Petroleum news

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North America's source for oil and gas news

Week of June 5, 2005 • $1.50

page 4 Apache nearly doubles output from Prudhoe Bay of North Sea

JUDY PATRICK

Nabors roughnecks on a North Slope rig.

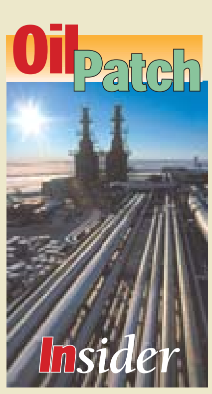
U.S. rotary rig count jumps by 16, Canada up by 4 rigs

The number of rotary drilling rigs operating in the United States and Canada during the week ending May 27 stood at a combined 1,602, up by 20 rigs compared to the previous week and up by 238 rigs compared to the same period last year, according to rig monitor Baker Hughes.

The Canadian rig count alone increased by four to 271 from the previous week and increased by 76 versus the year-ago period.

see **COUNT** *page 20*

Welcome to dog days – lots of bark, no bite yet



IT CAN'T BE A CASE OF INACTIVITY breeding idle gossip.

So maybe there's something to the latest prattling in the Canadian oil patch.

At a time when the industry is running on all cylinders, the rumor mill has also been busily grinding.

The liveliest speculation has focused on the prospect of

see **INSIDER** *page 20*

BREAKING NEWS

EASTERN NORTH SLOPE

Back to Badami

BP restarting North Slope field due to high oil prices, new recovery technology

By KRISTEN NELSON

Petroleum News Editor-in-Chief

BP Exploration (Alaska) has applied to restart the Badami field for a three-year period to test new recovery techniques. The company applied to the Alaska Department of Environmental Conservation for an air quality control construction permit earlier this year; DEC published a proposed permit for public comment May 27.

BP plans well drilling and workover activity from the existing pad as part of the restart and asked for a flexible permit to allow operation predominantly on gas-fired turbines, while in produc-

see **BADAMI** *page 22*

COURTESY BP

The Badami field, developed in the late 1990s, is on Mikkelsen Bay east of Prudhoe Bay and is the farthest east development on the North Slope. It was the first turbidite reservoir to be developed on the slope, and has been in warm shutdown because oil production from the field was at much lower levels than the company anticipated.

GULF OF MEXICO

Explorers choke on salt

Image-distorting salt layers in Gulf pose problems, delays, as drillers go deeper

By RAY TYSON

Petroleum News Houston Correspondent

For years, explorers have struggled with finding new oil and gas fields beneath the massive, seismic image-distorting salt layers that cover much of the Gulf of Mexico. But the problem appears to be getting much worse, even resulting in planning delays as companies pursue deeper targets that lay many thousands of feet below the salt.

Exploration and production independent Kerr-McGee and major energy company BP are two deepwater explorers, regardless of the difference in their size, that fight the U.S. Gulf salt barrier on a daily basis.

David Hager, Kerr-McGee's senior vice-president of exploration and production, said May 25 at the UBS Global Oil & Gas Conference in Austin, Texas, that "more than anything it (salt) has … slowed down the pace of prospecting in the deepwater Gulf."

"More than anything it (salt) has … slowed down the pace of prospecting in the deepwater Gulf." —David Hager, Kerr-McGee

Eyton says deepwater Gulf three times more costly

David Eyton, BP's vice president of deepwater developments for the U.S. Gulf, told industry analysts at the same conference that compared to many offshore areas, including West Africa's Angola, explorers operating in deepwater U.S. Gulf likely spend three times the cost of

see **SALT** *page 23*

ALBERTA

Chinese invasion troubles U.S.

Sinopec joins CNOOC, PetroChina in Alberta oil sands, causing worries in Washington over loss of Canadian crude for North American market

By GARY PARK

Petroleum News Canadian Correspondent

Three of China's energy giants are now players in the Alberta oil sands at the same time anxiety is building in Washington, D.C., over the loss of Canadian crude production to Asia.

The drive by state-owned enterprises to diversify China's sources of foreign oil is causing concern in U.S. government circles "because they want to know what's going on with China," said Murray Smith, Alberta's former energy minister and the province's top representative in the U.S.

"There's no question that the U.S. wants every barrel of energy (in the Western Hemisphere) for itself," he told a Calgary business audience May 30, the day before the latest deal with a Chinese company was unveiled.

If Alberta, for the first time, exports to markets other than the United States that "could put additional upward pressure on the price of oil in North America," Murray Smith said.

In the space of six weeks, Sinopec has paid C$105 million in cash for a 40 percent stake in oil sands start-up Synenco Energy and CNOOC

see **CHINA** *page 22*

contents

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Alaska - Mackenzie Rig Report

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

Alaska Rig Status

North Slope - Onshore

Doyon Drilling			
Dreco 1250 UE	14 (SCR/TD)	Drilling, Milne Point, E pad MPE-12	BP
Sky Top Brewster NE-12	15 (SCR/TD)	Drilling, Kuparuk, well 1C-21	ConocoPhillips
Dreco 1000 UE	16 (SCR)	Workovers, J-Pad, well J-18	BP
Dreco D2000 UEBD	19 (SCR/TD)	Drilling, Alpine CD2-59	ConocoPhillips
OIME 2000	141 (SCR/TD)	Drilling, Kuparuk, 1E-105	ConocoPhillips
Nabors Alaska Drilling			
Trans-ocean rig	CDR-1 (CT)	Stacked, Prudhoe Bay	Available
Dreco 1000 UE	2-ES (SCR)	Prudhoe Bay, U-06B	BP
Mid-Continent U36A	3-S	Stacked, Deadhorse	Available
Oilwell 700 E	4-ES (SCR)	Milne Point, MPF-38	BP
Dreco 1000 UE	7-ES (SCR/TD)	Prudhoe Bay, S-111i	BP
Dreco 1000 UE	9-ES (SCR/TD)	Niakuk Field, L-214i	BP
Oilwell 2000 Hercules	14-E (SCR)	Stacked, Deadhorse	Available
Oilwell 2000 Hercules	16-E (SCR/TD)	Stacked, Prudhoe Bay	Available
Oilwell 2000	17-E (SCR/TD)	Stacked, Point McIntyre	Available
Emsco Electro-hoist -2	18-E (SCR)	Stacked, Deadhorse	Available
OIME 1000	19-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
OIME 2000	245-E	Stacked, Kuparuk	Available
Emsco Electro-hoist Canrig 1050E	27-E (SCR/TD)	Stacked on 12-acre pad	Kerr-McGee
Nordic Calista Services			
Superior 700 UE	1 (SCR/CTD)	Drill site 5 well 36a	BP

North Slope - Offshore

Nabors Alaska Drilling			
Oilwell 2000	33-E (SCR/TD)	Cold stacked on NorthStar Island	BP
Nordic Calista Services			
Superior 700 UE	2 (SCR/CTD)	Kuparuk, 1-F well No. 1a	BP
Ideco 900	3 (SCR/TD)	Stacked, Kuparuk 1Q pad	Kerr-McGee

Cook Inlet Basin – Onshore

Aurora Well Service			
Franks 300 Srs. Explorer III	AWS 1	Rigging up to drill Moquawkie No. 3, should spud June 3	Aurora Gas
Pioneer Natural Resources			
Wilson Super 38	96-19	Stacked in Wasilla yard	Pioneer Natural Resources
Inlet Drilling Alaska/Cooper Construction			
Kremco 750	CC-1	Stacked, Kenai	Available
Kuukpik	5	Stacked Kenai	Available
Marathon Oil Co. (Inlet Drilling Alaska labor contractor)			
Taylor	Glacier 1	KBU 22-6	Marathon
Nabors Alaska Drilling			
National 110 UE	160 (SCR)	Stacked, Kenai	Available
Continental Emsco E3000	273	Stacked, Kenai	Available
Franks	26	Swanson River, 314-04	Unocal
IDECO 2100 E	429E (SCR)	Stacked, removed from Osprey platform	Available
Water Resources International			
Ideco	H-35 KD	Stacking, Pre to MOB to Kenai	Pelican Hill

Cook Inlet Basin – Offshore

Cudd Pressure Control	340K	Stacked	Available
Unocal (Nabors Alaska Drilling labor contractor)			
Not Available			
XTO Energy (Inlet Drilling Alaska labor contract)			
National 1320	A	Idle	XTO
National 110	C (TD)	Idle	XTO

Copper River Basin

Nabors Alaska Drilling			
Rigmasters 850	129	AHTNA 1-19	Rutter & Wilbanks

Mackenzie Rig Status

Mackenzie Delta-Onshore

AKITA Equtak			
Dreco 1250 UE	62 (SCR/TD)	Stacked, Tuktoyaktuk, NT	EnCana
Dreco 1250 UE	63 (SCR/TD)	Stacked, Lucas Point, NT	Chevron Texaco
National 370	64	Stacked, Inuvik, NT	Available

Central Mackenzie Valley

AKITA/SAHTU			
Oilwell 500	51	Stacked, Norman Wells, NT	Available
RigMaster P-850	40	Moving out after drilling Sahcho L-71	Northrock Resources
Nabors Canada			
	62	Racked	Apache
	8	Stacked, Alberta	Apache

Yukon Territories Rig Status

Yukon

AKITA/Kaska			
National 80UE	58	Stacked, Fort Liard, NT	Available
Ensign Resources Svc. Grp.			
Jackknife Double	55	Drilling completed, racked in Ft. Nelson	Devon Canada

The Alaska - Mackenzie Rig Report as of June 2, 2005. 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 Wadeen Hepworth

JUDY PATRICK

Baker Hughes North America rotary rig counts*

	May 27	May 20	Year Ago
US	1,331	1,315	1,169
Canada	271	267	195
Gulf	91	87	91

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

● NORTH SEA

Apache nearly doubles Forties production

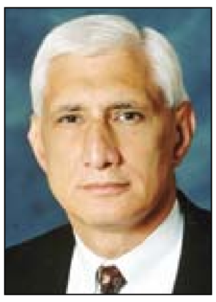
Took over North Sea field from BP two years ago; oil output has climbed to 70,000 bpd since; field producing better than expected

By RAY TYSON

Petroleum News Houston Correspondent

U.S.-based exploration and production independent Apache has nearly doubled oil production from the aging Forties field in the U.K. North Sea since taking over operations from BP some two years ago.

Moreover, in addition to producing better than initially expected, the Forties probably has more remaining recoverable oil than Apache thought when it purchased the field from BP in the spring of 2003.



"The capacity of the reservoir is much better than we ever anticipated." —Steve Farris, Apache's chief executive officer

"The capacity of the reservoir is much better than we ever anticipated," Steve Farris, Apache's chief executive officer, noted in the company's April conference call on 2005 first-quarter earnings.

As reflected in Apache's record quarterly profit of $559 million or $1.67 per share, up 62 percent from $345 million or $1.05 per share a year earlier, production from the Forties field has become a major contributor to the company's balance sheet, accounting for roughly 25 percent of Apache's worldwide oil production in the 2005 first quarter.

Production limited by infrastructure

Apache now believes the reservoir's ability to produce more oil is limited only by the field's infrastructure, which is undergoing a major upgrade to further improve field output, with most of the remaining work expected to be completed by this year's fourth quarter.

Apache invested $370 million on field improvements in 2004 and said it expects to spend about the same this year. About 550 Apache employees are working on various offshore platforms that support Forties production.

"I'm in a hurry to get the work done," Farris said.

Forties output during the 2005 first quarter averaged 61,870 barrels per day, up dramatically from an average 44,299 barrels per day during the previous year's first quarter. But production jumped to an average 70,000 barrels per day in April, and during one week in April production exceeded 80,000 b/d, Apache said.

"The Forties is already a major contributor to Apache production, but we want to increase our presence and production in the UK North Sea overall."

— Tony Lentini, Apache's vice president of public and international affairs

Challenge to limit production downside during renovations

"Quite frankly the field is now capable of producing volumes much greater than what we have averaged over any one quarter thus far," Farris said. "Our real challenge is to limit the (production) downside while we complete the major renovations projects that we have underway."

Apache would not discuss how much more oil the company expects to produce on a daily basis after platform work is completed, or how much additional oil it can recover from the Forties reservoir over the long term.

"We don't project production reserves, but I would say that the field's productive capacity is probably more limited by infrastructure … than by geology," said Tony Lentini, Apache's vice president of public and international affairs.

Forties field dubbed Prudhoe Bay of North Sea

The Forties, sometimes referred to as the Prudhoe Bay of the North Sea, was the first and largest field discovered in the U.K. sector of the North Sea. During its peak in the late 1970s, the field produced around 500,000 barrels per day. It had declined to about 45,000 barrels per day by the time Apache acquired the field from BP for $630 million, as part of a larger $1.3 billion deal that also included BP properties on the Gulf of Mexico's continental shelf.

At the time Apache purchased the Forties, the field had remaining recoverable proved reserves of about 147.6 million barrels of oil equivalent. That compared to around 2.5 billion barrels produced under BP's ownership.

Despite the huge decline in production over the years, "there is probably more recoverable oil than first thought, and we are drilling to develop that, in addition to making infrastructure improvements," Lentini said.

Apache picked up 14 blocks near Forties

Since the BP acquisition, Apache has picked up 14 exploration blocks located largely north and east of the Forties. The company has three new 3-D seismic surveys in the area and plans to drill several exploration wells near the Forties this year.

"The Forties is already a major contributor to Apache production, but we want to increase our presence and production in the UK North Sea overall," Lentini said.

Overall Apache production up

Overall, Apache production during the 2005 first quarter averaged 462,000 barrels of oil equivalent per day, up 7 percent from the first quarter of 2004 and up slightly from last year's fourth quarter. For this year's first quarter, that equates to 240,543 barrels of oil per day, up 10.5 percent from the year-ago period, and to 1.259 billion cubic feet of natural gas per day, up nearly 4 percent from the same period last year.

Based on combined oil and gas production, Apache increased output in the 2005 first quarter in nearly every country in which it operates except Australia, where oil production plummeted 32 percent to15,976 barrels per day and gas production fell 4 percent to 113.7 million cubic feet per day.

"Australia oil production is really the only weak spot in our 2005 production portfolio," Farris said, explaining that "we kind of got our drilling program backwards," meaning Apache had emphasized exploration over development. "We've now changed that," he said.

Production up in U.S., down in Canada

In the United States, Apache managed to increase oil production 9.4 percent to 73,630 barrels per day in the 2005 first quarter, despite having about 5,700 barrels of oil per day shut in due to Hurricane Ivan, which swept through the Gulf of Mexico last year causing widespread damage to offshore facilities. Apache's U.S. natural gas production was flat at 637.8 million cubic feet per day compared to last year's first quarter.

In Canada, Apache's oil production fell nearly 8 percent to 23,277 barrels per day in the 2005 first quarter versus the year ago period, but the oil decline was offset by a strong performance on the natural gas side, up 10.4 percent to 346.7 million cubic feet per day.

China, Egypt, Argentina output up

In Egypt, Apache's oil production during the 2005 first quarter increased 11 percent from the year-ago period to 54,579 barrels per day, while natural gas during the same period last year jumped more than 20 percent to 155.3 million barrels per day.

Apache's China oil production in the 2005 first quarter increased a strong 41 percent versus the year-ago period to 10,507 barrels per day. The company produces no gas in China.

In Argentina, Apache's oil production increased 27.5 percent to 704 barrels per day in the 2005 first quarter versus the year-ago period, while natural gas output declined 32.6 percent to 3.473 million cubic feet per day.

Although the company draws little natural gas production from the oil-rich Forties field in the U.K. North Sea, it did manage to increase gas output during the 2005 first quarter by nearly 40 percent to 2.178 million cubic feet per day. ●

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● INTERNATIONAL

Yergin: Oil price should settle at $30 price floor

Herrera challenges CERA chairman's assumptions, says OPEC produced 8 billion barrels more than members discovered in 2004

By KAY CASHMAN

Petroleum News

Daniel Yergin, chairman of Cambridge Energy Research Associates, believes oil prices will fall sharply in the next two years, settling in at a $30 price floor.

In a May 27 interview with CNBC, Yergin said current high prices should lead to an increase in global oil production, which in turn will cool the market, Dow Jones Newswires reported, noting that Saudi Arabia alone has said it will boost its oil production by 1.5 million barrels a day by the end of the decade.

JUDY PATRICK

ROGER HERRERA

"I think two years from now, we'll look more with $30 as a floor than what we're looking at today," he said in the interview.

Yergin challenges peak oil

Yergin challenged the peak oil theory, saying global production is expected to rise as much as 16 million barrels per day over the next decade.

"This is about the fifth or sixth time that the world has run out of oil, and at least in our study we see adding about 16 million barrels a day net of oil between now and the end of the decade, which is in fact very big number," he said.

Some analysts agree with Yergin, Dow Jones Newswires reported. Crude prices having risen sharply over the past two years due to increasing global demand. Because the upsurge has "eaten into the spare production needed to cushion supply disruptions," some industry observers see producers increasing exploration to boost production to meet demand, thus reliving the pressure on prices.

However, other analysts believe oil prices will "progressively" reach new highs as producers struggle to meet rising demand. Matthew Simmons, president of investment firm Simmons & Co., who spoke on the same program with Yergin, said production may have already peaked," Dow Jones Newswires reported.

Petroleum News' favorite oil price guru, Anchorage-based oil and gas consultant Roger Herrera, also takes issue with Yergin's prediction.

If the world does find an extra 16 million barrels of oil a day as Yergin suggests, "then his postulated price floor could well be right," Herrera said on May 28 in correspondence with Petroleum News.

"However, I have to question his optimism. Last year non-OPEC oil producers produced 8 billion barrels of oil more than they discovered. OPEC countries, to the extent that we can trust their figures, appear to have produced 8 billion more than they added to their reserves also. That hardly suggests that a miraculous extra 16 million barrels of oil a day is soon going to be found."

Herrera will put his money on Simmons

Herrera does "accept that the high price of oil is an incentive to explore for new oil, but new oil in large quantities is obviously very difficult to find."

In regard to the possibility of increased output from Saudi Arabia, he said he'd rather put his money on Matthew Simmons who has spent more time investigating Saudi oil capability than anyone."

And "the peak oil theory is not a theory. It is a fact in all producing nations except for five or six which haven't yet reached that plateau," Herrera said, noting that 'peak oil' does not indicate the world has run out of oil, but rather that about half the world's oil has been used.

"The other half is one hell of a lot of oil," he said.

"I personally, would be very happy if peak oil is delayed by a decade or two, but the geologists who are studying it most closely are extremely capable, experienced and level headed. They are in no way a bunch of pessimists.

"Geology, especially oil reserve estimation, is a very inexact science, but most of the available evidence from non-political geologists suggests that peak oil is probably imminent," Herrera said. ●

CANADA

Pioneer closes sale of Canadian properties

Pioneer Natural Resources said June 1 that its Canadian subsidiary has closed the sale of its Martin Creek, Conroy Black and Lookout Butte oil and gas properties to Ketch Resources "for proceeds after closing adjustments of approximately $199 million." The Dallas, Texas-based independent expects to recognize an after-tax gain of approximately $75 to $80 million from the asset sale based on its "intent to create a repatriation plan that qualifies for the provisions of the American Jobs Creation Act of 2004," Pioneer said in a press release. The company will report the operations results of the Canadian properties sold in its second quarter results.

Pioneer retained its core areas in Canada, the Chinchaga gas and the Horseshoe Canyon coalbed gas fields.

At Chinchaga, the company drilled 56 wells during its winter drilling campaign and said it has an "extensive inventory of locations remaining to drill in future years."

Beginning this month, Pioneer said it plans to drill a minimum of 80 wells to assess the potential of its Horseshoe Canyon coalbed acreage position.

Pioneer is an exploration and production company with operations in the United States, Argentina, Canada, Equatorial Guinea, Nigeria, South Africa and Tunisia.

—PETROLEUM NEWS

WESTERN CANADA

Dry spring boosts Canadian drilling

From the bog-like conditions of a year ago, dry weather has laid the foundation for the best drilling spring in four years across Western Canada.

The industry ended May with 43 percent of its 734 rigs at work in the region, the best showing for May since the 54 percent utilization rate in 2001 and from 58 to 102 more active rigs than a year ago.

To date this year, an average 487 rigs have been operating, beating the same period of 2004 by 55 rigs, with the utilization rate climbing to 67 percent from 62 percent.

For the final full week of May, 313 rigs were at work in Western Canada – 228 in Alberta, 57 in Saskatchewan and 28 in British Columbia.

EnCana is running 52 rigs belonging to member companies of the Canadian Association of Oilwell Drilling Contractors, drilling 25 development and eight exploratory wells in Alberta, 14 development and two exploratory wells in British Columbia and three development wells in Saskatchewan.

Husky Energy is a distant second with 15 wells underway.

Service operators have 448 rigs at work, with 480 idle.

The latest poll had 470 of the total rig fleet of 928 at work, down just 2 percent from a year earlier.

—GARY PARK

● VALDEZ

Prince William Sound RCAC sues Alyeska

Council sues to use Alyeska funds to analyze industry profits; Alyeska disputes funding of report, not right to do report

By KRISTEN NELSON

Petroleum News Editor-in-Chief

The Prince William Sound Regional Citizens' Advisory Council filed suit May 27 against Alyeska Pipeline Service Co., operator of the 800-mile trans-Alaska oil pipeline system from Prudhoe Bay to the port of Valdez. The lawsuit, filed in the Alaska Superior Court in Valdez, defends the group's right to use funds from Alyeska to analyze oil industry profits as they affect environmental safety.

Alyeska said it doesn't dispute the council's right to do the report, just the use of Alyeska funding for the report.

And, Alyeska spokesman Mike Heatwole told Petroleum News, the company objects to the implication "that we're somehow not in environmental compliance or that we're running an unsafe operation and that is just not true."

Heatwole said he is not aware of any previous litigation over terms of the contract, but said there was an earlier arbitration on the use of Alyeska funds for issues which Alyeska believed were outside the contract.

An arbitration panel decided in Alyeska's favor in 2000 over use of Alyeska funds to comment on a pipeline C-plan, Heatwole said. The panel said it agreed "generally with Alyeska that the plain language of the contract contemplates only review and comment on tanker and terminal operations, which generally means tanker and terminal C-plans…"

The council said in a May 27 press release that it acted in response to a demand from Alyeska that the council's base funding not be used to study industry profitability in Alaska. The funding is provided "under a long-term contract that, among other things, guarantees the council's independence from the industry," the council said.

TAPS compliance with environmental laws is not dependent upon profitability," Alyeska Pipeline President David Wight told the council's executive director, John Devens in a March 17 letter.

$25,000 report at issue

Alyeska told the council in mid-March that it would not approve the $25,000 contract with Richard Fineberg to analyze the profitability of ANS crude oil production and transportation. "North Slope production profitability and TAPS profitability are not topics that are included as subjects for local and regional input under the terms of our Contract. TAPS compliance with environmental laws is not dependent upon profitability," Alyeska Pipeline President David Wight told the council's executive director, John Devens, in a March 17 letter. Wight said that following the council board's approval of the contract at a September meeting, an Alyeska representative met with the board president and told him that Alyeska would request that funds provided by Alyeska not be used for this project.

Devens responded March 29 that the council had been told in September that a letter would be forthcoming, but only received the letter in mid-March. The project went forward, he said, and the council "neither sought nor obtained outside funding."

Devens said the council disagrees that the subject of the analysis is not covered under the contract. "Most of the work that we do is not explicitly named in the contract but, rather, can be interpreted to fall within the general description of services to be provided under the Contract." He said the council agrees that compliance with environmental laws is not dependent upon profitability, but said there have been "numerous occasions when you have cited economic justification for decisions being made on the Strategic Reconfiguration project…" and Alyeska personnel have given economics as a reason for not doing some projects. "Clearly, if economic reasons are being given for decisions about the system, we have a right to research the economic impact of those decisions on Alyeska" under terms of the council's contract with Alyeska, Devens said.

Alyeska Pipeline responded, through its attorney, asking if the council wished to arbitrate or litigate the issue of whether, to the extent the council has already used Alyeska funding to pay for this project, the council "has gone outside the constraints of the contract and the appropriate remedy."

The council said that while its contract with Alyeska provides for private arbitration proceedings or open proceedings in state court, it "went to court so that the matter would receive a full airing in a public forum."

Alyeska: dispute over use of funds

Alyeska's Heatwole said Alyeska doesn't disagree that the council has the ability to pursue the report, "what we disagree with is the use of Alyeska funds under the contract we have with the council."

North Slope production profitability and trans-Alaska pipeline profitability are not topics included in the contract, he said.

Heatwole said Alyeska is "disappointed that we're having to go to court over this issue." The company had believed it was headed to arbitration with the council over the issue, one of the options provided under the contract, he said.

The council was founded as a result of the Oil Pollution Act of 1990, is funded by Alyeska to the tune of some $2.8 million a year, and operates under OPA '90 and under a 1990 contract with Alyeska.

As to who pays for the council's litigation, apparently it will be Alyeska.

The contract between Alyeska and the council provides that funding by Alyeska will be used "only to engage in any or all activities authorized expressly or by implication by this Contract." The contract specifies that Alyeska funds may not "be used for attorney's fees, litigation consultants or witnesses, studies specifically undertaken for purposes of litigation, expert witnesses, or other litigation costs in connection with litigation against Alyeska or the TAPS owners, or for any litigation arising out of the Exxon Valdez oil spill of 1989…"

Alyeska funds, may, however, be used "for purposes of litigation or arbitration with Alyeska respecting disputes over the interpretation or performance of this Contract." ●

● NORTHERN CANADA

Mackenzie gas pipeline plans in real danger

Former Alberta energy minister sets 60-day deadline; says LNG could supplant Arctic gas

By GARY PARK

Petroleum News Canadian Correspondent

Unless the Canadian government and northern aboriginals can resolve their differences within 60 days, the Mackenzie Gas Project is in "real danger of not being built," said Murray Smith, former Alberta energy minister and now head of the province's office in Washington, D.C.

He told the Calgary Chamber of Commerce May 30 that "government inaction and intransigent negotiating positions" have put the C$7 billion scheme at risk.

Murray Smith, former Alberta energy minister and now head of the province's office in Washington, D.C.

"Competitive market forces will wait for no one and the demands for natural gas in a timely fashion and stable markets in Canada and the U.S. are no exception," Smith said.

The challenge posed by imported liquefied natural gas in both Eastern Canada and the United States could displace gas from Canada's Arctic if there is not quick action to resolve land access and benefits agreements with aboriginal communities in the Northwest Territories, he warned.

"There have to be some negotiations, there has to be some resolutions made for that pipeline to go ahead," Smith said. "It's important to Alberta and it's important to Canada and it's important to the North."

To that end, permitting and land access must be put on a fast track, with the Canadian government, Deh Cho First Nations and Mackenzie lead partner Imperial Oil putting an "extremely sharp focus" on the land deals over the next 60 days.

Early start of Alaska natural gas pipeline worries some

David MacInnis, president of the Canadian Energy Pipeline Association, agrees with Smith's call for urgency, suggesting that the Canadian government has been too slow in trying to end the impasse.

But MacInnis said he is more worried about the prospect of an early start on an Alaska gas pipeline, which observers say would put such pressure on construction labor, materials and the North American market that the Mackenzie project would likely be shelved.

The challenge posed by imported liquefied natural gas in both Eastern Canada and the United States could displace gas from Canada's Arctic if there is not quick action to resolve land access and benefits agreements with aboriginal communities in the Northwest Territories, Smith warned.

Greg Stringham, a vice-president of fiscal policy and markets at the Canadian Association of Petroleum Producers, took a different view, suggesting it could be another two years before the Alaska proposal could derail the Mackenzie line.

Meanwhile, confusion over the status of the Deh Cho negotiations and lawsuits seems to grow, not diminish.

News media reports in late May said the Deh Cho chiefs had given conditional approval to an agreement with the federal government.

The pact was said to include a C$15 million federal payment into a Deh Cho trust account, with the money earmarked for economic development.

A second resolution was reported to lay the groundwork for Deh Cho participation in the environmental and regulatory review processes.

Norwegian says no deal yet

But Deh Cho Grand Chief Herb Norwegian quickly dampened hopes of a deal, saying any talk of conditional approval was misleading, although he did indicate that the elements of an agreement are coming together.

"Nothing is final," he said, emphasizing that the Deh Cho communities will not give up their right to sue the federal government in the future.

He said details of any agreement will not be made public until a pact is signed, but declined to predict when that might happen.

"We have to make sure there is some content to it and that people are actually going to feel good about it," Norwegian told the Canadian Broadcasting Corporation. "We are not talking about selling out our people at this point."●

MISSISSIPPI

Military spending bill opens Mississippi national park to oil and gas exploration

Four paragraphs in a 96-page emergency military spending bill open a Mississippi national park designated as wilderness to oil and gas exploration, the Los Angeles Times reported May 31. The bill, signed by U.S. President George Bush in May, carries an amendment written by Sen. Thad Cochran, R-Miss., that codifies Mississippi's claim to mineral rights under federal lands and allows drilling for natural gas under the Gulf Islands National Seashore, a thin necklace of barrier islands from Mississippi to Florida in the Gulf of Mexico.

As a preliminary step to drilling … the rider allows seismic testing, marking the first time the federal government has sanctioned seismic exploration on national park property designated as wilderness.

Alabama's Dauphin Island, which is surrounded by oil and gas development, isn't included in the park.

As a preliminary step to drilling, the Times reported, the rider allows seismic testing, marking the first time the federal government has sanctioned seismic exploration on national park property designated as wilderness.

Still unresolved conflicts

State and federal officials have not agreed on the extent of exploration in the park. And there are still unresolved conflicts, the newspaper reported, including how shooting seismic on wilderness islands is compatible with the federal Wilderness Act, which prohibits ground disturbance and almost any type of development or construction.

Two of the five Mississippi islands and their surrounding environment are home to federally protected fish and birds, sea turtles and the Gulf's largest concentration of bottlenose dolphins, the Times reported.

"Seismic testing inside a park, in wilderness, with endangered species, arguably inside a place where the mineral rights arguably belong to all of us, I think that's particularly outrageous," said Dennis Galvin, former deputy director of the National Park Service.

Jack Moody, a geologist with the Mississippi Development Authority, which is responsible for energy leasing, told the Times that the authorization shouldn't be cause for alarm.

The law pertains only to Mississippi's mineral claims. "We want the right to develop the minerals that the state owns," he said. "But that doesn't mean we will go through there with a bulldozer."

Mississippi governor laid groundwork for amendment

Joe Sims, president of the Alabama and Mississippi division of the U.S. Oil and Gas Association, said the economic boon to the state could be significant – in the neighborhood of $200-$300 million over the life of production as an estimate of the state's share of royalties and taxes.

Mississippi Gov. Haley Barbour, the former head of the Republican National Committee and a Washington lobbyist, signed a bill last year allowing oil and gas leases in state waters surrounding the islands, which laid the groundwork for the amendment, the Times reported.

Barbour also signed legislation transferring authority over drilling from the state's environmental quality agency to the Mississippi Development Authority.

—PETROLEUM NEWS

● WASHINGTON, D.C.

DOE seeks comment on Alaska gas line loan

State of Alaska, potential lenders expected to submit ideas on administering program in North Slope gas pipeline project

By ROSE RAGSDALE
Petroleum News Contributing Writer

The U.S. Department of Energy is seeking public comment on an $18 billion loan guarantee program to encourage construction of a pipeline that will bring Alaska natural gas to the Lower 48. The federal agency published a notice of inquiry for a 60-day comment period in the Federal Register May 27. The comment period closes on July 26, 2005.

JUDY PATRICK

Secretary of Energy Samuel Bodman

DOE said the pipeline will provide access to Alaska's 35 trillion cubic feet of proven natural gas reserves and would be a major step forward in meeting America's growing energy needs and reducing U.S. dependence on foreign sources of energy. It also would fulfill the Bush Administration's policy to bring Alaska's natural gas reserves to market.

Alaska Commissioner of Revenue Bill Corbus

"Further developing our domestic energy supply is a key priority of the President's National Energy Policy," Secretary of Energy Samuel Bodman said in announcing the notice. "When the Alaska pipeline is fully operational, it will have the potential to add nearly 2 trillion cubic feet of natural gas each year to our supply, which would help to further stabilize prices."

Natural gas serves six of every 10 American households, about 62 million homes, and is used to generate about 16 percent of the nation's electric power. It is also indispensable as a feedstock for fertilizer and chemical manufacturers.

In recent years, rising demand and limited increases in supply have resulted in high natural gas prices that affected residential and industrial users across the economy, DOE said.

DOE is also asking for comment on specific issues about how the loan guarantee program should be administered. "One purpose of the notice gathering comment is to work out how the loan guarantee program will work," said DOE spokesman Bill Purvis.

Alaska Commissioner of Revenue Bill Corbus said the federal loan guarantee program is important to the proposed gas pipeline project. "The gas producers and the State of Alaska were some of the heavy supporters of including it in the energy legislation last year and they worked for that," Corbus said June 1.

In conversations with a number of investment banking houses, Corbus said he learned that potential lenders are also interested in the loan guarantee. "They suggested various ways the loan guarantee would be put to good use," he said.

Corbus said he anticipated that the state will submit comments to DOE on the loan guarantee program. Alaska is proposing to take an ownership interest in the gas pipeline project and would therefore have a proportionate share of the debt responsibility, he said. "I could see that federal loan guarantee coming into play with our portion of the debt," Corbus added.

Wants input on program administration

DOE is also asking for comment on specific issues about how the loan guarantee program should be administered. "One purpose of the notice gathering comment is to work out how the loan guarantee program will work," said DOE spokesman Bill Purvis.

While potential lenders and banks are expected to comment, DOE wants to hear from everyone who has an interest in the gas pipeline, a spokesman said.

No final decision has been made on whether regulations to implement the loan guarantee program are needed. ●

● CANADA

Rocking the energy trust boat

Oil patch financier Murray Edwards says corporate and trust tax rules are detrimental to Canadians; calls for end to foreign advantage, wants more funds in government coffers

By GARY PARK

Petroleum News Canadian Correspondent

It amounted to possibly the strongest claim yet for changes to Canada's energy income trusts and it could scarcely have come from a more credible source.

Murray Edwards would never be mistaken for a carping critic of the petroleum industry.

One of the toughest competitors in the Canadian oil patch over almost 20 years, he has rescued floundering companies and pulled off legendary deals.

MURRAY EDWARDS

He invested C$100,000 in Canadian Natural Resources in 1988 to help save the company from financial ruin. At last check his 2 percent stake in the independent was worth close to C$400 million.

Dubbed Mr. Patient Money by industry observers, he has been a key player in other companies such as Penn West Petroleum, Ensign Resource Group, Meota Resources and Rio Alto Exploration, building value through takeover coups and the drillbit.

In the process he has also become a partner owner of the National Hockey League's Calgary Flames.

Edwards' down-to-earth style has seen him take a contrary view of the scramble among small- and mid-size E&P companies to join the income trust ranks, building their reserves through acquisitions rather than exploration.

Steps down as Penn West chairman in protest

His persistent questioning of the trust trend boiled over May 26 when Penn West ended 14 months of agonizing over its future and switch from being Canada's fifth largest independent oil and gas firm to become the largest conventional producer among the 30 trusts at 101,000 barrels of oil equivalent per day.

With the conversion, endorsed by 92.6 percent of Penn West shareholders, Edwards (who holds 3.5 million shares worth almost C$300 million and abstained from the vote), immediately stepped down as chairman.

And he did so with a detailed assessment of the trust structure, saying he is concerned that trust cash distributions are being made at the expense of capital investment, causing him concern about the "structure and long-term viability" of trusts – although he gave a special exemption to Penn West, saying he has full confidence in the new trusts management and the quality of its assets.

Misgivings extend beyond industry

Edwards even extended his misgivings beyond the industry itself to the drain on federal revenues from the trust structure.

He suggested the Canadian government will have to modify rules that put cash distributions in the hands of foreigners with only minimal returns to federal coffers and often none to the provinces.

Foreign investors in trusts are charged only a 15 percent withholding tax, compared with the 40 percent or more

"I find it challenging that we're the only country in the world that basically allows income to be drawn from the country at a tax rate of only 15 percent."
—Murray Edwards

imposed on Canadians

Edwards pointed to the irony of funneling cash out of Canada at a time when the provincial governments are struggling to keep pace with rising health care and education costs.

"I find it challenging that we're the only country in the world that basically allows income to be drawn from the country at a tax rate of only 15 percent," he said.

He also pointed out that exploration companies pay taxes in the province where they are operating, while trust taxes go to the provinces where the unitholder resides.

Reduce the gap in tax treatment

Edwards suggested it is time for governments to reduce the gap in tax treatment between the distributions of trusts and the dividends that corporations pay to shareholders.

While dividends are taxed at both the corporate and personal levels, trusts are taxed only once – giving them an unfair advantage, he said.

Penn West president Bill Andrew said that discrepancy was what finally drove the company into the trust fold.

"We (found) ourselves taxable, we (found) ourselves not able to put out a dividend in a tax-effective manner to our shareholders compared to a trust, so there's a bit of a niche created right now for trusts," he said.

But the Canadian government has shown no sign of acting on the criticism of double-taxation of dividends.

Andrew also argued that the switch will broaden Penn West's base to include more retail investors.

With a market capitalization of C$4.6 billion, Penn West produced 53,162 barrels per day of crude and liquids and 289 million cubic feet per day of gas in the first quarter, earning C$66.9 million.

It has 310 million barrels of oil equivalent of proved and 60 million boe of probable reserves, of which 49 percent is light and medium crude, 17 percent heavy oil and 34 percent gas. It also holds 5.8 million acres of undeveloped land in Western Canada.

The final week before the shareholder vote generated some other turbulence when the Ontario Teachers Pension Plan Board, Canada's second largest pension fund with C$85 billion invested in assets, challenged plans to reward management

He is concerned that trust cash distributions are being made at the expense of capital investment, causing him concern about the "structure and long-term viability" of trusts – although he gave a special exemption to Penn West, saying he has full confidence in the new trusts management and the quality of its assets.

and employees holding 900,000 stock options with C$95 million if the conversion proposal was adopted.

Teachers' chief executive officer Claude Lamoureux said he objected to transferring a "lot of wealth" to management when nothing would change except the form under which Penn West would operate.

The board said it was ready to fight the matter in court, although Lamoureux conceded that Penn West was so widely held it would be an uphill struggle to sway shareholders.

In the end, Teachers backed down when Penn West agreed to count the votes from shareholders and options holders separately.

In the end option holders voted 100 percent in favor and shareholders have a 91.6 percent backing to the change. ●

ALASKA

Governor signs extension for ACMP plans

Alaska Gov. Frank Murkowski signed Senate Bill 102 May 26, giving the state's coastal districts an extra eight months to submit revised district coastal plans to the Alaska Department of Natural Resources.

The Alaska Legislature reformed and simplified the state's Alaska coastal management program in 2003, and the state has been working with the federal Office of Coastal Resource Management to ensure federal approval of the state's amended plan.

Under the 2003 bill, coastal districts had until the end of June 2005 to submit revised district plans.

Districts told the Legislature that they needed more time, and SB 102 extends by eight months the deadline for coastal resource districts to submit their revised plans to the state, and also extends by eight months the effective authority of existing district plans.

—PETROLEUM NEWS

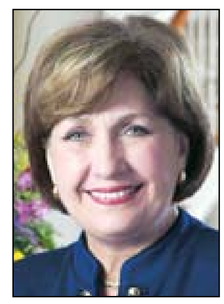
● WASHINGTON, D.C.

Energy bill with federal LNG rules advances

THE ASSOCIATED PRESS

Governors, mayors and local officials would have little chance to block construction of a liquefied natural gas terminal under an energy bill that advanced May 26 from a Senate committee. (See related story on page 16 of this issue.)

A provision in the bill gives the Federal Energy Regulatory Commission exclusive jurisdiction over final approval of such a terminal. A dozen or more such facilities probably will be built in the next decade.



The vote came after Louisiana Gov. Kathleen Blanco and five other coastal-state governors asked senators not to take away states' role in approving gas import terminals

The Senate Energy and Natural Resources Committee advanced the non-tax portion of the energy legislation by a 21-1 vote. Several lawmakers said contentious issues such as the siting of LNG terminals would have to be settled by the full Senate.

The vote came after Louisiana Gov. Kathleen Blanco and five other coastal-state governors asked senators not to take away states' role in approving natural gas import terminals.

In a May 25 letter to the energy committee's chairman and top Democrat, California Gov. Arnold Schwarzenegger and the governors of Massachusetts, Louisiana, Delaware, Rhode Island and New Jersey said states and local agencies should have shared jurisdiction with the federal government over projects on their coasts.

"We support legislation that would provide for concurrent state and federal jurisdiction over LNG and other energy facilities," said the letter to Sens. Pete Domenici, R-N.M., and Jeff Bingaman, D-N.M.

House bill affirms FERC's authority

The House has already passed an energy bill affirming FERC's authority to approve the natural gas import terminals. The provisions passed by the GOP-controlled House "unacceptably pre-empt state and local jurisdiction," the three Republican and three Democratic governors wrote.

FERC Chairman Patrick Wood said he didn't think the energy bill language would diminish states' authority over LNG terminals.

"I don't see in the energy bill's LNG language where the states' robust regulatory authority will be affected, except to set a reasonable and statutorily supported timeline for the states to act," he told reporters after a commission meeting.

There are now just a handful of LNG import facilities in the United States and companies are trying to build three dozen more.

The Long Beach, Calif., city council on May 24 postponed a vote on a $450 million natural gas terminal proposed by ConocoPhillips and Mitsubishi.

In addition to Schwarzenegger, a Republican, the governors signing the letter were Republicans Mitt Romney of Massachusetts and Donald Carcieri of Rhode Island, and Democrats Blanco of Louisiana, Ruth Ann Minner of Delaware and Richard Codey of New Jersey, the acting governor.

Other items in the legislation approved by the Senate committee include:

• A requirement to double ethanol use in gasoline.

• New rules to ensure the reliability of the nation's electricity grid.

• Loan guarantees for new, innovative energy technologies such as clean coal gasification plants and new generation nuclear reactors.

Sen. Mary Landrieu, D-La., won approval for an inventory of Outer Continental Shelf oil and gas reserves. This plan is similar to one the Senate approved in energy legislation two years ago. ●

ALBERTA

Deer Creek moves on several fronts

Oil sands start-up Deer Creek Energy is pushing ahead with a new phase of its plans to produce 200,000 barrels per day by 2020.

Through newly-formed subsidiary, Deer Creek Pipelines, jointly-owned with Enerplus Resources Fund, it has unveiled plans for a C$37 million pipeline to carry blended bitumen from its Joslyn operation to the Athabasca terminal near Fort McMurray.

Deer Creek owns 84 percent of both the Joslyn venture and the pipeline unit.

The sales line will cover about 40 miles and carry 40,000 bpd of bitumen production.

Construction work on Joslyn is expected to start in the third quarter, moving from a first phase of 600 bpd to 10,000 bpd in early 2006.

Deer Creek president and chief executive officer Glen Schmidt said the pipeline is an "important step for Deer Creek (providing) the first direct pipeline transportation route to market."

Deer Creek is also part of a 14-member team at Quadrise Canada Fuel Systems, a private firm that is testing another technology innovation in the Alberta oil sands.

Known as MSAR (multi-phase superfine atomized residue), it is the offspring of an emulsion fuel developed in the 1980s by BP and Venezuela's stated owned PDVSA for bitumen deposits similar top those being extracted in northern Alberta.

MSAR not only reduces the wasteful use of scarce and costly natural gas, it is projected to lower the cost of producing bitumen by US$2.50 per barrel.

Deer Creek has also announced that a letter of intent has been executed with a major oil sands producer that will see Deer Creek purchase light density diluents for its produced bitumen and sell the resultant blended bitumen to the producer.

The proposed deal covers two years from April 2006 and is expected to have a positive impact on bitumen value for Deer Creek by providing similar price economics to blending with gas condensate.

—GARY PARK

● NORTH SLOPE

Slope's first pentalateral in production

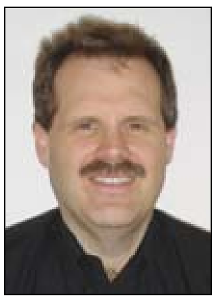
Pushing the technology envelope: five laterals producing from 27,000 feet of reservoir at Polaris, Prudhoe viscous satellite

By KRISTEN NELSON
Petroleum News Editor-in-Chief

BP Exploration (Alaska) is pushing the technology envelope at its Prudhoe Bay viscous oil satellites, drilling multiple horizontal lateral legs from single well bores to access as much reservoir sand as possible in the shallow Schrader Bluff reservoir. In 2003 BP drilled the first trilateral well on the slope; in 2004 it drilled the first quadrilateral; and this winter the company completed the first pentalateral. All targeted the Schrader, either at Orion or Polaris, two satellite fields under development on the western side of the Prudhoe Bay field.

In the 1990s the Schrader was accessed with vertical wells, crossing vertically through multiple narrow reservoir sands, but production rates were not economic. Current well technology enables BP to drill horizontally, opening reservoirs to production for a mile or more; and the company is opening multiple reservoir sands from one well bore.

The five horizontal laterals in the S-213A well at Polaris access 27,000 feet of reservoir, Gil Beuhler, Prudhoe Bay satellite development manager, told Petroleum News in a May 10 interview. Compare that, he said, to 200-250 feet of reservoir opened up when a well is drilled vertically through four or five Schrader Bluff sands each up to 50 feet thick.



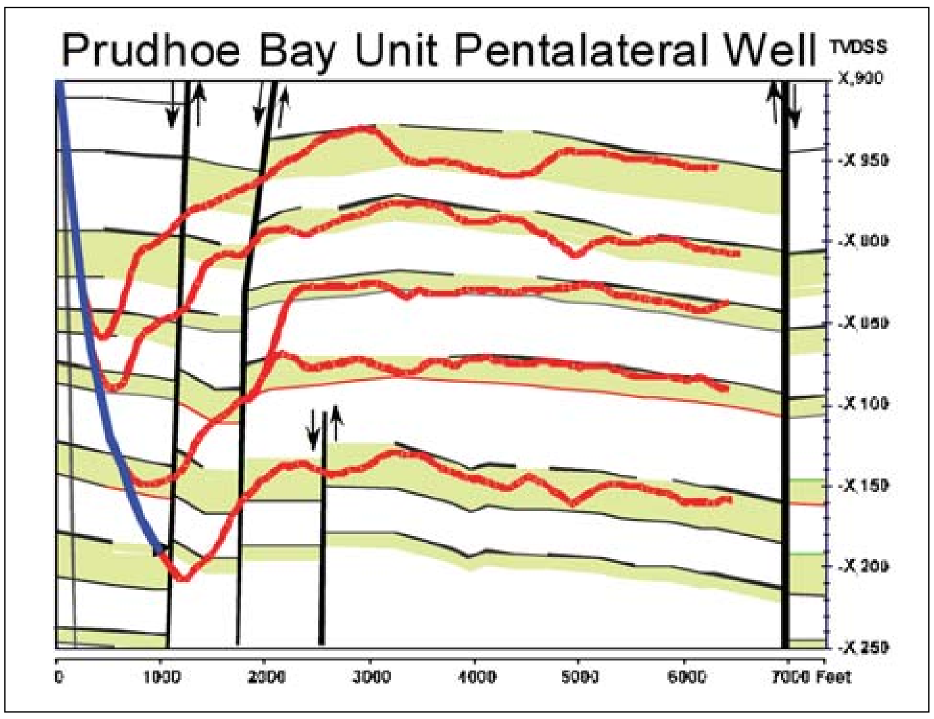
GIL BEUHLER

The impacts on production are dramatic. The S-213A, sidetracked off an older vertical well bore, came on production in March at several thousand barrels per day and Beuhler said the last test he saw was in the 3,500 bpd range. While long-term flow rates are expected to be in the 1,000 to 1,500 bpd rate, the original vertical well, the S-213, had a long-term rate of 200-300 bpd, he said.

That production comes at a price, Buehler said, with a lot more money invested in this pentalateral, $10 million, than in a vertical well to the Schrader, which might cost a quarter of that to drill.

But those vertical wells "weren't fully accessing the potential" of the Schrader Bluff formation, he said. Although the multilateral wells are more expensive and more challenging, "now you're progressing the opportunity."

North Slope viscous oil is in shallow reservoirs, close to the permafrost: it is cold and doesn't flow as readily as oil in deeper, warmer reservoirs: hence the productivity problem which BP is addressing with multilateral wells. The shallow reservoirs also aren't as well consolidated as deeper sandstones and fine sand from



COURTESY BP

MIK TRIOLO

the reservoirs is produced to the surface along with the oil. That issue —handling the solids — is a separate issue, Beuhler said, a facilities issue. Those solids have to be removed from oil processing facilities and trucked to a grind and inject facility, adding costs to Schrader production.

Wells more complicated

The wells BP is drilling in the Schrader Bluff formation — and wells that ConocoPhillips Alaska is drilling in the analogous West Sak formation at the Kuparuk River field — address the viscous oil productivity issue with technology. The companies have a regional viscous team which shares technology and best practices, Buehler said: "We can't afford to make the same mistakes across multiple assets. We can't afford to have a success and not apply it across all the assets." The team shares current challenges and technology developments, including where a new technology might best be tried first. It's "a very collaborative effort," he said, because the developments are similar and have "similar challenges that require similar solutions."

That's also true within BP-operated North Slope fields. Prudhoe Bay operations drilling engineer Mik Triolo started working the viscous issue at Milne Point and then moved over to Prudhoe, working on early multilateral and horizontal well designs.

The Polaris pentalateral builds on the technology used at the Orion quadrilateral, he said. Both have multi-lateral junctions. But the S-213A also has an open-hole junction kick-off for one sand small enough it didn't justify the cost of a junction box. Because of uncertainties about what the reservoir will do under production conditions — and how stable that open-hole junction would be once the well was producing — they ran an aluminum billet, an aluminum tube, out to the end of the liner and milled off that to reduce the open-hole area at the junction.

Triolo said it too early to know how it will work, but the drilling portion of the work was successful, the liner was successfully inserted past the open-hole junction and "it significantly reduces the cost" of the two laterals because a junction isn't required.

S-213A took longer to drill

The L-201 quadrilateral took about 40 days to drill, Triolo said. The S-213A pentalateral took about 80 days to drill, partly due to completion difficulties, "none that we were not able to overcome."

Buehler said that goes with technology development:

see **PENTALATERAL** *page 12*

COLORADO

Suncor buys Valero refinery in Colorado

Suncor Energy's U.S. subsidiary has bought a small refinery in Colorado adjacent to a bigger facility the Canadian oil sands company purchased from ConocoPhillips in 2003. The deal was announced June 1.

Suncor Energy (U.S.A.) paid $30 million for the Valero refinery that can process 30,000 barrels per day. That operation will be integrated with the one next door for a combined refining capacity of about 90,000 bpd. The plants are six miles northeast of downtown Denver in Commerce City.

"These two plants belong together … because they are much stronger and have a much brighter future together than either has individually," noted Valero's chairman and CEO, Bill Greehey. His firm is in the process of buying fellow refiner Premcor for $8.7 billion in cash and stock. That deal, if it goes through, will make Valero the largest U.S. refiner. For Suncor, the deal adds to its eventual ability to process increased production from Alberta oil sands operations, though the company has assured local crude oil suppliers currently providing feedstock to the Valero refinery that they won't be affected by the transaction. Suncor also has a refinery in southern Ontario.

—ALLEN BAKER

Orion quadrilateral won BP award

BP Exploration (Alaska) Prudhoe Bay drilling engineer Mik Triolo and Steve Deckert, Alaska Drilling and Wells staff engineer, are on senior petroleum engineer Donn Schmohr's team, which won BP's 2004 Paul Martins production excellence award for the L-201 quadrilateral drilled in 2004 at the Orion satellite at Prudhoe Bay.

This is the first time the award has been given.

The reward goes to individuals and small teams within BP's exploration and production segment, or those working in partnership with BP, who have made an outstanding contribution to production excellence.

It is for technology excellence in drilling and completion, with competition among BP business units worldwide based on six criteria: materiality — significant business impact; integration; long-term sustainability; sharing of ideas; initiative; and measureability. The reward goes to individuals and small teams within BP's exploration and production segment, or those working in partnership with BP, who have made an outstanding contribution to production excellence.

The award was created in honor of Paul Martins, who died last fall, by colleagues who wanted to memorialize his contributions to the company.

Martins, 50, was BP's head of discipline, completions and wells. He was with BP in Alaska from 1990 to 1996 as lead stimulation engineer and team leader for production technology, returning to the United Kingdom in 1996 as subsurface manager for the Magnus field. He was then named well performance technology network leader. Martins earned a Ph.D. in geomechanics from Imperial College and B.A. and M.A. degrees in engineering science from Oxford and began his career with BP in 1982 at the research and development center in Sunbury, UK.

The Alaska multilateral well team took top honors.

Also among the finalists were Diane Richmond, Milne Point reservoir management lead, and her team.

They increased production from the Kuparuk reservoir at Milne by 5,000 barrels per day with no additional capital spending, cutting the decline of oil production from the Kuparuk reservoir from 17 percent to 7 percent a year.

continued from page 11

PENTALATERAL

"We're pushing the technology envelope. We've got to; we can't live with status quo," so while it's painful to spend 80 days drilling a well, "if we don't do that we won't unlock the well component of the viscous strategy and technology development."

The angle of the wells — each lateral about a mile long — also makes them challenging, Triolo said. These are shallow extended reach drilling wells, with true vertical depths of between 4,000 and 5,000 feet, stepping out 12,000 to 13,000 feet in measured depth. That is at "the very edge of the envelope" industry-wide for shallow ERD wells, he said.

In addition to the aluminum billet, BP also ran swell packers in the S-213A well, Triolo said. The 10-foot long elements area a little bigger than the liner and expand over time and seal off the annular area between the liner and the well bore. As the wells are drilled, logs are run, and determinations are made then whether to run in packers and where, providing future potential shut-off capabilities along the length of the lateral.

Packers help manage the well over time, Buehler said. In a vertical well if one reservoir zone starts producing water you can go in and shut off that zone. In a lateral well, the swell packer provides a way "to go in and isolate specific parts of a specific well bore."

"We're not just trying to maximize productivity right now, we're trying to maximize the total life-cycle benefit of the well," Buehler said. How will you manage the well 20 or 30 years from now? The swell packers are used for "formation integrity — trying to keep things in place" and for well-bore mitigation.

What's next?

More multilaterals per well isn't the direction Buehler sees this technology going in the Schrader Bluff formation.

The number of multilaterals depends on the number of sands in a reservoir, he said.

Typically ConocoPhillips is drilling two laterals from West Sak wells while BP is drilling four to five in the Schrader. It's a function of the reservoir, Buehler said. "Their pay can be accessed with fewer laterals because it's a little bit thicker. … In Polaris we have five distinct pay intervals." Orion has four.

"The reservoir's talking to you in terms of how many laterals you need" and the technology component determines "how many laterals you can actually do," Buehler said.

As for what's next: "I would like to be able to drill farther," put in more openhole junctions vs. junction boxes, because of the cost factor, and "be able to hold more of the reservoir in place and reduce our solids production." ●

● COOK INLET

Forest to drill west side Tutna prospect

By KAY CASHMAN

Petroleum News Publisher & Managing Editor

Forest Oil plans to drill its Tutna prospect on the west side of Cook Inlet, the company said in paperwork filed with the Alaska Department of Environmental Conservation in late May.

Forest applied for an oil discharge prevention and contingency plan with DEC to drill Tutna, which it describes as an "oil and gas prospect," during the 2005/2006 winter season. The company said operations for "other potential projects" at different locations within the Cook Inlet area will be added to the plan as site specific plans are developed.

Tutna a gas prospect

In 2002, Forest's former top executive in Alaska, Gary Carlson, told Petroleum News the Tutna prospect was strictly a gas play with an estimated 36 billion cubic feet of gas in place. It was one of eight "hot plays" for which Forest was seeking a partner.

The Tutna drill site is in the Trading Bay State Game Refuge, on the shoreline of Trading Bay, 20 miles northwest of Nikiski. Next to Middle River, the site is approximately a half mile from Cook Inlet and 16 miles southwest along the shore from the Native village of Tyonek. Its exact location is Sec.8, T 10 N, R 12 W, Seward Meridian.

Forest is looking at building 4 to 9 miles of temporary road, including a temporary bridge over Nikolai Creek, depending upon which route is chosen to provide access between the site and the road system in the Tyonek/Beluga area.

The access road and pad will consist of temporary construction — timbers, rig mats, or other specialized systems — over a snow/ice foundation.

The company said the "plan proposes to address oil spill prevention and response measures to support Forest's operation for a proposed response planning standard of 5,500 barrels per day for 15 days to total 82,500 barrels at the drilling site."

Looking to expand production in area

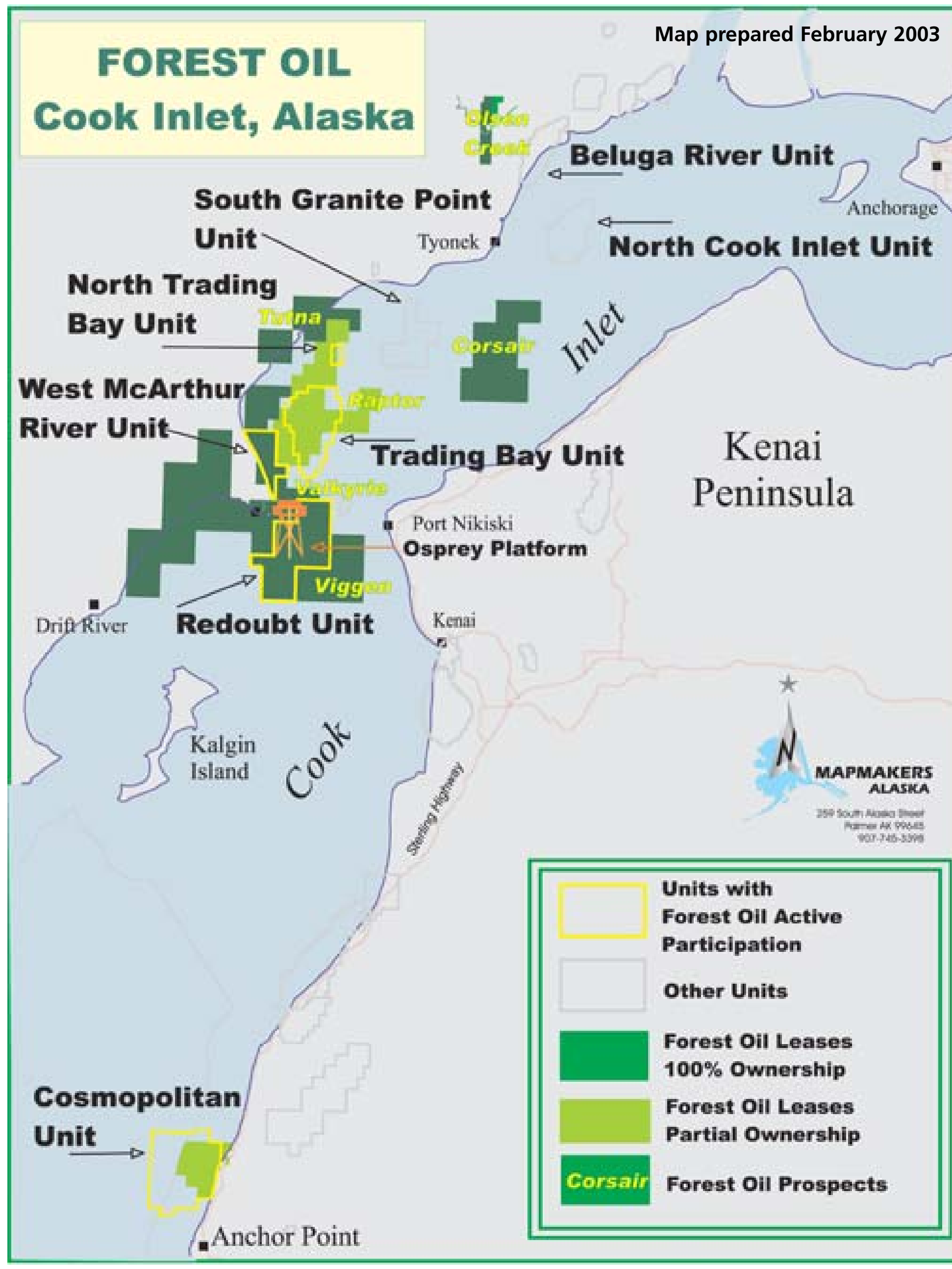
Forest already owns and operates onshore oil and gas production facilities on the West Forelands area on the west side of Cook Inlet. It is also partners with Aurora Gas on that side on the inlet. These operations currently include natural gas production from several reservoirs.

Forest told the state it hopes to ultimately increase its oil and gas production in the general area with its drilling at Tutna and other prospects.

The 30 day public notice period for the spill plan began running May 26.

A pre-application meeting with other agencies has already taken place, although the only paperwork available as of June 1 was the DEC spill plan application.

Bob Britch of Northern Consulting is coordinating permitting for Forest's Anchorage office, a state official said. ●



● COOK INLET

Looking for resolution on CIGGS dispute

Companies in long-running dispute over the operation of the Cook Inlet Gas Gathering System opt for mediation

By ALAN BAILEY

Petroleum News Staff Writer

In an attempt to resolve a long-running dispute over the operation of the Cook Inlet Gas Gathering System, known as CIGGS, Agrium Inc., the Cook Inlet gas producers and the state of Alaska entered mediation on May 26.

Agrium spokeswoman Lisa Parker told Petroleum News that mediation will speed up resolution of the dispute.

The Regulatory Commission of Alaska is currently determining whether CIGGS should be regulated and expects to announce a decision in November. Mediation will deliver a solution in July, Parker said.

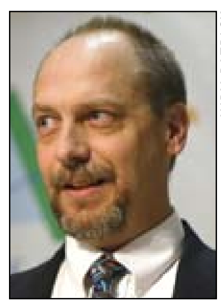
CIGGS consists of a gas pipeline system that connects the Trading Bay and Granite Point processing facilities on the west side of Cook Inlet with the fertilizer and LNG plants at Nikiski on the east side of the Inlet. Marathon Oil and Unocal jointly own CIGGS, while Agrium owns the Nikiski fertilizer plant.

Built in the 1960s

The companies operating the Cook Inlet oil fields built CIGGS in the 1960s to move excess gas from the west side of the Inlet to the industrial plants on the east side.

The Alaska Right-of-Way Leasing Act, passed in 1972, mandates that all pipelines crossing state lands or state waters must be regulated as common carrier pipelines or gas utility lines. In general, a pipeline that is regulated in this way must offer service to anyone who needs to transport petroleum products appropriate to the operation of the pipeline.

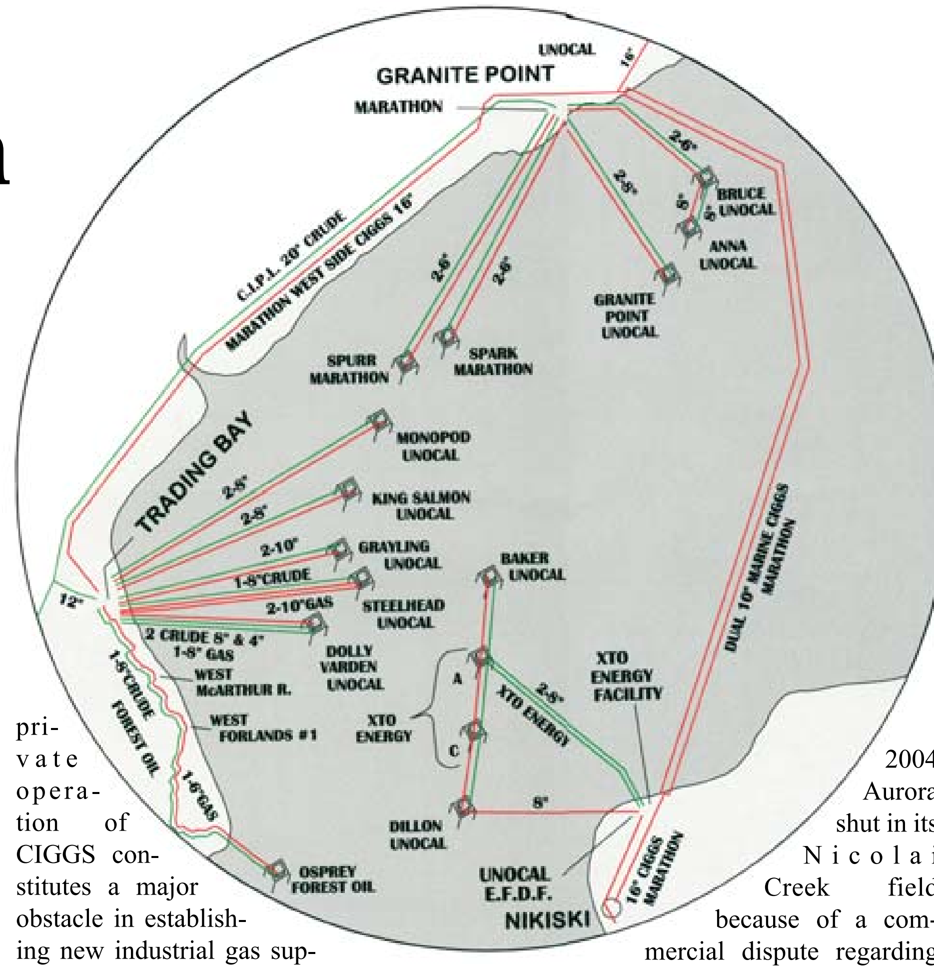
However, a grandfathering provision in the Right-of-Way Leasing Act allows pipelines built prior to May 20, 1972 to remain exempt from regulation "so long as their original or present purpose and function remain." As a result, CIGGS has remained a privately operated system, with access only available through commercial agreement with the system owners.



JUDY PATRICK

"We're looking for a reasonable resolution that meets everyone's needs." —John Barnes, Marathon's Alaska business unit manager

Agrium, anxious to bolster dwindling gas supplies for its Nikiski fertilizer plant, has for some time argued that the private operation of CIGGS constitutes a major obstacle in establishing new industrial gas supplies to Nikiski from gas fields on the west side of the Inlet. The Agrium fertilizer plant is scheduled to close in November 2005 unless additional gas supplies for the plant can be established.



It is possible to move gas to Nikiski from the west side of the Inlet through a series of Enstar Natural Gas Co. pipelines that run up to Wasilla in the Mat-Su Valley and then down to the Kenai Peninsula through Anchorage. However, Enstar has to add odor agents called mercaptans to the gas in these pipelines: the mercaptans render the gas unusable for industrial processing.

Since early 2004 Agrium has filed two petitions with the Regulatory Commission of Alaska to regulate CIGGS. The commission dismissed Agrium's first petition and is still making a determination on the second petition, filed in October 2004.

Regulation or agreement

Marathon has in the past said that commercial agreements present the simplest way of enabling new gas shippers to use CIGGS. The company has said that millions of dollars of expenditure would be required to install the metering and control facilities needed to convert CIGGS into a regulated line. And Marathon has also told Petroleum News that major costs and delays resulting from the regulatory process for the Kenai-Kachemak pipeline on the east side of the Inlet demonstrate that regulation is less efficient than a commercial agreement.

Aurora Gas, an operator of several gas fields on the west side of Cook Inlet, sees pipeline access south of Granite Point as a major issue for companies wanting to develop fields in that area. In December 2004 Aurora shut in its Nicolai Creek field because of a commercial dispute regarding the use of CIGGS — Nicolai Creek connects into CIGGS.

Recent events

In April 2005 RCA denied a motion to allow limited private-carriage access to CIGGS for gas from Nicolai Creek — the commission said that consideration of the motion would deflect resources from investigating regulation of the system. The CIGGS owners had wanted an assurance from the commission that a contract carriage arrangement on the system would not trigger common carriage regulation.

In April 2005 RCA denied a motion to allow limited private-carriage access to CIGGS for gas from Nicolai Creek — the commission said that consideration of the motion would deflect resources from investigating regulation of the system.

However, on May 10 the commission granted Aurora Gas immediate and continuing access to CIGGS to transport gas from the Nicolai Creek Unit pending resolution of the CIGGS dispute. Then on May 20 Agrium, Unocal, Marathon, Enstar, Aurora Gas and the state of Alaska jointly filed a motion to initiate the current mediation of the dispute, with a commission appointed judge as mediator.

If successful, mediation will result in an agreement signed by all parties.

"We're looking for a reasonable resolution that meets everyone's needs," John Barnes, Marathon's Alaska business unit manager, told Petroleum News. "Marathon supports the concept of getting to a better resolution more quickly," he said. ●

● WESTERN CANADA

Entering a new generation

Canadian producers and governments awaken to enhanced oil recovery prospects; Kyoto Protocol helps ignite investment

By GARY PARK
Petroleum News Canadian Correspondent

The prize could be billions of barrels of oil that Western Canada's producers have been unable to profitably drag to the surface by conventional means.

But the rapid descent of conventional crude, projected to slump from 1.4 million barrels per day for all of Canada in 1995 to under 700,000 bpd by 2015, has dreams and dollars shifting to enhanced oil recovery (EOR) schemes, bolstered by government incentives.

Saskatchewan alone estimates that EOR techniques can raise its recoverable oil potential to 35 billion barrels from the 5 billion barrels that are currently accessible by primary (vertical well drilling) and secondary (water flooding) techniques.

A mere 5 percent increase in the overall recovery rate would more than double Saskatchewan's remaining recoverable oil reserves to 2.4 billion barrels, said the province's Resources Minister Eric Cline.

Environmental benefits

In some cases, the drive to squeeze as much oil as possible from Western Canada's aging fields also yields environmental benefits now that producers have figured out ways to pump carbon dioxide — the primary culprit among greenhouse gases — to rebuild reservoir pressures and, as the CO2 mixes with oil, allow the oil to flow more easily to the surface..

Federal and provincial cabinet ministers have also seized the chance to help Canada achieve its Kyoto Protocol commitments by offering C$30 million over two years as an incentive for companies to develop ways to capture and store CO2.

One of those emerging techniques involves pumping solvents into heavy oil, virtually eliminating greenhouse gases and significantly reducing water consumption.

Penn West on verge of deal

Penn West Petroleum, which is about to become an income trust, is hoping to cash in big time by playing the CO2 card.

Company President Bill Andrew said May 27 that his company is on the verge of negotiating a deal with the Alberta and Canadian governments to build a C$350 million-$400 million pipeline to move CO2 from refining plants in the Edmonton area to oilfields in central and southern Alberta and possibly Saskatchewan.

He hopes the two governments will each shoulder one-third of the pipeline's costs, with the federal government tapping into money available under its Kyoto plan.

The objective is to get a pipeline in service by 2008 or 2009, initially supporting EOR activities in the mature plays of Swan Hills and Pembina in central Alberta.

Andrew said Penn West would operate the main line, while a supporting CO2 supply from the Fort McMurray oil sands region would be run by oil sands operators.

Without getting into details, he said the options on the table include a combination of tax, royalty and greenhouse gas emissions credits to accelerate construction.

Andrew bases his case partly on the costs of retrofitting refineries and coal-fired power generators to comply with Kyoto standards, which could run from C$150 million to C$500 million per plant.

He said Canada's decision to implement Kyoto will help create a stable domestic supply of CO2 that is vital for a pipeline to proceed.

Canada's Natural Resources Minister John Efford said experts have estimated that 75 million metric tons of CO2 "could be geologically stored in Canada every year."

One CO2 sequestration project, operated by EnCana in the Weyburn area of southeastern Saskatchewan, earned high accolades from international scientists in 2004.

Funded by 15 public and private sector agencies, including the U.S. Department of Energy, BP, Chevron and France's Total, the four-year, C$40 million study concluded that large volumes of CO2 can be safely stored in oil-bearing formations.

Further work needed

Billed as the largest in-the-field study of CO2 storage, the research effort estimated that over 5,000 years only a tiny fraction of CO2 would ever seep into the atmosphere.

However, the scientists said further work is needed before there is greater certainty about how much oil can be recovered.

"We don't want any unanswered questions," said study co-founder Malcolm Wilson, director of energy and environment at Saskatchewan's University of Regina.

To date, the C$1.1 billion Weyburn venture has buried 14 million metric tons of CO2 and expects to produce an incremental 130 million barrels from the field.

EnCana injects 25 million cubic feet per day of CO2 into the reservoir, importing the volumes from a North Dakota synthetic fuel plant.

A study by the Canadian Energy Research Institute said the Western Canada Sedimentary Basin has CO2 storage space for 15 billion metric tons in 25,400 natural gas pools and 9,300 oil pools, although current costs of transporting and sequestering CO2 could be as high as C$4 per thousand cubic feet.

To make storage a better financial proposition, the Saskatchewan government this year revamped its policies relating to large-scale EOR projects as a first step in a 10-year plan to boost oil and gas production.

The changes lower EOR taxes and royalties and offer sales and fuel tax exemptions on EOR materials.

Husky will take fresh look at projects

"With the new regime, we will take a fresh look at the economics of (various) projects," said a spokesman for Husky Energy, Saskatchewan's leading driller in 2004.

Saskatchewan Premier Lorne Calvert said his government wants to create a positive climate for growth through competitive taxes.

But he conceded that the high-flying production goals will not be attained without greater industry investment in infrastructure and facilities to upgrade heavy crude.

The immediate response was encouraging for the government.

Apache Canada unveiled plans to recover 45 million barrels from the Midale field near Weyburn and store up to 8.75 million metric tons of CO2 in the process.

Calgary-based independent Nexen, which relies on Saskatchewan heavy oil for 40 percent of its Canadian production, said a 5 percent to 10 percent increase in its recovery rate would double its reserves in the province.

Alberta has taken smaller steps to improve oil and gas recovery methods through CO2 injection, offering royalty credits of C$15 million a year to cover 30 percent of approved project costs.

Penn West itself has led the way in central Alberta, injecting 3 million cubic feet per day of CO2 to generate 700 bpd of light oil and gain 15 percent incremental recovery.

Based on that success, it has started a second project involving pools that have more than 2 billion barrels of oil in place, with the goal of doubling its output.

Anadarko Petroleum has embarked on a pilot EOR project in central Alberta that could open up "several additional opportunities that have similar EOR potential," the company said. ●

● WASHINGTON, D.C.

Plenty for Alaska in Senate energy bill

Legislation contains numerous provisions for tapping Alaska's resources, other measures to stimulate production, conservation

By ROSE RAGSDALE

Petroleum News Contributing Writer

The U.S. Senate version of a national energy bill, approved by the Senate Energy and Natural Resources Committee May 26 in a 21 to 1 vote, authorizes hundreds of millions of dollars in federal spending across Alaska. Alaska Sens. Lisa Murkowski and Ted Stevens said the measure contains provisions that offer historic opportunities for Alaska and its Native residents to both develop their energy sources for the benefit of the economy and to generate low-cost power for residents statewide.

"This bill offers provisions to help develop our oil, natural gas, huge coal resources and the future gold mine of our vast gas hydrate reserves," Murkowski said. "It also provides the means to help Alaskans build a modern electrical system involving a range of both renewable and non-renewable sources.

"Alaska has oil, natural gas, coal and immense gas hydrate reserves," said Stevens. "Developing our natural resources is critical to providing our nation with a dependable, secure source of energy and with providing Alaska with jobs and economic development well into the future."

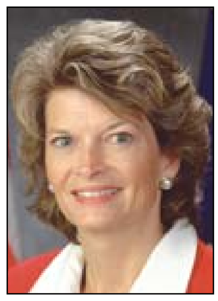
At least a few months from passage

The bill is at least a few months from being approved by Congress and sent to President Bush. The Senate Finance Committee is working on its portion of the legislation.

Murkowski said that she will continue to work to improve the bill, both on the Senate floor and in a later conference with House members.

The committee proposal and adopted amendments contain the following Alaska-specific provisions:

• National Petroleum Reserve Oil-Gas Leasing Changes: This provision allows oil leases to be extended for 10 years to give lease holders more time to develop oil inside the 23.3-million acre petroleum reserve, which holds an estimated 10.6 billion barrels of oil and 73 trillion cubic feet of natural gas. It allows for speedier lease sales, reduced lease royalties where needed to stimulate production and unit agreements to speed oil or gas field development. It also creates the North Slope Science Initiative to fund better scientific research into the effects of oil and gas leasing in northern Alaska authorizing future funding for the effort.




Alaska Sens. Lisa Murkowski (left) and Ted Stevens (right) said the measure contains provisions that offer historic opportunities for Alaska and its Native residents to both develop their energy sources for the benefit of the economy and to generate low-cost power for residents statewide.

• Alaska Offshore Royalty Suspension: This provision allows the Secretary of the Interior to suspend federal royalty requirements in Outer Continental Shelf lease planning areas in Alaska where the aid is needed to encourage oil and gas production. The authority is the same that the secretary enjoys in other areas nationwide and is intended to help increase Alaska OCS production. The bill provides $500 million in OCS revenues to producing states based on production, with Alaska receiving a guaranteed minimum of $5 million in funding.

• Indian Energy Assistance: The bill provides grant assistance and up to $2 billion in loan guarantees to help tribes nationally and Alaska Native corporations develop energy resources on their lands. The bill gives priority for federal funding to projects that will utilize new technology, such as coal gasification, carbon capture and sequestration and renewable energy-based electricity generation.

• Gas Hydrate Research and Development Assistance: The measure, authored by Murkowski, Stevens and Sen. Daniel Akaka of Hawaii, is designed to continue research and expand efforts to develop a commercial process for producing natural gas from methane hydrates – gas locked in ice and permafrost. The nation is estimated to contain a fourth of the world's total reserves of methane hydrates – about 200,000 trillion cubic feet - with Alaska holding about 15 percent of the nation's resource – 600 trillion cubic feet onshore and 32,000 trillion cubic feet offshore.

• Cook Inlet Carbon Dioxide Oil Enhancement Program: Murkowski won an amendment that permits the U.S. Department of Energy to determine the feasibility of using carbon dioxide to increase oil output from maturing Cook Inlet oil fields. DOE issued a report in May that indicated about 670 million barrels of oil could be recovered from aging Cook Inlet reservoirs near Kenai.

• Alaska Natural Gas Pipeline Provision: Building on last year's success in winning loan guarantees and two tax deductions for pipeline segments and a North Slope gas conditioning plant, the bill includes a provision requiring DOE to write a progress report every six months on how work is proceeding on an Alaska gas line – a provision designed to help maintain momentum for the project.

• Rural Energy Assistance: The bill authorizes $550 million over the next decade for improvements to Alaska's energy infrastructure. The Denali Commission can spend some $55 million yearly to fund a host of projects including energy generation and development, alternative energy sources transmission networks, interties, fuel tank replacement and cleanup, fuel transportation networks and related facilities and coal energy generation and alternative coal fuel projects.

Pro-drilling forces plan instead to put ANWR language in a budget bill later this year that is immune to filibuster.

• Power Cost Equalization: Funding to the Denali Commission is also intended to provide up to $5 million a year for a decade to endow the Alaska Power Cost Equalization program. Currently that fund contains $185 million. Interest on the money is used to subsidize the first 500 kilowatts of electric usage by rural residents. The funding is intended to increase the size of the endowment to fully fund the program, which currently cuts the cost of power by 20-30 cents per kilowatt hour in 175 rural communities.

• Healy Clean Coal Loan: The bill authorizes a market-rate loan of up to $80 million to fund improvements to get the Healy clean coal power plant up and running. The nearly $300 million clean-coal technology power plant has not operated since its testing period because of concern over the reliability of the plant.

The Alaska Industrial Development and Export Authority, the state agency that owns the generator, has said the plant could become operational with just $25 million.

• Renewable Energy Provisions: The bill provides assistance to renewable energy projects, anticipating a continuation of a production tax credit for wind, solar, biomass and geothermal energy among other forms of renewable energy. The bill includes assistance to development of ocean energy including tidal, current and thermal ocean energy electricity projects. The biomass provision also gives a preference for grants to development of power from biomass obtained from disease-infested timber, which could affect the Kenai Peninsula where roughly 5 million acres of spruce have been killed by the spruce bark beetle in the past decade.

• Coal Production Assistance: The bill includes $200 million per year in aid for projects to use the nation's coal resources, with 80 percent especially intended to aid construction of clean coal gasification combined cycle plants. Alaska, with an estimated 160 billion short tons, leads the nation in known reserves of low-rank, low-sulfur coal.

• Alaska Science Provisions: While the Senate bill does not contain earmarked appropriations, projects that were included in the House energy bill and will be considered during conference include funding for an Arctic Engineering Research Center at the University of Alaska Fairbanks and a $61 million authorization for a Barrow Geophysical Research Facility to provide a home for climate research in the Far North.

The bill also includes two provisions that would assist Alaska hydropower projects.

Murkowski said she will be working with the Senate Finance Committee to include provisions in the tax title of the bill to further a host of energy developments in the state and across the nation. The tax component is likely to be developed by the Finance panel in mid-June.

ANWR likely stay out of energy bill

The Senate version of the energy bill does not mention drilling for oil in the Arctic National Wildlife Refuge. The House version calls for such work. A conference committee will work out differences once the Senate finishes and passes its bill, but few expect the final compromise will contain ANWR language because of filibuster threats. Pro-drilling forces plan instead to put ANWR language in a budget bill later this year that is immune to filibuster.

Other major provisions of the energy bill include provisions for royalty relief on marginal oil wells, incentives for natural gas production from deep wells in the shallow waters of the Gulf of Mexico; suspension of royalties for leases in water depths greater than 400 meters in certain offshore areas; clarifying FERC's authority for siting, construction, expansion and operation of LNG import/export terminals (see related article on page 10 of this issue) and testing new technology for producing oil from oil shale. The western United States is estimated to contain 1.8 trillion barrels of oil — more reserves than the Middle East — locked in rock underground.

The bill also contains numerous conservation measures directing the President to develop and implement measures to save 1 million barrels of oil per day by 2015. ●

● ALASKA

Sempra ends alliance with Alaska port authority

By KAY CASHMAN

Petroleum News Publisher & Managing Editor

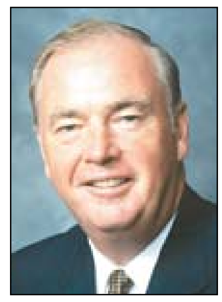
According to Sempra LNG spokesman Art Larson, Sempra has withdrawn its support of the Alaska Gasline Port Authority's all-Alaska LNG project.

"We have notified the port authority by letter," Larson said.

He said the decision was not due to "our relationship with the port authority or our belief that a project could not be successful."

Larson said "capturing the natural gas market in a competitive market requires quick, decisive action, especially in a West Coast market being actively pursued by others. In our view the protracted political wrestling within the state has proven both costly and time consuming for the project. And the legislative support that the project had hoped to attain by the end of May did not materialize. That delay played a key role in our decision."

Alaska Gov. Frank Murkowski reportedly telephoned Fairbanks North Star Borough Mayor Jim Whitaker when informed of the news. Whitaker is chairman of the port authority.



Alaska Gov. Frank Murkowski

"I was both disappointed and surprised that Sempra felt the challenges too great to proceed. Upon hearing of Sempra's decision, I shared with Mayor Whitaker my disappointment with the company's action. I also reaffirmed my commitment to assist the port authority in its efforts to craft a successful North Slope gas commercialization effort," Murkowski said.

The state is in two sets of negotiations under the Alaska Stranded Gas Development Act — with the North Slope producers and a Canadian pipeline company — for fiscal terms in lieu of taxes for a North Slope gas project. Both would take the gas through Alaska and then Canada to Lower 48 markets.

The port authority hoped to build an 800 mile gas pipeline in parallel with the existing oil pipeline from the North Slope to Valdez – hence, the name "all-Alaska" gas line. In Valdez, the gas would be liquefied and then transported to the U.S. West Coast via LNG carriers. In December the port authority signed an agreement with Sempra LNG, a unit of San Diego-based Sempra Energy, to assist in developing the project.

Recently the state Department of Revenue told the port authority it had until Aug. 5 to show it has access to natural gas for its project, or to provide a financial guarantee of its performance, in order to be eligible to negotiate with the state for a fiscal contract under the stranded gas act.

A May report from Tristone Capital on Arctic gas projects and how well they compete with LNG projects for North America markets, dubbed the Alaska LNG project the mostly costly of all Arctic gas projects.

"We've looked at over 200 LNG trains around the world. This (Alaska LNG project) is the highest capital cost by far," the author of Tristone's report, Chris Theal, said. (See story in May 15 issue of Petroleum News.) ●

● VIENNA, AUSTRIA

Oil prices slip but stay above $54 per barrel

Despite OPEC pledge to maintain output, crude futures ease slightly as strong demand for diesel rekindles worries of distillate shortfall

THE ASSOCIATED PRESS

Crude futures eased but remained above $54 per barrel June 2 despite a new pledge from OPEC to maintain current production levels, as strong demand for diesel rekindled worries of a distillate shortfall in the second half of the year.

Analysts said the focus on heating oil and diesel was unusually early. Still, some suggested that with gasoline plentiful as refineries concentrate on churning out that product, the market had nowhere else to go but focus on diesel tightness in Europe, the United States and Asia.

Some concern that increased OPEC production had failed to put a lasting dent in prices and forecasts of an active hurricane season in the United States with the potential for disruptions in refining and downloading crude added to sentiment that has prompted prices to surge from the $47 level in two weeks.

Light sweet crude for July was down 33 cents by afternoon in Europe at $54.27 a barrel on the New York Mercantile Exchange. Crude prices had jumped $2.63 on June 1 to close at $54.60 per barrel.

Unleaded gas fell by nearly a cent to $1.5350 a gallon (3.8 liters), while heating oil edged down to $1.5398 a gallon.

In London, Brent crude was down 27 cents at $53.00 on the International Petroleum Exchange.

Prices 25% higher than a year ago

Oil prices are now around 25 percent higher than a year ago but would still need to surpass $90 a barrel to match the inflation-adjusted high set in 1980. Still, the 5 percent gain in crude on June 1 was the seventh increase in a row.

Analysts attributed the start of Wednesday's rally to robust heating oil prices, which shot up by 9.05 cents to $1.54 a gallon. Gains then spread to other commodities, they said.

"With the U.S. driving season officially under way, gasoline was supposed to spark, but the fireworks are in heating oil instead," said Energyintel analyst Matt Piotrowski.

This, he said reflected a "tight global market for road diesel and other middle distillates, such as jet fuel, kerosene and heating oil."

Demand traditionally peaks in the second half of year, when heating oil and jet fuel usage rises during the Northern Hemisphere winter. Analysts say too much emphasis has been placed on refineries to produce more petrol in the summer driving season neglecting other fuels such as diesel and other distillates.

"Distillates are stealing the show from gasoline at the start of the U.S. driving season," PVM Oil Associates in Vienna said in its daily energy market report. "In the U.S., the concern is that refiners' prime target to churn out as much gasoline as possible will leave distillates supplies inadequate throughout the rest of the year.

"In particular, diesel demand from the trucking sector is continuously running strongly ahead of year-ago figures," PVM said, adding estimated year-on diesel demand is up about 6 percent.

Close to max in refining capabilities

Frederic Lasserre, head of commodities research at SG Securities in Paris, said that "in terms of refining capacities … we are close to the max," as far as diesel and heating oil is concerned, adding: "The market is now fearing that we will see a global shortage … for next winter."

"It's crazy," he said of the timing of the focus on heating oil and diesel which essentially undergo the same distilling procedures. "It's the kind of development you should have in the heart of winter."

The U.S. Energy Department releases its next petroleum supply snapshot later June 2 (after Petroleum News goes to press), a day after the usual weekly announcement because of the Memorial Day holiday.

The report would have to show substantial across-the-board growth in petroleum stocks to bring prices down but Lasserre said "the market was now convinced that the stock build is almost over," suggesting that was another trend driving up prices.

On June 1 the president of the Organization of Petroleum Exporting Countries, Sheik Ahmed Fahd Al Ahmed Al Sabah, said the cartel, which produces 40 percent of global crude, would maintain its current production ceiling until the third quarter of 2005.

OPEC is to meet June 15 in Vienna to discuss production levels. Al Sabah's comments are likely to rile price hawks like Venezuela who have indicated a preference for an output cut to keep prices high.

The 11-member group is pumping out around 30 million barrels daily in its attempt to keep prices in check and calm markets. ●

● ALASKA

Optimizing heavy oil recovery

DOE-funded research uses state-of-the-art laboratory techniques to assess the best ways to recover North Slope's heavy oil

By ALAN BAILEY

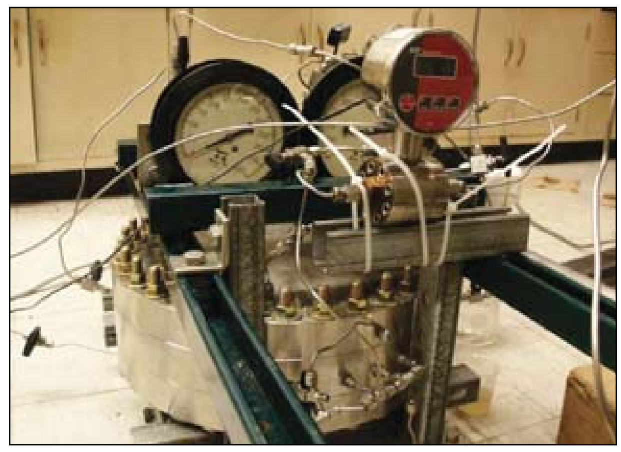
Petroleum News Staff Writer

In the past few years extended horizontal drilling techniques have made North Slope heavy oil pools such as Schrader Bluff and West Sak economic. And enhanced recovery techniques using injected fluids to drive the viscous oil from reservoir pores have further improved oil recovery.

But even with the use of these techniques a significant percentage of the 23 billion barrels of heavy oil around Kuparuk and Prudhoe Bay is likely to remain in the ground — stuck like treacle under the cold permafrost.

U.S. Department of Energy-funded research at the University of Houston has been investigating ways of further improving the recovery rates from the North Slope heavy oil reservoirs. The University of Houston's chief researcher for the program, Dr. Kishore Mohante, has reported the results of this research, Jim Barnes, DOE project manager for the program, told Petroleum News.

Barnes said researchers used advanced laboratory techniques to find the best ways of applying enhanced oil recovery, especially a form of recovery known as WAG. The term "WAG" refers to water alternate gas, a technique in which



U.S. DEPARTMENT OF ENERGY

The 5-spot high-pressure cell used by University of Houston researchers to test the enhanced recovery of heavy oil

waterflood alternates with gas injection to sweep oil from the reservoir.

"(The research program) would serve those that are operating there (on the North Slope) and those that think to operate there as a good source of information," Barnes said.

Mohante used to work in the Alaska oil industry and is familiar with the North Slope heavy oil deposits, Barnes said.

Simulated oil recovery

According to the research report the University of Houston researchers built a device called a quarter 5-spot high-pressure cell to replicate in the laboratory a series of WAG sweeps through an oil-saturated sandstone core. Another apparatus called a slimtube enabled the researchers to test the displacement of oil by various injectants. Other experiments tested the interactions between solvents and oil-saturated substrates.

The tests and experiments used actual Schrader Bluff oil and tested the effectiveness of injectant sweeps with various combinations of natural gas liquids, carbon dioxide and simulated Prudhoe Bay natural gas.

In the course of their work the researchers determined a new four fluid phase model for calculating relative permeability in WAG enhanced recovery.

State-of-the-art computer simulation

The researchers used a state-of-the-art reservoir modeling technique known as streamliner based simulation to test the likely effect of using various enhanced recovery techniques.

see **HEAVY OIL** *page 19*

● HOUSTON, TEXAS

EOG mum on location of 'look-alike' play

Independent won't pinpoint Barnett Shale mystery play; natural gas reserves estimated at 500 to 800 bcfe

By RAY TYSON

Petroleum News Houston Correspondent

Independent producer EOG Resources has caused quite a stir in industry with its mysterious Barnett Shale 'look-alike' play, located somewhere in the vast expanse of Texas and a good distance from Fort Worth in East Texas, home of the prolific Barnett Shale field, among the hottest gas plays in the United States.

EOG chief executive Mark Papa lately has been talking up the company's position in the Barnett look-alike shale play, willing to discuss with analysts and investors everything from reserve estimates to drilling plans on EOG's current 125,000-acre stake in the mystery play.

EOG chief executive Mark Papa told analysts that … a "large cap peer company," apparently had accumulated a large stake in the play similar in size to EOG's position.

However, Papa and the company refuse to disclose the play's exact location, supposedly for competitive reasons while EOG negotiates for another 25,000 acres in the area, according to the company.

Papa told analysts at the recent UBS Global Oil & Gas Conference in Austin that an EOG competitor, described by Papa as a "large cap peer company," apparently had accumulated a large stake in the play similar in size to EOG's position.

Vintage grabbed 135,000 acres in Palo Duro

"All I can say is that it's somewhere in the state of Texas hundreds of miles from Fort Worth," EOG spokeswoman Marie Baldwin said June 1.

Industry speculation has the Barnett look-alike mystery play located in the Palo Duro Basin just south of the Texas Panhandle, or possibly near El Paso on the western edge of the Lone Star State.

Vintage Petroleum hardly qualifies as a large independent referred to by EOG's Papa. But the Tulsa, Oklahoma-based producer has acquired more than 135,000 acres in the Palo Duro Basin, roughly the amount of EOG's stake in the mystery play, and currently is among the largest acreage holders in the region.

Vintage Petroleum … has acquired more than 135,000 acres in the Palo Duro Basin, roughly the amount of EOG's stake in the mystery play, and currently is among the largest acreage holders in the region.

Robert Phaneuf, Vintage's vice president of corporate development, who also addressed the UBS conference, said Vintage had received some core results from the company's first well in the Palo Duro play and that results from a second test well were expected soon.

Vintage not disappointed

"To date all the information we've seen from the cores are not disappointing to us relative to our expectations," Phaneuf said.

At the UBS conference, Papa made available an EOG chart showing reserve estimates of 500 to 800 billion cubic feet of gas equivalent on the company's portion of the Barnett look-alike shale play.

He said that based on information gathered from deeper wells drilled in the area, the play is about 350 feet thick and should produce around 120 bcfe per square mile, compared to 10-15 bcfe per square mile for most other shale plays EOG has observed in the United States.

"So what we've done is look around for shale plays in the U.S. and basically say let's look for the ones that have about as much gas in place as the Barnett, and that really limits how many of them that we've been able to screen and focus on," Papa said.

He said that as far as the Barnett look-alike play in Texas goes, "we know that it is gas-bearing and rich. It's identical, as far as we can tell" to the Barnett Shale field near Fort Worth. In fact, "the shale itself is actually called the Barnett shale in this area," Papa said.

Meanwhile, Papa said drilling had started on EOG's Barnett look-alike acreage and that the company would analyze a core section from the first well, followed by the drilling of an offset horizontal "frac" well.

Should know by end of year

"So certainly by the end of the year we'll have a good feeling for whether this is a screaming success, or an ignominious failure," he said.

The "big unknown" in the mystery play is whether the shale rock contains so-called "micro-fractures" necessary for proper gas extraction, Papa said.

"If there are no … fractures, we're dead in the water," he said. "If there are … fractures, we probably are going to look like geniuses."

Houston-based EOG holds some 460,000 acres in the Barnett Shale field near Fort Worth, probably the largest acreage position in the huge play next to big exploration and production independent Devon Energy, by far the dominant producer in the Barnett Shale with about 550-million cubic feet of gas production per day.

Papa, during the company's April conference call on 2005 first-quarter earnings, raised a few eyebrows when he claimed the Barnett Shale field was much larger than initially believed, covering portions of at least six additional Texas counties generally westward of the Barnett Shale core area.

Papa said that EOG's entire 460,000-acre position lay within the new boundaries of the Barnett Shale "gas window," adding that the company planned to acquire another 40,000 acres in the Barnett, elevating the company's total stake in the Barnett to around 500,000 acres.

He also said EOG plans to increase its Barnett production to 60 million cubic feet per day this year from 6 million cubic feet per day last year. To reach that goal, Papa said the company intended to increase the number of rigs operating on its acreage to seven from four by June 1, "and we'll likely increase the rig count even further in 2006." ●

OBITUARY

Nuiqsut leader Napageak dies at 71

Elder Thomas Oyagak Napageak of Nuiqsut died May 6 in Anchorage at age 71.

Mr. Napageak was a major player in the development of the Alpine oil field and was a former president of Kuukpik Corp., the Native village corporation. He also led the Alaska Eskimo Whaling Commission and was both mayor of Nuiqsut and president of the Native Village of Nuiqsut.

In 1994, when Alpine was discovered, Mr. Napageak was a member of the negotiating team representing Nuiqsut and Kuukpik as they hammered out development terms for the field.

As Kuukpik's Native hire and training coordinator and later as president of Nanuq Inc., Kuukpik's oil field service subsidiary, he pressed the oil industry to hire and train Alaska Natives at Alpine and elsewhere.

Earlier, he was the leader of a resettlement drive for the community in 1973, when he helped lead a cat train into the village site. The area had been essentially depopulated in the 1930s and 1940s because the territorial magistrate decreed that local children had to attend school, and the only school in the region was in Barrow.

When the village was resettled, Mr. Napageak was chosen as the first mayor, guiding a community that was just a tent city through two winters, with residents gathering driftwood from the Colville River to heat the wall tents.

As a skilled whaling captain, he was first elected to the Alaska Eskimo Whaling Commission in 1977 and served as chairman of the AEWC from 1998 to his death. He harvested a bowhead whale for Nuiqsut virtually every year from 1972 to 2003 and several times harvested two whales in a single season.

Services for Mr. Napageak were held in Anchorage, Barrow and Nuiqsut.

continued from page 18

HEAVY OIL

"These tools have been out for several years but they've not been applied to my knowledge to the North Slope deposits," Barnes said.

Traditional computer models, known as finite-difference simulators, require excessive computational time to model a 3-dimensional WAG system, according to the research report.

And using data from the quarter 5-spot experiment, the streamliner simulation could test the effect of well architecture on oil recovery efficiency — well architecture includes factors such as the length of a horizontal well. The researchers also used the computer model to test the impact on fluid flow of electromagnetic heating in a well.

Using more gas beneficial

The researchers found that you can improve WAG oil recovery by increasing the ratio of gas to water and by increasing the sizes of the injected slugs of fluid, Barnes said. And according to the research report the slimtube experiments and the computer simulations both indicated that mixtures of carbon dioxide and NGL work better as gas injectants than do mixtures of Prudhoe Bay natural gas and NGL.

The well architecture also impacts recovery rates. Although horizontal production wells increase access to the oil in the reservoirs, the reservoir simulation results showed that the sweep efficiency of the enhanced recovery fluids can be less for horizontal wells than for more steeply inclined wells.

There's a similar trade off with well length — increasing the length improves well productivity but tends to reduce sweep efficiency.

The research also pointed to the potential for major improvements in well productivity through the use of electromagnetic heating in the well. However, Barnes said that the energy requirements to generate the necessary electricity for electromagnetic heating result in marginal overall efficiency improvements.

Further information about the University of Houston research can be found by going to

www.netl.doe.gov/scngo/Petroleum/WebFactSheets/ProgramExplorationProduction/ and clicking on the project entry under the "Completion and simulation" section. ●

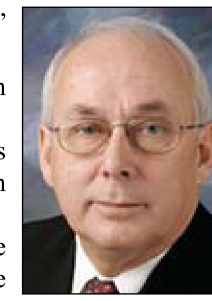
CANADA/FRANCE

Hands across the border in Atlantic Canada

Canada and France will work together to manage exploration and development of oil and natural gas offshore Newfoundland and Nova Scotia and the French territorial islands of St Pierre and Miquelon.

An agreement signed by the two governments in mid-May is the "result of negotiations characterized by a tremendous spirit of co-operation," said Canada's Foreign Affairs Minister Pierre Pettigrew.

Natural Resources Minister John Efford said the partnership will facilitate "sustainable development of petroleum resources" in the Atlantic Canada offshore.



Natural Resources Minister John Efford said the partnership will facilitate "sustainable development of petroleum resources" in the Atlantic Canada offshore.

Under the pact, Canada and France will exchange information on industry activities within a clearly defined maritime area.

It also includes mechanisms to share resources and benefits from any trans-boundary field and to negotiate exploitation agreements for specific fields.

The agreement gives added momentum to opening up the Laurentian sub-basin after a 38-year jurisdictional dispute between Newfoundland and Nova Scotia was settled three years ago. The 3,000 square mile sub-basin has estimated resources of 8-9 trillion cubic feet of gas and up to 700 million barrels of oil.

ConocoPhillips might drill in 2007

ConocoPhillips and ExxonMobil Canada share a 1,250-square mile exploration permit in the adjoining French waters where seismic has been gathered and a well was drilled in 2001 by the two companies, plus Murphy Oil.

The Bandol No. 1 well cost about C$30 million and was abandoned as a dry hole.

But ConocoPhillips has indicated it might drill again in 2007.

—GARY PARK

continued from page 1

COUNT

The number of rigs operating in the United States compared to the prior week jumped by 16 to 1,331 and increased by 162 compared to the same period last year. Compared to the previous week alone, land rigs increased by 11 to 1,213, while offshore rigs increased by four to 94 and inland water rigs increased by one to 24. Of the total number of rigs operating in the United States during the recent week, 1,183 were drilling for natural gas and 148 for oil. Of the total, 834 were vertical wells, 329 directional wells and 168 horizontal wells.

Among the leading U.S. producing states during the recent week, Texas registered the largest gain in drilling rigs compared to the previous week, increasing by eight to 599. Louisiana picked up four rigs for a total of 181 rigs, while Colorado picked up three rigs for a total of 67 rigs, Oklahoma picked up two rigs for a total of 151 rigs and Alaska picked up one rig for a total of nine rigs. California's rig count fell by four to 23, while New Mexico's slipped by two to 81 rigs. Wyoming was unchanged from the previous week with 71 rigs.

—RAY TYSON

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INSIDER

Shell Canada relieving EnCana of its Atlantic Canada miseries and buying the big independent's Deep Panuke natural gas assets, and the chances of Talisman Energy getting swallowed in a takeover.

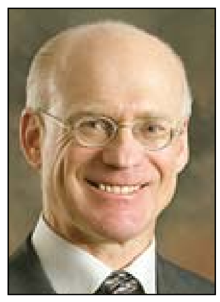
Of all the rumors circulating, the one that makes most sense is the prospect of Shell taking over Deep Panuke – a natural fit for Shell, which owns one-third of the producing Sable gas field offshore Nova Scotia, and would welcome the chance of putting a stop to its rapid decline in Sable reserves.

From the outset, Sable has failed to live up to hopes of a 20-year producing life.

In a series of downward revisions, often led by Shell, reserves have been slashed from an original 3.6 trillion cubic feet to 1.35 tcf, while production (all of it exported to New England) has tumbled more than 100 million cubic feet per day from a peak of about 465 million cubic feet per day.

These trends have raised concerns that the field will run out of gas by 2014, 10 years ahead of original hopes.

Drilling has failed to generate more than optimism that the decline will be slowed.



EnCana has insisted it is not ready to walk away from Deep Panuke, but Chief Executive Officer Gwyn Morgan (pictured above) did not rule out an eventual sale last fall when he said that even if the field does come on stream there is no assurance his firm will own the project. A Shell executive stoked the embers recently when he said Shell has discussed "potential synergies" relating to the field's future development.

But EnCana's decision more than two years ago to put its C$1.1 billion Deep Panuke project on hold, while it looked for new gas, possibly a new partner and better economics, opened the door to 950 billion cubic feet of possible new reserves.

As part of its rethinking, EnCana has engaged the Sable partners in talks about sharing infrastructure, although there has been little word this year of progress in that direction.

Not helping matters was EnCana's loss last month of Marauder Resources East Coast as a junior partner to drill a well this year in the same trend as Deep Panuke as a final shot at shoring up the discovery.

EnCana has insisted it is not ready to walk away from Deep Panuke, but Chief Executive Officer Gwyn Morgan did not rule out an eventual sale last fall when he said that even if the field does come on stream there is no assurance his firm will own the project.

Ian Kilgour, Shell's vice-president of E&P, stoked the embers recently when he said Shell has discussed "potential synergies" relating to the field's future development.

Paul McEachern, executive director of the Offshore/Onshore Technologies Association of Nova Scotia, told the Halifax Chronicle-Herald that Deep Panuke would be a "neat fit" with Sable and added it should be no "surprise that it is being shopped around."

Steve Calderwood with Raymond James said a better bet as a suitor for Talisman would be ConocoPhillips.

On the takeover front, Talisman shares got a 10 percent lift over a week in late May on the basis of "street noise" that France's Total might be about to mount a bid for the C$15.6 billion independent with assets in North America, Southeast Asia and the North Sea.

But, among analysts, there were more who scoffed at the Total reports than those who gave weight to them and Talisman itself seemed to put an end to matters May 30 when a spokesman for chief executive officer Jim Buckee said there are no discussions with Total.

Steve Calderwood with Raymond James said a better bet as a suitor would be ConocoPhillips.

Terry Peters with Canaccord Capital might have been the trigger for speculation when he issued a research note May 26 making an argument that Talisman is undervalued when stacked up against its senior peers, such as Nexen, Canadian Natural Resources and EnCana.

He said Talisman represents an attractive company to own, although he has no knowledge that it is in anyone's sights.

With the pot simmering, it was a chance to bring it to full boil.

Husky Energy and Nexen suddenly found themselves rated as a hot prospects for acquisition by Italy's ENI and EnCana was said to be under the microscope of Royal Dutch/Shell.

But Peters cautioned that long-term oil and gas price volatility could make any large scale acquisitions unlikely at this time.

BP not taking it to extremes, says Dean

BP OFFICIALS WERE QUICK TO SHOOT DOWN – well, sort of – a recent policy change calling for publications carrying BP advertising to inform BP in advance of any news items that mention the company.

BP spokesman Scott Dean told AdAge.com after the issue surfaced that WPP Group's MindShare, ad buyer for the giant company, had penned the memo to publications saying those publications had to inform BP in advance of any news, text, or visuals they plan to publish that mention the company – or even a competitor or the industry in general. That's a pretty broad field.

Dean called the language in the memo unfortunate and regrettable.

"This is not meant to be Draconian or to influence coverage," says Dean. Still, he indicated the company isn't backing away from the concept entirely. "We are just asking for a heads-up," he says. "We never asked to read (stories) in advance."

The BP policy came in the wake of a similar dictum from MorganStanley, the embattled Wall Street giant, which told publications its ads must be automatically pulled from any edition containing "objectionable editorial coverage."

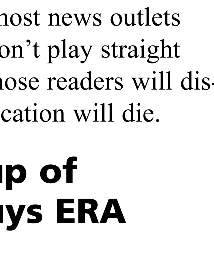
But the publishing giant of Wall Street, The Wall Street Journal, didn't flinch. The Journal has written extensively on the increasingly contentious internal struggles at the investment banking/brokerage firm.

"It would not be a practical condition at The Wall Street Journal," Publisher Karen Elliott House told AdAge.com. "The ad department has no knowledge of what stories are running in the next morning's newspaper."

Aside from that "Chinese wall" built between the ad and news departments at virtually all reputable publications, editors and owners of most news outlets realize that if they don't play straight with their readers, those readers will disappear and the publication will die.

Private group of investors buys ERA Aviation

ERA AVIATION INVESTMENT GROUP (EAIG) announced on June 1 that it has entered into an agreement with Seacor Holdings Inc. to acquire Alaska-based regional airline, Era Aviation Inc. The airline's all-Alaska team of officers and managers will include president and CEO Paul Landis. Marcia Davis will be vice president and general council.



PAUL LANDIS

EAIG consists of a private group of investors primarily based on the U.S. West Coast.

Under the agreement, which should close in the next 45 to 60 days, EAIG will acquire all of ERA's current airline operations and will operate under the name Era Aviation Inc. Seacor will retain ownership of the ERA Aviation Center and its associated fixed base aviation services.

"The acquisition will not affect current flights and customers can expect the same superior service during the transition," ERA said. ERA flights serve Southcentral and Western Alaska, using a combination of deHavilland Dash-8 and Twin Otter aircraft. ●

Companies involved in North America's oil and gas industry

ADVERTISER — PAGE AD APPEARS

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

Petroleum News Business Spotlight

By PAULA EASLEY

FORREST CRANE

Lewis Quinn, Owner and President

Capital Office Systems

At Capital Office Systems, interior spaces are designed to reflect special traditions, values and cultures. Innovative, functional and dynamic workplace solutions are available from Capital's three Alaska locations – Anchorage, Juneau and Fairbanks. The company's highly skilled team of professionals in management, sales, project coordination, interior design, service and administration, works hard to meet customer needs.

Lewis Quinn, an owner of the company since 1994, has 30-plus years of experience in the industry. His motto is "everything is doable." Outside the office, spending quality time with family is a priority – weekends at Stephan Lake, physical fitness programs, sailing and attending UAA hockey games are favorite activities. Lewis and wife Gayle have two sons, ages 18 and 15.

FORREST CRANE

Laurie Fagnani, Owner

Marketing Solutions

Anchorage-based Marketing Solutions offers clients results-based marketing and advertising services. Client projects start with identifying communication goals and then building the creative and media strategies to achieve them. The agency employs 12 of the industry's best creative minds who collaborate to turn client ideas into action. This year marks Marketing Solution's 10th anniversary serving Alaska clients. The agency has undertaken two non-profit projects this year — the Red Cross "Help from Home" campaign and the Arctic Winter Games "Release the Spirit" campaign. More company information is at: www.marketingsol.net.

After a busy workday, owner Laurie Fagnani "relaxes" playing women's hockey or skiing at Alyeska. The family – Laurie, Matthew, Madison 9 and Thomas 8 – spends weekends fishing and camping on the Kenai whenever possible.

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CHINA

(China's international oil explorer) put down C$150 million for 16.69 percent of MEG Energy, another privately held oil sands newcomer.

200,000 bpd in two PetroChina transactions

Between the two transactions, PetroChina and Enbridge signed a memorandum of understanding to arrange 200,000 barrels per day of oil sands production to fill half the capacity of Enbridge's planned Gateway pipeline to a northern British Columbia deepwater port.

Those modest investments could translate into billions of dollars if Sinopec and CNOOC cover their full share of capital costs.

Synenco is operator of the C$4.5 billion Northern Lights project, which is targeted for start-up in late 2009 or 2010 at either 50,000 bpd (doubling in size at a later date) or 100,000 bpd. It has 1.5 billion to 2.5 billion barrels of oil in place.

MEG is aiming to produce 25,000 bpd in 2008, growing to 145,000 bpd, on leases covering 33,000 acres with 4.8 billion barrels of bitumen in place.

But Murray Smith was unapologetic that the United States would no longer be able to take the oil sands for granted. "Having access to the world market will be beneficial to Alberta producers."

Both CNOOC and Sinopec have made it clear they want to get in on the ground floor of new projects and participate in evolving technologies.

Good for Alberta, says Smith

Smith said the United States is not just interested but concerned about potential exports from the oil sands to China and multiple other markets.

If Alberta, for the first time, exports to markets other than the United States that "could put additional upward pressure on the price of oil in North America," he said.

But he was unapologetic that the United States would no longer be able to take the oil sands for granted.

"Having access to the world market will be beneficial to Alberta producers," he said.

"This is one of the best times for Alberta's economy …and I think that our ability to have multiple market access will reinforce that."

Smith said there is no reason why the Gateway pipeline should be a source of Canada-U.S. friction, given that Enbridge hopes to ship 100,000 bpd to California refineries, which are facing dwindling volumes from Alaska.

Since the Alberta office opened in March, Smith said his job has been to "quell rumors and you do that by communicating. It's like, 'Let me see, you use 20 million bpd and you're concerned about 250,000 bpd from the Alberta oil sands going to China?'"

Cautioned against using China as leverage in lumber, beef disputes

But he cautioned that Canada would be unwise to play China against the United States or use energy as leverage to settle long-standing disputes over softwood lumber and beef.

Earlier this year, Smith's successor, Greg Melchin, said he was "nervous" at the prospect of China's state-owned enterprises buying into the oil sands.

He said foreign government ownership of the resource could see Alberta bitumen diverted out of Canada for upgrading and processing, putting tens of thousands of jobs at risk in Canada.

Jim Donnell, president and chief executive officer of privately-held Synenco, told Petroleum News he could not comment on the geo-political debate over where oil sands production is exported, but he insisted that 100,000 bpd of new supply from Northern Lights "is a good thing for every region."

He said Sinopec has not indicated where its 40 percent share will go. Synenco will only make up its mind closer to the start-up date, although to many observers China will be the destination.

On the plus side, Donnell said Sinopec, a producing, refining, marketing and petrochemical giant, brings a full range of expertise to the partnership, meaning the Northern Lights is "now real, with a high degree of certainty."

He said Sinopec's experience includes the engineering, designing and construction of 26 refineries with 3 million bpd of capacity, giving Synenco optimism that its Chinese partner can keep capital costs under control.

UBS Securities Canada, in a research note, estimated Sinopec paid less than half the cost per barrel of the MEG investment by CNOOC. ●

continued from page 1

BADAMI

tion, or on diesel-fired main generators while in warm shutdown.

BP spokesman Daren Beaudo told Petroleum News June 1 that the "best timeline estimate" for restarting the field is late summer, but if and when the field goes back online is "absolutely contingent," he said, "upon receiving the permit approvals in a timely fashion."

The Badami field, developed in the late 1990s, is on Mikkelsen Bay east of Prudhoe Bay and is the farthest east development on the North Slope. It was the first turbidite reservoir to be developed on the slope, and has been in warm shutdown because oil production from the field was at much lower levels than the company anticipated.

DEC said BP decided to restart Badami because of the current high price of oil and because of the availability of new reservoir oil recovery methods designed specifically for Badami. The permit covers three proposed operation modes because BP does not know "which oil recovery strategy will work best for the Badami reservoir specifics," DEC said in a preliminary technical analysis report issued May 27. The field may go back into warm shutdown; it may be operated intermittently; or it may be operated continuously.

BP told DEC the restart operations are part of a "production exploration program" of the Badami oil reservoir, and said it expects the operations will take a maximum of three years, "or even shorter if the oil reservoir production results are not satisfactory." BP expects recovery from the reservoir "will benefit from the new oil recovery technologies, specific for the Badami reservoir, and there is a chance that it will become a good producer."

DEC said the restart project is "an evaluation project of limited duration to apply new drilling technology and to assess how the field will operate in the future."

BP began producing from Badami in August 1998, and expected to be at rates of more than 10,000 barrels per day by that fall. In October 1998, however, production was only at 4,000-5,000 bpd from eight reservoir penetrations. Production dropped to 1,350 bpd in early 2003, and production was suspended and the field put into warm shutdown.

Production exploration program

BP told DEC the restart operations are part of a "production exploration program" of the Badami oil reservoir, and said it expects the operations will take a maximum of three years, "or even shorter if the oil reservoir production results are not satisfactory." BP expects recovery from the reservoir "will benefit from the new oil recovery technologies, specific for the Badami reservoir, and there is a chance that it will become a good producer."

BP told DEC it expects the reservoir could be a good "intermittent producer," but said there is also a possibility the reservoir will become a good "continuous producer." At this time it is not known if the restart will continue for the entire planned 36-month period, and it is not known if Badami production rates are sufficient to maintain Badami operations now or in the future, the agency said.

Changing oil economics will determine if short-term or long-term operations at Badami are possible.

Reservoir known to be challenging

Badami was recognized as a complex reservoir before production began.

In a 1997 interview, Ken Konrad, then BP developments manager, said "even on a global-BP basis, the reservoir aspects of Badami are considered within our corporation either one of the most challenging or the most challenging attempts to date. There's just a high degree of complexity which we're increasingly confident that we understand, but nevertheless it is an extraordinarily complex system."

The oil at Badami has been described as occurring in channels or fingers, and Bill Bredar, Badami subsurface manager, said in that same 1997 interview that of the compartmentalized channels identified, about 10 would be targeted initially. He characterized the reservoir as "channelized areas. They're multiple channels that are kind of stacked up. And we are targeting these … amalgamated channels."

The depositional environment, Bredar said, was a turbidity current: sands, clays and muds piled up at the bottom of an underwater shelf following an event like an earthquake.

The sand holds oil, but unfortunately there's a lot more mud than sand, Bredar said.

Another complexity at Badami is the range of oil gravity from 19 degrees to 29 degrees API.

Pipeline shutdown approved in 2003

The Regulatory Commission of Alaska approved BP Transportation (Alaska)'s request for a temporary shutdown of the Badami oil pipeline and the Badami gas and products pipeline in 2003. BP said it expected the shutdown to last for about two years while it evaluated "options for restart or reuse" of the Badami unit facilities, but the company also said the shutdown could be extended if restart or reuse of the facilities is not possible within two years.

The state approved BP's application to suspend production from Badami and to mothball the unit's facilities for a two-year period beginning Aug. 1, 2003, and ending June 30, 2005.

BP said in May 2003 that the field's 1,350 bpd production rate "cannot offset field operating costs … making it uneconomical to continue operations." The company said field production had been dropping each year, and was expected to continue to decline. BP spokesman Daren Beaudo told Petroleum News in June 2003 that BP would "continue to evaluate various options for Badami. The two-year suspension will give us time to do that."

Options identified for Badami in paperwork filed with the state in 2003 included selling it to a third party, hosting BP's proposed offshore Liberty development or use by the nearby Point Thomson project.

BP had drilled seven production wells, six of which were producing when the field was shutdown, two gas injection wells and a disposal well.

Production had been temporarily suspended in February 1999 due to low temperatures and concerns about the pipeline freezing since it was carrying much less oil than originally expected; the drilling program was suspended in May 1999 after the wells had significantly underperformed.●

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SALT

finding and appraising a deepwater discovery.

"The time scale for proving up these basins in the Gulf of Mexico is very long, and the reason is it is probably the most difficult geology in the world," he said. "So you have to be very good at seeing though the salt and continuously improving that capability."

For example, BP's Atlantis and Mad Dog discoveries are two major deepwater discoveries in the U.S. Gulf that are partially obscured by salt.

"BP intentionally approved both of those developments (only) on the basis of what it could see," Eyton said.

Moreover, with increasing water depths and increasing drilling depths in the U.S. Gulf, plus the problem of figuring out what looms below the salt, "the costs are obviously challenged because you have big wells that cost more," Eyton said.

He said that while the "large scale" of a structure can often be seen through seismic imaging, "the exact definition of how that would play out in the reservoir and where the various sands" are located can be "extremely difficult to see."

Moreover, with increasing water depths and increasing drilling depths in the U.S. Gulf, plus the problem of figuring out what looms below the salt, "the costs are obviously challenged because you have big wells that cost more," Eyton said.

Data processing shops backed up with deepwater prospects

Kerr-McGee's Hager said the company's data processing shops "are very backed up" on deepwater prospects, causing a slowdown in the whole planning process.

"I think the biggest challenge that we face in industry is primarily around the imaging of these large new wildcat opportunities," he added. "It's a very time consuming process and, frankly, I feel there's quite a bit of backup occurring out there."

Hager said there is a big difference between "capturing" those wildcat prospects and getting them to the drillable stage, which requires financial commitment.

"So that's the nut we need to crack more than anything," he said of the U.S. Gulf's salt barrier. "The whole industry is struggling, I think, to some degree to get the cycle time moved up on the data and have the confidence to drill the wells."

However, today's deepwater explorers, even when teaming up with other companies on a prospect, are said to be reluctant to invest in an exploration well that can cost up to $50 million or more before having the best geological data in hand.

"Somehow we need to figure out how to improve the imaging on these prospects, and improve the turnaround on the processing to get the pace of exploration moved forward," Hager said.

Kerr-McGee, a highly successful independent explorer in deepwater U.S. Gulf, is hoping next year to drill its first exploration well into the geologically deep Eocene or lower tertiary trend, among the hottest plays in the "ultra-deepwater" Gulf of Mexico.

"We're interested in that play (and) think it is a viable play," Hager said, "and possibly next year you'll start seeing some wells showing up on our schedule in that play type."

However, he said Kerr-McGee has no intention of placing all its bets on the promising but risky lower tertiary, located roughly 28,000 feet below sea level in water depths ranging up to 10,000 feet.

"We think it's appropriate from a risk reduction strategy to not have all of our prospects in any one play type, because history tells us that some of these play types work and some don't," Hager said. "So we think it's appropriate to have exposure to multiple plays from a geological perspective in the deepwater Gulf."

BP: 1/3 to 1/2 international exploration budget tied up in Gulf

Between a third and a half of BP's worldwide exploration dollars are invested in the U.S .Gulf, resulting in major discoveries over the years that include Thunder Horse in Mississippi Canyon, the largest find ever in the US Gulf at roughly 1-billion barrels.

In the U.S. Gulf, BP explorers strictly for giant oil and gas fields in excess of a quarter-billion barrels of reserves, Eyton said.

"The majority of what we're now looking for is entirely sub-salt," he said. "So you need to have some of the best seismic technology in the world to be able to peer through salt, to figure out what goes on underneath."

Kerr-McGee's Hager said that transitioning to the "new prospect type," which is located in deeper geological sections like the Eocene, is one of industry's biggest problems in the U.S. Gulf.

"It's us getting the data, plus all of our partners getting the data, and then getting an alignment (partnership) around a $40 or $50-million well which is the biggest challenge, not only for us, I think, but for the whole industry out there," he said. ●