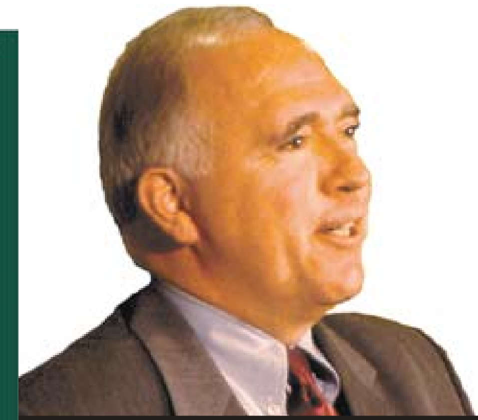
Petroleum news



page 10 Brooks Range permits backup prospects, UltraStar gets option

Vol. 13, No. 1 • www.PetroleumNews.com *A weekly oil & gas newspaper based in Anchorage, Alaska* **Week of January 6, 2008 • $1.50**

Snow needed in northern Alaska

JUDY PATRICK

On Dec. 29, the Alaska Department of Natural Resources announced the opening of the Western coastal tundra region to off-road travel, an area that extends from the Kuparuk River west to the Colville River. DNR's Gary Schultz told Petroleum News Jan. 2 that there still wasn't enough snow in the eastern coastal, lower and upper foothills areas to open them to general off-road travel. "However, it is snowing and blowing now," so that might change when the storm is over, Schultz said. Low-impact, pre-approved vehicles such as rolligons (pictured above) can go on the tundra now, he said, but DNR is waiting on more snow before it will allow conventional vehicles on state land. The department oversees off-road travel on state lands between the Canning and Colville rivers within 120 miles or so of the coast.

Oil surges to $100 a barrel

Crude oil prices soared to $100 a barrel Jan. 2, for the first time, reaching that milestone amid an unshakeable view that global demand for oil and petroleum products will outstrip supplies. Surging economies in China and India fed by oil and gasoline have sent prices soaring over the past year, while tensions in oil producing nations like Nigeria and Iran have increasingly made investors nervous and invited speculators to drive prices even higher.

Jump won't affect OPEC meeting date

The Organization of Petroleum Exporting Countries is expected to hold its next meeting as scheduled on Feb. 1 despite crude

see **$100** *page 16*

BREAKING NEWS

LAND & LEASING

State wins lawsuit

Judge agrees with Alaska on 22nd Point Thomson plan; requires hearing on remedy

By KRISTEN NELSON

Petroleum News

Superior Court Judge Sharon Gleason has ruled that the Alaska Department of Natural Resources acted properly when it rejected the 22nd plan of development for the Point Thomson Unit. The governor's office said Dec. 27 that the judge's decision affirming DNR's actions reflects her agreement with the arguments made by the state's attorneys.

The judge directed DNR to hold an additional hearing to provide the appellants with the opportunity to argue about what the appropriate remedy should be when the working interest owners have failed to fulfill their obligation to develop a unit.

"This court finds that DNR possessed the authority to administratively terminate the Point Thomson unit agreement when that agreement was adopted in 1977 under the statutory and regulatory structure as it existed at that time."
—Alaska Superior Court Judge Sharon Gleason

"This ruling represents another significant step forward in the state's efforts to develop the valuable oil and gas resources in the Point Thomson reservoir and to hold the lessees to the commitments they made in the unit agreement," Gov.

see **LAWSUIT** *page 13*

PIPELINES & DOWNSTREAM

Yukon in holding pattern

Rights awarded to AustroCan; major exploration push awaits Mac, Alaska gaslines

By GARY PARK

For Petroleum News

The Yukon government freely concedes it needs both the Alaska and Mackenzie natural gas pipelines to proceed before there is any real hope of unlocking its natural gas potential.

Energy, Mines and Resources Minister Archie Lang has told conferences over recent years that construction of the two gas ipelines is key to promoting exploration of the territory's eight sedimentary basins, where gas potential is estimated at 20 trillion cubic feet and oil is rated at 900 million barrels.

While it awaits pipeline decisions, the Yukon — even more than the Northwest Territories — is left in the doldrums, shut out of any exploration activity.

A 2006 study funded by the Yukon government, with participation by three first nations … concluded that a spur line from the Yukon could be connected to the Mackenzie mainline as early as 2014.

Despite changes two years ago to its rights disposition process — allowing companies to request a posting in an area of interest and putting the Yukon on the same footing as governments in Western Canada — there hasn't been much to celebrate.

The latest call for bids resulted in only one dis-

see **YUKON** *page 16*

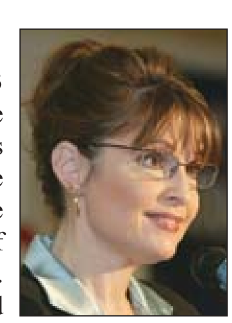
NATURAL GAS

Alaska cuts deal on LNG

Governor, Kenai plant owners reach agreement on state support for export license

PETROLEUM NEWS

Alaska Gov. Sarah Palin said Jan. 3 that her administration and the owners of the liquefied natural gas plant on the Kenai Peninsula have reached an agreement that would give state support for a two-year extension of the LNG plant's federal export license. Plant co-owners Marathon Oil and ConocoPhillips filed for the extension in January 2007. The present export license expires in 2009.



JUDY PATRICK

GOV. SARAH PALIN

Palin said the agreement ensures that there will be adequate supplies of gas for local utilities, requiring, among other things, that Marathon and ConocoPhillips develop additional natural gas reserves in Cook Inlet. Specifically, ConocoPhillips agreed to approve at least two wells for 2008 drilling, and Marathon agreed to approve five wells for its 2008 program.

Under the agreement with the state both companies are required to continue negotiations with Enstar Natural Gas Co. and Chugach Electric Association on gas supply agreements to satisfy local gas supply needs; and if certain local gas supply milestones are not met, the companies agreed to reduce exports below the LNG export quantities requested in the application.

Additionally, ConocoPhillips and Marathon agreed to allow third parties the opportunity to monetize their gas production through the LNG plant, meaning they will purchase natural gas from

see **DEAL** *page 15*

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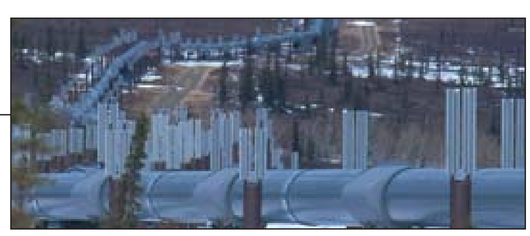
EXPLORATION & PRODUCTION



FINANCE & ECONOMY

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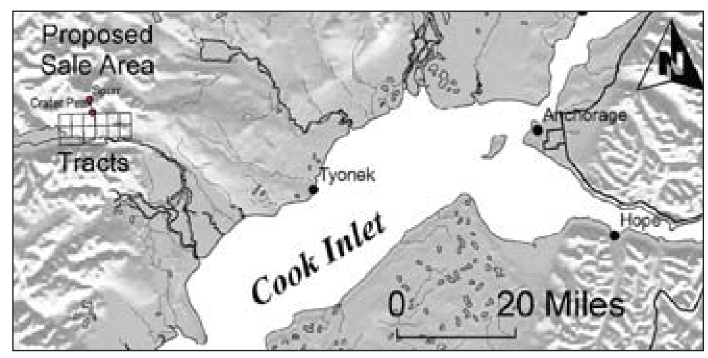


NATURAL GAS

PIPELINES & DOWNSTREAM

Alaska - Mackenzie Rig Report

The Alaska - Mackenzie Rig Report as of January 3, 2008. 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 Alan Bailey

Alaska Rig Status

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
North Slope - Onshore			
Akita Drilling Ltd.			
Dreco 1250 UE	63 (SCR/TD)	Racked in Deadhorse	Anadarko
Doyon Drilling			
Dreco 1250 UE	14 (SCR/TD)	Prudhoe Bay S-26	BP
Sky Top Brewster NE-12	15 (SCR/TD)	Kuparuk 1J-174	ConocoPhillips
Dreco 1000 UE	16 (SCR/TD)	Prudhoe Bay DS 14-29	BP
Dreco D2000 UEBD	19 (SCR/TD)	Alpine CD4-301	ConocoPhillips
OIME 2000	141 (SCR/TD)	Kuparuk River Unit 3S-08C	ConocoPhillips
TSM 7000	Arctic Fox #1	Stacked in Yard	Pioneer Natural Resources
	Arctic Wolf #2	Stacked in yard	FEX
Kuukpik	5	Kupcake #1, waiting on location	Savant
Nabors Alaska Drilling			
Trans-ocean rig	CDR-1 (CT)	Stacked, Prudhoe Bay	Available
Dreco 1000 UE	2-ES	Prudhoe Bay DS 02-09C	BP
Mid-Continental U36A	3-S	Kuparuk KRU2D-15	ConocoPhillips
Oilwell 700 E	4-ES (SCR)	Prudhoe Bay DS18-32A	BP
Dreco 1000 UE	7-ES (SCR/TD)	Prudhoe Bay L219i	BP
Dreco 1000 UE	9-ES (SCR/TD)	Prudhoe Bay W-45	BP
Oilwell 2000 Hercules	14-E (SCR)	Stacked	Available
Oilwell 2000 Hercules	16-E (SCR/TD)	Stacked	Available
Oilwell 2000	17-E (SCR/TD)	Stacked, Point McIntyre	Available
Emsco Electro-hoist -2	18-E (SCR)	Stacked, Deadhorse	Available
OIME 1000	19-AC (SCR)	Oooguruk ODSDW 1-44	Pioneer Natural Resources
Emsco Electro-hoist Varco TDS3	22-E (SCR/TD)	Stacked, Milne Point	Available
Emsco Electro-hoist	28-E (SCR)	Stacked, Deadhorse	Available
OIME 2000	245-E	Oliktok Point OPi2	Anadarko
Emsco Electro-hoist Canrig 1050E	27-E (SCR-TD)	Mobilizing to North Shore #1, Gwydyr Bay	Brooks Range Petroleum
Academy AC electric Canrig	105E (SCR/TD)	Mobilizing to Gubik #3, near Umiat	Anadarko
Nordic Calista Services			
Superior 700 UE	1 (SCR/CTD)	Prudhoe Bay well DS15-04b	BP
Superior 700 UE	2 (SCR/CTD)	Prudhoe Bay well C-35b	BP
Ideco 900	3 (SCR/TD)	Kuparuk well 3M-24	ConocoPhillips
North Slope - Offshore			
Nabors Alaska Drilling			
Oilwell 2000	33-E	Maintenance/mobilization Northstar	BP
Cook Inlet Basin – Onshore			
Aurora Well Service			
Franks 300 Srs. Explorer III	AWS 1	Stacked at Nikiski	Available
Marathon Oil Co. (Inlet Drilling Alaska labor contractor)			
Taylor	Glacier 1	Kenai gas field KDU 4dr	Marathon
Nabors Alaska Drilling			
National 110 UE	160 (SCR)	Stacked, Kenai	Available
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	NNA-1	Chevron
Academy AC electric Heli-Rig	106E (SCR/TD)	DS Happy Valley #13	Chevron
Rowan Companies			
AC Electric	68AC (SCR/TD)	Cosmopolitan Hansen #1A-L1	Pioneer Natural Resources
Cook Inlet Basin – Offshore			
Unocal (Nabors Alaska Drilling labor contractor)			
Not Available			
XTO Energy			
National 1320	A	Platform A no drilling or workovers at present	XTO
National 110	C (TD)	Idle	XTO

Mackenzie Rig Status

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Canadian Beaufort Sea			
Seatankers (AKITA Equtak labor contract)			
SSDC CANMAR Island Rig #2	SDC	Set down at Roland Bay	Devon ARL Corp.
Mackenzie Delta-Onshore			
AKITA Equtak			
Dreco 1250 UE	62 (SCR/TD)	Rig Racked in Inuvik, NT	Available
Modified National 370	64 (TD)	Drilling ATIK P-19	MGM Energy Group

JUDY PATRICK

Baker Hughes North America rotary rig counts*

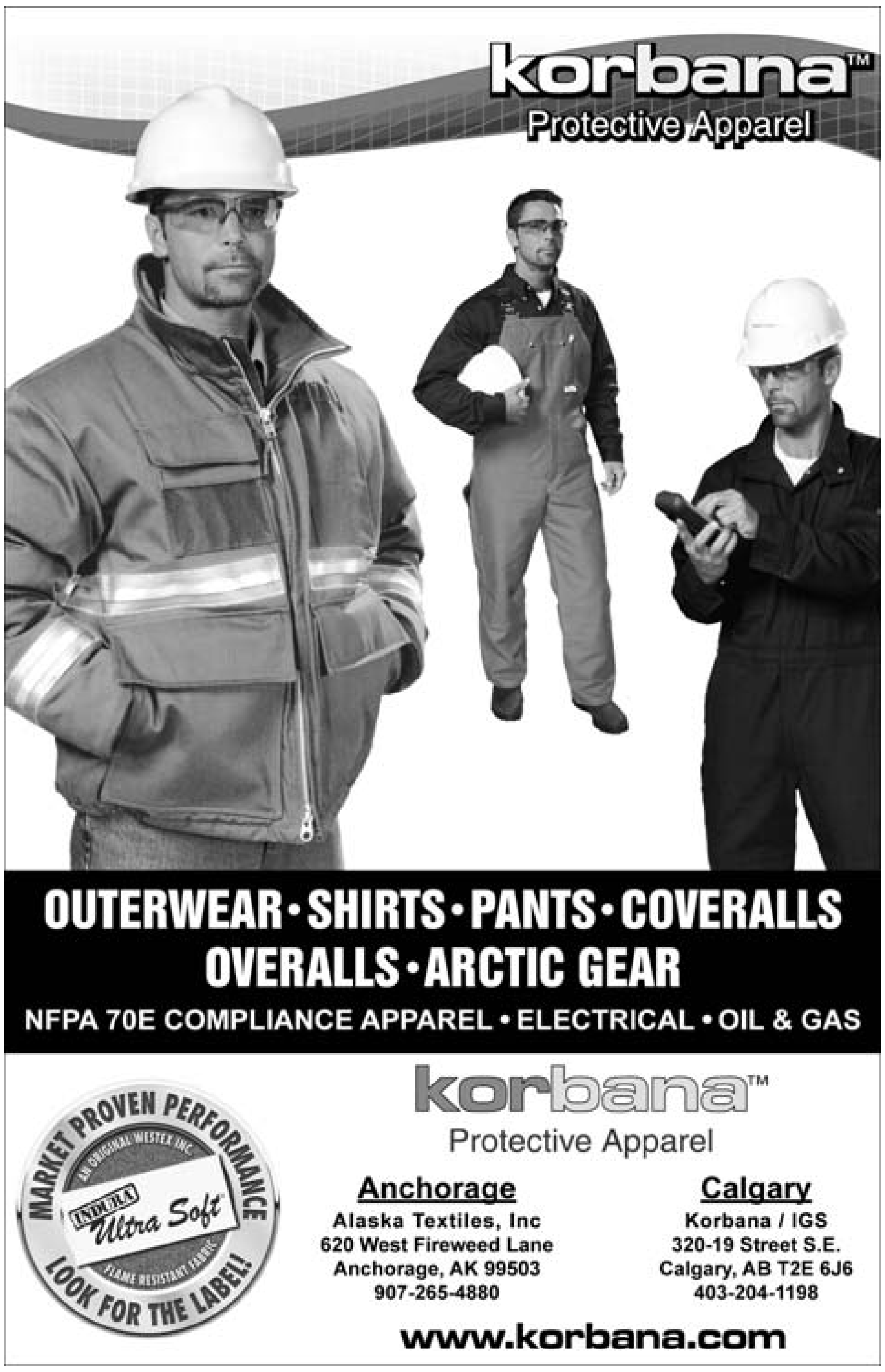
	December 28	December 21	Year Ago
US	1,782	1,809	1,710
Canada	260	372	429
Gulf	61	60	81

Highest/Lowest

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

*Issued by Baker Hughes since 1944

The Alaska - Mackenzie Rig Report is sponsored by:



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EXPLORATION & DEVELOPMENT

Conoco's grand oil sands dreams

By GARY PARK
For Petroleum News

ConocoPhillips has set its sights on becoming Alberta's leading oil sands producer, having made its debut as operator of the Surmont project, a joint venture with the Canadian subsidiary of France's Total.

Rating the resource as a vital part of North America's energy security, the company expects to convert its industry-leading land position into 1 million barrels per day over the next 20 years, Canadian oil sands Senior Vice President Murray Fox told reporters.

He made the forecast after ConocoPhillips started commercial production at its 25,000 bpd Surmont facility.

Fox said the joint venture expects to complete basic engineering for the second phase of the thermal project in the first quarter of 2008 and reach the project sanctioning stage in mid-2009 that is designed to boost Surmont output to 100,000 bpd by 2012-13.

He has little doubt that Surmont will expand beyond its second phase, given the "significant strategic position" ConocoPhillips has taken in the oil sands. Its initial holdings were acquired as part of its takeover of Gulf Canada Resources.

Target above goals of peers

Setting 1 million bpd as its eventual target pushes the company far above the goals of its peers, including Royal Dutch/Shell at 770,000 bpd, Syncrude Canada 550,000 bpd, Suncor Energy 500,000 bpd, Canadian Natural Resources 500,000 bpd, Husky Energy in the range of 500,000 bpd and Imperial, along with sister company ExxonMobil Canada, 300,000 bpd.

Fox said the start of commercial production at Surmont is the "first step on a long journey to something that is really, really important," driven by his company's conviction that oil sands production must "come to market for energy-security reasons and to meet demand."

That view is reinforced by ConocoPhillips; decision in 2007 to abandon its heavy oil assets in Venezuela's Orinoco belt after President Hugo Chavez unilaterally changed contracts.

In addition to Surmont, ConocoPhillips is sole owner of leases at Saleski, Thornberry and Clyden.

But the focus remains on Surmont, where Fox said the startup phase — often accompanied by major mechanical problems at other projects — has proceeded safely over the past six weeks.

Shipment to U.S. refineries

Diluted bitumen from Surmont will be shipped to ConocoPhillips refineries at Wood River, Ill., and Borger, Texas, which are being upgraded to process Canadian heavy crudes under a joint venture to develop EnCana's Foster Creek and Christina Lake properties, which give a substantial lift to ConocoPhillips' production targets.

"There will be very significant growth here over the next five and 10 years as we ramp up production in the (EnCana) joint venture and Surmont and start to invest in other land positions," he told the Financial Post.

Total E&P Canada President Michael Borrell said in a statement Surmont is a "key part of Total's integrated strategy for the oil sands."

Total is also 84 percent operator of the Joslyn lease, with Enerplus Resources Fund and Laricina as partners.

A proposed 100,000 bpd North Mine project is on track for startup in late 2012 or 2013 and Total is in the early stages of seeking regulatory approval for an upgrader in the Edmonton area.

Fox said that although ConocoPhillips has no plans to build its own upgrader in Alberta, he did not rule out that possibility as the company develops its 20-year growth plans.

He said the royalty increases proposed by the Alberta government have hurt the oil sands, but ConocoPhillips believes the impact can be softened through advances in technology. ●

FINANCE & ECONOMY

BP settles $379M in prior year taxes

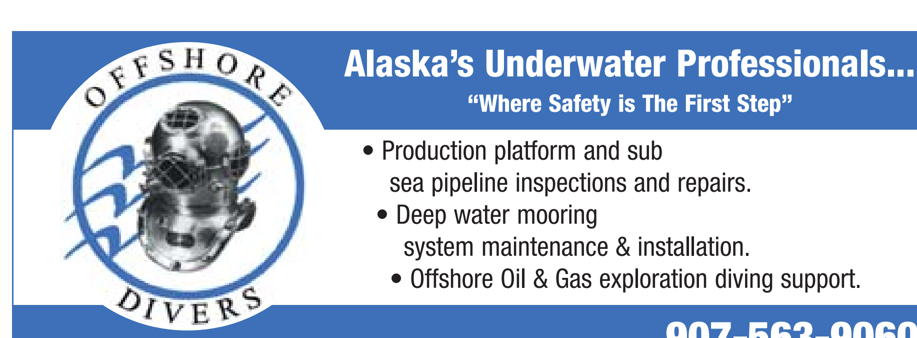
Gov. Sarah Palin announced Dec. 31 that the State of Alaska and BP Exploration (Alaska) Inc. have resolved a tax dispute concerning outstanding corporate income tax liabilities.

The taxes related to disputed amounts for tax years 2000 through 2002. Alaska tax statutes require the specific terms and conditions of the dispute and agreement to be kept confidential.

"I am very pleased with this settlement and appreciate BP's willingness to work with the State of Alaska and come to a fair resolution," Palin said.

BP agreed to make the payment of $379 million on Dec. 31. The governor's office said the funds will be deposited in the Constitutional Budget Reserve, which was created as the state's main savings account by a vote of the people in 1990.

—PETROLEUM NEWS



● GOVERNMENT

Fairbanks borough considers energy projects fund

THE ASSOCIATED PRESS

Fairbanks North Star Borough Mayor Jim Whitaker wants to set aside funds to support energy projects.

Whitaker said his proposal could turn into help for the Alaska Gasline Port Authority.

JUDY PATRICK

Fairbanks North Star Borough Mayor Jim Whitaker said his proposal could turn into help for the Alaska Gasline Port Authority.

The proposal is part of a larger plan to support several projects using portion of a state grant the borough received nearly two years ago.

The proposed $2.8 million ordinance would give Whitaker the authority to spend as much as $636,139 on two agencies, including the port authority, a municipal organization created more than eight years ago to build a natural gas pipeline across the state.

The other agency is the Fairbanks-based nonprofit Alaska Sustainable Energy Center, created last year to help carry renewable energy projects and technology to market.

Whitaker said the ordinance could be tweaked to instead benefit another organization considering a commercial clean-coal project.

Either project, he said, would reduce long-term energy costs and save millions of dollars.

"We have no higher priority than to deal with our cost of energy," he said.

The port authority this past fall submitted a plan, under the Alaska Gasline Inducement Act, to the state for rights to build a gas pipeline. The state is reviewing the application and others submitted under the act.

Whitaker, chairman of the port authority's board of directors, said the agency needs funding to pay its bills as the review progresses.

A significant grant from the borough to the port authority would be the first such payment in more than three years.

Whitaker's proposal comes after Valdez Mayor Bert Cottle successfully lobbied the Valdez City Council to contribute $250,000 to the port authority. Cottle said the authority is keeping the issue of a gas pipeline on the state's "front burner."

"Without (it), there wouldn't even be any talk of a gas line in Alaska," he said of the authority, which was created by voters in Valdez, Fairbanks and the North Slope. ●

GOVERNMENT

Wagoner calls for energy credit for electricity

A Kenai Republican state senator says Alaskans need an energy credit program to ease the pain of home electricity bills triggered by high oil prices.

Tom Wagoner says he is putting together legislation to get a discussion started about ways to cut energy costs of residential users.

Wagoner proposes that the energy credit be triggered when the price of a barrel of oil stays above $60 for one year.

The measure would give every person in Alaska who paid for electricity distributed through a meter system a $750 credit.

Wagoner says the money would go directly from the state to utilities.

—THE ASSOCIATED PRESS

NATURAL GAS

Chevron ready to unload B.C. gas facility

Chevron Canada has attracted only minimal interest in its plan for selling British Columbia's only large-scale natural gas storage facility.

The Aitken Creek plant, which has a working capacity of 71 million cubic feet per day and could be expanded by 40 percent, carries an estimated price tag of about C$1 billion and is estimated to process gas worth C$420 million a year.

Several candidates have been touted as likely bidders, but only Alberta-based Moneta Energy, formed recently with the specific intention of acquiring the assets in northeastern B.C., has openly declared its intentions.

Moneta founder Rex Kary told the Vancouver Sun the company is motivated by a "fundamental belief that North America is depleting its natural gas reserves."

"There is not as much gas that can be delivered as easily as several years ago, yet the demand is increasing. What's starting to happen is that the volatility in price, the price difference between summer and winter, is becoming greater," he said.

To prepare for a sale, Chevron has asked the British Columbia Utilities Commission to establish a separate company to run Aitken Creek, opening the way to a deal.

So far, only Terasen Gas and the B.C. Old Age Pensioners have filed written comments on the planned disposal and neither opposed the arrangement.

Canada's National Energy Board has commented that gas storage in B.C., the fastest growing gas-producing province in Canada, is "extremely limited," consisting of Aitken Creek and a small liquefied natural gas plant in the Vancouver area.

—GARY PARK

GOVERNMENT

Newfoundland formalizes first equity role

The Newfoundland government has secured its first success on the road to a direct role for the province in the energy industry.

Through a ground-breaking agreement between the government's energy corporation and Husky Energy, it will take a 5 percent stake in the North Amethyst, West White Rose and South White Rose satellite fields surrounding the White Rose offshore project and introduce a 36.5 percent super royalty.

The super royalty adds 6.5 percent to Newfoundland's 30 percent generic royalty when oil trades above $50 per barrel.

As well, Husky, as 72.5 percent operator, and Petro-Canada, which holds 27.5 percent, have agreed that about 93 percent of the 9 million work hours associated with the satellite development will be completed in Newfoundland.

The first oil from the satellite tie-ins is expected in the final quarter of 2009. Currently, White Rose produces 110,000-125,000 barrels per day and has regulatory approval for a maximum 140,000 bpd.

The White Rose agreement is the first implementation of the Newfoundland government's new energy strategy, which targets up to 10 percent government ownership in future projects. The province had earlier reached a memorandum of understanding to become a 4.9 percent partner in the Chevron-led Hebron-Ben Nevis project.

It will pay C$30 million for its equity interest in the White Rose satellites and C$175 million towards the C$3 billion cost of the extension.

Husky plans to spend C$425 million on North Amethyst in 2008 and C$120 million on the existing White Rose project.

Husky Chief Executive Officer John Lau — the first industry leader to find common ground with Newfoundland Premier Danny Williams during a prolonged period of tension after the initial Hebron project collapsed — said in a statement the agreement provides "clarity, stability and fiscal certainty and will allow us to advance the tiebacks in a timely manner."

—GARY PARK

● PIPELINES & DOWNSTREAM

Sun hasn't set on Orient

Northern B.C. deepwater ports live in hopes of oil links from Alberta to Asia; Enbridge prepares for reg reviews, despite setbacks

By GARY PARK
For Petroleum News

In 1910, the Canadian prime minister of the day, Sir Wilfrid Laurier, told the people of Prince Rupert that their deepwater port on the northern British Columbia coast would eventually be the shipping link to an "awakening" Orient.

He was right on one count. Asia is awake … and hungering for natural resources to fuel its rampant economies.

Meanwhile, Prince Rupert is languishing — a victim of a precipitous decline in exports of coal, grain and lumber.

But the town of 13,000 and the nearby community of Kitimat, whose 10,500 residents have also been battered by tough economic times, are not without hope.

The Alberta oil sands hold the key to their economic prosperity.

Both Enbridge and Kinder Morgan have plans to establish supertanker terminals on the B.C. coast to deliver Canadian crude to new markets in China, Japan, Korea and Singapore, as well as California.

And those plans remain alive, despite setbacks over the past year.

The heaviest blow occurred in July when China National Petroleum Corp., amid a blaze of accusations directed at the Canadian government and Canada's oil producers, said it would not renew a memorandum of agreement with Enbridge to round up 200,000 barrels per day of production to launch the 400,000 bpd Gateway project.

That, combined with the fact that Enbridge has not posted a new Gateway newsletter on its Web site since 2006, seemed to indicate the project was sidelined for the foreseeable future.

PetroChina still negotiating

But PetroChina, a unit of CNPC, and Enbridge are still quietly negotiating with prospective Asian customers, while Enbridge quietly assembles its regulatory case for engineering, safety and environmental hearings.

"We still feel the line will be built," Enbridge Chief Executive Officer Pat Daniel told the Edmonton Journal in a series of year-end interviews, adding that the project is not targeted solely at China.

He said oil sands developers are eager to find buyers outside North America for the anticipated growth in production and Asian buyers would provide a favorable element of "pricing tension" in a market dominated by the United States.

Although Enbridge is concentrated on a C$12 billion, five-year capital plan, mostly targeted at crude deliveries to the U.S. Midwest and Gulf Coast, the company has its eye on another C$14 billion in additional liquids pipeline investment beyond 2011, Daniel told investment analysts in the fall.

And that includes a broadening interest in Asian markets.

"Western Canadian producers continue to tell us that ultimately they need that relief valve in order to maximize the netback pricing that they need for their crude oil," he said.

Heavy crude price dropping

Their motivation has grown since 2000, when a barrel of Canadian heavy crude fetched about the same price at Hardisty, Alberta, as it would have on the Gulf Coast. In 2007, the Hardisty price averaged about US$8 per barrel less than Gulf Coast prices and dropped as low as US$13.

Enbridge Executive Vice President Richard Bird told the same analysts that his company believes action to open up new markets is needed within the next three years, although it has been an "uphill battle getting individual producers to focus on the need for those markets."

For now, Daniel said, Gateway has a flexible startup date of 2012-14, but that could be moved to a fast track if an Asian company were to make a significant investment in developing the oil sands.

But Enbridge has no intention of undertaking a new project until it has firm shipping commitments from producers, he said.

"Everyone wants access to the Gulf; everyone wants access to the (B.C.) coast, but they know that if they go ahead, everybody else benefits," he said.

Enbridge keeping Gateway alive

At the same time, Enbridge is keeping the Gateway plan alive.

It has hired Force Technology, a Danish-based marine traffic consultant, to identify suitable shipping routes off the B.C. coast for VLCCs (very large crude carriers).

Enbridge has reported that experienced mariners, using Danish ship simulators, have shown that VLCCs can negotiate the challenging coastline to its proposed Kitimat terminal. Energy consultants say the supertankers are a crucial part of the cost equation because they are much cheaper to operate on a per barrel basis than smaller vessels.

The company is also optimistic that it can build two tunnels through the mountain ranges between Alberta and the B.C. coast for the pipeline, thus minimizing the environmental impact.

Construction of the 780-mile pipeline from Edmonton would take about three years and employ 5,000 workers. No new cost estimates have been released since 2005, when the price tag was set at C$4 billion.

But it's not clear where the budget process stands now, given the sharp rise in costs, and the response to a non-binding open season two years ago, which prompted Enbridge to consider design changes to boost Gateway capacity to 800,000-1 million bpd.

Kinder Morgan has plans on the books for Northern Option

And Enbridge does not have the field to itself. Kinder Morgan still has plans on its books that include a so-called Northern Option — a branch line to a northern B.C. port from its Trans Mountain system that currently delivers 260,000 bpd to Vancouver and Puget Sound refineries in Washington State. Kinder Morgan has talked about raising its pipeline capacity out of Alberta to 850,000 bpd, including a possible 400,000 bpd for shipment to Asia.

The Alberta government has bought into the Asian opportunity by studying the prospects for Canadian synthetic crude and blended bitumen, apparently motivated by a Japanese consultant's study of 2006 that estimated Asian demand for Canadian crude would reach 2 million bpd by 2015. ●

GOVERNMENT

Tax Division sets workshop on regs

The Department of Revenue's Tax Division has a public workshop scheduled for Jan. 14 on potential changes in its regulations to implement legislation passed in November changing the state's oil and gas production tax and on a proposed interim form for monthly reporting of certain information relating to the production tax.

The division said principal subjects to be addressed at the workshop are tax credits and qualified capital expenditures. A draft version of the proposed interim form for reporting monthly information on North Slope oil production, North Slope lease expenditures and tax credits is available on the division's Web site at www.tax.alaska.gov; select the "ACES Production Tax" choice from the "Tax Division Links."

The workshop will be held in Room 240 in the Atwood building at 550 West 7th Ave., Anchorage, on Monday, Jan. 14, from noon to 4 p.m.

● LAND & LEASING

Ninilchik unit tract operation, PA merged

By KRISTEN NELSON

Petroleum News

A consolidation of the Susan Dionne participating area and the Paxton tract operation at the southern end of the Ninilchik unit has been approved by the Alaska Department of Natural Resources Division of Oil and Gas.

Participating areas within a unit are based on production. The state approved formation of the Ninilchik unit in 2001, some 25,800 acres overlying the Ninilchik anticline. The Ninilchik unit was expanded to include the former Falls Creek unit in 2003. There are three participating areas at Ninilchik: Falls Creek, Grassim Oskolkoff and Susan Dionne.

Marathon Oil Co. is the unit operator and majority working interest owner at the Ninilchik unit, which lies along the shoreline of the Kenai Peninsula from near Clam Gulch to just north of Ninilchik. The other working interest owner is Chevron.

The original Susan Dionne PA contained 1,761 acres, including state leases, one Cook Inlet Region Inc. lease and various fee oil and gas leases.

There are 2,123 acres in the combined participating area: 1,646 acres on state leases; 215 acres of CIRI acreage; 30 acres of University of Alaska acreage; and 231 acres of various fee lands.

Some 545 acres were contracted from the original Susan Dionne PA and 907 acres were added to the proposed Susan Dionne-Paxton PA.

The division said data submitted by Marathon justifies the consolidation of the two areas, which produce natural gas from intervals within the upper Tyonek formation.

Original PA approved in 2003

The original Susan Dionne PA was approved in 2003. Marathon requested an expansion of the PA in October 2004 based on the Susan Dionne 2 well, but the division took no action because mechanical problems in the wellbore precluded production from the well and made expansion of the PA unnecessary.

The 480-acre Paxton tract operation was approved in January 2005, allowing production from the Paxton 1 well prior to the formation of the Paxton PA. Marathon requested approval of a Paxton participating area in April 2005 and amended the request in November 2005. The division said it had not taken action on the amended Paxton PA application and Marathon withdrew the amended application when it applied to consolidate the Susan Dionne PA and the Paxton tract operation.

When the Susan Dionne PA was approved, it was believed to be isolated from the Paxton reservoir.

"More recent data suggest the Susan Dionne reservoir sands are continuous with the Paxton reservoir sands to the southwest," the division said. A structural saddle separates the Susan Dionne PA from the Grassim Oskolkoff PA to the northeast.

Development from existing pads

Further delineation and development of the Susan Dionne-Paxton PA will be from existing Ninilchik unit drill sites and infrastructure, specifically the Susan Dionne and Paxton pads.

In Marathon Oil's fourth plan of development for the Ninilchik unit, approved by the division in October, the company proposed two additional wells for the combined PA in 2008. "In addition to the two wells, Marathon plans to install a new gas compressor for the Susan Dionne Pad during the summer of 2008." ●

EXPLORATION & PRODUCTION

Petrobank sets wide-ranging plans for '08

Petrobank Energy and Resources, a Calgary-based company which is promoting a new heavy oil recovery technology on a global scale and has posted the most successful stock-market year of any Canadian energy company, is accelerating the pace of its Canadian oil sands ventures.

Over the last year, Petrobank has climbed upwards on the Toronto Stock Exchange, with only minor blips along the way, trading from a low of C$14.77 to a high of C$58.42 and has a market value of about C$4.3 billion.

Over the last year, Petrobank has climbed upwards on the Toronto Stock Exchange, with only minor blips along the way, trading from a low of C$14.77 to a high of C$58.42 and has a market value of about C$4.3 billion.

Having established its ability to operate the proprietary THAI (toe-to-heel-air-injection) method under a variety of conditions, and produce 2,000 barrels per day, it is now designing the first commercial phase of its Whitesands project, with the goal of achieving 15,000 bpd and eventually growing to 100,000 bpd at its adjacent May River project, where delineation wells boosted gross discovered resources of bitumen-in-place on the company's leases to 2.6 billion barrels.

As well, Petrobank is designing and building its Dawson project in the Peace River area of northwestern Alberta at a cost of C$225 million in 2008; preparing for initial exploration and delineation at its Sutton Creek acreage in Saskatchewan; and acquiring additional heavy oil resources globally.

Dawson Creek, which involves a license agreement and property acquisition from Duvernay Oil, covers 2,880 acres which are estimated to hold 100 million barrels of original-oil-in-place.

The 23,000-acre Sutton Creek license is planned for initial resource delineation in late 2008.

The THAI process involves injecting air into a controlled underground fire to melt bitumen, allowing it to flow, thus achieving higher oil recovery rates while reducing greenhouse gas emissions and water consumption in the process.

Calgary-based brokerage Tristone Capital estimates THAI developments will cost about C$28,000 per barrel of productive capacity, a fraction of the operating budgets for either open-pit mining or steam-assisted gravity drainage projects.

Tristone analyst Chris Feltin said that although it is too soon to be sure the benefits will achieve Petrobank's predictions, the company has the potential to be a "step change" for the industry.

To round out its prospects, Petrobank expects to be the most active driller next year in the Bakken formation in southeastern Saskatchewan, where it holds 155,000 net acres of undeveloped land and more than 600 gross drilling locations, and also expects to be one of the most active explorers in Colombia.

—GARY PARK

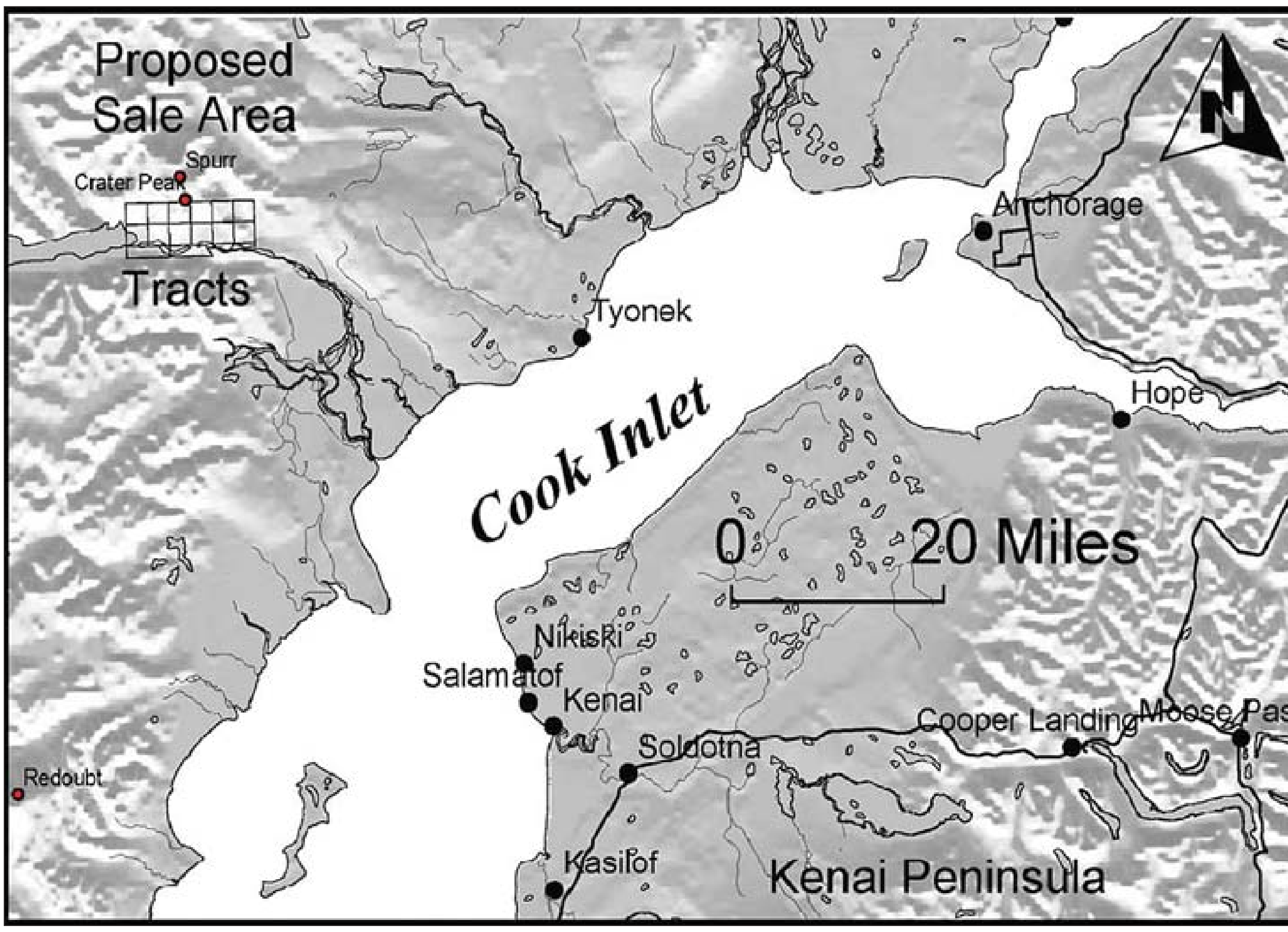
● LAND & LEASING

Preliminary BIF out for Mount Spurr

DNR proposing geothermal exploration area for 16 tracts totaling some 36,000 acres northwest of Trading Bay in Southcentral

By KRISTEN NELSON

Petroleum News



ALASKA DNR

A preliminary best interest finding has been issued for a proposed Mount Spurr geothermal exploration area.

The Alaska Department of Natural Resources Division of Oil and Gas said Dec. 27 that comments must be received on or before Jan. 28 to be considered in the final best interest finding which is expected to be issued in March.

Mount Spurr geothermal lease sale No. 3 would include 16 tracts of state-owned land, a total of approximately 36,057 acres, northwest of Trading Bay along the southern flank of Mount Spurr, including the east end of Chakachamna Lake and part of the Chakachatna River. The area is entirely within the Kenai Peninsula Borough, approximately 40 miles west of the village of Tyonek, within townships 13 and 14 north, ranges 16 and 17 west, Seward Meridian.

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

Offering would be third sale

This offering would be the third geothermal lease sale in the Mount Spurr area.

Geothermal energy is heat taken from the earth and geothermal resources include underground reservoirs of hot water or steam which can reach the surface as hot springs, geysers, mud pots or steam vents. Mount Spurr is an active volcano and has potential as a geothermal energy source, but the division said "the presence of exploitable reservoirs remains unknown."

Geothermal resources must be trapped in reservoirs near the surface of the earth to be extractable and can be accessed with wells. The heat energy is used to create electricity or used directly to heat buildings, for greenhouses, industrial processes and aquaculture. Because Mount Spurr is remote, the division said "if development occurs, the geothermal energy produced will be converted to electricity."

Location in relation to population is an issue. While Alaska has some 140 volcanoes — one-third of which are active — and more than 90 hot springs, many of those resources are far from population centers. Mount Spurr, however, is close to the Southcentral power grid.

Mount Spurr tracts were offered in the state's first geothermal lease sale in 1982; a single tract was leased and the lease was terminated in 1992. The state's second geothermal sale, in 1986, offered two tracts, both of which were leased; one lease expired in 1996; the second lease was terminated in 1990.

No coastal zone acreage included

The division said the state's initial proposal for the Mount Spurr geothermal exploration area included a small portion of land within the state's coastal zone; that acreage has been deleted. As a result the proposed geothermal exploration area is not subject to the policies of the Alaska Coastal Management Program or the Kenai Peninsula Borough Coastal Management Program.

To dispose of geothermal resources, the state's administrative code requires that the state designate tracts and call for applications. The division designated tracts and called for applications and comments in April 2007.

If tracts receive only one application, the state can issue noncompetitive prospecting permits; for tracts receiving two or more applications, competitive leasing is required.

The division said all tracts in the proposed Mount Spurr geothermal lease sale will be leased competitively.

There is a 30-day public comment period. The director of the Division of Oil and Gas will then determine if the proposed geothermal lease sale is in the state's best interest and issue a decision and final finding; that decision is expected to be issued in March.

Exploration would be for reservoirs

The division said geothermal exploration is a search for hydrothermal reservoirs. The depth, volume, temperature and permeability of such reservoirs are then estimated, along with the chemical and physical nature of the reservoir fluids.

Geologic field crews would do initial reconnaissance and prospective locations could be further explored by electrical and electromagnetic surveys.

"Passive seismic monitors that record seismic movements are often used to locate geothermal reservoirs," the division said.

If an area still looks prospective, "shallow holes are drilled to allow measurement of the temperature gradient." The goal is to determine if a heat source is present. Temperature gradient holes, the division said, are typically 300-500 meters deep and can be drilled from portable, truck-mounted or helicopter-lifted drill rigs.

The next step is deep exploratory drilling.

"Only deep drilling, often of two or more wells, and well testing can prove the commercial viability of a geothermal system," the division said.

Numerous wells, spaced over the reservoir, are used for commercial production. The producing wells are connected to nearby power plants with gathering lines.

Geothermal energy must be used or converted to electricity "within a few miles of its recovery from the ground," the division said. Because of that, it is likely a power plant would be built close to the geothermal resource and a power line built to the existing electrical grid. The Beluga power plant, which has transmission lines to Anchorage, is approximately seven miles northeast of Tyonek and underwater cables carry power between Point MacKenzie and Point Woronzof. ●

● EXPLORATION & PRODUCTION

ANS production down at year end

By KRISTEN NELSON
Petroleum News

Alaska North Slope oil production ended the year at an average of 755,807 barrels per day — down 1.1 percent since November, when the daily average was 764,525. It's also a drop from a year ago: ANS production for December 2006 averaged 808,129 bpd.

Kuparuk and Lisburne had slight production increases in December over November; production was down at all other fields.

BP Exploration (Alaska)-operated Lisburne, which includes Niakuk, averaged 34,526 bpd, up 1.43 percent from a November average of 34,040 bpd.

Kuparuk River, which includes production from Tabasco, Tarn, Meltwater and West Sak, averaged 153,162 bpd, up 1.13 percent from a November average of 151,451 bpd. Kuparuk is operated by ConocoPhillips Alaska.

Most fields down

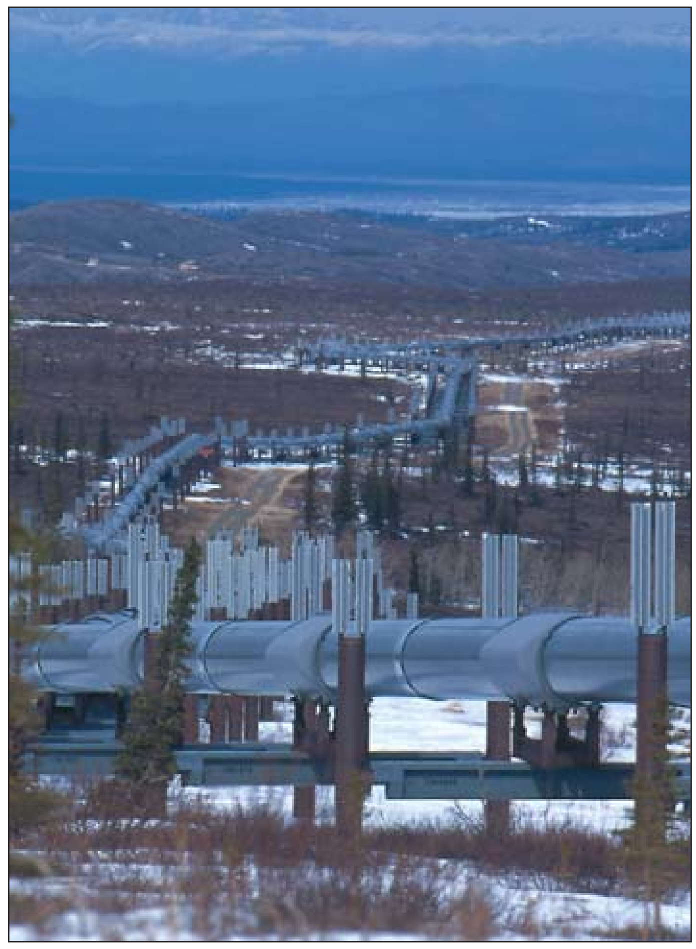
BP-operated Endicott (including Sag Delta, Eider, Badami and approximately 33,000 bpd of Prudhoe Bay Flow Station 2 oil) averaged 43,371 bpd in December, down 10.3 percent from a November average of 48,369 bpd.

BP's Milne Point field averaged 34,515 bpd in December, down 5.8 percent from a November average of 36,637 bpd. Milne Point production includes Sag River and Schrader Bluff.

Production from Alpine, operated by ConocoPhillips, averaged 116,205 bpd in December, a drop of 1.6 percent from a November average of 118,061 bpd; Alpine includes Fiord and Nanuq.

BP-operated Prudhoe Bay averaged 337,490 bpd in December, down 0.5 percent from a November average of 339,255 bpd. Prudhoe production includes satellite production from Aurora, Borealis, Midnight Sun, Orion, Polaris; some 400-600 bpd of Lisburne production; and production from Point McIntyre.

The greater Prudhoe Bay field, which includes Lisburne and the 33,000 bpd currently coming through the Endicott pipeline, averaged 405,016 bpd in December, down 0.3 percent from a November average of 406,295 bpd.


JUDY PATRICK
Trans-Alaska oil pipeline

BP-operated Northstar averaged 36,538 bpd, down 0.5 percent from a November average of 36,712 bpd.

The temperature at Pump Station 1 averaged minus 0.9 degrees Fahrenheit in December, compared to a five-year average of minus 2.8 degrees F.

Elsewhere in Alaska, Cook Inlet production averaged 15,515 bpd in December, up 2.9 percent from a November average of 15,073 bpd. ●

GOVERNMENT

Corps hosts regional ports conference

The U.S. Army Corps of Engineers is hosting an Alaska Regional Ports Conference Jan. 10-11.

The conference, to be held at the Hotel Captain Cook in Anchorage, will focus on opportunities to enhance Alaska's global role, particularly with regard to opening a northern route through the Bering Straits and Chukchi Sea to the Arctic and the great circle route from the Orient through the Aleutian Islands to the U.S. West Coast.

The conference agenda is available at: www.poa.usace.army.mil/en/cw/AGENDA%20Dec%2021%202007.doc.

There is no charge; please contact the project manager, Julie Anderson, in advance to register. Anderson may be reached by e-mail at julie.l.anderson@poa02.usace.army.mil or by telephone at (907) 753-5685.

A working lunch is planned for both conference days. Box lunches can be purchased from the Hotel Captain Cook for $12.50 if they are reserved in advance with the Corps of Engineers.

—PETROLEUM NEWS

LAND & LEASING

MMS issues final notice for Chukchi sale

The Minerals Management Service has issued its final notice for Chukchi Sea Sale 193. The sale, scheduled for Feb. 6, will be the first federal outer continental shelf oil and gas lease sale in the Chukchi Sea since 1991.

MMS Director Randall Luthi said in a Jan. 2 news release that the agency believes the decision to hold the sale "is a good balance and will allow companies to explore this intriguing frontier area while still protecting the resources important to the coastal residents."

"All leases will be subject to MMS's existing regulations that include extensive requirements for safety, drilling operations and pollution prevention, plus regulations of other agencies protecting marine mammals, endangered species, and air and water quality," Luthi said.

The sale area includes some 29.7 million acres offshore Alaska from north of Point Barrow to northwest of Cape Lisburne and extends for 25 or 50 miles to 200 miles offshore. Two sales have been held in the Chukchi Sea: Sale 109 in 1988 (351 leases issued) and Sale 126 in 1991 (28 leases issued). All leases issued in the two previous sales have expired.

Sale details are available on the MMS Web page at www.mms.gov/alaska.

—PETROLEUM NEWS

EXPLORATION & PRODUCTION

Shell Canada aims high in oil sands

Shell Canada has entered the regulatory phase of a massive expansion of its Athabasca oil sands project that holds the promise of keeping an average 3,000 construction workers in jobs over at least the next 10 years.

It heads a consortium that includes Chevron Canada and Marathon Oil (each holding 20 percent) that is aiming to build production from 155,000 barrels per day to 770,000 bpd within two decades.

The application, covering the next 10 years, seeks permission to expand the existing Jackpine mine by 100,000 bpd from previously approved levels to 300,000 bpd and build a new 200,000 bpd mine at Pierre River, north of the Jackpine leases.

The application, covering the next 10 years, seeks permission to expand the existing Jackpine mine by 100,000 bpd from previously approved levels to 300,000 bpd and build a new 200,000 bpd mine at Pierre River, north of the Jackpine leases.

Public hearings are expected to start in 2009 and, pending a green light, construction is scheduled for 2010, with production starting in 2012.

C$12.8 billion in construction under way already

Currently, Shell Canada has construction worth an estimated C$12.8 billion under way.

No cost forecasts were attached to the latest filings with Alberta regulators, partly because decisions to proceed with each phase will hinge on cost projections, economic conditions, regulatory developments and consultations with communities affected by the developments.

In addition to the mines, Shell Canada has applied for staged construction of a new 400,000 bpd Scotford upgrader complex near Edmonton that could cost C$22 billion-C$27 billion.

The minority Athabasca partners will have the option to export their share of production for upgrading in the United States, where Marathon has already announced plans to expand its Detroit refinery to handle greater volumes of heavy oil.

—GARY PARK

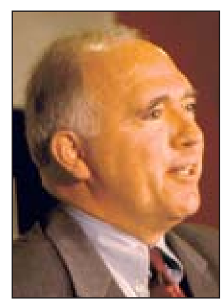
EXPLORATION & PRODUCTION

Brooks Range permits backup prospects

By KRISTEN NELSON
Petroleum News

As previously reported by Petroleum News, Brooks Range Petroleum Corp.'s North Slope winter exploration plans include re-entering its North Shore 1 well and drilling at its Tofkat prospect (see story in Oct. 28 issue). BRPC has Nabors rig 27 under contract for the season and has started permitting moving on seven other possibilities as options for the back half of the season.

Jim Winegarner, vice president of land for Brooks Range Petroleum Corp., told Petroleum News Jan. 2 that the company will re-enter the North Shore 1 well and then move on to Tofkat. A second well could be drilled at Tofkat, or the rig could move back to North Shore, where there are two other wells that could be drilled.


JUDY PATRICK

The UltraStar prospect is identified as East Shore Dewline. Jim Weeks, managing member of UltraStar, told Petroleum News last year that he expected BP to manage drilling of UltraStar's Dewline Deep No. 1 well, which was to be drilled from BP's Point McIntyre 1 drill pad. Weeks said Jan. 3 that Brooks Range's involvement would give his company another option.

Two plans of operations submitted to the state in November and public noticed in mid-December cover seven other possible well locations, only one of which is on a lease the company controls.

That lease is held by AVCG LLC, Alaska Venture Capital Group. AVCG is one of the joint venture partners in BRPC, the operator for the joint venture, along with TG World Energy Inc., Nabors subsidiary Ramshorn Investments Inc. and Bow Valley Alaska Corp.

The other prospects being permitted are on UltraStar Exploration LLC leases (three prospects); on leases held by ExxonMobil, ConocoPhillips, BP Exploration (Alaska) and Chevron (two prospects); and one prospect on a lease held by ExxonMobil, ConocoPhillips and BP.

Winegarner said the permitting is in advance of farmout agreements and is being done to create options for the back half of the season.

One of the permitting packages is for the UltraStar exploration project north of the Prudhoe Bay unit, approximately two miles east of the Point McIntyre No. 1 drill site in section 18 of township 10 north, range 14 east, Umiat Meridian, on state oil and gas lease ADL 389944, a lease held by UltraStar.

BRPC said in its application that UltraStar is the owner of the lease and BRPC would serve as operator for the exploration program.

In its plan of operations for the UltraStar exploration program, BRPC said up to two wells would be drilled from a single ice pad in section 18 T10N-R14E, UM, within state oil and gas lease ADL 389944. The ice pad is north of the Prudhoe Bay unit and east of the Kuparuk River.

A two-mile ice road would begin at BP Exploration (Alaska)'s PM-1 pad in section 21, T12N-R14E, UM. BRPC said it planned to pre-pack the ice road alignment with approved tundra travel vehicles.

The other permitting plan is for the East Shore exploration project. This is the area that includes prospects on leases held by ExxonMobil, ConocoPhillips, BP Exploration (Alaska) and Chevron, as well as one lease held by AVCG and one held by UltraStar.

The UltraStar prospect is identified as East Shore Dewline. Jim Weeks, managing member of UltraStar, told Petroleum News last year that he expected BP to manage drilling of UltraStar's Dewline Deep No. 1 well, which was to be drilled from BP's Point McIntyre 1 drill pad. Weeks said Jan. 3 that Brooks Range's involvement would give his company another option.

This plan includes two ice pads north of the Prudhoe Bay unit approximately three miles northeast of T pad in Prudhoe Bay in section 24 of T12N-R13E, UM. AVCG is the owner of state oil and gas lease ADL 389947, the proposed surface locations. The ice pads would be accessed by a three-mile ice road from existing gravel infrastructure within the Prudhoe Bay unit, BRPC said in its application. ●

Editor's note: Jim Weeks is speaking at the Alliance's Thursday morning breakfast Jan. 10 about the challenges for small companies drilling on the North Slope, including the most recent challenge brought on by the passage of a new tax regime for Alaska. The breakfast is at the Petroleum Club in Anchorage. For reservations call 907 563-2226 or sign up online at www.alaskaalliance.com.

● NATURAL GAS

JPO solicits bids for Parks gas line study

State pipeline coordinator Mike Thompson says $1-1.6 million RFP 'in no way represents an endorsement by DNR of any route'

By KAY CASHMAN

Petroleum News

The Alaska Joint Pipeline Office is soliciting proposals for a contractor to perform a feasibility study of a 322-mile natural gas pipeline from Fairbanks to Wasilla, generally along the Parks Highway right of way, and terminating at the existing Enstar gas transmission pipeline.

In the RFP's background information, Alaska Joint Pipeline Office, which is part of the Alaska Department of Natural Resources, said the purpose of the spur line would be to deliver North Slope gas to the Cook Inlet region of Southcentral Alaska, where gas supplies are a concern to local residents and politicians. A Parks Highway line would take North Slope gas from a larger diameter pipeline at Fairbanks, as well as potentially connect with as-yet-undiscovered gas in the Nenana basin.

1 2 SERIES

The contractor's budget for the feasibility study, $1 million to $1.6 million, comes from "Congressional financing for investigations along the Parks Highway corridor," state pipeline coordinator Mike Thompson told Petroleum News in December.

The RFP "in no way represents an endorsement by DNR of any route," Thompson said. "…The Alaskan Congressional delegation outlined the scope of the project. DNR developed the RFP to be consistent with these directives."

Delta Junction spur line

The other spur line route, favored by the voter-mandated Alaska Natural Gas Development Authority and commonly referred to as the Delta Junction or Glenn Highway spur line, would connect with a larger diameter pipeline from the North Slope at Delta Junction, and generally follow the Richardson Highway through the Alaska Range to the Glennallen area. From that point it would follow the Glenn Highway through the Matanuska Valley and terminate at the same Enstar transmission line, but approximately 30 miles to the east near Palmer. This line would be positioned to pick up additional gas from yet-to-be-discovered sources in the Copper River basin.

After a multi-year effort, ANGDA determined that the Glenn Highway route, about 41 miles shorter than the Parks route, appeared to offer the lowest cost of deliverability to Cook Inlet residents. ANGDA also said, in a briefing to Alaska Gov. Sarah Palin in December 2006, that a gas pipeline segment that delivered gas to "even a small LNG project" at Valdez "significantly lowers the gas delivery cost to Cook Inlet."

When asked why there is no comparison to the Glenn Highway spur line included in the RFP, Thompson said a DOE report, issued Oct. 24, provided this analysis," referring to a document titled "Conceptual Engineering / Socioeconomic Impact Study-Alaska Spur Pipeline," in which DOE essentially both routes appear to be feasible. (The study can be found at www.jpo.doi.gov.)

"In addition, the Alaskan Congressional delegation states the intent of the funding 'is to continue the Parks Highway Spur study begun under the DOE project,'" Thompson said.

Proposals due by Jan. 25

Proposals for the Parks Highway pipeline feasibility study are due Jan. 25. A proposal evaluation committee is scheduled to complete its evaluation by Jan. 29; the state will issue a notice of intent to award the contract by Jan. 30, expecting to make the actual award by Feb. 12.

The contractor has to have the study completed by Dec. 15.

The RFP said the purpose of the study is to define "the Parks Highway gas pipeline alternative … by reviewing existing information and collecting data, performing field reconnaissance and holding public meetings. The final product will consist of a report(s) containing information necessary for interested entities to complete an AS 38.35 pipeline right-of-way application and other land-use applications. The report(s) must include: engineering necessary for preliminary pipeline design to provide for a fixed system concept; land title along the pipeline corridor; environmental, waterway and wildlife information along the corridor; cost and construction estimates; and public outreach concerns. Parameters and criteria established shall ensure the pipeline will perform its desired functions reliably and economically."

In addition, the RPF said, "a separate right-of-way report documenting the scope of work and associated cost required to obtain necessary rights-of-way, easements, permits, waivers, etc. for any gas pipeline project along a State of Alaska Department of Transportation and Public Facilities and Alaska Railroad Corporation transportation corridor. This report will not be specific to crossings along the Parks Highway route; rather it will examine what efforts are necessary for any gas project to utilize and/or cross existing transportation corridors in Alaska."

Crosses both Denali parks

The route, which crosses Denali National Park and Preserve and Denali State Park, passes through both lowland river valleys and steep mountainous terrain, beginning at an elevation of about 450 feet in Fairbanks and rising to elevations greater than 2,400 feet in the Cantwell area before gradually dropping back to approximately 150 feet in the Wasilla area.

Beginning in Fairbanks, the route proceeds south through the Tanana Flats and Nenana River basin before traversing the Alaska Range between the communities of Healy and Cantwell. Just south of Cantwell, it enters the Susitna River valley, remaining in the valley between Trapper Creek, Willow and Wasilla.

For more information on the RFP, contact Marlys Hagen, C.P.M., at marlys.hagen@alaska.gov or 907 269-8666.

A copy of the RFP can be found at http://notes5.state.ak.us/pn/pubnotic.nsf/0/c176082aa075e0c5892573ad00743702/$FILE/jpo+parks+hwy+RFP+final+12-10-07.pdf.

The DOE study released in October was done by Arctic Slope Regional Corporation Constructors Inc. (ACI); Norstar Pipeline Company, an affiliate of Enstar; and the engineering firm Michael Baker Jr., Inc, with ACI managing the overall study. ●

Editor's note: Part two of this story will appear no later than mid-February in Petroleum News.

FINANCE & ECONOMY

ConocoPhillips: $250M more in taxes

In a Jan. 3 fourth-quarter interim update, ConocoPhillips said its worldwide production, including Syncrude and excluding Lukoil, is anticipated to be some 60,000 barrels-of-oil-equivalent per day higher than in the third quarter.

Exploration expenses are expected to be approximately $250 million before-tax for the fourth quarter.

The company said the new production tax legislation passed in Alaska in the fourth quarter is expected to have a negative after-tax impact of some $250 million, some $100 million of which is retroactive to prior periods in 2006 and 2007.

Conoco said its fourth-quarter results are expected to be positively impacted by approximately $350 million due to a tax-rate reduction recently enacted in Canada and the release of escrowed funds in connection with the extinguishment of the Hamaca project financing indebtedness.

—PETROLEUM NEWS

LAND & LEASING

Potential Alaska state and federal oil and gas lease sales

Agency	Sale and Area	Proposed Date
MMS	Sale 193 Chukchi Sea	Feb. 6, 2008
DNR	Alaska Peninsula Areawide	Feb. 27, 2008
DNR	North Slope Foothills Areawide	Feb. 27, 2008
DNR	Cook Inlet Areawide	May 21, 2008
DNR	Beaufort Sea Areawide	October 2008
DNR	North Slope Areawide	October 2008
BLM	NE NPR-A	To be determined
BLM	NW NPR-A	To be determined
DNR	Alaska Peninsula Areawide	February 2009
DNR	North Slope Foothills Areawide	February 2009
DNR	Cook Inlet Areawide	May 2009
DNR	Beaufort Sea Areawide	October 2009
DNR	North Slope Areawide	October 2009
MMS	Sale 209 Beaufort Sea	2009
MMS	Sale 211 Cook Inlet	2009
DNR	Alaska Peninsula Areawide	February 2010
DNR	North Slope Foothills Areawide	February 2010
DNR	Cook Inlet Areawide	May 2010
DNR	Beaufort Sea Areawide	October 2010
DNR	North Slope Areawide	October 2010
MMS	Sale 212 Chukchi Sea	2010
MMS	Sale 217 Beaufort Sea	2011
MMS	Sale 214 North Aleutian basin	2011
MMS	Sale 219 Cook Inlet	2011
MMS	Sale 221 Chukchi Sea	2012

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

This week's lease sale chart sponsored by:

PGS Onshore, Inc.

PGS

FINANCE & ECONOMY

Galvin: Alaska's new tax won't cause oil companies to pull investments

The three major oil companies that operate on Alaska's North Slope say they are reviewing their investments in Alaska now that they'll have to pay more taxes, but state Revenue Commissioner Patrick Galvin on Dec. 28 treated the statements as a bluff.

"We believe that the incentives that are included in the tax program, the resources that are available on the North Slope, and the tremendous value that oil is getting in the market right now are all reasons why Alaska will remain a very attractive place to invest," he said. "I don't expect to see a reduction in investment, given the attractiveness of Alaska."

PATRICK GALVIN

Exxon Mobil Corp. recently joined BP and ConocoPhillips in saying it would review its Alaska investments in light of the tax hike, with Exxon media relations advisor, Kimberly Brasington, writing in an e-mail Dec. 28 that the new tax "reduces the attractiveness of future oil developments" in Alaska. "We are re-evaluating investment plans," she said.

BP and Exxon have not said outright whether the tax increase would lead to a reduction in investment.

Galvin told the Anchorage Daily News he expected the companies to reassess their investments and suggested they were letting people know as a way of opposing the tax hike.

He said the tax rate is only one of an array of factors oil companies consider when deciding where to invest.

Lawmakers increased the base rate of the profits-based tax from 22.5 percent to 25 percent, and changed how quickly the tax rate increased when oil prices are high. Lawmakers approved the new tax Nov. 16 and Gov. Sarah Palin signed it into law earlier in December.

Under changes made in 2006, the Department of Revenue is required to study the effects of the oil production tax on exploration, development, and production of oil and submit a report to the Alaska Legislature by the first day of the 2011 legislative session.

—THE ASSOCIATED PRESS

GOVERNMENT

New BLM application fee goes into effect

The U.S. Bureau of Land Management said Jan. 2 that it is implementing a new $4,000 processing fee for each new oil and gas drilling permit application, known as an application for permit to drill or APD.

The fee is required under the fiscal year 2008 omnibus appropriations bill which was signed into law by President Bush on Dec. 26. BLM said the money generated by the fees is not new revenue but is a reimbursement to the U.S. Treasury for the estimated cost of processing new APDs for the duration of fiscal year 2008.

BLM said it has developed interim guidance for field offices for the collection and handling of the new fees, which took effect Dec. 26; final guidance will be developed over the next several weeks.

—PETROLEUM NEWS

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LAWSUIT

Sarah Palin said. "We are pleased that the court has affirmed the Department's efforts to ensure that the oil and gas in this reservoir is responsibly produced."

At the remand hearing, DNR will hear and consider arguments about whether or not termination of the unit is the appropriate remedy for failure to adequately develop this reservoir; or what other action the state should take.

The governor's office said DNR will act quickly to resolve this matter.

Gleason said Oct. 5 at the end of oral arguments in the case that the likelihood of an appeal was extremely high. She said it was her goal to get a decision out as soon as possible so the case can move on to the Alaska Supreme Court.

Rejection of plan affirmed

Gleason affirmed DNR's rejection of the lessees' proposed modified 22nd plan of development. She also affirmed DNR's interpretation of section 10 of the Point Thomson unit agreement. A sentence in section 10 of the unit agreement says: "The unit operator expressly covenants to develop the unit area as a reasonably prudent operator in a reasonably prudent manner."

The appellants — unit operator Exxon Mobil Corp., BP Exploration (Alaska) Inc., Chevron U.S.A. Inc. and ConocoPhillips Alaska Inc. — asserted "that this contractual language, in conjunction with applicable statutes, 'makes clear that DNR may not require the operator to carry out a plan that is not reasonable from the perspective of the operator, because it does not adequately protect the lessees' interests'," Gleason said in her decision.

The state's position is that the unit agreement's "reference to the reasonably prudent operator 'acts primarily as a covenant by the lessee to act as a RPO and does not alter how DNR is to administer the PTUA. It defines the lessees' commitment rather than limiting DNR's authority.'"

Gleason said that while issues of contractual interpretation are generally "legal issues as to which a court is to apply its independent judgment," in this case section 10 of the unit agreement "expressly confers" on the division the authority to require a plan from the lessees that is as complete and adequate as the director determines is necessary for timely development of resources in the unitized area. As a result, the court's review of the determinations needs to defer to the agency.

"Adoption of the appellants' interpretation of the contract to mandate the RPO standard would run counter to the regulatory and statutory provisions that were in effect at the time of the contract's creation," Gleason said. The regulation in effect at the time the Point Thomson unit agreement was signed in 1977 required the state to determine "that the agreement is necessary or advisable in the public interest … and adequately protects all parties in interest including Alaska," she said, quoting the regulation. The regulations also required that the same standard apply to modifications of approved unit agreements.

The current regulation "is not inconsistent with Section 10 of the PTUA or the former regulations," Gleason said. It requires the DNR commission to approve a proposed plan of development that promotes conservation of natural resources, promotes the prevention of economic and physical waste and provides "for the protection of all parties of interest, including the state."

Evidence supports rejection

Gleason also said that there is substantial evidence in the record to support DNR's rejection of the modified 22nd plan of development based on the department's finding that the plan did not contain a commitment to develop the unit or to adequately delineate reservoirs.

DNR rejected the plan, which required a gas pipeline to develop Point Thomson. The department concluded the oil and the gas condensate did not require a gas pipeline. Gleason said that finding "is not directly refuted" by the appellants.

Appellants also argued that the DNR commissioner acted in bad faith in rejecting the modified plan in light of the state's actions during the negotiations over the fiscal contract to develop a North Slope gas pipeline. The appellants said they relied on provisions of the proposed fiscal contract which relieved the lessees of submitting plans of development as long as the fiscal contract was in place.

Gleason said the state has asserted that any reliance on the fiscal contract "is unreasonable because that contract was never finalized when legislative approval was not forthcoming." She said appellants have not pointed to any instance outside of the fiscal contract negotiations when the state said it would accept a modified plan of development that did not require unit production.

"To the extent the appellants relied upon the proposed fiscal contract when they presented the modified POD, such reliance was unreasonable," Gleason said. DNR did not advise the appellants it would relieve them of their obligations if the fiscal contract was not approved, she said; in fact, it told them it would not delay a drilling commitment while fiscal contract negotiations were under way.

Administrative termination

The director's 2005 amended decision rejecting the 22nd plan of development "did not purport to terminate the unit agreement," Gleason said. The decision said the Point Thomson unit agreement was in default and listed ways to cure that default. The decision also said that failure to submit an acceptable plan was grounds for termination of the unit.

The commissioner's 2006 decision and 2007 decision on reconsideration not only rejected the modified 22nd POD "it terminated the unit."

The appellants have asserted that DNR "does not have the authority to administratively terminate the unit, but must instead seek to terminate the agreement through judicial proceedings," Gleason said.

Section 10 of the unit agreement, which applies to the situation after a discovery well, "is silent on the rights of either party to terminate or cancel the contract. It does not expressly accord to the DNR a right to administratively terminate the unit — nor does it eliminate any such right," she said.

Parties to the action recognize the state could seek to cancel based on breach of section 10. "At issue is whether that cancellation proceeding would need to be initiated in state court or if the agency could seek to cancel the contract in an administrative proceeding," Gleason said.

"This court finds that DNR possessed the authority to administratively terminate the Point Thomson unit agreement when that agreement was adopted in 1977 under the statutory and regulatory structure as it existed at that time," she said.

Hearing required

Current regulations also allow DNR to "seek to administratively terminate" the Point Thomson unit, Gleason said, but neither the Point Thomson unit agreement nor statutes and regulations in effect in 1977 "permitted an automatic termination" whenever a plan of development was unacceptable to the state.

However, "rejection of a proposed plan of development does not result in automatic termination" under the unit agreement. "Rather, a separate administrative determination as to the appropriate remedy is required in such instance," Gleason said.

This is a right to due process issue, the judge said.

Nothing in the unit agreement or the 1977 regulatory framework "mandated or authorized automatic termination of the unit when DNR rejected the proposed POD. And while this court has concluded that the PTUA and then-existing regulations did not preclude DNR from pursuing termination at the administrative level, the appellants were constitutionally entitled to a clear written notice that DNR was considering this remedy when it rejected the POD, and should have been accorded the opportunity to be heard with respect to the appropriate remedy when the modified 22nd POD was rejected," Gleason said.

"Accordingly, this matter is remanded to the DNR for the purpose of according to the appellants a hearing on the appropriate remedy to the state under DNR's rejection of the proposed 22nd plan of development." ●

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

Petroleum news

Business Spotlight

FORREST CRANE

April Brehm, Environmental Scientist/Planner

URS Corp.

URS Corp. offers a range of professional planning, engineering and architectural design, environmental, construction and program and construction management services. This fully integrated global company also provides system integration, operations and maintenance, management and a wide range of specialized technical services.

April Brehm spent three years with a local nonprofit organization working on land issues and conservation easements before joining URS in 2005. Off duty, she enjoys reading, writing, traveling and roughhousing with her two unruly husky mixes. She and husband Bill, who owns Livingreen Services, an interior/exterior plant care and landscaping business, live in beautiful downtown Spenard. April contributes her land management expertise to the Anchorage Waterways Council and the Great Land Trust.

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DEAL

other producers "when practical for the production of LNG at the Kenai LNG facility," the governor's press release said.

The companies have also committed to sell Cook Inlet seismic and well data to other potential oil and gas explorers in the Cook Inlet region on a commercially reasonable basis to encourage exploration and development.

The agreement includes "a framework for cooperation" between the state and the LNG plant owners for "future applications to the DOE (U.S. Department of Energy) for additional LNG export authorizations, with the common goal of making a minimum of 30 million standard cubic feet per day of plant inlet capacity available for natural gas purchased from other producers," the governor's office said.

State will support future extensions

If additional LNG export license extension applications are filed by ConocoPhillips, the governor's office has agreed to support them "provided, among other things, that the natural gas to be exported is excess to the requirements of the regional utilities for the period covered by the application," the governor's office said, noting that it recognizes the local market alone is not large enough or flexible enough to sustain exploration and development activities in the Cook Inlet basin.

"It is our hope that, by reaching this agreement, the U.S. Department of Energy will have the assurances necessary to approve their request," said Palin. "We understand that the export approval is just one step in the process of securing a future for the LNG operation and look forward to working with all stakeholders in achieving the goal of improved gas supply security for Southcentral."

The Kenai LNG facility, located in Nikiski, is the only LNG export plant in North America. The facility began operations in 1969 and today employs 58 people, the governor's office said, noting that the plant also supports 128 other jobs in the Kenai Peninsula community.

The LNG plant contributes approximately $50 million in royalties and taxes to the state and local economies, the governor's office said.

"This agreement improves the prospects for future drilling in the Cook Inlet and supports continued operation of the Kenai plant," said Jim Bowles, president of ConocoPhillips Alaska. "This new level of cooperation is a very positive outcome and is essential for a solution to the natural gas development issues facing Southcentral and the state as a whole."

"Extending the life of the Kenai LNG facility will help manage gas deliveries during peak winter demand and encourage new development," said Steven Hinchman, Marathon's senior vice president of worldwide production. "This agreement is clearly a win-win for the State of Alaska, the economy of the Kenai region and the local utility needs."

"It is important that the producers and the state can work together," said Gene Dubay, senior vice president of operations for Semco, which the governor's office identified as Enstar's parent. "In this case the state intervention was the catalyst to reaching agreement on our near-term supply needs."

The agreement, a summary and maps can be found at: www.dog.dnr.state.ak.us/oil/. ●

COURTESY PHOTO

The Nikiski LNG plant

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$100

prices hitting a nominal high of $100 a barrel in New York Wednesday night, group officials said Thursday, Jan. 3.

OPEC, whose output meets about 40 percent of the 86 million barrels consumed daily worldwide, can't react to daily crude oil price swings but will study market developments closely throughout January, the officials said.

"OPEC isn't geared to act on daily price movements," Javad Yarjani, the Iranian oil ministry's head of the OPEC affairs department, told Dow Jones Newswires in a phone interview from Tehran.

"We still have almost one month and will then have a better understanding of the fundamentals," Yarjani said.

Other OPEC officials have struck a similar note.

"The market is very sensitive right now, and OPEC will be monitoring the situation very closely in the coming weeks ahead of its Feb. 1 meeting," Falah Al Amery, head of Iraq's 13-nation State Oil Marketing Organization, or SOMO, told Dow Jones Newswires in a phone interview.

Al Amery said that 2008 "will most likely see oil prices continue to hover around the $100 a barrel level," and could cross it if geopolitical tension in the region intensifies.

"But the bottom line remains that if we find that the reason behind high oil prices is speculation and not demand and supply levels, then there will not be an (output) increase," he added.

Al Amery said that 2008 "will most likely see oil prices continue to hover around the $100 a barrel level," and could cross it if geopolitical tension in the region intensifies.

Two camps in OPEC

Al Amery said there are two camps within OPEC with differing opinions about price levels.

"You have the hard-liners who are happy with a $100 per barrel price level, and you have the moderate member countries who understand it is bad for the world economy and would like to see prices fall back to the range of $70 to $80 a barrel," he said.

In 2008, "member countries must live with this volatility of price," OPEC Secretary General told Dow Jones Newswires in a recent interview.

"We hope 2008 will be a more successful year in terms of stability for us, not in terms of prices," he added.

In early December, OPEC rebuffed calls from oil-consuming nations for another output increase after agreeing on a production increase of 500,000 barrels a day in September that took effect Nov. 1.

OPEC has expressed concerns about world economic growth in the aftermath of the unfolding U.S. subprime mortgage crisis and its impact on oil demand.

—THE ASSOCIATED PRESS

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YUKON

position — a successful bid of C$2.28 million by little-known AustroCan Petroleum Corp. to secure rights in the Peel Plateau-Plain basin of the northwest Yukon. One other offering attracted no bids.

Lang said he was encouraged to see "continued interest from the oil and gas industry in North Yukon."

Pending regulatory approvals and an environmental and socio-economic assessment, AustroCan must drill a well within six years to extend its term to 10 years.

Hopes tied to pipeline

The company president, Tore Jorgensen, in an interview with the Canadian Broadcasting Corp. from his sailboat in the Caribbean, said AustroCan is tying its hopes to the Mackenzie pipeline going ahead.

He said the company, which has interests in South Africa and Argentina and is eying prospects in British Columbia and Alberta, is anxious to identify the gas potential of the Peel basin before sanctioning of the Mackenzie project.

Jorgensen said there is urgency to establish the gas potential before decisions are made on Mackenzie pipeline capacity.

He said the company will spend C$2 million over the next two years on aerial surveys of the 152 square mile parcel and follow that with ground work.

If a target is identified, a well would cost C$10 million to C$20 million, Jorgensen said.

For now, AustroCan has made a C$500,000 deposit that will be refunded if qualifying work valued at C$2 million is completed.

A 2006 study funded by the Yukon government, with participation by three first nations, and conducted by Fekete Associates and Vector Research, concluded that a spur line from the Yukon could be connected to the Mackenzie mainline as early as 2014.

Nineteen wells drilled to date

The Yukon Geological Survey has estimated the gas-prone north Yukon has resource potential of about 11 tcf.

To date, 19 exploratory wells have been drilled in the Peel Plateau and Plain, yielding some petroleum shows, without unlocking economic resources.

A resource assessment points to about 3 tcf of initial raw gas in place in 88 pools, according to the Geological Survey of Canada.

The northeast corner, with a prospective region covering about 4,000 square miles, has so far produced "unfavorable results" from exploratory drilling, which studies say are part of a larger unsuccessful effort in the adjacent NWT.

Fekete Vice President Dave Dunn said in 2005 that future gas discoveries in the north Yukon would likely not be large enough to support a standalone pipeline to southern markets.

As a result, he said, they would need to piggyback on either the Mackenzie or Alaska lines, with the most likely option covering a route of 210 miles north to Inuvik from the southeast corner of Eagle Plain (where 34 wells have been drilled and potential is estimated at 6 tcf), which lies west and north of Peel, following the Dempster Highway where possible.

Dunn said less likely options would be south along the Dempster Highway and over to Tok, Alaska, or to Whitehorse and then to the Alaska system.

A hypothetical 20-inch pipeline out of the north Yukon would have initial capacity of 256 million cubic feet per day, which could be increased to 410 million cubic feet per day.

Dunn said that until there is certainty about the Mackenzie or Alaska projects there is no reason for a surge in drilling to prove up the north Yukon's potential. ●