Bankruptcy Court in Delaware

By WESLEY LOY
For Petroleum News

An effort by Pacific Energy Resources Ltd. to recoup and then sell some of its abandoned Alaska oil and gas assets has ignited a competition for the properties, and drawn a flurry of objections.

The whole affair is headed for a showdown on Nov. 3 in U.S. Bankruptcy Court in Delaware, where Pacific Energy has been disposing of its holdings as well as its debts.

Pacific Energy in September walked away from the bulk of its assets around Alaska's Cook Inlet after sale attempts failed.

On Oct. 14, the company filed a motion to retrieve a portion of the assets for purposes of a sale to a firm called Cook Inlet Energy LLC. The proposed sale price is $875,000 plus assumption of certain debts and other obligations.

At least three other contenders have emerged and are trying to claw away some or all of the properties Pacific Energy wants to deal to Cook Inlet Energy.

Meanwhile, lawyers for both the state and federal governments have filed objections to the proposed sale. So has Chevron, which formerly was Pacific Energy's partner in certain Cook Inlet operations.

The objectors

In papers filed on Oct. 27, lawyers for the State of Alaska object to the sale, noting Pacific Energy still owes the state property taxes, interest and penalties amounting to just over $250,000 in connection with several leases on the west side of Cook Inlet.

In addition, the state says it was forced to spend $204,822 to de-water and freeze protect abandoned Pacific Energy pipelines and other facilities to prevent cracking and possible spills in the coming winter and spring.

Lawyers for the U.S. Department of the Interior also filed objections. They argue Pacific Energy can't recoup and then sell a West Foreland lease with two natural gas wells on Native land without the permission of the U.S. government. The federal lawyers cite concern about how Pacific Energy or its proposed property buyer will take care of more than $500,000 in royalty obligations and also post the required bond for well plugging and abandonment.

Chevron, through its Unocal subsidiary, also filed an objection. The company argues Pacific Energy shouldn't be allowed to reverse the judge's Sept. 11 abandonment order. Pacific Energy is "out of time" under bankruptcy rules to reopen the order, and is attempting to "re-plow old ground," Chevron's lawyers argue.

The Chevron lawyers also complain that Pacific Energy is trying to sell items it has no right to sell, such as an airstrip right of way at Chevron's Trading Bay production facility. Pacific Energy previously owned a share in Trading Bay but abandoned its interest on Sept. 1.

Chevron further complains that Pacific Energy has yet to provide a clear and complete list, with proper legal descriptions, of exactly what properties it intends to sell.

"At a minimum, the Court should require a specific description of assets to be sold so parties-in-interest may understand their position and, if necessary, act to protect their rights," Chevron's lawyers argue.

Contenders include Miller

Cook Inlet Energy is an Alaska limited liability company organized on Jan. 13 of this year and based in Anchorage. The owners are David M. Hall of Kenai and Walter J. Wilcox II of Anchorage.

Other contenders for the abandoned Pacific Energy properties have emerged in recent days.

One is a new company called Stellar Energy LLC, incorporated on Oct. 26 in Delaware. The principals behind the company are unknown.

On Oct. 27, lawyers for Stellar filed an objection seeking to block the asset sale to Cook Inlet Energy on grounds that Stellar is willing to offer the higher price of $1.25 million for the properties.

Stellar took a novel path to gain standing as a creditor in the case. It approached one of Pacific Energy's unsecured creditors, Alaska Cab, which "assigned its claim in the amount of $452.54 to Stellar," the company's filing says.

The abandoned Pacific Energy properties have two other suitors.

Longtime Alaska oil and gas player Daniel Donkel has been battling through the Delaware bankruptcy court for some of the assets, and complains in an Oct. 27 filing that Cook Inlet Energy might have an unfair advantage because co-owner Hall is, or was, a manager for Pacific Energy.

Outside of court, Miller Petroleum Inc., doing business as Miller Energy Resources of Huntsville, Tenn., announced in an Oct. 20 press release it has "completed an agreement to purchase the assets of Cook Inlet Energy, LLC including $115 million in oil and natural gas reserves, 600,000 lease acres with potential additional reserves based upon $8.5 million in completed 3D seismic geology, and numerous production facilities valued at almost $200 million for $875,000."

"We hit it out of the park on this one," said Miller's chief executive, Scott M. Boruff.

In a filing with the U.S. Securities and Exchange Commission, Miller noted the deal is contingent on Cook Inlet Energy's successful purchase of assets from the Pacific Energy bankruptcy estate.

Miller's press release said the deal will close on Nov. 4, the day after the scheduled court hearing in Delaware where Bankruptcy Judge Kevin Carey could approve Pacific Energy's motion to reclaim and then sell its abandoned Cook Inlet assets. Miller is an oil and gas exploration, production and drilling company active predominantly in the Tennessee portion of the Appalachian basin. Its stock price is quoted on the OTC Bulletin Board. The shares closed at 64 cents on Oct. 28.

Miller's most recent annual report says the company had total revenue of $1.57 million and a loss from operations of $3.2 million for the fiscal year ended April 30. The company reported proved oil reserves of 53,443 barrels.

The sale properties

The properties Pacific Energy wants to recoup and sell, all located along the west side of Cook Inlet, are believed to include state oil and gas leases, the West McArthur River oil field, and the West Foreland field with two producing natural gas wells.

Pacific Energy also appears to be proposing to sell a stake in the Three Mile Creek field, which Aurora Gas operates, plus some nonproducing, exploratory holdings that weren't among assets abandoned in September.

One former Pacific Energy property that apparently won't be included in the sale is the Osprey offshore platform, which sits over the Redoubt Shoal field.

Pacific Energy, a small oil and gas explorer based in Long Beach, Calif., filed for Chapter 11 bankruptcy reorganization on March 9, citing a steep decline in oil prices. Faced with mounting losses, the company moved to either sell or abandon its assets in Alaska as well as California.

Cook Inlet Region Inc., the Native regional corporation that acts as landlord for some of the abandoned Pacific Energy assets, filed papers in the Delaware court conditionally supporting the proposed sale to Cook Inlet Energy.

"Retaining the assets, and all related contracts, leases and easements, as a cohesive package enhances their value and avoids a chaotic situation," lawyers for CIRI wrote. ●

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EXPLORATION & PRODUCTION

Rising from Canada's upstream E&P ashes

2009 drilling heads for 17-year low; regulators see some turnaround in permit applications; CAPP expects modest upturn in spending

By GARY PARK

For Petroleum News

Amid the wreckage there are a few pieces of hope in Canada's upstream, mostly pointing to a partial recovery in 2010.

With drilling currently headed for its lowest point in 17 years, regulators have seen a modest turnaround in new well permit applications and the Canadian Association of Petroleum Producers, the industry's chief lobby organization, expects total oil and gas spending next year will nudge C$40 billion, up 15 percent from 2009.

But the best prognosis CAPP Vice President Greg Stringham will offer for 2010 investment is "cautious optimism of growth."

GREG STRINGHAM

And data from the first nine months shows how much the industry needs that shot of hope.

Well completions tallied 5,719, down a jaw-dropping 12,028 from the peak year of 2006 and 6,334 from 2008; government-issued new well licenses tumbled to 7,660 from 16,415 for the same period last year; and drilling contractors have reported a 38 percent drop in the number of operating days to 41,032.

CAPP expects conventional gas spending will rise C$4 billion after taking a C$12 billion setback this year, while the oil sands will increase C$2 billion after falling C$8 billion in 2009.

Number of wells down

In its preliminary forecasts, CAPP is counting on 8,000 wells this year and 9,500 in 2010, while the Canadian Association of Oilwell Drilling Contractors believes 2010 will be only the second year since 1998 that the industry has failed to top 10,000 wells.

However, CAODC President Don Herring believes next year will mark a turning point towards recovery, helped by the fact that operators are drilling a higher percentage of deeper, horizontal wells, which are stretching the average time taken to drill a well.

But the best prognosis CAPP Vice President Greg Stringham will offer for 2010 investment is "cautious optimism of growth."

Drilling contractors reported an average 10.16 days to drill a well in Western Canada in the first nine months of 2009, up 20 percent from 2008 and the most in 17 years.

British Columbia reached a 20-year high of 26.88 days per well, up 29 percent from last year, as operators swung into action with horizontal wells in the Montney and Horn River plays; Saskatchewan wells edged up to 8.08 days from 6.9 days; and Alberta's average rose to 8.9 days from 8.09 days.

Precision Drilling Trust led Canadian contractors in the first three quarters with 1,607 wells and 7.6 million feet drilled. Its major workload came from Canadian Natural Resources with 338 wells, EnCana 185 wells and Devon Canada 143 wells.

Ensign Drilling totaled 1,462 wells and 5.38 million feet of hole. It drilled 286 wells for EnCana, 244 wells for Canadian Natural and 101 wells for Enerplus Resources Fund.

Savanna Energy Services took third place at 1,142 wells and 3.58 million feet.

EnCana top operator

EnCana held top spot among operators at 1,196 wells (4.85 million feet), followed by Canadian Natural at 579 wells (2.15 million feet), Husky Energy 297 wells (836,389 feet) and Devon 235 wells.

The leading explorers, in order, were EnCana, Talisman Energy, Canadian Natural, ConocoPhillips and Royal Dutch Shell (which has made heavy commitments to tight and shale gas plays).

Although the majors took the knife to their 2009 programs in response to natural gas prices, a handful of companies increased their drilling activity, including StatoilHydro Canada (34 wells), Shelter Bay Energy (41 wells), Progress Energy Resources (34 wells) and Tourmaline Oil (12 wells).

Topping the lists of those securing new conventional oil well permits were Husky (191 wells) and Canadian Natural (185), which also led the bitumen list at 359 permits, followed by Devon at 108 permits. EnCana obtained 716 gas licenses, followed by Enerplus at 171 and ConocoPhillips Canada at 135. ●

ALTERNATIVE ENERGY

Renewables, conservation in draft plan

Alaska legislators looking at energy efficiency, state goals, more money for various plans in review of state's energy situation

By KRISTEN NELSON
Petroleum News

Members of the Alaska Senate energy policy group have taken a wide-ranging look at the state's energy situation and in a draft released Oct. 19 have proposed a variety of approaches to deal with everything from energy-efficient buildings to incentives for more oil and gas exploration, some of which the Legislature could promote with funding and some of which it could encourage with legislation.

1 2 SERIES

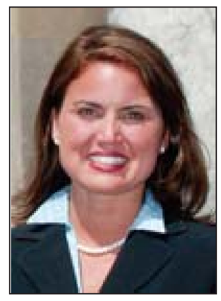
Sens. Bill Wielechowski, D-Anchorage, and Lesil McGuire, R-Anchorage, said the recommendations are designed to promote more reliable and affordable energy for Alaskans. The two are co-chairs of the Senate Resources Committee; McGuire also chairs the Senate Special Committee on Energy.

"This is a plan to help Alaskan families save money and make Alaskan businesses more profitable and competitive," Wielechowski said in a statement. "It will help ensure that Alaska has a robust economy, fueled by affordable and abundant energy."

There are seven energy goals and detailed recommendations to achieve those goals.

"The recommendations focus on improving energy efficiency, among many other strategies," said McGuire. "Increasing efficiency is a way to cut costs without compromising comfort or productivity."

McGuire said the recommendations also call for investing more in renewable energy with tax credits and low-interest loans.


LESIL MCGUIRE

"While we recognize that Alaska relies on fossil fuels for the vast majority of its power production and heating, we have seen the benefits of transitioning to more local, sustainable and flat-priced sources of energy," McGuire said. "Southeast Alaska with its interconnected hydro systems is a model for other parts of the state."

Wielechowski emphasized that the recommendations will help the state and its families move toward greater energy independence.

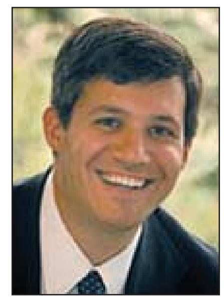
"This report is a call to action. Alaska's energy future depends on what we do now," Wielechowski said. "With oil prices on the rise again, Alaska is at a crossroads. We need to invest now for Alaska's long-term benefit."

McGuire said the recommendations "are a way to ensure a strong Alaska for decades to come, with families that can afford to heat and power their homes, drive to school and work, and build profitable businesses."

Input requested

In a letter to Alaskans, issued with the draft report, Wielechowski and McGuire said with all of the state's resources, "we're facing natural gas shortages in Southcentral, businesses are closing their doors because of the price of energy, and some rural Alaskans are leaving their communities because they can't afford to heat their homes and keep their lights on."

A Web site for the report, www.energy.aksenate.org, says members of the Senate Resources and Energy com-


BILL WIELECHOWSKI

mittees have been working over the summer to find long-term solutions to energy issues, many of which have plagued Alaska for years.

The senators requested input from the public on the report, and requested comments at the Web site, where the report and recommendations are also available.

In addition to McGuire and Wielechowski, members of the Senate's energy policy group, all members of the Resources and Energy committees, include: Hollis French, D-Anchorage; Lyman Hoffman, D-Bethel; Charlie Huggins, R-Wasilla; Albert Kookesh, D-Angoon; Bert Stedman, R-Sitka; Gary Stevens, R-Kodiak; and Tom Wagoner, R-Kenai.

State challenges

On the plus side, the draft report says, "Alaska is blessed with abundant energy resources," both fossil fuels and "considerable, largely untapped renewable energy resources."

But there are challenges: Alaska ranks first among the states "in terms of our energy consumption per capita," with prices for energy in the state "among the highest in the nation."

Getting reliable supplies of energy is also a challenge. "If freeze-up comes early and barge travel is blocked, fuel may not be delivered to a village on the brink of running out."

And generators failing in a remote community can leave it without power for days.

"Even Alaska's largest city faces the prospect of natural gas shortages this winter, which could result in rolling blackouts and the need to cut back on home heating."

Costs to meet these challenges are high, the report said: in excess of $4 billion for a small-diameter in-state line to bring natural gas from the North Slope to the Interior and Southcentral; $16 billion or more for a Susitna hydroelectric plant; and hundreds of millions to ensure communities have adequate bulk fuel storage and efficient generators.

Electricity

Alaska ranks sixth in the U.S. for electric rates with rates 50 percent higher than the national average and much higher in some areas of the state, the report said. The U.S. national average cost in 2008 was 11 cents per kilowatt hour, but in Lime Village the cost — before Power Cost Equalization payments — was $1.17 per kilowatt hour.

Electrical consumption is growing much faster in Alaska than in the U.S. as a whole and Alaska's higher costs are due in part to the fact that outside of Alaska's major cities most electricity users are not linked to large electric grids.

The report recommends consolidating the six existing Railbelt utilities into a single entity for purposes of planning, financing and building future electrical generation and transmission projects with maximum efficiency, and calls for amending Senate Bill 143, "An Act establishing the Greater Railbelt Energy and Transmission Corporation," and passing a revised bill.

A regional integrated resource plan is being developed for the Railbelt with a draft report due in November; legislative hearings are proposed in January to review the findings and make recommendations.

Investment in Railbelt projects that will provide the lowest cost and most reliable energy is recommended, with capital added to the Railbelt Energy Fund as needed.

The report also recommends adding a minimum of $10 million to the state's Power Project Loan Fund which provides loans to utilities, local governments and independent power producers.

Improving the efficiency of diesel power generation is recommended through increased funding for the Alaska Energy Authority's Rural Power System Upgrade Program, which has upgraded some 35 rural power systems producing an average increase in efficiency of 26 percent; some 25-30 community power systems still need to be upgraded. Recent funding for the upgrades has been primarily from the Denali Commission, but the commission's budget is in sharp decline and $10 million in state funding for the program is recommended.

Other funding recommendations include $200,000 for the Rural Power Systems Technical Assistance Program, the "circuit rider program," and continued funding of the Power Cost Equalization Program, with $37 million for fiscal year 2011.

In Southeast, continued development of the region's hydroelectric potential is recommended, specifically completion of an integrated resource plan for Southeast

see ENERGY PLAN page 9

● EXPLORATION & PRODUCTION

Preparing and planning for the OCS

Shell engineer describes the complex, multiyear process required to bring an oil field online in the Beaufort or Chukchi Seas

By ALAN BAILEY
Petroleum News

As Shell waits behind the starting gate, champing at the bit, ready to move ahead with exploratory drilling on the Alaska outer continental shelf of the Beaufort and Chukchi seas, it may be tempting to think that the start of OCS drilling could bring a new flow of offshore oil down the trans-Alaska oil pipeline in short order.

In fact, it would be quite a few years before first oil started to flow from any Shell Arctic OCS field, Brian Miller, the engineering leader for Shell's OCS Alaska development opportunities, told the U.S. Minerals Management Service Arctic Technologies Workshop in Anchorage on Oct. 15.

In the Arctic offshore, initial exploration, including the acquisition of seismic and the drilling of exploration wells might take three to seven years; appraisal drilling and feasibility studies for an oil discovery might take another three to seven years; selection of suitable offshore field technology and doing the preliminary design for a development project might take two to four years; and then, if things still look good, detailed engineering, construction and facility installation might take four to eight years.

"This basically totals up to … 12 to 14 years," Miller said.

Head start

However, Shell does have a little bit of a head start on its planned Alaska OCS ventures.

For example, the company's first Beaufort Sea target, the Sivulliq prospect, is ready for the start of appraisal drilling, since two mid-1980s exploration wells previously discovered an oil pool in the prospect (Sivulliq was known as Hammerhead at the time of the original oil discovery). In the Chukchi, Shell has already acquired the seismic data that it needs and is ready to start drilling exploration wells in 2010, Miller said.

But in addition to obvious exploration and development activities such as drilling, facilities design and facilities development, there is a great deal of OCS work to be done, much of it directed at addressing concerns about the risk of damaging the environment, Miller explained.

"This is driving some data acquisition technology development and the (facility) designs that we do," Miller said. "Our focus is really trying to reduce the environmental risk, using technology in many cases. …We also want to minimize and mitigate the impacts to the subsistence hunting lifestyle and culture."

Shell is also hearing concerns from the North Slope villages about the impacts of an industrial economy on rural societies, with particular anxiety about the future for young people, Miller said. The company is trying hard to develop employment opportunities for people in the communities, as well as pushing for revenue sharing of federal income from OCS oil and gas production. Onshore facilities associated with offshore operations would also provide income from property taxes, while new oil developments offshore could extend the life of the trans-Alaska oil pipeline, thus prolonging the economic benefits of the North Slope oil industry, Miller said.

Environmental data

Shell has been gathering environmental data, to better understand the offshore environment, ahead of any drilling operations. And the company has to conduct shallow hazards surveys and conduct site clearance operations at potential drilling sites, to ensure that drilling can be conducted safely.

But in parallel with all of that activity, the company is conducting preliminary research into future oil field development options, using environmental data to evaluate the best way to construct oil field systems, should an oil or gas find appear viable for development. Different types of oil field structure, such as the use of a gravel island or steel-legged platform, are applicable in different environmental settings. And, as well as reviewing lessons learned from the previous use of these different facility designs and performing an engineering assessment of each development option, discussions with the various stakeholders in any development project are critical to success.

"It's really important to engage stakeholders. There's a tremendous amount of traditional knowledge, and we also need to work with the regulators. … You need to pick the right system for the right location," Miller said.

The leading candidate for an Alaska outer continental shelf oil field development is currently a concept involving a massive structure resting on the sea floor. Because of the severe sea-ice conditions, the structure would be fully enclosed, rather than freely standing on legs.

But at this point Shell is still working in data gathering mode: It is much too early to say what type of structure the company would actually use, Miller emphasized. And once the company has decided on its preferred development option, the company would have to submit its development plans to the appropriate government regulatory agency for the development of an environmental impact statement, a critical task that would take a number of years to complete.

"It's a critical activity that has to happen in a location like Alaska," Miller said.

Environmental data

Meantime, some of Shell's data gathering is targeting aspects of the Arctic offshore environment that could, if not handled appropriately, threaten structures such as subsea oil pipelines, perhaps creating the risk of a future oil spill. For example, an understanding of the gouging of the sea floor by moving sea ice is critical to the placement and burial of pipelines.

"The ice does gouge the bottom and we need to measure those gouge depths," Miller said.

However, since some of the gouges may be hundreds or even thousands of years old, dating from times when sea conditions were different from the present day, it is also important to identify, track and date specific gouges.

Strudel scours on the seafloor, where spring melt water from rivers pours through holes in the sea ice, could also

see PLANNING page 21

Watching the offshore drilling from afar

Any drilling that Shell does in the Beaufort and Chukchi seas would be closely scrutinized, not just by personnel on the drillship, but by multiple, expert eyes, thousands of miles from the drilling operation, Cody Teff, Shell engineering team lead in Alaska, told the U.S. Minerals Management Service Arctic Technologies Workshop in Anchorage, Oct. 14.

Originally developed in 2002 to improve drilling efficiency in the Gulf of Mexico, real-time operations centers located in places such as Houston and New Orleans enable expert consultation on drilling decisions to be made without undue delay to the drilling operation, while also improving drilling safety through continuous oversight of what the drillers are doing.

In these centers, far from the drilling operations, computer displays hooked live into the drilling rig control and monitoring systems enable experts to observe drilling data along with the rig crews, advising on actions that the drillers might take and watching for any possibility of a drilling problem. In fact, it is possible for Shell staff to link into the operations center data over the Internet from pretty much anywhere — Shell is considering setting up an operations center hub in Anchorage, Alaska, for example, Teff said.

And technology such as "measurement while drilling," in which well log information can be transmitted to the surface as pulses in the drilling mud, makes a wealth of drilling and well information available continuously while drilling takes place.

Layers of control

The real-time operations centers dovetail into a modern drilling operation involving three layers of well control, to ensure that hydrocarbons are safely restrained within a well bore, Teff said. Layer 1 involves detailed well planning, training of personnel and detailed well design, taking into account potential risks associated with the drilling operation. Layer 2 involves monitoring of the drilling operation both on the rig and in a real-time operations center, looking for unexpected changes in the well parameters to anticipate any potential problems. Layer 3 swings into action in an emergency situation and involves the use of mechanical barriers, including a blowout preventer, to block any oil flow from the well.

Only in the unlikely event of all layers of well control somehow failing would oil escape to the environment, causing oil spill response contingency plans to be activated and the drilling of a relief well to block the uncontrolled well to be started.

—ALAN BAILEY

● LAND & LEASING

B.C. hits land sale homerun in October

By GARY PARK

For Petroleum News

British Columbia has put a decisive end to Western Canada's dismal land sales year, raking in C$370 million from its October auction, with bidders showing strong interest in the well-established Montney tight gas play.

In posting its sixth-largest sale, B.C. more than doubled its 2009 revenues to C$700.6 million, leaving its eastern neighbors lagging far behind, with Alberta totaling C$269 million and Saskatchewan C$83.2 million.

But B.C. Energy Minister Blair Lekstrom tactfully side-stepped any suggestion of a battle among the three provinces, noting that the competition for resource dollars is now global.

"If you want to be a player and attract capital, you'd better have a competitive environment to invest in," he said.

Lekstrom told the Vancouver Sun that both the Montney and Horn River formations continue to get better because of the success by exploration companies in posting resource potential numbers in the hundreds of trillions of cubic feet.

He doubted the B.C. government's latest royalty incentives were a major influence in the latest sale, but said there is no doubt that B.C. is determined to compete with Louisiana, Texas and Alberta.

In August, the province introduced a number of incentives, including royalty breaks to move from land sales to exploration activity, estimating that for every C$1 of royalty credit it generates C$2.50 in activity.

Lekstrom said the stimulus package "gives some certainty to the industry about where our province stands with oil and gas and the future."

Average of C$5,625 per hectare

The latest bonus bids averaged C$5,625 per hectare, the second-highest in B.C. history, with three Montney parcels accounting for C$265 million and one parcel in the Altares area acquired by Canadian Coastal Resources going for C$117.3 million, or a staggering C$18,650 per hectare.

Talisman Energy is the most active operator in the Altares. Others with licenses include Northpoint Energy, Canbriam Energy and Progress Energy Resources, while Canadian Spirit Resources has a significant land holding in the region.

Another parcel fetched C$60.9 million, with Basm Land & Resources spending C$16.315 per hectare for a 3,738-hectare parcel alongside a block held by Canadian Spirit.

Talisman is completing several horizontal wells and building a sweet gas processing facility in the area with capacity of 30 million cubic feet per day.

Northpoint Chief Operating Officer Ron Lambie told the Calgary Herald that the bidders "obviously have deep pockets. … They're probably big players."

Chris Theal, an analyst with Macquarie Securities, said the area northwest of the established Montney plays, such as Dawson and Tower, could hold up to 10 trillion cubic feet of gas in place and recoverable reserves of 20 billion cubic feet per section, based on preliminary data.

Progress reported earlier in October that it had drilled a Montney gas well that tested at 10 million cubic feet per day, while Talisman tested 5 million cubic feet per day from one well. ●

continued from page 6

ENERGY PLAN

Alaska. Regional electrical grid interconnections are also recommended for adjacent Southeast communities, as well as broadening the scope of the Southeast Alaska Energy Fund and capitalizing it.

Increased state funding for the Bulk Fuel Upgrade Program is recommended — $5 million per year for the next three years; this is another program which has been funded by the Denali Commission. The report also recommends revising interest rates for the Bulk Fuel Revolving Loan Program and Bridge Fuel Loan Program to ensure there is an incentive for communities to maintain good credit histories. Five to 10 training classes per year are recommended for power plant and bulk fuel operators to teach operations, maintenance and management best practices.

Home heating

Alaska is one of the coldest states, the report says, and Alaska homes use more energy for space heat than counterparts in the Lower 48. The Institute of Social and Economic Research found the average annual cost to heat a home in Alaska in 2008 was $4,500, about 45 percent of the total energy used to run a home.

Additional funding is recommended for the state's weatherization program. The report said the $200 million the state appropriated for the program in 2008 is expected to be fully encumbered by the end of FY'10 and an additional $150 million is recommended for the program in FY'11.

Additional funding is also recommended for the state's Home Energy Rebate program, which assists homeowners in making energy efficiency improvements. The Legislature appropriated $160 million for the program in 2008 and that is expected to be fully encumbered by June 30, 2010; an additional $50 million is recommended for FY'11.

Energy efficiency

The report said conventional electrical generation, nationwide, costs 7-15 cents a kilowatt hour; by comparison, energy efficiency costs 0.25 cent a kilowatt hour. "It is also stably priced, in contrast with volatile fossil fuels, and beyond the reach of international disruptions."

Alaska is ranked 37th in terms of energy efficiency policies.

"We can reduce our energy consumption and costs more easily than other states by harvesting the 'low-hanging fruit' of energy efficiency."

The report recommends reducing the demand for electricity and heating fuels by 10 percent by 2015 and said the state made energy efficiency upgrades to eight public facilities and reduced energy in those buildings by 24 percent in the first year.

The report recommends a $2 million program to create an appliance rebate program to encourage consumers to replace older appliances with those which are more energy efficient.

It recommends $100,000 to AEA for ongoing technical assistance to businesses to improve energy efficiency and $250,000 toward a more extensive building energy monitor program.

The report says since energy efficiency and conservation is typically 50-75 percent cheaper than building new power plants, setting efficiency goals and implementing a strong education program would allow the state and utilities to forecast energy efficiency gains; AEA and the Alaska Housing Finance Corp. would be tasked with implementing this $175,000 program.

The Department of Education would be encouraged to include energy efficiency lessons in the K-12 curriculum.

Legislative hearings would be held to investigate the costs and benefits of requiring utilities to decouple revenues from sales to provide greater incentives for the utilities to promote and invest in energy efficiency.

Technical assistance would be provided to communities for implementation, code enforcement, energy audits and efficient building design.

A voluntary energy efficiency labeling program is recommended for buildings.

And low-interest loans are recommended for Alaska's commercial fishers for energy efficiency upgrades, since volatility in fuel costs continues to have an impact on Alaska's commercial fishing fleets, cutting into profits and threatening productivity. ●

Editor's note: Part 2 of this story, recommendations for renewable and conventional energy development in the state, will appear in the Nov. 8 issue of Petroleum News.

● PIPELINES & DOWNSTREAM

New pipelines to move heavy oil markets

By GARY PARK

For Petroleum News

Canada could soon remove 9 million barrels of crude from the heavy oil market, followed next year by another 5 million barrels.

The 9 million barrels is what it will take later this quarter when TransCanada starts filling the 2,900-mile Keystone crude oil pipeline from Hardisty, Alberta, to the Wood River-Patoka refinery region in Illinois.

The process of line fill is due to start this quarter and take about 90 days, allowing Keystone to start operations in the first quarter of 2010.

TransCanada rival Enbridge has scheduled line fills in the second quarter of 2010 for its 450,000 bpd Alberta Clipper pipeline which will remove about 5 million barrels of heavy oil from the market, said Calgary-based investment dealer Peters & Co.

Keystone is expected to start drawing about 100,000 barrels per day once the process starts and Keystone becomes the largest new pipeline in years to join the North American network.

Although Keystone is not officially disclosing how much crude will be needed to fill the pipeline, Peters calculates 9 million barrels, which some say could give a temporary boost to heavy oil prices if it removes about 6 percent of Canadian production from the market.

Analyst expects differentials to tighten

Jared Layton, a crude oil specialist with Phoenix Energy Marketing Consultants, suggested that whatever Keystone needs will likely tighten heavy oil differentials, because heavy oil sells at a discount to light crude.

The shrinking output from Mexico and Venezuela this year has already reduced that price differential to a current 12 percent from 22 percent last year and the introduction of Keystone could shrink the gap even more.

For every C$1 narrowing of the spread over a full year add about C$340 million to the Canadian industry's topline revenues.

Keystone is expected to start drawing about 100,000 barrels per day once the process starts and Keystone becomes the largest new pipeline in years to join the North American network.

Keystone's initial phase to Wood River-Patoka will have initial nominal capacity of 435,000 barrels per day.

The line is scheduled to extend to Cushing, Okla., in late 2010 when capacity will grow to 590,000 bpd based on TransCanada's success so far in signing contracts with shippers for 495,000 bpd for 18 years.

Keystone could provide Canada's first link from Alberta to U.S. Gulf Coast refineries by 2012. ●

● PIPELINES & DOWNSTREAM

Trading coal for bitumen at Christmas

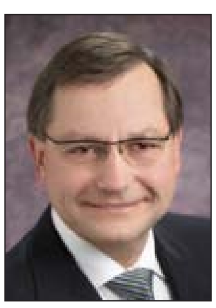
Alberta issues revised RFP for a processor in the province to process 50,000-75,000 bpd of bitumen; goal more processing at home

By GARY PARK

For Petroleum News

It's a bit early for Christmas wish lists, but the Alberta government isn't waiting for a spot on Santa's lap.

Rather than visions of sugar plums dancing in its head, the province has images of bitumen from oil sands operations overflowing its stocking.



ED STELMACH

What Premier Ed Stelmach and his cabinet want is success in their campaign to keep more of the "value-added" end of the oil sands business within Alberta for upgrading and refining, rather than seeing the product shipped to plants in the United States.

But the plan has encountered a few hitches and snags.

To spur more secondary processing at home, the government issued a draft Request for Proposals two months ago, seeking industry comment.

A final draft was issued Oct. 19 with some minor tweaking.

Initially, the government proposed collecting 50,000-75,000 barrels per day of bitumen in kind rather than cash and using that as feedstock for an Alberta-based processor.

For companies to qualify for that feedstock, they were required to propose a new plant with capacity of at least 100,000 bpd, with a startup by the end of 2016.

Deadline extended

In response to some negative reaction, the government had stretched the deadline to year-end 2018 and will give companies more time to build the second phases of their upgraders.

Whether that will attract more contenders is not clear.

Energy Minister Mel Knight said the changes made to the draft RFP "are relatively minor, but illustrate out commitment to listen to stakeholders, take firm action and prepare the province for future economic growth."

The two-year extension was prompted by industry observations that commercialization of a new upgrader would need more time to be planned and move through the regulatory phase.

Knight said the royalty-in-kind scheme will "add value to the bitumen resource, diversify our economy, keeps jobs in the province and will produce larger total energy revenues for Alberta."

Proposals due in January

Whether that will translate into a belated Christmas gift will be known by Jan. 27, 2010, the deadline for industry proposals.

So far, the only openly declared contender is privately held North West Upgrading, which has targeted a possible C$15 billion project in three phases, each processing 77,000 bpd of diluted bitumen feedstock (50,000 bpd of raw bitumen) for diesel fuel.

To qualify for the royalty bitumen, North West must have two phases operating by year-end 2018.

North West already has a commitment of 25,000 bpd of heavy oil from Canadian Natural Resources and, having raised C$400 million to date, hopes to have the first phase up and running by early 2013.

Company Chairman Ian MacGregor said that securing royalty bitumen would allow the company to negotiate financing.

He said it was encouraging to "see this government continuing to move forward to ensure that all Albertans will benefit from the added value of upgrading and refining here at home."

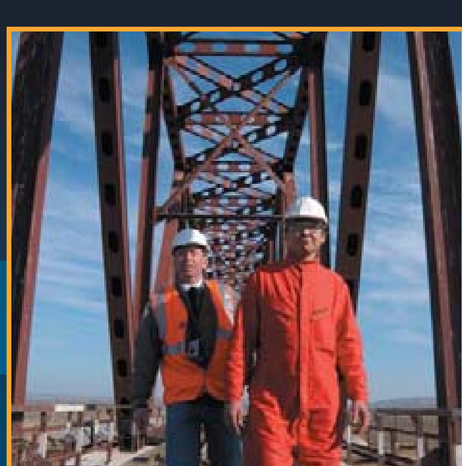
MacGregor estimated upgrading in Alberta would double revenues collected by the government from royalty bitumen production.

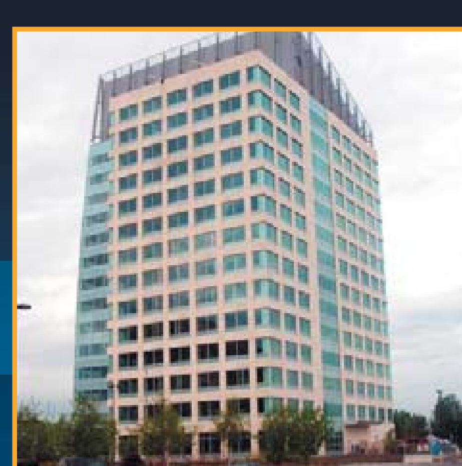
He said the credit markets are paying close attention to determine that Alberta is serious about achieving its goal and cautioned that any "significant" delays could cause financing problems.

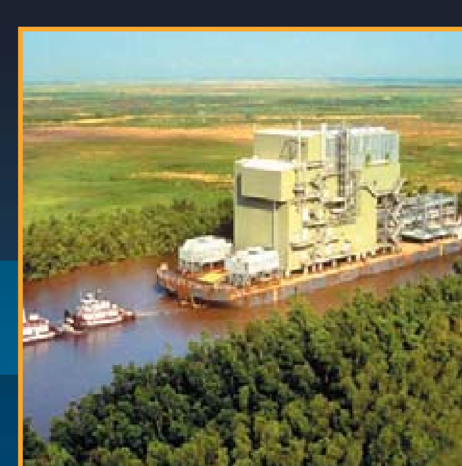
U.S. refining surplus

Chris Theal, an analyst with Macquarie Securities, said reduced shipments from Mexico and Venezuela have created a surplus of refining capacity in the United States, making it more attractive for producers to ship Alberta bitumen south of the border.

Suncor Energy has already dropped plans to add a C$1 billion heavy oil processing unit to its Montreal refinery and decided output from its Alberta oil sands expansion will be shipped directly to U.S. refineries. In addition, it has postponed indefinitely plans for a new upgrader. ●



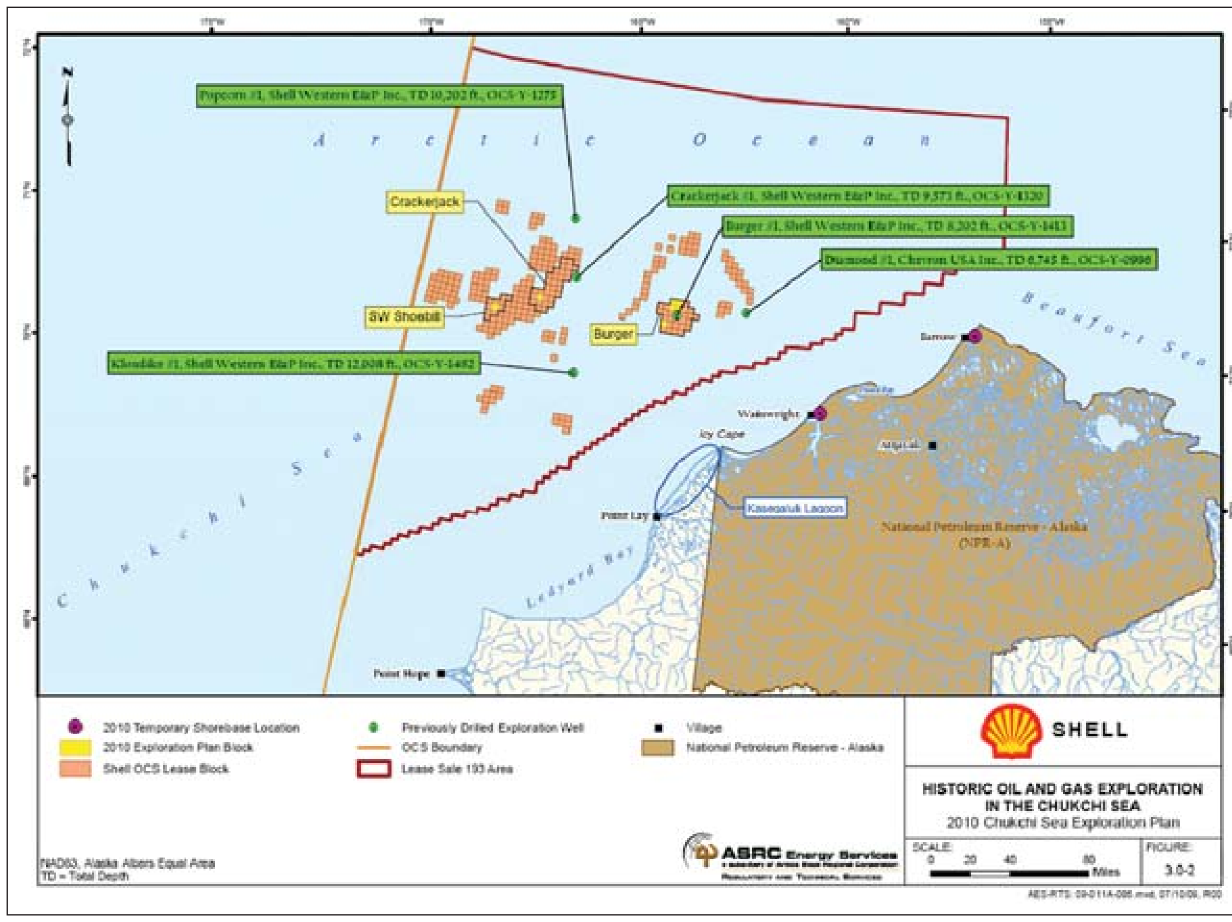




● EXPLORATION & PRODUCTION

Shell puts Burger at top in Chukchi

Company want to drill up to three wells in three prospects, but known Burger gas pool will get priority treatment in 2010 program



SHELL GULF OF MEXICO INC.

Shell plans to permit five wells in seven exploration blocks, with the potential to drill up to three of those wells in the Chukchi Sea in the 2010 open water season. The target prospects are Burger, Crackerjack and Southwest Shoebill.

By ALAN BAILEY
Petroleum News

With $105 million placed on the table at the Chukchi Sea lease sale in February 2008 for just one of the tracts around the old Burger well, some 80 miles offshore the western end of Alaska's North Slope, it's fair to assume that Shell has more than a passing interest in the 25-mile-diameter Burger structure that is thought to hold perhaps 14 trillion cubic feet of natural gas.

So it perhaps comes as no surprise that Burger appears at the head of three Chukchi Sea prospects that Shell says it wants to test with a drill bit during the 2010 open water drilling season, according to the company's 2010 Chukchi Sea exploration plan, recently put on public display by the U.S. Minerals Management Service. MMS has deemed the plan complete and is now in the process of determining whether to authorize it.

Three wells, five sites

In the interests of flexibility, in the face of uncertain ice conditions, uncertain weather and uncertain drilling results during the drilling season, Shell plans to permit five Chukchi Sea drilling sites for 2010, although the company will not drill at more than three of those sites. Three sites are in the Burger prospect; one site is in the Crackerjack prospect, about 110 miles offshore; and the other site is in the Southwest Shoebill prospect, about 20 to 30 miles southwest of Crackerjack.

The old Burger well, drilled in 1989-90 to a depth of 8,202 feet, discovered a major gas field in a 107-foot-thick sandstone unit occupying a huge dome-shaped structure. Although MMS has estimated that the structure may contain 14 trillion cubic feet of natural gas, the agency has said that there could be anywhere from 2 trillion to 63 trillion cubic feet of gas in the field. The high level of uncertainty in the estimate reflects the fact that only one well has penetrated the structure.

The Crackerjack prospect, located on the flank of a huge fault structure, was the target of a Shell well drilled in 1990-91 — Shell's proposed new well site appears to be more that 20 miles southwest of that old Crackerjack well. The Southwest Shoebill prospect has not previously been drilled.

According to MMS the Crackerjack area has several potential exploration plays involving rock units in what geologists refer to as the Ellesmerian and Beaufortian sequences. The original Crackerjack well sought oil in similar Ellesmerian rocks to those of the Prudhoe Bay oil field in the central North Slope. However, despite encountering oil and gas in some sandstone units, the well failed to make a commercial find.

Interplay of factors

In its exploration plan Shell says that the order in which it drills Chukchi sea wells during the 2010 open water season will depend on a "complex interplay" of factors such as ice conditions; regulatory restrictions on when operations can be carried out; and the results of the drilling.

But it is clear that Burger is the company's primary target.

"Given favorable conditions, it is anticipated that the initial drilling activity will begin at the Burger prospect," the plan says. "If Burger is not accessible, then the next preferred location to begin the exploration drilling, if favorable conditions exist, is at the Southwest Shoebill prospect."

The company will drill at Crackerjack initially, if that prospect is open but the other two prospects are inaccessible.

"(But) it should be noted that the focus of the 2010 drilling program will be shifted immediately to the Burger prospect as soon as it becomes safe to anchor and operate the drillship on that prospect," the plan says. "Given favorable drilling performance and subsurface results at the initial Burger drill site, another of the permitted drill sites in the Burger prospect may be the next well drilled."

And the total number of wells drilled will depend on the ice conditions and the length of time available for operating in the Chukchi. Shell says that it plans to use the ice-reinforced drillship, Frontier Discoverer, for the drilling, moving the drillship into the Chukchi Sea around July 1, ready to start drilling around July 4. Drilling operations will end by Oct. 31.

Shell has previously said that it also plans to use the Frontier Discoverer to drill two wells in the Beaufort Sea in 2010. So, presumably the company will shuttle the drillship and its attendant fleet of support vessels across to the Beaufort Sea for part of the drilling season.

Oil spill response

The support fleet will include an on-site oil spill response vessel with sufficient oil storage capacity to handle the first 24 hours of any oil spill emergency. An Arctic oil storage tanker with capacity to handle at least a 30-hour well blowout will be staged within a 24-hour sailing time of an active drill site. And an additional oil spill response barge and tug will be positioned ready to respond to any spilled oil that might reach the nearshore area of the Chukchi.

Shell also has a plan for dealing with a well blowout, including the possibility of drilling a relief well to plug the oil flow.

However, Shell says that any kind of oil spill is very unlikely. In addition to using state-of-the-art well planning and drilling techniques, including the use of remote operations centers for monitoring what is happening at the drill site, the company has a critical operations and curtailment

see **BURGER** *page 14*

SAFETY & ENVIRONMENT

Americans cooling on global warming

In April 2008, 44% viewed global warming as a serious problem; latest Pew survey says that number appears to be down to 35%

PETROLEUM NEWS

There has been a sharp decline over the past year in the percentage of Americans who believe there is solid evidence that global temperatures are rising. And fewer also see global warming as a very serious problem — 35 percent say that today, down from 44 percent in April 2008.

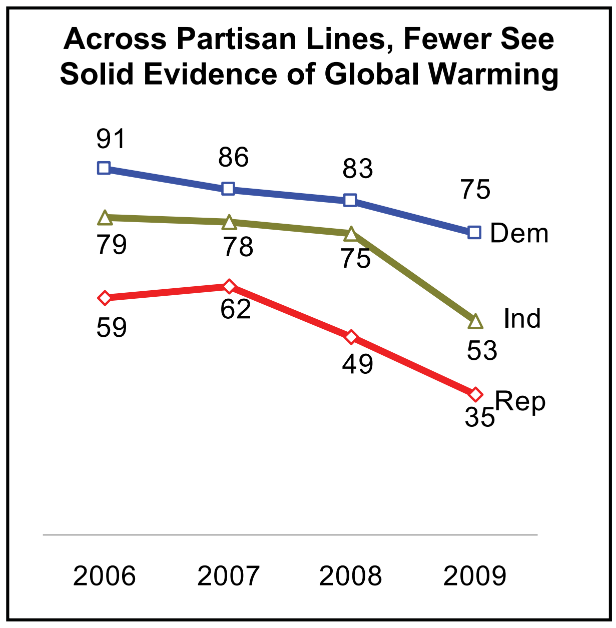
The latest national survey by the Pew Research Center for the People & the Press, conducted Sept. 30-Oct. 4 among 1,500 adults reached on cell phones and landlines, finds that 57 percent think there is solid evidence that the average temperature on earth has been getting warmer over the past few decades. In April 2008, 71 percent said there was solid evidence of rising global temperatures.

Over the same period, there has been a comparable decline in the proportion of Americans who say global temperatures are rising as a result of human activity, such as burning fossil fuels. Just 36 percent say that currently, down from 47 percent last year.

Andrew Kohut, director of the research center, believes that "the priority that people give to pollution and environmental concerns and a whole host of other issues is down because of the economy and because of the focus on other things."

Democrats: 83% in 2008 to 75% today

The decline in the belief in solid evidence of global warming has come across the political spectrum, but has been particularly pronounced among independents, the survey indicated. Just 53 percent of independents now see solid evidence of global warming, compared with 75 percent who did so in April 2008. Republicans, who already were highly skeptical of the evidence of global warming, have become even more so: Just 35 percent of Republicans now see solid evidence of rising global temperatures, down from 49 percent in 2008 and 62 percent in 2007. Fewer Democrats also express this view — 75 percent today compared with 83 percent last year.



Despite the growing public skepticism about global warming, the survey finds more support than opposition for a policy to set limits on carbon emissions. Half of Americans favor setting limits on carbon emissions and making companies pay for their emissions, even if this may lead to higher energy prices; 39 percent oppose imposing limits on carbon emissions under these circumstances.

This issue has not registered widely with the public. Just 14 percent say they have heard a lot about the "cap and trade" policy that would set carbon dioxide emissions limits; another 30 percent say they have heard a little about the policy, while a majority of 55 percent has heard nothing at all.

The small minority that has heard a lot about the issue opposes carbon emissions limits by two-to-one — 64 percent to 32 percent. More Republicans (20 percent) and independents (17 percent) than Democrats (8 percent) have heard a lot about cap and trade. Among the much larger group that has heard little or nothing about the issue, most support it (58 percent little, 50 percent nothing).

With less than two months before the United Nations Climate Change Conference in Copenhagen, 56 percent of Americans think the United States should join other countries in setting standards to address global climate change while 32 percent say that the United States should set its own standards.

With less than two months before the United Nations Climate Change Conference in Copenhagen, 56 percent of Americans think the United States should join other countries in setting standards to address global climate change while 32 percent say that the United States should set its own standards.

Believers say largely caused by human activity

Opinions about global warming changed little between 2006 and 2008, the survey showed. In August 2006 and January 2007, 77 percent said there was solid evidence that the earth's temperatures were increasing; that figure fell modestly to 71 percent in April of last year.

Among those who saw solid evidence of global warming, most said it was largely caused by human activity, such as burning fossil fuels; in all three of those surveys, 47 percent of the public expressed this view. Far smaller percentages — including just 18 percent in 2008

see SURVEY page 15

● EXPLORATION & PRODUCTION

Seeking answer to vexing gas-oil issue

EnCana testing nitrogen, CO2 in bitumen production; Alberta Energy Resources Conservation Board continues to shut in gas wells

By GARY PARK

For Petroleum News

EnCana thinks it might be on track to solve what has been dubbed the most significant energy conservation issue in 70 years of a government regulated industry in Alberta.

What rapidly morphed into one of the nastiest disputes between the natural gas and oil sands sectors when it first surfaced 12 years ago has reappeared.

At play is the future of billions of barrels of potentially recoverable bitumen in northeastern Alberta and billions of cubic feet of natural gas reserves.

Despite six years of consultation and public hearings, Alberta's energy regulator was unable to find a way to protect the value of both resources.

The issue boils down to the impact of gas production in an area containing some of Alberta's highest-quality bitumen resources.

As the gas is produced, reservoir pressure drops in the gas pools posing a risk to bitumen recovery using thermal techniques, such as steam-assisted gravity drainage.

In the view of what is now the Alberta Energy Resources Conservation Board, there is no currently proven technology that can satisfactorily protect the value of the bitumen, whose energy content is about 600 times greater than the overlying gas.

Shut-ins in 2003

The initial round of regulatory decisions in 2003 shut in production by 16 producers from 835 gas wells that were yielding about 123 million cubic feet per day.

Faced with threats of costly lawsuits by the gas producers, the government agreed to a compensation formula that paid out C$95 million to 12 producers in 2005. No updated compensation figures have been released.

The so-called gas-over-bitumen issue flared up again Oct. 15 when the Alberta ERCB ordered an interim shut-in of 158 gas wells affecting a potential 33 million cubic feet per day of output pending a full hearing in spring 2010.

The board reiterated its earlier insistence that it was required only to determine that potential, not commercial, bitumen recovery was at risk from continued gas development.

But it said the interim order is "not conclusive or permanent" until it concludes a full hearing.

EnCana testing new technology

EnCana, which has 16 wells in the affected area and is also a major oil sands operator, did not file a submission in the latest case.

But, as it has done before, the big independent is leading the way in seeking an answer.

Following the first shut-in, it obtained regulatory permission to develop the EnCana Air Injection and Displacement technology and has been running tests over the past two years.

To maintain pressure in the reservoirs, EnCana has been injecting nitrogen and carbon dioxide, which also helps heat up the bitumen, allowing it to flow more easily.

But, pending a solution, the ERCB shows no signs of wavering.

The latest case was triggered by oil sands startup Sunshine Oilsands and the French major Total.

Sunshine is seeking approval for an initial 8,000-barrel-per-day facility to exploit 15 million barrels of primary recovery bitumen and 30 million barrels using enhanced recovery methods.

It has budgeted C$31 million for an initial 1,800 bpd project and C$460 million for a five-phase project to reach 8,000 bpd.

The company estimates it has petroleum initially in place on its leases of 312 million barrels, enough to support a 180,000-bpd development, with an operating life of 30 years.

Total is involved in evaluations of steam-recovery potential for bitumen deposits, also in the Liege field of the Athabasca oil sands region.

Sunshine: protecting bitumen

Sunshine Chief Executive Officer Doug Brown welcomed the ERCB decision as proof that the regulator wants to protect the bitumen resource "for the benefit of Albertans."

He said the board's response is "very helpful" for the timely development of his company's plans to harness its bitumen resources by using conventional steam-recovery technology.

Athabasca Oil Sands (which recently sold 60 percent stakes in two of its oil sands projects to China's CNOPOC) and Grizzly oil sands filed submission's supporting Sunshine's case.

Objections were registered by Canadian Natural Resources, and its working-interest partner Japan Oil Sands, which is licensee of 25 affected gas wells, and Paramount Energy Trust, which has 69 affected wells.

Paramount said price forecasts for gas and royalty reductions applicable to shut-in wells will soften the impact of the ERCB order and not have a material impact on the trust's funds. ●

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BURGER

plan that specifies situations such as severe weather, in which drilling would stop, with the drillship perhaps moving off site.

Marine mammals

Shell also says that it is voluntarily submitting to MMS a site-specific plan for monitoring marine mammals, including the use of marine mammal observers onboard vessels, the use of subsea acoustic recorders and the carrying out of aerial surveys along a zone that extends about 20 miles out from the Chukchi Sea coast. And, as part of applications to the National Marine Fisheries Service and the U.S. Fish and Wildlife Service for authorizations for the nonlethal, incidental take of marine mammals, the company has specified how many animals of various species might be exposed to significant sound from its drilling activities.

"Any impacts to whales and seals from the planned exploration drilling program would be temporary and result in only short-term disturbance or displacement," the plan says. "From a historical perspective, the temporary activity of offshore exploration drilling and associated support vessel activities, collectively and individually, have not resulted in impacts of biological significance to marine mammals of the Arctic, or interference with the subsistence harvest of those marine mammals by the residents of the communities along the Beaufort and Chukchi Seas."

Shell says that it has prepared a plan of cooperation with Chukchi Sea coastal communities that depend on the subsistence hunting of marine mammals. ●

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SURVEY

— said it was mostly caused because of natural environmental patterns.

According to the survey, fewer than four-in-10, or 36 percent, now say global warming is mostly caused by human activity such as burning fossil fuels, while 16 percent say it is occurring mostly because of natural environmental patterns.

Opinions about Global Warming 2006-2009

Is there solid evidence the earth is warming?	Aug 2006	Jan 2007	April 2008	Oct 2009
	%	%	%	%
Yes	77	77	71	57
Because of human activity	47	47	47	36
Because of natural patterns	20	20	18	16
Don't know (Vol.)	10	10	6	6
No	17	16	21	33
Mixed/Don't know (Vol.)	6	7	8	10
	100	100	100	100

Q41 & Q42. Figures may not add to 100% because of rounding.

Decline steepest among moderate, liberal Republicans

Fifty-three percent of independents say there is solid evidence of warming, including 33 percent who say it is mostly caused by human activity. But this is far lower than in April 2008 when 75 percent said global warming was happening and 50 percent said it was due to human activity.

The proportion of Republicans saying there is solid evidence of global warming declined from 62 percent in 2007 to 49 percent in 2008, Pew's survey shows.

The balance of opinion among Republicans has shifted, with a majority of 57 percent now saying there is no hard evidence of global warming. The drop among moderate and liberal Republicans has been particularly steep; 41 percent now say there is solid evidence of global warming, compared with 69 percent last year. The decline among conservative Republicans has been more modest, from 43 percent to 32 percent.

The survey suggests there has been less change in opinions among Democrats. Seventy-five percent of Democrats say there is solid evidence the earth is warming, including 50 percent who say that it is mostly because of human activity. In April 2008, 83 percent of Democrats said the earth is warming and 58 percent attributed it to human actions. More liberal Democrats than conservative and moderate Democrats say the earth is warming — 83 percent vs. 72 percent — and far more liberal Democrats say that global warming is caused by human activity — 69 percent vs. 43 percent.

Strong regional differences

There also are strong regional differences in opinions about global warming. Fewer people living in the Mountain West (44 percent) and the Midwest (48 percent) say there is solid evidence of warming than in other regions.

Similarly, there have been sharp declines since April 2008 in the proportion who say the earth is warming in the Mountain West (75 percent to 44 percent) and the Great Lakes region (69 percent to 49 percent). Both regions have also seen large drops in the percentage who say that warming is caused by human activity.

Fewer see warming as serious problem

Sixty-five percent of the public continues to view global warming as a very (35 percent) or somewhat (30 percent) serious problem. But in April 2008, 73 percent expressed this view, including 44 percent who thought it was a very serious problem.

About a third (32 percent) says global warming is not too serious (15 percent) or not a problem at all (17 percent). Last year, 24 percent said it was little or no problem. From 2006 to 2008, these numbers had been quite stable.

How Serious a Problem Is Global Warming?

	July 2006	Jan 2007	April 2008	Oct 2009
	%	%	%	%
Very serious	43	45	44	35
Somewhat serious	36	32	29	30
Not too serious	11	12	13	15
Not a problem	9	8	11	17
Don't know (Vol.)	1	3	3	3
	100	100	100	100

Q43. Figures may not add to 100% because of rounding.

Partisan differences also are evident on evaluations of the seriousness of global warming. Forty-nine percent of Democrats say global warming is a very serious problem, down from 57 percent in April 2008. Far fewer conservative and moderate Democrats say global warming is a serious problem than did so last year, widening the gap between them and liberal Democrats. Currently, 39 percent of conservative and moderate Democrats say it is a very serious problem compared with 70 percent of liberal Democrats. A third of independents now say global warming is a very serious problem, a decline of 13 points from last year.

Only 14 percent of Republicans say that global warming is a very serious problem, down from 22 percent in April 2008. Just 20 percent of moderate and liberal Republicans now say that global warming is a very serious problem, down from 35 percent last year. Only 10 percent of conservative Republicans now say global warming is a very serious problem.

People living in the Midwest (30 percent) and the Mountain West (26 percent) are the least likely to view global warming as a very serious problem. There have been modest declines across regions, but they are particularly steep in the West (52 percent April 2008 to 36 percent now).

Young people most concerned

According to the Pew survey, young people are now far more likely than older Americans to view global warming as a very serious problem. Across all age groups, except those younger than 30, the percent who think warming is a very serious problem has declined since April 2008.

Unsurprisingly, views about the seriousness of global warming are also related to whether people think there is solid evidence the earth is warming and whether it is humanly caused. A third of those who do not think there is solid evidence of global warming say it is a very or somewhat serious problem while 65 percent say it is not too serious or not a problem at all.

According to the Pew survey, young people are now far more likely than older Americans to view global warming as a very serious problem.

By comparison, the survey showed 65 percent of those who say that the warming is mostly caused by natural patterns in the earth's environment say global warming is at least a somewhat serious problem. Nearly all (97 percent) who think the earth is warming mostly because of human activity say it is a problem. These numbers, Pew says, are largely unchanged from April 2008.

Ranked at bottom of everyone's priorities

In January 2009, Pew said global warming ranked at the bottom of the public's list of policy priorities for the president and Congress this year. Only 30 percent of the public said it should be a top priority, down from 35 percent in 2008.

More than twice as many Democrats (45 percent) as Republicans (16 percent) rank global warming as a top priority, along with 25 percent of independents. Global warming is the lowest-rated priority for both independents and Republicans and ranks sixteenth for Democrats among 20 issues (http://people-press.org/report/554/news-iq-knowledge-quiz).

About Pew

The Pew Research Center for the People & the Press is an independent opinion research group that studies attitudes toward the press, politics and public policy issues. All of its current survey results are made available free of charge. ●

For information about Pew's survey methodology, see http://people-press.org/methodology/.

FINANCE & ECONOMY

Koreans stun Canadian oil patch

State-run KNOC offers premium for Harvest Energy Trust holdings in search for energy security; bolsters chances of new sands market

By GARY PARK

For Petroleum News

South Korea's state-run Korea National Oil Corp. has taken a headlong plunge into Canada's energy sector in a highly complex move that is causing widespread head scratching within the industry.

The move came amid reports that KNOC was still seething over its failure earlier this year to outwit and outbid China Petrochemical Corp. (better known as Sinopec) in a contest for Swiss-based Addax Petroleum.

Sinopec landed Addax, which is active in West Africa and Iraq's Kurdistan region, for US$7.24 billion.

KNOC retaliated Oct. 22 with a C$4.1 billion offer (C$1.8 billion in cash and C$2.3 billion assumed debt) for Harvest Energy Trust, effectively laying out C$63,000 per flowing barrel of Harvest production and a widely scattered bundle of assets.

If there is a competing bid, which few seem to expect, KNOC will have five business days to counter.

Should the deal not go through, KNOC has also agreed to a noncompletion fee of C$100 million.

Analyst doesn't expect competition

UBS analyst Travis Wood said in a research note that competing bidders are unlikely to emerge given that KNOC, on a flowing barrel-of-production basis, is pay-

"KNOC has ambitious plans for future growth and is committed to a long-term investment strategy for Canada." **—Young-won Kang, president of KNOC**

ing a 25 percent premium to recent deals and about 10 percent for reserves in the ground.

"Harvest's rationale — take it and run," he said.

Wood said he expects KNOC will spend more capital than Harvest has as it chases production growth.

What startles observers is KNOC's offer of C$10 per trust unit, a 47 percent premium over the 30-day weighted average trading price on the Toronto Stock Exchange and 37 percent over Oct. 21, the day before the offer was launched.

To complete the deal in December, KNOC needs support from two-thirds of Harvest unit holders, regulatory and court approvals and an automatic review under the Investment Canada Act, which can reject foreign takeovers seen to be at odds with Canada's strategic interests and unable to establish a net benefit for Canada.

Foreign takeovers a trend

The aggressive buying of KNOC, PetroChina and Abu Dhabi's TAQA are expanding the pattern of foreign takeovers in Canada's energy sector, one that Clarus Securities analyst Victor Rodberg said is "certainly a trend and it's definitely not slowing down."

He said foreign acquisitors apparently see more long-term value in Canadian companies that domestic buyers, but the danger for Canada is losing head offices and becoming branch plants or subsidiaries of foreign state-controlled enterprises.

If the various hurdles can be cleared, KNOC will inherit 154 million barrels of oil equivalent in proved reserves and 220 million boe in proved-plus-probable reserves, few of which are considered gems outside of a stake in Saskatchewan's Bakken formation; conventional production of about 52,000 boe per day (70 percent oil and natural gas liquids and 30 percent natural gas); 3 billion barrels of potential oil sands reserves spread over 42,000 net acres in the Peace River and Cold Lake areas of Alberta; 2 trillion to 3 trillion cubic feet of coalbed methane prospects; and a 115,000 bpd refinery in Newfoundland.

Shoring up energy security

The conclusion, given this disparate bundle, is that KNOC is ready to make bold moves to shore up South Korea's energy security and was not prepared to sit back and watch China expand its oil sands presence, two months after PetroChina offered C$1.9 billion for a 60 percent share of two projects by Athabasca Oil Sands.

It may also have been prodded into action by word from Enbridge that it hopes to submit a regulatory application in November for its proposed Northern Gateway pipeline from Alberta to the Kitimat deepwater port on the northern British Columbia coast.

The pipeline is designed to carry 525,000 bpd, with the bulk tagged for Asian refiners, with Korea and Japan thought to be higher on the list than China.

It could hold the key to growing industry and government beliefs that Canada needs an alternative outlet to the United States for its bitumen.

"Selling into the declining or even stagnant market is a difficult thing to do, especially when it is your only market," Peter Tertzakian, energy economist at ARC Financial, told the Globe and Mail earlier in October. "That's why it is paramount for Canada to be thinking about opening up other markets, particularly the growth markets of Asia for our product."

Increased production the goal

South Korea has its sight set on raising KNOC's production from 70,000 bpd (excluding Harvest's volumes) to 300,000 bpd by 2012, accounting for about 18.1 percent of its needs and reducing its role as the world's fifth largest importer of crude.

That program has included asset purchases and exploration in Peru, the U.S. Gulf Coast and Iraq this year.

To that end, KNOC expects to buy at least one more company this year, a government official said.

KNOC established a toehold in 2006, paying C$270 million to Newmont Mining for the BlackGold oil sands leases estimated to hold about 300 million barrels of recoverable bitumen.

So far, KNOC's only significant moves have been to scale back its original plans to produce 100,000 bpd by 2015 to a 30,000-35,000 bpd operation (starting at 10,000 bpd in 2010), then putting an indefinite hold on development pending the release of government environmental regulations and an economic recovery. The feeling within the industry is that KNOC has been unable to hire the talent needed to commercialize BlackGold.

Young-won Kang, president of KNOC, said the Harvest takeover is a "perfect fit for KNOC's North American growth strategy."

"KNOC has ambitious plans for future growth and is committed to a long-term investment strategy for Canada," he said.

The company has set a goal to become "expert in the oil sands" by about 2015, certain that oil prices and its own technological skills will make the oil sands deposits a prime development resource.

Korea Gas signs with Kitimat

Also operating outside the spotlight, Korea Gas Corp. signed a memorandum of understanding this year with Kitimat LNG to take 40 percent of its proposed 5 million metric tons a year of LNG shipments from the Kitimat export terminal that could start operations within five years.

Kyle Preston, an analyst with Canaccord Adams, said Harvest has landed a good price after struggling with debt issues and weaker refining margins.

From having one of the trust sector's highest cash distribution ratios, it slashed annual payouts in March to C$100 million from C$500 million

Despite these problems, Harvest Chief Executive Officer John Zahary said the board of directors was not looking to sell

see KNOC page 17

GOVERNMENT

Rules for wells deeper than 1,000 feet

AOGCC says its regulations will apply to wells in the Bristol Bay area because of likelihood of unexpected oil, gas encounters

By KRISTEN NELSON

Petroleum News

The Alaska Oil and Gas Conservation Commission has determined that there is "sufficient likelihood" that wells drilled in designated townships in the Bristol Bay area would "encounter oil, gas or other hazardous substances." Because of that, the commission said in an Oct. 27 order for geothermal exploration wells, it has determined that wells in the area drilled deeper than 1,000 feet will be subject to the commission's regulations and requirements.

AOGCC permits oil and gas wells, but geothermal wells are permitted by the Department of Natural Resources.

At the commission's August public meeting AOGCC Commissioner Cathy Foerster said DNR's drilling regulations are based on 1986 commission regulations. Art Saltmarsh, senior petroleum geologist with the commission, said at the August meeting that the commission has stricter standards in a number of areas than DNR does, including: protection of correlative rights — the rights of adjacent resource owners; demonstration by the operator of safe drilling operations; demonstration by the operator of knowledge of geology and offset data in the area of the well; and ensuring the operator has plans in place for unexpected occurrences during drilling.

AOGCC permits oil and gas wells, but geothermal wells are permitted by the Department of Natural Resources.

Saltmarsh said the commission had started receiving requests from DNR to review geothermal drilling proposals and expected that such requests would continue since DNR has held a geothermal lease sale.

Also at the August meeting commission reservoir engineer Winton Aubert said the commission's drilling regulations differ significantly from those enforced by DNR, with blowout equipment and testing regulations "significantly different and less stringent" in DNR's regulations. He said DNR's regulations do not include a methane gas detection requirement and there is no completion equipment requirement.

Naknek Electric drilling for geothermal

The commission held a hearing Sept. 23 on a commission motion to require an AOGCC drilling permit for any well with a total vertical depth greater than 1,000 feet in specified townships and ranges within the Bristol Bay Borough, an area where Naknek Electric Association is proposing to drill geothermal wells.

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

Tab Ballantine, the assistant attorney general who works with the commission, told the commission in August that its authority would arguably be circumscribed by whether there was a likelihood of an unexpected encounter with oil or gas during the drilling of a geothermal well. At the September hearing he said the commission could require compliance with its regulations even though DNR was issuing a drilling permit.

In its October order the commission listed wells in the general area of the townships listed in its order which encountered oil or gas shows.

The commission's order is effective for all wells drilled in the specified townships after the date of the order. ●

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KNOC

the trust until KNOC arrived on the doorstep.

"KNOC knew what it wanted. … It was very motivated," he said, adding the financial backing from KNOC will be "helpful in funding the attractive investment opportunities in our assets."

Help with refinery capital

In particular, Zahary suggested KNOC may be able to solve the bind Harvest faces with its Come By Chance refinery in Newfoundland, which it acquired three years ago in a C$1.6 billion takeover of North American Refining.

Plans to spend C$2 billion adding 75,000 bpd of capacity were shelved last year, while Harvest started looking for a partner to share the costs.

KNOC's financial clout improves the odds of that work going ahead, as well as ensuring that some other projects that were deferred or slowed down can resume progress, Zahary said.

"You've got to put some capital spending into your business and our capital spending has been somewhat constrained lately with the state of the capital markets," he said.

Harvest also had some good news related to the refinery earlier in October when it renewed and extended its existing crude oil supply and refined product offtake agreement with Vitol Refining, adding two years to a deal that takes effect on Nov. 1. ●

EXPLORATION & PRODUCTION

Oil sands tries to move past ducks

By GARY PARK

For Petroleum News

It's an issue the Alberta oil sands sector just can't duck, but the industry is doing whatever it can to put distance between itself and 1,606 dead ducks at the Syncrude Canada operations last year.

The industry has sent one of its chief spokesman on the road to put a different perspective on the waterfowl episode that is now the overriding public image of the Alberta resource.

And oil sands giant Suncor Energy has submitted an application to the Alberta Energy Resources Conservation Board and Alberta Environment to speed up the reclamation of tailings ponds, a toxic sludge where the ducks — a small fraction of those killed during the hunting season — came to a messy end last year.

Meanwhile, the Syncrude consortium has pleaded not guilty to charges in the duck deaths. The trial is set to begin March 2010 in Alberta Provincial Court.

Suncor, which pioneered oil sands production 40 years ago, said its plans for tailings ponds will allow reclamation to begin in as few as seven years compared with the 40 years it now takes.

It said a patented technology, which has been under study for six years, allows mature fine tailings to be pumped from the ponds by using a polymer agent to separate water from the tailings, thus reducing the number and size of tailings ponds.

Suncor Executive Vice President Kirk Bailey said the new treatment "will help us meet new provincial regulatory requirements and, just as importantly, the changing expectations of stakeholders."

Fine particle reduction ordered

The Alberta Energy Resources Conservation Board has ordered oil sands producers to reduce fine particles in liquids tailings by 20 percent by June 30, 2011, and by 50 percent by 2013.

Simon Dyer, oil sands program director with the Pembina Institute, said he was "cautiously positive" about Suncor's proposal, but said his environmental organization would not shift from its call for a moratorium on new or expanded oil sands projects until all environmental questions were resolved.

Under that directive, bitumen mining companies had a Sept. 30 deadline to submit their plans to meet the new standards.Six met that target — Albian Sands Energy (operated by Royal Dutch Shell), Canadian Natural Resources, Imperial Oil, Shell Canada, Suncor and Syncrude.

The inventory of fine tailings that require long-term containment covers about 16 square miles in northeastern Alberta.

To counter the growing criticism of the oil sands business, Marcel Coutu, chief executive officer of Canadian Oil Sands Trust, which owns 36.74 percent of Syncrude, spread a message in Eastern Canada that the industry is "trying to get beyond ducks."

"My personal objective is to instill a sense of pride in Canadians about what this asset really is to us," he said.

"We're trying to tell people, 'Listen, this is a Canadian world-class asset, this is not an Alberta backyard money-making operation.' More than half the revenues from the oil sands and taxes go to the federal government … paying for health, education (and) infrastructure," Coutu said.

He also said that the tailings ponds result from mining operations, which account for only 15 percent of the resource, while 85 percent is extracted using technologies such as steam injection." ●

SAFETY & ENVIRONMENT

Wins and losses for sands sector

Industry gets boost from study estimating employment, economic spinoffs; runs afoul of chemical producers, who demand single standard

By GARY PARK

For Petroleum News

The Alberta oil sands, as is so often the case, are being pulled in opposite directions, quietly ramping up production, while unease builds as the sector awaits greenhouse gas regulations from the Obama administration and a loosely knit coalition in Canada challenges any attempts to give the resource special treatment under Canada's GHG legislation.

On the positive side, oil sands output this year has edged up by 200,000 barrels per day to 1.4 million bpd from average levels in 2007 and 2008.

All of that incremental growth is being shipped to the United States for refining, bolstering Canada's leading role as the largest external source of U.S. crude at 2.1 million bpd.

Peter Tertzakian, chief energy economist at ARC Financial, noted in the Calgary Herald that this expansion comes at a time when U.S. oil demand has dropped by 2 million bpd, underscoring the fact that Canada is taking market share away from Mexico and Venezuela, where production has been declining due to lack of investment, political issues and inefficient exploration and production practices.

Employment positives

Injecting further momentum into the trend is a new report by the Canadian Energy Research Institute, commissioned by the American Petroleum Institute.

The major element of the study is the positive employment and economic spin-off for the U.S. from the oil sands, which are projected to create 343,000 new jobs between 2011 and 2015 and add $34 billion to the U.S. Gross Domestic Product by 2015, provided investment on new projects starts to ramp up in 2013, triggering an increase in demand for U.S. goods and services to $40.4 billion in 2020 and $42.2 billion in 2025.

The study forecasts output of raw bitumen will climb over the 2009 to 2025 period to 4 million bpd, within a range projected at 1.9 million to 2.9 million bpd in 2015 and 3.5 million to 5.1 million bpd in 2025.

Total investments over the study period on new oil sands projects are calculated at $218 billion, while combined capital spending and operating costs could reach $379 billion over the 16 years.

"What is often not clearly understood is that the large investment in the oil sands industry contributes to increased economic activity in the rest of North America by stimulating demand for goods and services across a wide range of industries," said the report.

While manufacturing will reap the greatest rewards, finance and insurance sectors also benefit, with professional, scientific and technical services in the U.S. seeing an average $4.2 billion a year increase in output, it said.

CERI's projections are based on oil prices remaining at current levels for the next year, but averaging $100 for West Texas Intermediate crude over 2009-25.

It said the billions of dollars needed to develop the oil sands over the next several decades will give rise to a "long-lived, robust period of increased economic activity in Canada. Due to the deep and rich trading relationship between Canada and the U.S, the U.S. derives significant benefit …"

Doer: too much criticism

Gary Doer, the former premier of Manitoba and now Canada's new ambassador to the U.S, reinforced that message, arguing the oil sands face a "disproportionate amount" of criticism in the climate-change debate, telling CanWest News that North America risks missing the "big picture" on global warming if Canadian crude is singled out as the chief carbon emissions culprit.

Noting the oil sands represent only a "small amount" of North America's greenhouse gas emissions, he said concentrating too much criticism on the resource and failing to deal with all sources of emissions will prevent governments from developing a comprehensive solution.

"You've got to look at everything," he said. "How do you reduce emissions from coal? How do you increase the use of renewables? How do you increase energy efficiency? All of these items have to be on the agenda."

But there is concern that the future of the oil sands could unravel as President Barack Obama travels to China and India in November to seek a global climate deal before the Copenhagen summit and as the U.S. Senate debates legislation to create a

see OIL SANDS page 21

● EXPLORATION & PRODUCTION

22 percent of undiscovered oil in Arctic

EIA recycles USGS estimate from last year, says vast potential of shale gas could defer development of faraway Arctic gas deposits

By WESLEY LOY
For Petroleum News

The region north of the Arctic Circle could hold about 22 percent of the world's undiscovered conventional oil and natural gas, an Oct. 19 report from the U.S. Energy Information Administration says.

This isn't the freshest of news. The EIA report is based on a U.S. Geological Survey assessment released in 2008 that included the 22 percent estimate.

The 18-page EIA report rehashes the USGS findings and lays out the challenges of developing whatever oil and gas might be under the globe's frosty cap.

"The Arctic presents a 'good news, bad news' situation for oil and natural gas development," the EIA report concludes. "The good news is that the Arctic holds about 22 percent of the world's undiscovered conventional oil and natural gas resources, based on the USGS mean estimate."

The bad news is that the Arctic resources are believed to be more gas than oil, and that extreme risk, long project lead times, unresolved Arctic sovereignty claims, and costly environmental protections will make production of the resources very difficult, the EIA report says.

Distribution of resources

The EIA report says the area above the Arctic Circle encompasses about 6 percent of the Earth's surface area. Eight countries have some jurisdiction in the Arctic: Canada, Denmark (Greenland), Finland, Iceland, Norway, Russia, Sweden and the United States.

"The allure of the Arctic is great because of the significant oil and natural gas deposits that have already been found and the large areas that have not yet been explored," the EIA report says.

The report says 61 large oil and gas fields — fields exceeding 500 million barrels of oil equivalent — have been discovered within the Arctic Circle. Of these, 43 are in Russia, 11 are in Canada's Northwest Territories, six are in Alaska, and one is in Norway.

The USGS mean estimate of undiscovered, technically recoverable, conventional Arctic resources is 412 billion barrels of oil equivalent, with 78 percent expected to be natural gas and natural gas liquids.

The resources are believed to be concentrated in "just a few sedimentary provinces," the EIA report says.

The Eurasian side of the Arctic is more gas-prone, while the North American side is more oil-prone, the report says.

"The Arctic Alaska region is estimated to hold the largest undiscovered Arctic oil deposits, about 30 billion barrels," the report says. "The second largest oil province in the Arctic is the Amerasia Basin, located just north of Canada, and estimated to have about 9.7 billion barrels of undiscovered oil."

No go for Arctic gas?

As testament to the challenges of developing Arctic oil and gas, the report notes that 15 of the 61 large oil and gas fields already discovered still haven't gone into production. Most of the undeveloped fields were discovered in the 1970s and 1980s.

"The high cost of doing business in the Arctic suggests that only the world's largest oil companies, most likely as partners in joint venture projects, have the financial, technical, and managerial strength to accomplish the costly, long-lead-time projects dictated by Arctic conditions," the EIA report says.

With respect to natural gas, the report notes the long distance of Arctic gas from consumer markets. It adds that the relative importance of Arctic resources "is likely to be affected by the growing realization that shale beds in existing petroleum provinces around the world might be capable of producing 5,000 to 16,000 trillion cubic feet of natural gas.

"This potentially large shale gas resource could significantly defer the future development of Arctic natural gas resources.

"Of course, there could be exceptions."

The EIA report is posted online at www.eia.doe.gov under "What's New." ●

● FINANCE & ECONOMY

BP, Conoco both continuing cost cutting

By KRISTEN NELSON
Petroleum News

There were some common themes as BP and ConocoPhillips reported earnings at the end of October. Third-quarter earnings were down substantially from the 2008 third-quarter, when earnings were bolstered by high oil prices. But that is true for oil and gas companies generally.

Both companies said they have reduced spending to live within their means and have been cutting costs.

BP has been restructuring and reducing costs for more than two years and Byron Grote, the company's chief financial officer, said in an Oct. 27 analysts' call that the company has maintained momentum in reducing costs.

BP has been "driving greater efficiency" across the company, he said, and cash costs year-to-date are down by more than $3 billion, with a full-year decrease of some $4 billion expected, "twice the level projected at the start of the year."

Fergus MacLeod, BP's head of investor relations, said a decrease in unit costs in the third quarter was driven by high grading of activity, more efficient execution and supply-chain benefits. With rising oil prices "we'd expect to see something of a head wind developing from the supply chain," but high grading of activity and more efficient execution will continue.

"And so I think you would be overly pessimistic to expect us to revert to the cost structure of two and a half years ago, even if we were to see the oil price go back to where it was," MacLeod said.

"As a firm, we've said that we intend to balance our sources and uses of cash at about a $60 oil price environment and to invest at a level that is necessary to be able to grow the firm," Grote said.

Both men said there were benefits yet to be found in reducing costs.

MacLeod said some areas of BP's upstream operations were doing very well and some "still have a ways to travel."

BP has been restructuring and reducing costs for more than two years and Byron Grote, the company's chief financial officer, said in an Oct. 27 analysts' call that the company has maintained momentum in reducing costs.

In describing cost cutting Grote said BP was taking "general cost efficiency measures across the company, a thousand and one things that are being done consistent with the model 'every dollar counts,' which is held dear by everybody working at BP."

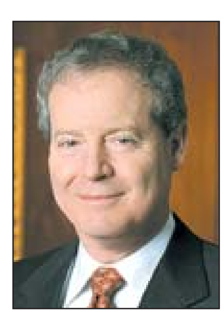
ConocoPhillips — the size issue

ConocoPhillips discussed cutting its costs and cutting the size of the company.

Jim Mulva, ConocoPhillips' chairman and CEO, said in an Oct. 28 analysts' call that while the company of today was created over the past 10 years, the business environment has changed in the last 12 to 18 months.

Access to resources worldwide continues to be an issue, he said, and the company's capital program is constrained.

ConocoPhillips is living within its means, he said, and while the company will continue to be an international integrated company it will be somewhat smaller with an emphasis on return rather than growth, and with projects prioritized to improve returns.


JIM MULVA

The goal of the sale of some $10 billion in assets, previously announced, is to reduce the company's debt, Mulva said.

Like BP, ConocoPhillips talked about reducing spending to live within its means.

Mulva said the company's capital budget will be reduced, from the $14 billion to $15 billion a year range where it has been recently to about $11 billion a year.

Mulva said the company believes a capital budget of $11 billion is really "the sweet spot" for Conoco in terms of business.

He said the company believes a capital budget of $11 billion is really "the sweet spot" for Conoco in terms of business.

Sig Cornelius, the company's chief financial officer, said lower operating costs improved the company's earnings. He said the company will continue to pursue cost reductions aggressively across the board working with service providers, with a goal of getting those costs down to where they were in 2007, a 10 percent reduction from 2008 cost levels.

He said that through the third quarter ConocoPhillips achieved its full-year cost reduction goals, and will continue to pursue additional cost-reduction opportunities. ●

Business Spotlight

Delta Pump & Equipment LLC

COURTESY PHOTO

Bill Ahrens, Pump Specialist

Delta Pump & Equipment LLC, a woman-owned business, started business in 2000 selling pumps and continues to do so with a menu of additional manufacturers and related equipment added over the years. The company has grown into systems design and fabrication for the oil-field, mining and sewage industries, and also is a warranty repair facility for some pumps.

After moving to Alaska in 1983, Bill Ahrens drove a dump truck, and later held a position at National Oilwell for nearly 17 years. He then worked for himself in an unrelated business venture, and subsequently worked for two local pump companies, after which, he went to work for Delta P Pump. When not working, Ahrens enjoys flying, hunting, fishing, history, science and reading a good novel.

—MARTI REEVE

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

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

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PLANNING

compromise pipeline safety. Areas of likely scouring can be identified from helicopter flights over sea ice near river mouths during the spring; then people return by boat to these areas in the early open water season, to locate scours before new sediment can fill them, Miller said.

Shell is also researching coastal stability in areas where a future oil pipeline may come onshore. The company is using data from surveying and satellite photography to try to find locations where a pipeline transition to land could be achieved without the need to build a protective structure. A site would need to remain viable for the entire life of an offshore oil field.

"You have to predict what's going to be happening 30, 40, 50 years into the future," Miller said.

Geotechnical surveys

In addition, Shell has been conducting geotechnical surveys along a potential pipeline route in the Beaufort Sea, determining what type of soil is present and measuring the soil strength. This type of information is important in ensuring a safe oil platform design, as well as in making sure that a pipeline can be adequately buried and protected.

Other data collection activities that have been in progress include the measurement of sea-ice movement using satellite buoys on the ice, and the evaluation of ice structures using computer-processed stereoscopic aerial photos. The assessment of ice structures will enable a determination of whether a vehicle such as a hovercraft could safely make its way on the ice to and from an offshore operation, as well as providing some of the information needed to understand the potential impact of ice on an offshore structure, Miller said. ●

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OIL SANDS

cap-and-trade system.

EPA regulations threatened

John Podesta, the former head of Obama's transition team, told an Ottawa conference Oct. 22 the administration has threatened that failure by U.S. lawmakers to pass climate-change legislation will result in the Environmental Protection Agency regulating emissions.

He said that is a "bold shot across the bow" of opponents in Congress and the U.S. business community, who are ready to fight legislative moves.

Podesta said the status quo is not an alternative, warning that the oil sands could find themselves in the cross-hairs of any White House plan to reduce U.S. reliance on "dirty oil" if a low-carbon fuel standard is adopted by Washington, arguing a clean energy agenda could benefit the planet and drive productivity growth and job creation.

Harper government in bind

The Canadian government of Prime Minister Stephen Harper, while attempting to head off any U.S. actions that would stifle oil sands' growth, has put itself in a bind by withholding its own plan to set GHG caps on large emitters until it knows how the U.S. will proceed and what an international treaty would look like.

As a result, Environment Minister Jim Prentice said the chances of a historic deal being reached in Copenhagen are fading.

"I have to take a realistic view that, given the amount of work that remains to be done (before the December summit), we're running out of time," he said.

A setback for the oil sands sector has come from DuPont Canada and Dow Chemical Canada, Canada's two largest chemical companies.

They have allied themselves with other companies and environmental groups in demanding a national regulatory system with "common definitions and standards" that would overrule any moves by governments to allow the oil sands to operate under an "intensity based" system, tying emissions to units of production rather than imposing absolute limits.

"The cap-and-trade system should place an absolute, national cap on emissions," the group said, arguing intensity measures are unsuitable for setting caps for large emitters, such as oil companies, chemical producers and power generators.

Different types of caps would create "equity issues" and undermine the efficient trading of emissions credits. ●

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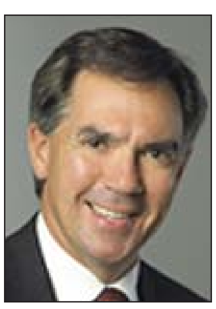
WEB

rejection came from the Planning and Priorities Committee, that could indicate Prentice and Prime Minister Stephen Harper are at odds over the MGP.



JIM PRENTICE

Prentice has consistently been touted as a leader-in-waiting for the governing Conservative Party if ever Harper resigns or is defeated and Harper is known to have little tolerance for rivals, real or imagined. (Just to muddy the waters, Prentice ranks high on the list of possible contenders to succeed Ed Stelmach should the Alberta premier get an effective no-confidence vote at his party's annual general meeting on Nov. 7).

Reluctance to provide aid

Further complicating matters — regardless of how much Harper has identified northern resource development as a vital part of Canada's Arctic sovereignty claims — is the probable reluctance of the Harper administration to provide financial aid for some of the world's largest oil companies (Imperial Oil, ExxonMobil Canada, Royal Dutch Shell and ConocoPhillips Canada) when the national budget deficit is soaring and the petroleum industry is so widely out of favor.

If it's true that the Planning and Priorities Committee has either rejected a submission by Prentice, or sent it back for reworking, that could be a damaging blow.

The committee, which is usually chaired by Harper, effectively controls the government agenda and occasionally acts for the whole cabinet.

Hint of wavering

It might also explain a hint of wavering by Prentice, who said in early October that a deal between the government and the MGP partners "has never been closer."

He was less emphatic when he spoke to reporters in Ottawa on Oct. 27.

Although refusing to discuss progress on a financial package, which had been presented to the MGP partners in January, he emphasized that the project is a "private sector investment that needs to make sense on an economic basis under market principles."

"That's what I've said repeatedly and that continues to be the case," Prentice said.

For now, he said the proponents are evaluating the government's fiscal framework and weighing the merits of the project.

Pius Rolheiser, a spokesman for Imperial, the MGP's lead partner, has told reporters that discussions continue with the government to see a fiscal agreement.

Otherwise "we haven't heard anything" from the government, he said.

Northwest Territories Industry Minister Bob McLeod told the National Post there is no chance of the MGP going ahead unless Canada is prepared to at least match Washington's pledge of at least US$18 billion in loan guarantees for an Alaska natural gas pipeline.

"If there is no fiscal arrangement in place (for the MGP) … it won't go ahead," he said. ●

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INSIDER

The lowest base tax rate under ACES, a progressive system, is 25 percent of net profits. This rate could be applicable when prices are $9 or $150, depending on the company's mix of oil and gas investments, and its cost to produce that oil or gas, but somewhere in the $90-per-barrel price range, the state could easily take 50 percent of a company's profits.

PAT GALVIN

During the first two quarters of 2009, ConocoPhillips fared pretty well under ACES, but in looking at the company's state tax hit in 2006, 2007 and 2008, a different picture emerges.

According to ConocoPhillips, in 2005, under the former production tax system, commonly referred to as ELF, the company paid $537 million in State of Alaska production and other taxes, excluding income tax.

In 2006, under the new net profits tax, called PPT (retroactive to Jan. 1, 2006), ConocoPhillips paid $914 million.

Expenditures for NPR-A exploration and development are deductible from state production revenue, and capital costs are eligible for capital credits.

In 2007, under ACES (again retroactive), ConocoPhillips paid $1.66 billion.

In 2008, when oil prices were exceptionally high, ConocoPhillips paid $3.4 billion.

The price of Alaska North Slope crude averaged $50.14 in 2005; $61.05 in 2006; $69.75 in 2007; and $98.18 in 2008. As of Oct. 6, 2009, the average ANS price per barrel was about $63.

Also part of the larger picture is the fact that North Slope explorers and producers are eligible for a tax credit equal to 20 percent of their qualified capital expenditures (whether exploration or development). These would be taken over two years; so half would be immediately applied to reduce a company's current tax bill, and the other half taken in the following year.

According to Alaska Revenue Commissioner Pat Galvin, because ConocoPhillips is a current tax payer (producer), it can deduct the credit immediately, and does not need to apply for a certificate, which would mean facing a lag time before enjoying the economic benefit.

Because the National Petroleum Reserve-Alaska, where ConocoPhillips has been a major explorer and is looking at developing several prospects, is within the territory of Alaska, it falls within the jurisdiction of the state's production tax. This means expenditures for NPR-A exploration and development are deductible from state production revenue, and capital costs are eligible for capital credits, Galvin said.

Production from NPR-A would also be subject to production tax.

Outer Continental Shelf development, because it is outside the territorial boundary of the state is not subject to production tax, even though some OCS production (in the 3-6 mile band) is subject to royalty sharing with the state.

—KAY CASHMAN

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LEASE SALE

pany acquired in last year's Beaufort Sea and North Slope areawide sales, and also had the highest per-acre bids, $95.01 per acre on tract 455 (total bid of $547,257.60) and $82.07 per acre on tract 454 (total bid of $472,723.20).

Tract 455 is due south of ARCO's Meltwater South oil exploration well, drilled to a true vertical depth of 8,377 feet in 1999. Tract 454 is southwest of the Texaco 32-7-8 Wolfbutton, a gas exploration well drilled in 1989 to a depth of 9,550 feet.

Largest state acreage position

Ed Kerr, Armstrong's vice president for land and business development, told Petroleum News after the sale that with the acreage from the sale, the company's state oil and gas lease acreage now totals some 475,000 acres.

The company picked up almost 200,000 acres in the 2008 North Slope and Beaufort Sea sales, and once leases from the Oct. 28 sale are awarded, Armstrong will top the list of state oil and gas lease acreage holders, although Anadarko Petroleum, ConocoPhillips and FEX, with substantial acreage in the National Petroleum Reserve-Alaska and, for Anadarko, from Arctic Slope Regional Corp., will continue to have larger overall lease positions.

(Prior to this sale the state had some 4.6 million acres under oil and gas lease; the U.S. Bureau of Land Management has more than 3 million acres under lease in the National Petroleum Reserve-Alaska.)

AVCG, Savant

While the only major to bid, ConocoPhillips, was outbid on that lease by 70 & 148, several other independents took tracts.

AVCG LLC took five leases for $411,840, 4.8 percent of the apparent high bids, going after tracts on the west side near Nuiqsut where the company has a considerable acreage position and one tract closer to Kuparuk, on which it outbid 70 & 148. Prior to this sale AVCG held 109,187 acres of state leases.

Savant Alaska LLC took three tracts on the east side, southeast of Point Thomson on the border with the Arctic National Wildlife Refuge, for $170,028.80, 2 percent of the apparent high bids. Prior to this sale Savant held 12,080 acres of state leases.

Daniel K. Donkel, 25 percent, and Samuel H. Cade, 75 percent, took two leases for $76,800; Donkel, bidding on his own, took one lease for $25,600. Prior to this sale Cade held 135,729 acres of state leases; Donkel held 41,523 acres.

James A. White took one lease for $60,595.20. Prior to this sale White held 5,713 acres of state leases.

A bidding group of J. Andrew Bachner (90 percent) and Keith C. Forsgren (10 percent) also bid in the sale, but were outbid by 70 & 148 and AVCG.

The southern fairway

Banks told Petroleum News after the sale that 70 & 148 LLC affiliate Armstrong has historically done more than just acquire land.

"Folks like Ed Kerr and his company, they're more than just — historically they're more than just somebody picking up a piece of ground. Obviously the exploration work they did at Oooguruk and Nikaitchuq led to producing oil fields," with Oooguruk producing and Nikaitchuq on the way to production, he said.

Asked about what the company might be looking for on the acreage they won at the sale, Banks said "the farther south you go you're getting into more gas-prone areas and in part that's because of the rock."

Denver-based Armstrong first took acreage on the North Slope in an areawide sale in 2001 and eventually brought three new companies to Alaska to partner on prospects at Oooguruk and Nikaitchuq — Pioneer Natural Resources, Kerr-McGee and Eni.

The fairway where 70 & 148 LLC has acquired acreage stretches to the southwest from Kuparuk.

As you go farther south, "we know that the rock is a little tighter …, but if you can find good quality oil, the good quality oil moves through that rock," Banks said.

He compared the area to the type of play that exists on the southern and western edges of the Kuparuk River unit, at Meltwater and Tarn. Those are "the same type of plays," Banks said.

"So if you've got fairly good quality oil it can move through somewhat tighter rock and they can make a go of it.

"But gas of course can flow there, too."

"The rock may be tight as you move farther south, but it's nothing like a shale," Banks said, and the technology designed to work on shale would work extremely well on the type of rock in this southern fairway.

Then there is natural gas.

Banks said the state is "fairly confident that with the development of a gas pipeline … we could see some major gas fields in this region."

Armstrong history

Denver-based Armstrong first took 1acreage on the North Slope in an areawide sale in 2001 and eventually brought three new companies to Alaska to partner on prospects at Oooguruk and Nikaitchuq — Pioneer Natural Resources, Kerr-McGee and Eni.

Armstrong had discoveries at wells drilled on three prospects with the larger partners it brought in, at Oooguruk, Nikaitchuq and Tuvaaq.

The company sold its remaining North Slope acreage in 2005, and acquired Cook Inlet acreage in the North Fork area in 2007.

In 2008 the company returned to the North Slope in a big way, as the largest bidder in both the 2008 North Slope and Beaufort Sea areawide lease sales.

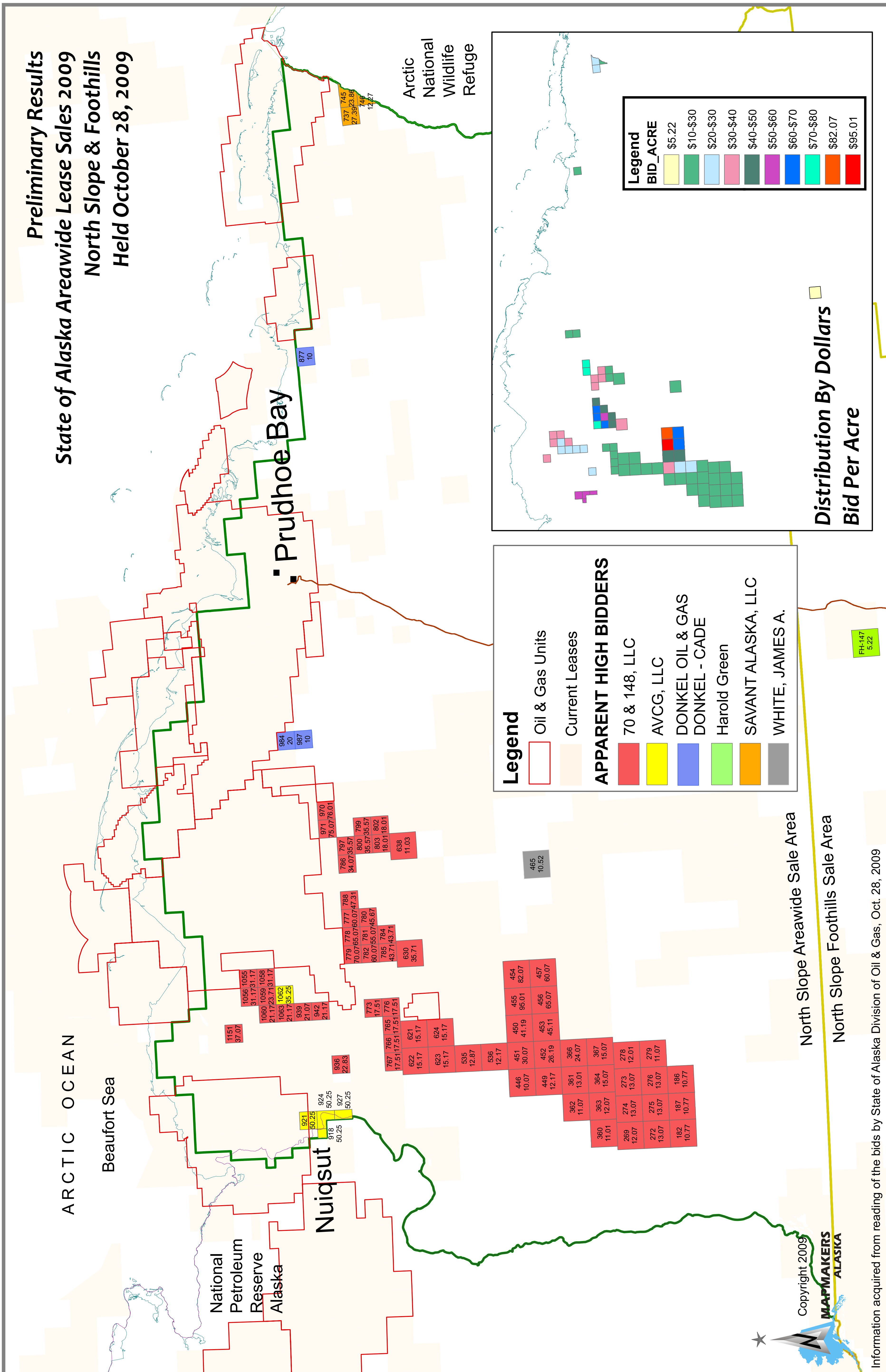
In 2008 the company bid under the name of affiliate 70 & 148 — named for the latitude and longitude of Prudhoe Bay.

Next Beaufort sale early next year

Banks said at the sale that the Beaufort Sea areawide sale, typically held in the fall at the same time as the North Slope and Foothills sales, was delayed because of an administrative error. The state was doing a new best interest finding and failed to advertise it in a statewide newspaper.

He said the new 10-year best interest finding for the Beaufort Sea areawide sale is being completed and will be released shortly.

A Beaufort Sea sale will be held early next year, maybe in February or March, Banks said. A second 2010 Beaufort Sea areawide sale will be held next fall, in conjunction with the 2010 North Slope and North Slope Foothills areawide sales. ●


Preliminary Results
State of Alaska Areawide Lease Sales 2009
North Slope & Foothills
Held October 28, 2009
ARCTIC OCEAN
Beaufort Sea
Prudhoe Bay
Nuiqsut
National Petroleum Reserve Alaska
Arctic National Wildlife Refuge
Legend
Oil & Gas Units
Current Leases
APPARENT HIGH BIDDERS
70 & 148, LLC
AVCG, LLC
DONKEL OIL & GAS DONKEL - CADE
Harold Green
SAVANT ALASKA, LLC
WHITE, JAMES A.
Legend
BID_ACRE
$5.22
$10-$30
$20-$30
$30-$40
$40-$50
$50-$60
$60-$70
$70-$80
$82.07
$95.01
Distribution By Dollars Bid Per Acre
North Slope Areawide Sale Area
North Slope Foothills Sale Area
FH-147 5.22
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MAPMAKERS ALASKA
Information acquired from reading of the bids by State of Alaska Division of Oil & Gas, Oct. 28, 2009

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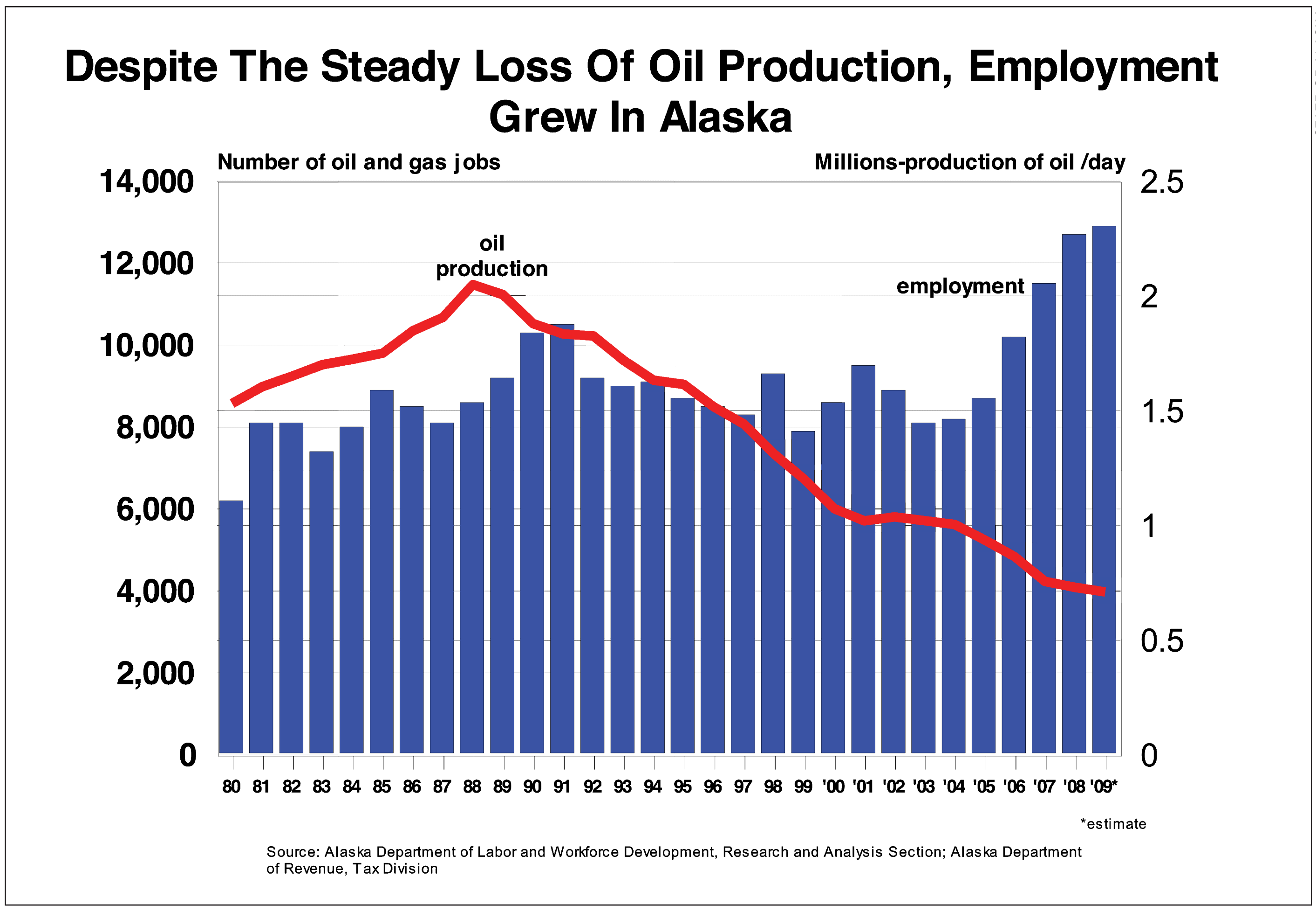
JOBS



STATE OF ALASKA

Fried said.

The employment levels are remarkable when you consider the backdrop of sliding oil production in Alaska. Production from Alaska's dominant oil and gas zone, the North Slope, was averaging 701,484 barrels per day through nearly the end of October. Five years ago, the October average was 970,026 barrels.

A striking graphic Fried prepared shows employment going up even as production trends down.

How can this be? Shouldn't employment fall in tandem with production?

High prices, geriatric fields

One major factor that can never be overlooked is the price of oil, Fried said.

North Slope crude closed at $75.46 a barrel on Oct. 28.

"Prices have been spectacular and they remain that way," Fried said. "We kind of look at oil at $70 or $80 a barrel and say, 'Big deal.' Well, it is a big deal. If oil was $20 or $30 a barrel, I think the employment story would be very different."

But price alone can't account for the full texture of Alaska's job picture.

The oil and gas industry here saw a strong surge in employment through the middle of the decade.

From 2003 to 2008 the industry picked up nearly 5,000 jobs and added $750 million in wages to the Alaska economy, the state Department of Labor reports in the October issue of its "Trends" newsletter.

Since 2001, job growth has been stronger for oil field services providers than for oil and gas producers, according to a slate of figures Fried provided to Petroleum News.

His numbers show that from 2001 through the first half of this year, jobs in the services sector climbed by 48 percent while oil extraction jobs — producers account for most of these — increased by 24 percent.

Now employment has leveled off right at record levels, Fried said.

Oil and gas jobs are some of the best in Alaska, with many positions paying more than $100,000 a year.

One factor that seemed to fuel some of the employment growth was the campaign to replace pipelines in Prudhoe Bay and adjoining fields following corrosion-related leaks in 2006, Fried said.

Aside from that effort, which largely has been completed, BP and the Slope's other major operator, ConocoPhillips, are having to put increasing effort into prodding and maintaining old fields including giants Prudhoe and Kuparuk.

Another contributor to Alaska's robust employment is work on planned or new North Slope fields, such as BP's Liberty project, Eni's offshore Nikaitchuq field, and the offshore Oooguruk field that Pioneer Natural Resources brought onstream in 2008.

Alaska is quirky in that the amount of oil it produces per employee is much higher than for the rest of the country, Fried said. That's because of the large size of North Slope fields.

Tougher oil

When it comes to jobs in Alaska's oil patch, BP drives the crew bus as operator of the state's dominant field, Prudhoe Bay.

Steve Rinehart, spokesman for BP Exploration (Alaska) Inc., said his company now employs just shy of 2,000 people. That's up substantially from about 1,650 in 2006.

BP supplements its own workforce with about 6,400 contractors.

Many jobs are project-dependent, he said, with Liberty being an example.

The company has 200 to 250 people assigned to the $1.5 billion Liberty project, which involves drilling long-reach wells from the shore at Endicott to tap the Liberty oil deposit beneath the Beaufort Sea. Drilling is slated to start next year and production in 2011, with expected recovery of about 100 million barrels.

BP's employment levels aren't expected to change much, Rinehart said.

While oil production is dropping, the demand for people and supplies keeps mounting as Prudhoe Bay, which has yielded some 12 billion barrels since 1977, continues to age, he said.

"This summer we had an especially big maintenance season, turnarounds at a lot of big plants," Rinehart said.

"It takes more and more effort to get the remaining oil out of the ground — drilling and workovers and sidetracks," he said.

One example of BP's increasing maintenance burden is the growth of a specialized unit called CUI — the Corrosion Under Insulation team. The unit has grown from fewer than 20 people to about 120, Rinehart said.

The people providers

Despite sturdy oil prices and the upkeep demands on the Slope, BP has taken steps this year to control its costs both externally and in-house.

In March, the company's Alaska president, John Minge, invited more than a hundred of the company's contractors and suppliers to meetings. They talked about two priorities, Rinehart said, safety and operating efficiency.

Last year, oil prices went sky high and then ran off a cliff for a time. But oil field costs didn't drop, he said, citing an IHS Cambridge Energy Research Associates report from last November that said "costs associated with constructing new oil and gas upstream facilities have reached a record high."

The contractor meetings were aimed at bringing costs back in line, Rinehart said.

"We got a positive response from some of them early on, and we're continuing to work with others," he said. "It's very much a drive toward efficiency for a long-term future. I suspect there are companies that are feeling the pressure."

One big change BP made was to tighten up its use of staffing agencies. In Alaska, BP had been dealing with 39 different firms to contract for 350 or 400 people with all sorts of skills, Rinehart said.

The company since has pared the number of people providers to eight firms, including four giants that BP uses globally plus four others that BP had been tapping on a more local basis. By choosing a smaller stable of providers, BP believes it'll achieve more efficiency plus something closer to market rates, Rinehart said.

The four giants include Fircroft, Moody International, Swift Oil and Gas, and the Orion Group. The other four are ASRC Energy Services, Udelhoven and Petrotechnical Resources Alaska, all based in Anchorage, and Philadelphia-based CDI.

BP's selection of the staffing agencies has triggered what appears to be a scramble among the winning companies to lure people to their stables, giving perhaps a misleading impression of a hiring boom in Alaska.

Swift announced Sept. 1 it had opened an office in Anchorage and had job openings in engineering, construction, inspection, procurement and other fields. Last week it was touting Alaska opportunities on the home page of its Web site: "New positions available in Alaska! Over 100 opportunities!"

Fircroft on Sept. 9 also announced it had opened an Anchorage office. Meantime, Moody International is touting BP Alaska projects including Liberty on its Web site, and Orion and CDI are advertising such positions as cost adviser, construction manager, staff engineer and equipment coordinator. ●