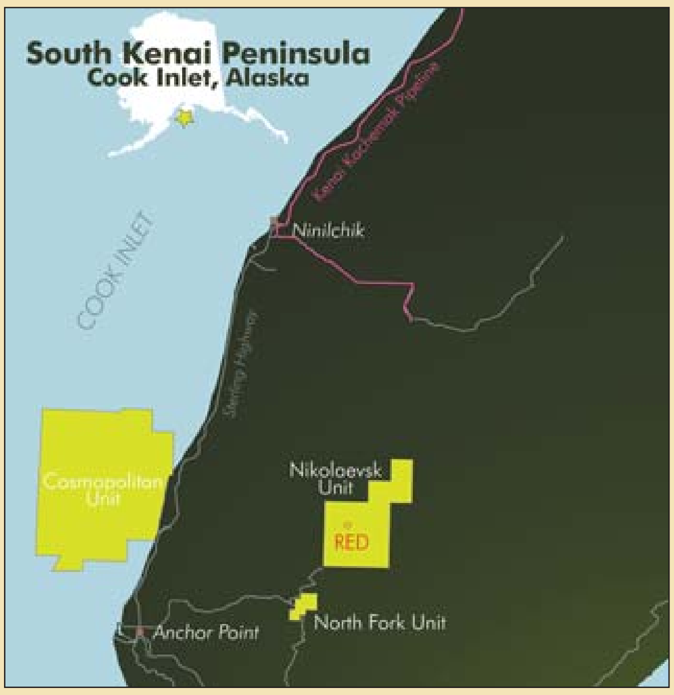
Petroleum news

Vol. 12, No. 2 • www.PetroleumNews.com | A weekly oil & gas newspaper based in Anchorage, Alaska | Week of January 14, 2007 • $1.50

page 5 Clean-up time in Canada: Harper dumps environment minister

Cracking south Kenai gas puzzle



As Enstar edges forward with ideas for an extension to the Kenai Kachemak pipeline, DNR extends the North Fork unit. See story and map on page 10.

Begich berates ANWR drilling ban bill; Palin names Hartig to head DEC; Governor to speak at Jan. 19 Meet Alaska conference

THE LATEST BID IN WASHINGTON, D.C., by Rep. Ed Markey, R-Mass., to prohibit oil exploration on the 1.2-million-acre coastal plain of the Arctic National Wildlife Refuge lit a fire under at least one Democrat, who took the U.S. congressman to task Jan. 8. Anchorage Mayor Mark Begich wrote a letter to Markey, pointing out fallacies in the East Coast Democrat's reasoning behind the drilling ban legislation and urging him to reconsider.

"Permanently banning future oil and gas development in the Arctic Refuge, the site of America's best prospect for a major energy discovery, is short-sighted," extolled Begich. "As last year's record gasoline prices dramatically illustrated, America needs a comprehensive national energy policy … That policy also must include environmentally responsible development of this nation's enormous energy resources, most of which lie beneath our public lands. To help lessen our dependence on uncertain foreign sources of energy, we also need to look at environmentally responsible development of domestic energy sources, such as the Arctic Refuge."

As a fellow Democrat and mayor of Alaska's largest city,

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LAND & LEASING

Bush lifts moratorium

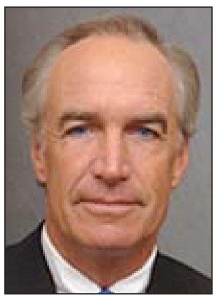
Bristol Bay will probably be part of MMS 2007-2012 lease sale schedule

By ALAN BAILEY
Petroleum News

In a not entirely unexpected move on Jan. 9 President Bush lifted the moratorium on oil and gas leasing in the North Aleutian planning area, an area that includes the outer continental shelf of Alaska's Bristol Bay and the southeastern corner of the Bering Sea. The president's action should enable the U.S. Minerals Management Service to include two North Aleutian lease sales in its 2007 to 2012 leasing program.

JUDY PATRICK

Alaska Gov. Sarah Palin



Interior Secretary Dirk Kempthorne

The president also lifted the moratorium on leasing in the central Gulf of Mexico. The federal government is increasing the royalty rate for most new offshore deepwater federal oil and gas leases outside Alaska to 16.7 percent.

"Together, these actions will enhance America's energy security by improving opportunities for domestic energy production, and will also increase the revenues that the federal government collects from oil and gas companies on behalf of American taxpayers," said Interior Secretary Dirk Kempthorne.

see MORATORIUM page 19

FINANCE & ECONOMY

Forest selling Alaska assets

Reducing debt after Houston Exploration buy, focus on onshore Lower 48 properties

By ALAN BAILEY
Petroleum News

Forest Oil Corp.'s November announcement that it was spinning off its Alaska assets as a separate subsidiary triggered speculation that the company was planning to sell off those assets. That speculation proved correct on Jan. 7 when the company announced its $1.6 billion takeover of Houston Exploration Co. Forest intends to divest its Alaska entity to reduce pro forma debt, the company said as part of the takeover announcement. (see related story on page 13 of this issue.)

"In order to reduce our leverage and to further narrow our geographic focus, we will seek to sell our Alaskan entity in 2007," said Craig Clark, Forest's president and chief executive officer. In a Jan. 8 teleconference Clark reviewed a post-takeover exploration and development strategy focused on a suite of lease properties in Texas, Oklahoma and the Rocky Mountains; Alaska was conspicuous by its absence.

LEONARD GURULE

Forest says that it hopes to reduce its debt by $500 million to $600 million by the end of 2007 by the "sale of Alaska and other assets and free cash flow."

"Alaska will be the major part of that," Forest

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NATURAL GAS

Alaska LNG rumor denied

News report indicates biggest customer may be edging away from Nikiski supply

By ALLEN BAKER
For Petroleum News

The biggest customer for liquefied natural gas coming from Nikiski's LNG plant may be looking for other sources of supply after March 2009.

That's when the aging plant will need a new export license from the U.S. Department of Energy to keep sending its product to Japan.

A Jan. 9 report in Japan's top financial newspaper, Nihon Keizai Shimbun, said Tokyo Electric Power Co. had decided not to renew its contract with the ConocoPhillips-Marathon joint venture, or another smaller contract with Indonesia. The report said Tepco believed reserves for the two LNG producers were close to being exhausted.

But a company spokesman was quoted by Dow Jones later that day as saying no decision had been

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Alaska's only LNG facility

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● LAND & LEASING

Dems float bid to lock up ANWR's coastal plain

Markey, a Massachusetts Democrat, proposes ban on oil drilling in 1002 Area; Ted Stevens offers plan to raise CAFÉ standards to 40 miles per gallon by 2017 to reduce greenhouse gases

By ROSE RAGSDALE
For Petroleum News

Rep. Edward Markey, D-Mass., one of the most strident voices against oil drilling on the coastal plain of the Arctic National Wildlife Refuge, is now pushing legislation to convert the 1.2 million-acre strip of barren tundra into permanent wilderness.

Markey, who introduced H.R. 39 with Rep. Jim Ramstad, R-Minn., in the House Resources Committee Jan. 5, has introduced similar legislation in each of the last three congressional sessions. However, a Republican-controlled House of Representatives has approved ANWR drilling 10 times in the past decade, only to see the effort die in the Senate, where supporters couldn't muster the 60 votes needed to overcome a likely filibuster.

This time, with Democrats in the majority and a number of moderate Republicans on record as opposed to drilling, Markey is calling for the House to declare the refuge's 1002 Area, or coastal plain, permanently off-limits to oil development.

When Congress established ANWR, which Markey called the "crown jewel" of the nation's Wildlife Refuge System, it set aside the 1002 Area, the northernmost edge of the 19.5-million-acre refuge for possible future oil development. The area is believed to contain 10.5 billion barrels of oil, approaching the size of Alaska's Prudhoe Bay field to the west. At peak production, the refuge could supply 1 million barrels a day by 2025, according to the Interior Department.

H.R. 39 would remove the 1002 Area designation and make the coastal plain permanent wilderness just like the other 18.3 million acres of ANWR to the south.

"Our addiction to oil is real and enduring and still largely untreated," Markey said in announcing the legislation. "Drilling in the refuge would amount to a declaration that we remain in denial about this addiction, its impact on our planet and our obligation to future generations."

Markey also cited the huge oil spill at Prudhoe Bay in 2006 as evidence that drilling proponents are mistaken when they say new oil industry technology can keep ANWR relatively free of the undesirable effects of oil and gas production. However, the Prudhoe Bay field is nearly 40 years old and was built with technology that the industry now considers outdated.

Greens to fight for legislation

Environmental groups hailed Markey's bill as a realistic bid for Congress to put the 1002 area off limits to oil drilling.

"What's changed is we won't have those daily assaults" from pro-drilling forces, said Cindy Shogan, executive director of the Alaska Wilderness League. "We are definitely on the offense."

Environmentalists said they plan to mobilize behind the Markey-Ramstad legislation, the same people that have fought drilling proposals in past years.

Two years ago, when Republicans expanded their majorities in the House and Senate, the likelihood of opening the refuge to oil development gained new momentum. It already had been a top energy priority of President Bush since 2001. But a concerted push by pro-drilling forces again fell short in the Senate.

Roger Herrera, a longtime Alaska consultant who has lobbied for oil drilling on the coastal plain in Congress, said Markey's bill comes as no surprise and appears to be more "noise than substance."

Now Markey is hoping momentum will swing the other way.

Markey bill will face opposition

But the Massachusetts congressman will lose that bet, according to a spokeswoman for U.S. Rep. Don Young, R-Alaska, a powerful member of the House Resources Committee.

"We don't see Mr. Markey's bill going very far, perhaps not even out of committee. Regardless, Cong. Young wouldn't consider letting it out of the House without a fight," said Meredith Kenny, Young's press secretary. "At this point, we don't think the bill has enough support to pass the House, and we think Mr. Markey knows that. He just wants to make a point."

Roger Herrera, a longtime Alaska consultant who has lobbied for oil drilling on the coastal plain in Congress, said Markey's bill comes as no surprise and appears to be more "noise than substance."

"The chances of him succeeding with this bill are close to zilch, and even in the House where he would need only a simple majority, it wouldn't be a slam dunk," Herrera said Jan. 9. "Too many people in Congress are concerned about our energy future to take away what they consider to be a valuable option."

In announcing his bill, Markey said a better choice than a "temporary solution" like drilling in ANWR for meeting the nation's energy needs, would be to "increase fuel economy to 40 miles per gallon over 10 years."

Stevens gets jump with fuel economy bill

Ironically, Sen. Ted Stevens, R-Alaska, one of the strongest advocates on Capitol Hill for drilling in ANWR's coastal plain, introduced legislation in the Senate a day earlier calling for just such an increase.

Stevens wants to boost Corporate Average Fuel Economy (or CAFE) standards to 40 miles per gallon by 2017, if not sooner.

The United States imports nearly 11 million barrels of crude oil every day, compared with only five million bpd produced domestically.

Working our way out of this imbalance will require both increased domestic energy production and improved fuel economy, according to Stevens.

Noting that Alaska is ready and able to do its part to increase domestic energy production, Stevens said savings achieved by increasing fuel economy standards for the entire U.S. passenger vehicle fleet is essential to the equation.

Stevens' bill would clarify the secretary of Transportation's authority to raise and reform current CAFE standards for passenger automobiles, and allow the secretary to prescribe standards for different classes of automobiles based on one or more vehicle attributes. It would require the secretary to issue CAFE standards for any model year at least 18 months before the beginning of that particular model year.

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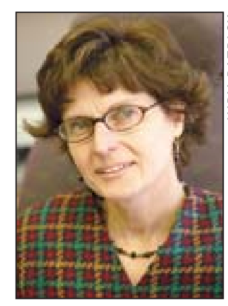
GOVERNMENT

AOGCC to review gas flaring regs

Agency has RFP out for process engineering assistance to do scoping to identify issues to be addressed in regulation rewrite

By KRISTEN NELSON
Petroleum News

The Alaska Oil and Gas Conservation Commission is beginning work on revising its regulations on gas disposition — how oil and gas field operators account for and report natural gas which is flared or vented or used in pilot lights and other field uses, and when such gas use is waste.


JUDY PATRICK

"We expect this scoping study to lead to and help us prepare for a significant revision of our gas disposition regulatory procedures." —AOGCC Commissioner Cathy Foerster

The commission has a request out for proposals, looking for "engineers who have extensive experience in large-scale natural gas production processing design and operation to assist in examining gas disposition" including field use, flaring or venting and pilot or purge gas.

The estimated $30,000 project will produce a scoping study which the commission will use to "plan and seek more detailed engineering contract support for AOGCC's rewrite of gas disposition regulations."

"We expect this scoping study to lead to and help us prepare for a significant revision of our gas disposition regulatory procedures," AOGCC Commissioner Cathy Foerster told Petroleum News in an e-mail.

Travel to Cook Inlet platforms, Kenai Peninsula onshore facilities and the North Slope "may be necessary to assess the current flaring practices and equipment unique to each location and to fully understand the variations involved in gas handling throughout the state," the RFP said.

Tied to prevention of waste

The commission's regulation of gas disposition is part of its mandate to prevent physical waste of oil and gas.

"In accordance with this mandate," the commission said in its RFP, "the AOGCC seeks to evaluate and assess current gas disposition practices specific to flaring, venting, pilot-purge and lease uses throughout Alaska hydrocarbon fields."

The commission last assessed gas disposition practices in 1995 and did "an extensive rewrite of the procedures and decision criteria used for gas disposition decisions," it said.

The commission said current trends in the volume of gas used in field production activities warrants "a thorough review of the equipment volumes of consumed gas associated with particular operations, and what triggers reporting of gas disposition to the AOGCC."

The commission said its current regulations for reporting of gas consumed in the field "are too interpretive, based on out of date operator field management practices, and based on criteria driven by equipment, operational, and environmental considerations known to the operator but not always understood by the regulating agency."

Another factor in the commission's desire to study gas disposition practices is an increase in inconsistencies in what triggers gas disposition reporting.

Timing factor in reporting

Currently the commission looks at gas volumes that are flared or vented in events

see **AOGCC** page 12

continued from page 3

ANWR

Less pollution another goal

The bill also would amend existing criteria that the secretary must consider when determining CAFE standards to include motor vehicle safety, the effect of the standard on emissions and the need of the United States to reduce its dependency on oil. It prohibits any CAFE regulation that would require a "uniform percentage increase" by manufacturers, and requires that any regulation pass a cost/benefit test.

The legislation also requires the secretary of Commerce to establish a national registry system for greenhouse gas trading of credits. Participation in the registry would be voluntary, and any entity conducting business in the United States would be eligible to use the services of the registry. Therefore, automobile manufacturers would be able to contribute or purchase a limited number of emissions credits with other industries that generate greenhouse gases in order to achieve compliance with CAFE standards.

Stevens also noted that increasing CAFE standards will help reduce emissions of greenhouse gases.

The U.S. transportation sector contributes roughly one third of all greenhouse gas emissions, a statistic that Markey also cited in making his case for prohibiting oil drilling on ANWR's coastal plain. ●

The Associated Press contributed to this report.

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GOVERNMENT

Enviro clean-up time in Canada

Prime minister dumps embattled environment minister, says more must be done; uneasy industry waits for action on greenhouse gases

By GARY PARK

For Petroleum News

The Canadian government has done an about-face on its environmental priorities, dragging the oil and gas industry back into the unknown.

Conceding his administration had lost control of the issue, Prime Minister Stephen Harper unloaded embattled Rona Ambrose from the environment portfolio, replacing her with John Baird, seen as more decisive and a better communicator.

Harper, who did not include the environment among his five top priorities when he was elected a year ago, underscored his change of heart by creating a new cabinet committee on the environment and energy security that will consult with industry and across government departments on implementing the government's Clean Air Act.

In patching up what was widely perceived as his government's greatest vulnerability, Harper put the final cabinet pieces in place for an election that is anticipated this spring.

Making a rare concession, Harper said Jan. 4 that the cabinet shuffle is clear evidence that "we need to do more on the environment. We recognize that, particularly when it comes to clean air and climate change, that Canadians deserve a lot more."

"It should be a priority, so that is going to occupy a lot of our time," he said.

Will Kyoto be revived?

How much more might be a source of concern in the oil and gas industry, which has understood that a Harper administration will not attempt to enforce the greenhouse gas emission limits contained in the Kyoto Protocol.

There is no indication yet from Harper or Baird that the government has any intention of reviving Kyoto, but the government is under pressure from Canadians to introduce measures aimed at tackling climate change — an issue that has become the leading concern after several months of some of the most extreme weather on record.

But there is cause for disquiet in the industry as pressure builds on the government to take tougher action against the leading industrial sources of greenhouse gases, with the Alberta oil sands at the top of the hit list.

Even Indian Affairs and Northern Development Minister Jim Prentice, who comes from Calgary, has waved a warning flag.

As chairman of the committee on environment and energy security, he said the environment is now clearly a priority for the government and Harper, which carries implications for fossil-fuel burning electricity producers, the oil sands sector and pipeline companies.

That puts Prentice in a tight spot. He is already the cabinet minister who oversees pipeline projects, notably the proposed Mackenzie Gas Project, which he wants to see move ahead.

Oil sands pose a challenge

While the pipelines pose a challenge, an even greater test will be how the government deals with the oil sands, which have become synonymous with greenhouse gases.

Emissions from the northern Alberta resource were estimated at 27 million metric tons in 2005 and, if work proceeds on more than C$100 billion worth of projects, are forecast to reach 114 million metric tons in 2017.


Prime Minister Stephen Harper

The industry is no longer trying to deny its contributions to greenhouse gas emissions or the urgent need to find solutions.

Rick George, chief executive officer of Suncor Energy, said last year that the intensity of emissions has been reduced over recent years, but the total emissions are rising making "this an especially pressing issue."

Despite efforts by many oil sands operators to develop new recovery and processing technologies, Harper is under pressure from Canadians and within his own party to act on greenhouse gases and blunt the growing view that the Liberal party opposition under new leader Stephane Dion (a former federal environment minister and pro-Kyoto advocate) had seized control of an issue that could decide the next election.

Harper believed he could satisfy Canadians by shifting from Kyoto, which he suggested was a recipe for economic chaos, and introducing the Clean Air Act which put the emphasis on reducing air pollution and protecting the health of Canadians.

The act concentrated on compulsory cuts to industrial air pollution, but came under fire for targeting a 45 to 65 percent reduction in greenhouse gas emissions from 2033 by 2050.

Ambrose struggled to win public support for the legislation and the Conservatives appeared to pay a price by sliding behind the Liberals in the polls.

Environmental policy a top priority

The act was sent to special House of Commons committee in a bid to force strong amendments on the government.

A survey released Jan. 4 by Decima Research showed environmental policy has become the top priority for Canadians and the subject of most discontent with the Harper government.

The results showed that over the past four months the profoundly unseasonable weather that has hit most parts of Canada has produced a dramatic surge on national concern over the environment.

Decima found that 19 percent of respondents said the environment was the issue that concerned them most, compared with only 6 percent in September.

When respondents were asked to rate government action in 20 different areas, 74 percent said it was doing a bad job on the environment and only 18 percent gave their approval.

Even in Alberta, Canada's energy powerhouse and a Harper stronghold, 61 percent said the government was doing a poor job.

A survey released Jan. 4 by Decima Research showed environmental policy has become the top priority for Canadians and the subject of most discontent with the Harper government.

Some environmental optimism

There was some optimism among environmental groups that Baird would bolster that record.

Stephen Hazell, executive director of the Sierra Club of Canada, said Baird had shown he "can deliver, that he knows how Ottawa works."

But it would need Harper's backing for Baird to tackle climate change policy and succeed in the portfolio, Hazell said.

"The worry is that this is really just a political thing in the lead-up to the next election," he said.

Baird told CanWest News that he is ready to take a non-partisan approach to dealing with "one of the biggest challenges the planet is facing."

He plans to get the best advice from environmental groups and work with the other federal parties to achieve results, Baird said.

What he has yet to disclose is whether the oil and gas industry faces more stringent regulations than those contained in the Clean Air Act.

Dion has made no attempt to hide his view that the industry should make deep cuts in its greenhouse gas emissions through technology-based solutions. ●

● GOVERNMENT

Variety of industry-related bills prefiled

Include RCA extension to 2008 or 2015; money for wind farm on Fire Island; moving Thomson decision to Supreme Court

By KRISTEN NELSON

Petroleum News

A variety of oil and gas related bills were among prefiled bills released Jan. 5.

Both the House and the Senate have bills which would confer original jurisdiction in the Point Thomson dispute on the Supreme Court; both houses also have bills that would use money from the Railbelt energy fund for a wind farm on Fire Island off Anchorage. And there are two different proposals to extend the Regulatory Commission of Alaska, set to sunset in June: one to 2008 and one to 2015.

House bills

• House Bill 30, by Rep. Ralph Samuels, R-Anchorage, confers original jurisdiction on the Alaska Supreme Court for the purpose of providing judicial review of a final decision by the commissioner of Natural Resources terminating an oil and gas unit or lease in an oil and gas unit all or part of which lies north of 68 degrees north latitude, as does Senate Bill 26.

House Joint Resolution 1 by Rep. Mike Hawker, R-Anchorage, proposes amending the state constitution to create a gas revenue endowment fund.

A portion of HB 30 is retroactive to Nov. 26; former DNR Commissioner Mike Menge issued his decision on Point Thomson Nov. 27.

SB 26 does not have a retroactive provision. Both bills would require a two-thirds majority vote in each legislative body.

• HB 46 by Rep. Kurt Olson, R-Kenai, would extend the termination date for the Regulatory Commission of Alaska from June 30, 2007, to June 30, 2008.

• HB 41 by Rep. Les Gara, D-Anchorage, would return "certain duties regarding habitat management from the Department of Natural Resources to the Department of Fish and Game" with an effective date of July 1. The administration of former Gov. Frank Murkowski moved permitting related habitat issues from Fish and Game to DNR.

• HB 53 by Rep. Vic Kohring, R-Wasilla, would exempt low-volume oil production facilities from the requirements for oil discharge prevention and contingency plans and proof of financial responsibility.

Kohring said in a Jan. 4 statement that the bill provides a change in bonding for small operators, those producing less than 501 barrels of oil per day, per well. "We often hear from the big oil companies that a field is not economically viable. For them, using their worldwide formula, it isn't. However, a mom and pop operation could easily develop these fields and produce small amounts of oil or gas while increasing the amounts available for in-state refining. Many of these people could already be right here in Alaska, meaning the income from our resources stays in state," Kohring said.

The language in HB 53 refers to "a production facility that produces less than 501 barrels of oil a day," rather than less than 501 barrels per well per day, and puts that category of oil production into the same category as natural gas production facilities.

According to Alaska Oil and Gas Conservation Commission production records for November, the most recent month available, a facility producing less than 501 bpd would appear to include a number of Cook Inlet fields — Beaver Creek, Redoubt Shoal and Swanson River. Fields with wells that — on average — produce less than 501 bpd, include Trading Bay and West McArthur River in Cook Inlet, and Badami on the North Slope. Operators of those fields include Forest Oil, Chevron and BP.

• HB 56, by Rep. Harry Crawford, D-Anchorage, would establish the Hydrogen Energy Partnership in the Department of Commerce, Community and Economic Development, and require the commissioner "to seek public and private funding for the partnership." The idea presented in the legislative findings section of the bill is that there is funding available for hydrogen research and development and Alaska would be "an excellent site to attract federal government and industry investment in hydrogen" because of available renewable resources, including "geothermal energy for processing hydrogen at an industrial scale" and because Alaska's location is good for transport around the Pacific Rim.

• HB 63 by Rep. Bill Thomas, R-Haines, "An Act relating to the alternative energy grant fund and to alternative energy grants," would establish the alternative energy grant fund.

At the end of each calendar year, if the fund balance is less than $250 million, the Department of Revenue would calculate an amount equal to 10 cents for each barrel of crude oil produced in the state during the year while the average West Coast prevailing value for crude oil is $35 a barrel or higher. The bill says the Legislature "may

see BILLS page 7

PIPELINES & DOWNSTREAM

New Canadian refinery hub for northeast United States in works

Atlantic Canada has taken another step towards becoming a key source of refined petroleum products for the northeastern United States, with plans for a possible 300,000 barrel per day facility in Newfoundland deemed to be "economically feasible" by a group of private investors.

Backers of Newfoundland and Labrador Refining say the refinery in Newfoundland's Placentia Bay could generate a rate of return of 15 percent on a US$4.6 billion investment.

The company said the base-case projection was based on its own "conservative long-term refining margin outlook."

An earlier estimate had put the cost of the refinery at $2 billion, but the investors have since incorporated a number of equipment additions that would expand the options for handling various crude oil types.

The company's objective is to take advantage of the surging demand for petroleum products, especially in the U.S. northeast, and Newfoundland's accessibility for tanker traffic.

Newfoundland and Labrador Refining backers comprise Altius Minerals, a base-metal explorer; Dermot Desmond, founder of Irish-based International Investment and Underwriting; Harry Dobson, a Scottish financier; and Stephen Posford, former head of European operations for investment banker Salomon Brothers.

The plant would be located close to Newfoundland's 115,000 bpd Come By Chance refinery which was acquired in October by Harvest Energy Trust as part of a C$1.6 billion purchase that included gas stations and a home heating business.

Harvest indicated it is prepared to invest C$700 million in expansion projects, although it has yet to indicate whether its future has changed under the new rules for Canadian energy trusts.

However, Harvest has taken a bruising since the trust announcement on Oct. 31.

It was forced to reduce the price of trust units it plans to issue by 14 percent and more than double the number of units on offer as part of its C$638 million financing to pay down debt from the Come By Chance acquisition.

Also in the works is a plan by privately held Irving Oil to build a second refinery at its Saint John, New Brunswick complex.

If it proceeds with the C$7 billion investment, its capacity would double to 600,000 bpd. Currently 175,000 bpd of Irving's refined products are exported to the U.S.

—GARY PARK

● GOVERNMENT

Higher tariffs could cost state millions

Hit on state revenues from tariffs about 50% higher under new tax, but overall new tax will still bring in more revenue than old

THE ASSOCIATED PRESS

Increased oil shipping rates on the trans-Alaska oil pipeline could cost the state roughly $102 million a year if they stand, according to an estimate by a state petroleum economist.

With the rate hike, the hit on state revenues would be about 50 percent higher than it would have been under the state's old oil tax system, said Roger Marks with the Alaska Department of Revenue. The new tax system, however, would still bring in far more revenue than the old, he said.

The Alaska Legislature adopted the new system last year hoping to secure a natural gas pipeline deal with the major North Slope petroleum producers. The gas line deal stalled, but the oil tax revisions remain.

The owners of the 800-mile trans-Alaska pipeline, primarily the three main oil producers in the state, announced in December that they would raise the amount they charge to ship oil by an average of about $1.14 per barrel. The increase was effective New Year's Day.

Under the state's old production tax, the state collected about 9 percent of the oil's gross wellhead value, Marks said. The wellhead value is determined by subtracting transportation costs, such as pipeline shipping tariffs, from the oil's sale price.

Thus higher tariffs meant less money for the state and the tariff increases announced in December would have cut state income by about $68 million annually, Marks estimated.

New tax on net profits

Under the new tax system, oil companies are charged 22.5 percent of their net profits from North Slope production. The cost of shipping the oil, among other expenses, is subtracted from the taxable profits, again reducing state revenue.

But the effect of higher tariffs is greater under the new tax because the rate to which they apply is greater than the previous system. So the new tariffs would cost the state about $102 million annually, Marks estimated.

That greater loss, however, is overshadowed by an additional $800 million the state would earn as a result of the new tax system, under current oil prices of $58 per barrel, Marks said.

The Department of Revenue predicted in its fall 2006 forecast that the state would earn about $4.95 billion from oil revenue in the fiscal year ending July 1. Of that amount, about slightly more than $2 billion was expected to come from the new production tax.

An almost identical amount was expected from sales of the state's royalty share of oil produced from state leases. Most of the remaining $800 million was expected to come from corporate income taxes ●

continued from page 6

BILLS

appropriate" the amount calculated by the department to the alternate energy grant fund, along with any income earned on money in the fund.

The fund could be used to grant money for alternative energy projects determined to be economically viable and that "will result in reduced costs for consumers of the services of the electric utility." An electric utility would have to provide a match equal to 25 percent of the grant amount to quality for a grant.

Priority would be given "to alternative energy projects located in areas where fossil fuel costs are higher than in other areas of the state."

• HB 73 by Rep. Harry Crawford, D-Anchorage, makes a special appropriation of $24 million from the Railbelt energy fund to the Department of Commerce, Community and Economic Development for construction of a wind farm on Fire Island and transmission lines to connect it to existing electrical infrastructure in Anchorage, as does SB 44.

• House Joint Resolution 1 by Rep. Mike Hawker, R-Anchorage, proposes amending the state constitution to create a gas revenue endowment fund.

Senate bills

• Senate Bill 2 by Sen. Gary Wilken, R-Fairbanks, establishes a natural gas revenue fund in the general fund.

"The Department of Revenue shall deposit into the fund 25 percent of all money received by the state from lease rentals, royalties, and royalty sale proceeds for natural gas and from federal mineral revenue sharing payments and bonuses for natural gas," the bill says.

Money from the fund could be appropriated to the public education fund, then to the Alaska debt retirement fund; on June 30 of each year the unappropriated balance would be transferred to the general fund.

• SB 16 by Sen. Gene Therriault, R-North Pole, extends the termination date for the Regulatory Commission of Alaska from June 30, 2007, to June 30, 2015.

• SB 26, also by Therriault, gives original jurisdiction to the Alaska Supreme Court for the purpose of providing judicial review of a final decision by the commissioner of Natural Resources terminating an oil and gas unit or lease in an oil and gas unit all or part of which lies north of 68 degrees north latitude, as does HB 30.

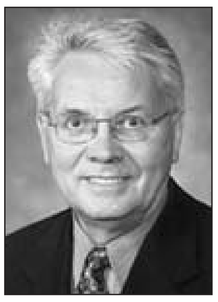
• SB 44 by Sen. Lesil McGuire, R-Anchorage, would, like HB 73, make a $24 million appropriation from the Railbelt energy fund for construction of a wind farm on Fire Island and transmission lines to connect it to existing electrical infrastructure in Anchorage. ●

GOVERNMENT

B.C. to overhaul 2002 energy plan

The British Columbia government is due to unveil a new set of energy policies in January, the first major update of its 2002 package which was credited with opening the door to a C$5 billion a year natural gas industry and for private-sector development of electricity generation.

Energy Minister Richard Neufeld has dropped few hints on what is in store this time, but there is a growing anticipation that the government is eager to push ahead with unconventional gas now that the conventional sector appears to have plateaued.



RICHARD NEUFELD

Even without getting into the controversial offshore debate, the government has the prospect of advancing trillions of cubic feet of coalbed methane, shale gas and tight gas prospects across the province.

Gains in technology and an expected steady decline in conventional gas output are the motivation for moving activity from the highly concentrated northeastern corner of British Columbia to new basins.

Coalbed methane proponents struggling to make case

But coalbed methane proponents have struggled to make their case in the face of community concerns about their impact on domestic water supplies, including the need to pump large volumes of saline and potentially toxic water from underground deposits before coalbed methane can be commercially produced.

Neufeld has insisted the bulk of coalbed methane projects in British Columbia will be forced to reinject their water.

However, he has not said whether he plans to start getting to grips with that issue in the policy update and allow British Columbia to join Alberta in commercial coalbed methane production.

Also on the table is the need to overhaul the province's deteriorating electricity transmission system; the future of planned coal-fired electricity plants at a time when greenhouse gas emissions is a national concern; and the future investment in "green" electricity projects by independent producers.

—GARY PARK

FINANCE & ECONOMY

Calpine fund rejects hostile bid

Calpine Power Income Fund, which owns a natural gas-fired power plant in Calgary and was spun off from bankrupt California-based Calpine, has spurned a hostile takeover offer of C$831 million.

The offer from New York-based Harbinger Capital Partners was deemed "financially inadequate" by BMO Nesbitt Burns, said Bob Hodgins, chairman of Calpine Commercial Trust, which oversees the fund.

He said the Harbinger bid did not reflect the quality of the fund's assets or the cash flow that is being generated.

Hodgins accused Harbinger, which invests in high-yield debt and distressed assets, of making "self-serving and exaggerated" claims on the risks faced by Calpine Power unit holders from claims against insolvent Calpine after it abandoned a long-term contract to buy power from the Calgary plant.

He said an affiliate 70 percent owned by Calpine Power plans to lower its court claim for repudiation to C$280 million from an earlier C$769 million now that the Calgary municipal utility has agreed to buy power from the plant for 20 years.

Calpine Power also owns a cogeneration plant in British Columbia and a King City plant in California.

Hodgins said several bidders have shown interest in Calpine Power and a number have reviewed the fund's financial information.

"Potentially superior offers may emerge," he said. "We're encouraged by the interest that we're seeing."

—GARY PARK

Strikes against Western Canada

The high-cost Western Canada Sedimentary basin has attracted two more black marks.

ConocoPhillips said its operations in the Foothills region of the Canadian Rockies will post a $90 million after-tax charge against its earnings for the final quarter of 2006.

It blamed "declining well performance and drilling results." The company currently produces about 363,000 barrels of oil equivalent per day in Canada.

Meanwhile, mid-sized producer Compton Petroleum has put the brakes on first-half spending for 2007 in hopes that a decline in upstream activity will lower oilfield service costs.

The Calgary-based company said it plans to trim its capital spending budget by 20 percent to C$375 million, following the lead of companies such as EnCana, Talisman Energy and Canadian Natural Resources who have restrained spending until there is an easing in field costs.

Compton Chief Executive Officer Ernie Sapieha told analysts he anticipates reduced activity will lower long-term costs.

The company still plans to match last year's performance by drilling about 330 wells, but will trim its budget by concentrating on cheaper, shallow natural gas wells, while restraining its land purchases and investment in facilities and equipment.

It is aiming for a 14 percent hike in production this year to 38,000 barrels of oil equivalent per day.

Canaccord Adams said it is cautious about the challenge Compton faces in meeting its growth objectives while reining in capital spending.

—GARY PARK

CORRECTION

It's BG Group

A story in the Dec. 24 issue of Petroleum News incorrectly referred to British Gas, a name that company hasn't used in a number of years.

The company changed its name to BG plc in 1997 and in 1999, following a financial restructuring, a new parent company, BG Group plc, was created.

BG Group describes itself as "a global natural gas business that finds, develops and connects gas to markets."

● ALTERNATIVE ENERGY

Economist says too much corn to ethanol

Earth Policy Institute says distilleries online or in works will pull 5.5 billion bushels of corn from the 2008 harvest to produce fuel

By DAVID PITT

Associated Press Business Writer

An agricultural economist and founder of a Washington-based environmental think tank said Jan. 4 that ethanol production will consume much more corn than the government has estimated and could result in shortages of corn for livestock feed, driving up production costs and causing higher food prices.

Lester Brown, founder of the Earth Policy Institute, said rapid ethanol industry expansion has caused data to fall behind developments in the field. He warned that nearly twice as much corn as the government has estimated will be needed from the 2008 harvest to feed the ethanol plants that will be online by then.

He blamed the lag on the failure of industry trade groups to keep up with development of ethanol plants.

Many industry observers rely on estimates by the Washington-based Renewable Fuels Association for figuring ethanol production capacity and corn demand.

Association President Bob Dinnen said the ethanol industry is moving rapidly, but his organization's estimates are as accurate as possible.

He questioned the criteria used by Earth Policy Institute, saying some plants in planning stages included in the group's estimates may never be built.

Ethanol plants: 116 online; 79 under construction

According to the Earth Policy Institute's data, U.S. ethanol distilleries now online or in the works will pull an estimated 139 million tons — or 5.5 billion bushels — of corn from the 2008 corn harvest to produce fuel for automobiles.

That's based on 116 existing ethanol plants, 79 under construction, 11 undergoing expansion and 200 plants in the planning stages expected to be running by corn harvest time in September 2008.

The government in a February report estimated ethanol plants would use about 60 million tons — or 2.4 billion bushels of corn.

Keith Collins, chief economist at the U.S. Department of Agriculture, acknowledged that industry estimates of ethanol production have lagged, but he was skeptical of the Earth Policy Institute's estimates.

"That strikes me as high," he said. "The point that they're making is a valid point. The expansion in the industry has been outstripping everybody's expectations. My experience over the last 18 months has been to be continually updating, increasing our own estimates of the production and corn use for ethanol."

Concern that food prices will rise

In a telephone conference call with reporters, Brown said the demand for corn by ethanol plants will result in higher prices for food staples such as milk, eggs, meat and cheese.

"In a sense, your refrigerator is stuffed with corn that has been converted into livestock products in one way or another," he said. "What happens to corn prices will very much affect the prices at the supermarket checkout counter."

That could create a backlash and strong vocal opposition to ethanol when consumers realize the cause for higher food prices is the massive use of corn for fuel, he said.

Dinnen said Brown's estimates fail to consider that as much as 10 million more acres of farmland may be put into production next year.

"It ignores the reality of the marketplace," he said. "We can't drive grain prices to the point that we can't produce ethanol economically. There are limitations to what we're going to be able to do. There are limitations to how much ethanol you can produce from grain."

He said that's why nearly all ethanol producers are looking at making ethanol from other feedstocks including switchgrass, wood chips and corn stalks.

Corn exports also a concern

Brown said increasing corn use for ethanol also reduces exports to low-income grain importing countries, which could cause political instability and result in urban food riots in many low- and middle-income countries.

"If the current scenario continues to unfold as we've projected here, it could create chaos in world grain markets and we should think through whether we want to do that or not," he said.

Brown was pushing for the U.S. government to declare a moratorium on the construction of new ethanol plants until the impact of increased corn usage can be determined.

He said another solution is for the government to require a 20 percent increase in the fuel efficiency standard for cars to cut fuel demand.

A longer term solution would be increased reliance on gas-electric hybrid cars and development of car engines that run in part on electric cells that can be recharged by plugging them in, he said.

That combined with increased wind energy to make clean renewable electricity would help reduce the need for foreign oil for gasoline and for corn-based ethanol, Brown said.

For more information: Earth Policy Institute: http://www.earth-policy.org; Renewable Fuels Association: http://www.ethanolrfa.org. ●

● NATURAL GAS

Battle brewing over methane drilling

Denali Borough opposing state over Usibelli's plan to explore for gas in the borough; company seeking state exploration license

By ELIZABETH BLUEMINK
Anchorage Daily News

Another battle over coalbed methane exploration is bubbling up in Alaska — this time near one of the state's most iconic spots.

On one side is the Denali Borough, taking up the cause for some residents worried about water contamination, noise and other drilling-related nuisances in their neighborhoods.

On the other is the state, which owns a large potential gas resource under the northern part of the borough.

Two Alaska industries also have a big stake in the battle's outcome. These are Usibelli Coal Mine Inc., a respected local employer, and the growing group of tourism operators who capitalize on the nearby Denali National Park.

It's a replay of a similar dispute that raged in the Mat-Su a couple of years ago, when angry Valley homeowners launched a public outcry to keep coalbed methane explorers from drilling on their land.

Denali Borough not dealing with strange company

The Denali battle has a key distinction. "We're not dealing with a strange company that's coming into the area that we don't know anything about," said borough Mayor David Talerico.

Usibelli is seeking a state license to explore 208,630 acres for both coalbed methane and natural gas in the northern part of the borough.

The state hasn't granted the company a license yet.

Instead, the state put its license review on hold last year while the borough studied the development. The borough assembly acted last fall: It voted to block gas exploration west of the Parks Highway — about 40 percent of the state land in the proposed license area.

State officials contend that the borough's new rule is probably illegal.

"This is a landmark issue that needs to be straightened out," said Steve Denton, Usibelli's vice president for business development.

No one wants gas explorers on their land, says Amanda Austin, treasurer of the Panguingue Creek Homeowners Association.

Austin — who hauls water to her cabin in the rural subdivision and works at the Tri-Valley community library — says she's involved in the fight to protect the environment and her home.

Yet under state law, oil and gas explorers may drill through private property to access state-owned oil and gas deposits underneath.

State has proposed guidelines

The state previously proposed guidelines for a Healy basin exploration license. For example, the state proposed to keep drill pads at least 500 feet from a home, unless the company gets consent from the homeowner.

The license would allow exploratory drilling for both natural gas and coalbed methane gas.

Coalbed methane is a gas created when decayed plants turn into coal. The gas remains trapped in coal seams but pumping water out of the seams allows the gas to be released.

> *"Essentially, the borough is taking resources for itself that belong to the rest of the State of Alaska."*
> **—Steve Denton, Usibelli's vice president for business development**

Unlike natural gas wells — which extract vast quantities of gas from a single, deep drill hole — coalbed methane extraction requires numerous shallow wells and roads to connect the drill sites.

Usibelli wants to power mine operations

Usibelli hopes to find enough conventional gas or coalbed methane to power its open-pit mine operations.

The mining company also says it might be able to distribute gas to Southcentral utilities pinched by Cook Inlet's diminishing gas supply, if even larger quantities are found.

Drilling success isn't guaranteed. No one has ever drilled for gas in the Healy basin, said Usibelli's Denton.

Borough assembly members said in December that they hope to reach a compromise with the state.

"We haven't heard from (the state) other than they are pretty unhappy," said Gerald Pollock, the assembly's presiding officer, who works as a Teamster at the mine.

Usibelli officials also are unhappy.

"Essentially, the borough is taking resources for itself that belong to the rest of the State of Alaska," Denton said.

"There's a conflict between what's best for the state as a whole and each individual property owner. We in the borough are having a hard time treading that fine line," Pollock said.

The conflict involves more than just a few homeowners, he said.

The Denali Borough's largest taxpayer is the tourism industry, which is growing rapidly along the Parks Highway.

The borough's hotel-room tax provides nearly 86 percent of its annual revenue.

"There is a line here. If you want to drill a natural gas well in front of the Princess (cruise company-owned) lodge, we are going to have a problem with that. You'll destroy the revenue coming into our borough," Pollock said.

But Usibelli claims it could lose out under the borough's new rule.

The company doesn't want to risk its money to demonstrate that the basin contains viable gas only to face another company swooping in later to claim the area Usibelli wasn't able to get access to, Denton said.

"It might be the best part of the basin," he said of the area the borough voted to close off.

State hasn't indicated what it will do

So far, the state has not signaled what it will do.

Just before the assembly passed the law to block exploration, a state official told Talerico in a letter that it was probably illegal. The borough's attorney gave similar advice to the borough after the vote.

> *It's a replay of a similar dispute that raged in the Mat-Su a couple of years ago, when angry Valley homeowners launched a public outcry to keep coalbed methane explorers from drilling on their land.*

A game of cat-and-mouse has developed, with the borough and the state waiting for each other to make the next move, Talerico said.

DNR spokesman Dan Saddler said the dispute is high on acting Natural Resources Commissioner Marty Rutherford's agenda but nothing has been decided yet.

There are statewide implications in the dispute.

It shows that the state's recently revised rules for gas exploration still aren't meeting the needs of private property owners, some observers said in late December.

"It all goes back to the split estate," which gives private landowners the surface rights and the state the subsurface rights, said Nancy Bale, with the Denali Citizens Council, an environmental group fighting the leases.

"People want the option to say (no gas exploration on) my property," she said.

A similar chain of events unfolded in the valley a few years ago: The Mat-Su Borough enacted its own rule to restrict coalbed methane development. State officials alleged it was illegal.

The Mat-Su rule became moot, however, when Pioneer Resources, the company that had obtained leases to explore the area, pulled out of the project. ●

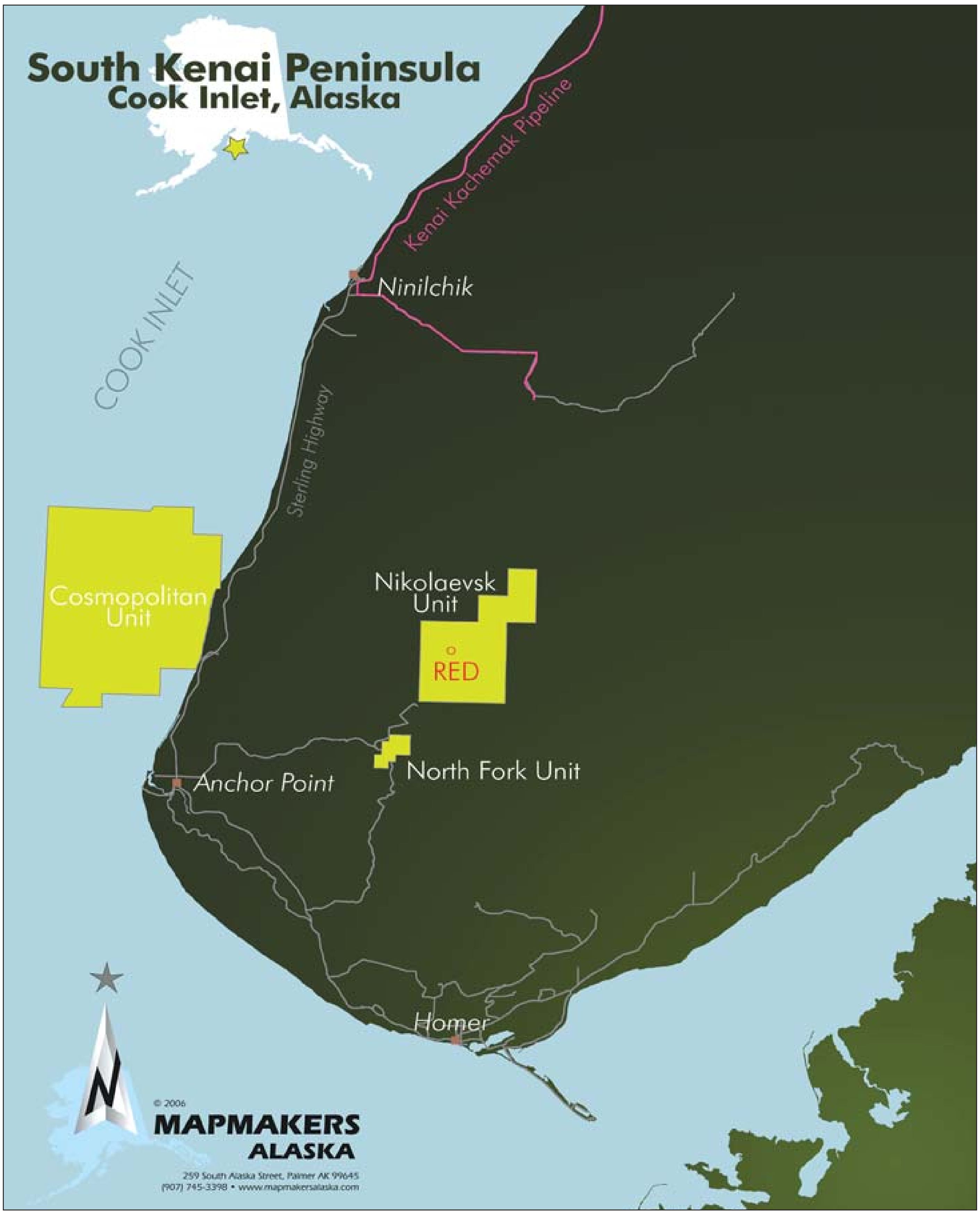
● NATURAL GAS

Cracking the southern Kenai gas puzzle

As Enstar edges forward with ideas for an extension to the Kenai Kachemak pipeline, DNR extends the North Fork unit

By ALAN BAILEY

Petroleum News



The potential development of natural gas in the southern part of Alaska's Kenai Peninsula is starting to look a bit like a chicken with a rather promising egg. Several known gas accumulations exist south of the existing pipeline infrastructure, but oil and gas companies with gas in the ground need access to markets through a convenient pipeline. And any company interested in building a pipeline needs some assurance that the oil and gas companies will develop sufficient gas reserves to justify pipeline development costs.

So, who will crack the egg first — a producer or a pipeline constructor? And is the egg big enough to be worth cracking?

In December the Alaska Department of Natural Resources' extended the North Fork unit, with its known gas pool about 10 miles north of the town of Homer. That and Enstar Natural Gas Co.'s continued interest in building a southern Kenai Peninsula gas pipeline seem to signal optimism about the gas potential of the region.

Kenai Kachemak pipeline

The Kenai Kachemak pipeline (or KKPL), jointly owned by Marathon and Chevron, is the most recent and most southerly pipeline on the Kenai Peninsula. KKPL started shipping gas north from the Ninilchik field, located a little more than halfway down the west coast of the peninsula, in 2003. A year later KKPL was extended inland 15 miles to the southeast to connect with Unocal's new Happy Valley gas field (Chevron later acquired Unocal).

But as early as 1965 Standard Oil of California struck natural gas in its North Fork 41-35 well when searching for oil in the area. North Fork lies inland in the peninsula about 12 miles south of the most southerly point on the Kenai Kachemak Pipeline.

Gas-Pro Alaska LLC acquired the North Fork unit from Unocal in 1996 and NorthStar Energy bought Gas-Pro in 2000. In 2001 NorthStar tested the 41-35 well and reported a flow of 4 million cubic feet per day of natural gas from one interval at 8,500 feet. In 2003 NorthStar struck a deal with Enstar to supply gas from North Fork to Homer. The deal involved Alliance Energy, a sister company to NorthStar, building a pipeline from North Fork to Anchor Point, a few miles northwest of Homer, and Enstar building a pipeline from Anchor Point to Homer.

However, both Enstar and the Regulatory Commission of Alaska required that pipeline construction be contingent on drilling a second North Fork well, to raise proved reserves in the field from 12 billion cubic feet to 14.5 bcf and to ensure a 20-year gas supply for Homer.

That second well has never been drilled.

Notice of unit termination

The North Fork unit included both federal and State of Alaska land and was administered by the U.S. Bureau of Land Management. In March 2006 BLM informed NorthStar that the unit would be terminated on Oct. 1 if a second well were not drilled in the unit. And in July 2006 NorthStar informed Enstar that it could no longer fulfill the Homer gas supply contract.

Then, in August, Enstar told Homer city council that the company was considering building a high-pressure gas transmission line south from the end of the Kenai Kachemak pipeline at Happy Valley to Homer. The new line would hook up to production from a known gas pool penetrated by the Red well in the Chevron-operated Nikolaevsk unit, close to North Fork. The line would take about four years to complete at an estimated cost of $16 million, Enstar said.

In parallel with the construction of the gas transmission line, Enstar would start building out a gas distribution network centered on Homer, at an estimated cost of $14 million, to serve an estimated 3,000 customers in the Homer area.

DNR unit extension

On Nov. 1 the title to the federal land within the North Fork unit was conveyed to the State of Alaska as part of the land transfers emanating from Alaska statehood. DNR took over administration of the unit from BLM. And on Dec. 13 Kevin Banks, acting director of the Division of Oil and Gas, wrote to Gas-Pro offering to extend the North Fork unit to March 31, provided that Gas-Pro met certain conditions, including the payment of a lease sale deferral bid payment and the posting of a performance bond payable to the state.

see **PUZZLE** page 11

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PUZZLE

Gas-Pro has met the state's stipulations for the extension of the lease, DOG told Petroleum News Jan. 3.

Also, under the stipulations set by the state, the terms of the current 41st plan of development for the unit will continue until March 31, by which time Gas-Pro must file the 42nd plan of development, to prevent unit termination at that date. DOG told Petroleum News that if the division approves the 42nd plan of development the division would extend the unit beyond March 31.

And Jan. 3 Barry Foote, Gas-Pro vice-president, told Petroleum News that his company still hopes to develop North Fork.

"We're still bullish on Alaska," Foote said. "We're ready to move."

Needs a pipeline

Foote said that Gas-Pro has been unable to justify the cost of drilling a second well at North Fork because of the lack of a pipeline to deliver gas to market. If the company were to go ahead and drill another well it would likely take several years before a pipeline to export gas from North Fork would be completed. That time delay might increase the effective cost of the well from perhaps $3 million or $4 million to $8 million, Foote said.

Foote also said that the small size of the Homer gas market detracts from the economics of developing North Fork.

Gas-Pro is enthusiastic about Enstar's proposal for a gas line connecting Homer with the Red well and the Kenai Kachemak pipeline — that pipeline would open up potential markets both north and south of North Fork.

"We're hopeful that Enstar is going to push forward aggressively with an extension of the KKPL," Foote said. "… We feel good about where our well is. … If the infrastructure was there we'd start drilling tomorrow."

Foote also said that acreage Alliance Energy picked up near North Fork in the last state Cook Inlet areawide lease sale contains a promising gas prospect that is also conveniently placed for a hook up with Enstar's proposed pipeline.

On Jan. 3 Enstar spokesman Curtis Thayer confirmed that Enstar still wants to develop a gas transmission line in the southern Kenai Peninsula and that the company is still very interested in the possibility of a line running south from the Red well. That would probably be a 4-inch transmission line, Thayer said (the Kenai Kachemak pipeline is a 12-inch line).

"If there is gas supply in the southern Kenai Peninsula we are interested in bringing it to market," Thayer told Petroleum News.

Cosmopolitan

Thayer said that Enstar has also been discussing with Pioneer Natural Resources the possibility of obtaining gas from the Cosmopolitan prospect, offshore Anchor Point. Although Cosmopolitan is an oil prospect, Pioneer has told Enstar that there is natural gas associated with the oil, Thayer said.

Thayer also said that a gas transmission line in the southern peninsula would open up other gas exploration opportunities in the area.

That view seems to be shared by other companies, judging by the results of the state's May 2006 Cook Inlet lease sale. In addition to Alliance Energy, Benchmark Oil & Gas and Rutter & Wilbanks both bought acreage inland in the region.

But it remains to be seen what it will take to crack open gas development in the southern peninsula.●

INTERNATIONAL

Eni finds oil at Goliat wildcat in Barents Sea

Italian oil company Eni SpA struck a column of oil with a wildcat exploration well drilled at its Goliat discovery in the Barents Sea in the Norwegian Arctic, the Norwegian Petroleum Directorate announced Jan. 9.

The Norwegian branch of Italy's largest oil company discovered the Goliat field with a well drilled last year about 50 miles off Norway's northernmost town of Hammerfest.

A petroleum directorate news release said the latest well, drilled by the Polar Pioneer offshore rig to a total depth of 6,400 feet, was not production tested. However, it said extensive logging and core samples from the well will help determine the size of the Goliat find.

Eni, which owns a 65 percent share of the field, is already evaluating ways of developing what would be a pioneering oil field in the Barents Sea that Norway shares with Russia. The state-controlled Norwegian oil company Statoil ASA has a 20 percent share, and the small Norwegian oil company DNO has 15 percent.

Goliat is about 30 miles southeast of Statoil's Snoehvit natural gas field, which is slated to become the first petroleum field to start up in the Barents Sea at the end of this year.

—THE ASSOCIATED PRESS

EXPLORATION & PRODUCTION

Engineering firms hit with lawsuit

Two years after one of the most destructive fires in the Alberta oil sands wiped out an average 115,000 barrels per day of production over eight months, operator Suncor Energy has filed lawsuits against some of the leading engineering firms in the sector.

It is claiming C$630 million in what is thought to be the largest suit in the history of the oil sands after a blaze shut down one of two upgraders.

Suncor alleges in its statement of claim that the fire originated with one of two nozzles connected to a fractionator that holds bitumen, heavy oil and natural gas at a temperature of about 380 degree Celsius and separates the oils.

The defendants include Bantrel and Bechtel Group, the leading firms behind Suncor's Millennium expansion.

Also being sued are Dacro Industries of Edmonton, Fluor Canada and Montreal-based SNC Lavalin.

The action is being taken by Suncor on behalf of its insurance companies, from whom it was awarded C$979 million to cover the loss of production following the fire on Jan. 4, 2005.

Suncor also collected C$148 million from property loss insurers to offset repairs.

Suncor: fire started in nozzle

Suncor alleges in its statement of claim that the fire originated with one of two nozzles connected to a fractionator that holds bitumen, heavy oil and natural gas at a temperature of about 380 degrees Celsius and separates the oils.

It claims the defendants should have known that the nozzle was not, as it should have been, clad and lined with stainless steel.

As a result, severe corrosion, erosion and thinning of the nozzle occurred, creating a "substantial risk of fire."

But the engineering firms failed to warn Suncor of the "dangerous defect," Suncor claimed.

In earlier oil sands related lawsuits, Shell Canada and its partners were paid C$220 million for loss of profit stemming from a 2003 fire that affected start-up production at its Athabasca project for four months.

—GARY PARK

● EXPLORATION & PRODUCTION

BP: 4Q production unlikely to change

Company expects final figures to mirror third quarter; problems include reduced Prudhoe output, delays at Gulf's Thunder Horse

THE ASSOCIATED PRESS

BP, Europe's second-largest oil company by market value, said Jan. 9 that production in the fourth quarter is unlikely to change compared with the previous three months, following more than a year of declining output.

The company expects to report production of 3.82 million barrels of oil equivalent per day in the quarter ended Dec. 31, slightly higher than the daily average of 3.816 million barrels in the third quarter, BP said in a trading update. In the fourth quarter last year, production was 4.022 million barrels of oil equivalent per day.

The company has been hit by a series of problems, including the temporary closure of operations at the Prudhoe Bay oil field in Alaska and delays to the opening of the key Thunder Horse platform in the Gulf of Mexico.

BP said production levels had been affected by weather-related delays in Alaska, unusually low seasonal gas demand and a quota cut by the Organization of Petroleum Exporting Countries.

Analyst: report in line with expectations

Brendan Wilders, an analyst at Oriel Securities, said the report was in line with expectations, although some had expected daily production closer to 4 million barrels.

"There's a list of new excuses, but no real surprises," Wilder said.

Shares in BP fell 2.7 percent to 53.75 pounds ($10.39) on the London Stock Exchange. They have lost about 20 percent of their value since April, following on a series of problems starting in 2005 when an explosion at its Texas City refinery killed 15 workers.

BP also said the average price of a barrel of Brent, the U.K. North Sea crude benchmark, was $59.60 a barrel in the fourth quarter, the first decline in a year and a drop of 14 percent from $69.60 in the third quarter.

The company said output increased after the company conducted maintenance in the North Sea and Alaska, but those gains were offset by delays in Alaska loadings and low demand for gas.

Prudhoe output back to 400,000 bpd

Output from the Prudhoe Bay oil field in Alaska had returned to 400,000 barrels a day by the end of the third quarter, BP said, after half of that amount was shut down in August after pipeline corrosion and a small oil spill were discovered.

The startup of the Dalia offshore oil field in Angola, in which BP has a 16.67 percent stake, was delayed from September to mid-December by Total SA, which operates the field. The Dalia field is expected to produce 240,000 barrels per day in the first half of this year.

BP has said it expects to produce more than 800,000 bpd from the Azeri-Chirag-Guneshli fields in Azerbaijan, in which it owns a 34.1 percent share. Media reports had suggested that production had temporarily fallen by around 40 percent in early December due to a power failure on an offshore platform.

The company said in the statement that it expects a steep decline in refining margins across most regions in the fourth quarter. Margins were the tightest at BP's U.S. Midwest and Gulf Coast plants.

Figures for the full year will be published Feb. 6. ●

continued from page 4

AOGCC

lasting more than an hour, and looks at trends in events that last less than an hour. Pilot-purge gas is reviewed based on historical trends, but "without any baseline to assess what is necessary for facility operation."

The commission said there is no engineering review by its personnel of the systems in use, "essentially forcing gas disposition decisions to be made based on historical trends and without any way to validate the actual flaring/venting needs for an efficiently running production processing system."

It cannot currently "determine what constitutes an acceptable volume of gas released (flared or vented), what volume of gas is necessary for the efficient operation of the flare system, and what is necessary for proper lease use."

What the commission wants from this contract is "a scoping study of natural gas disposition practices and their regulation."

It said the goal is "to outline a detailed plan for evaluating and potentially revising the AOGCC's gas disposition regulations."

Equipment capabilities to be studied

The commission said the evaluation "will include identification of equipment and equipment capabilities involved, delineation of reasons for flaring and venting, and the assessment of operational considerations, such as leak detection, process safety valve performance, measurement of gas diverted to flare, etc., that are integral to the gas disposition decisions."

It expects the scoping report to include an assessment of the effectiveness of gas disposition practices used by operating companies.

The commission said it expects the contract to be awarded in March and to be completed by the end of August. ●

PIPELINES & DOWNSTREAM

Utah company in Canada refinery mix

By GARY PARK

For Petroleum News

A Utah-based resource conglomerate has emerged as yet another candidate to establish Atlantic Canada as a new North American refining center.

Headwaters has confirmed it is in preliminary discussions with the Nova Scotia government to build a refinery in the Strait of Canso at the same time it is developing a technology to improve the upgrading of heavy oil to lighter transportation fuels.

Although the company has no refining experience and is reluctant to inflate hopes, it is being touted as a serious player by government and industry leaders in Nova Scotia.

Premier Rodney MacDonald told reporters that talks are under way with a U.S. company he declined to identify to build a refinery in the Strait of Canso, a deepwater, ice-free waterway.

He said the area has ample vacant industrial land, including a site near Anadarko's stalled liquefied natural gas project at Bear Head.

The discussions represent a quick turnaround from October, when Nova Scotia's search for companies interested in building a refinery was derailed when Irving Oil started exploring the feasibility of doubling the size of its Saint John, New Brunswick, refinery complex to 600,000 barrels per day.

That dashed the hopes of the Nova Scotia government and Nova Scotia Business, a private development agency, who had held discussions with companies in Canada and the United States.

Headwaters reports successful commercial run

Headwaters, which posted revenues of about $1 billion in 2006, has a stable of companies working on products, technologies and services to the energy, construction and home improvement industries.

In a separate announcement Jan. 5, Headwaters reported a third successful commercial run of its HCAT technology which is targeting a breakthrough in the refining of heavy petroleum feedstocks.

The latest two runs took place at a commercial heavy oil hydrocracking unit located at a "major" unidentified North American refinery.

Craig Hickman, president of Headwaters Heavy Oil, said in a statement that the HCAT catalyst performed consistently with Headwaters' expectations.

The company did not disclose its next moves or whether the technology might have a role in any Nova Scotia refinery.

In addition to the Irving refinery expansion, Newfoundland has two projects on the table — a 300,000 bpd plant by Newfoundland and Labrador Refining and a possible C$700 million expansion of the Come By Chance refinery, now owned by Harvest Energy Trust, to produce the RBOB blendstock which is in high demand since the U.S. banned the use of MTBE as a gasoline additive. ●

FINANCE & ECONOMY

Forest buys Houston Exploration in $1.5B deal

Company antes up cash and stock, making fifth acquisition in three years, securing onshore natural gas in Texas and Rockies

By RAY TYSON

For Petroleum News

Denver-based exploration and production independent Forest Oil, for the fifth time since changing its growth strategy three years ago, has gone to the acquisition well to secure and expand its U.S. onshore natural gas positions, primarily in Texas and the Rocky Mountains.

This time Forest is pursuing E&P independent Houston Exploration in a friendly stock-and-cash deal valued at $1.5 billion that calls for Forest to pick up about $100 million in Houston debt, bringing the total to $1.6 billion. It represents Forest's largest acquisition to date.

"This is a significant transaction and major step for Forest Oil," Craig Clark, Forest's chief executive officer, said in a Jan. 8 conference call with industry analysts explaining the deal. "We're firmly entrenched as a North American producer with multiple growth platforms — a huge contrast to where we were three years ago."

Houston Exploration and Forest have gone through similar transitions, "with an asset base moving from offshore to onshore," Clark added, noting last year's successful spin-off of Forest's Gulf of Mexico subsidiary to Mariner Energy.

Reduction in exposure began three years ago

Three years ago, under new management with Clark at the head, Forest began reducing its exposure to frontier exploration and began to concentrate more on less risky ventures closer to home and reducing costs. Clark said then the company would continue to look for acquisitions near Forest's existing properties.

So, it comes as no surprise that Forest said it now intends to sell its Alaska assets, which presumably include the company's ill-performing offshore Redoubt Shoal oil field in Cook Inlet, to help pay down $600 million of $1.9 billion in total Forest debt, at least in part stemming from the pending Houston Exploration acquisition. (See related story on page 1 of this issue.)

"In order to reduce our leverage and to further narrow our geographic focus, we will seek to sell our Alaskan entity in 2007," Clark said in a prepared statement.

David Keyte, Forest's chief financial officer, said during the conference call that Forest intends to use the same cost-reducing tactics with Houston Exploration that it has with other recent acquisitions such as Wiser Oil, including plans to "weed out underperforming properties."

Houston Exploration and Forest have gone through similar transitions, "with an asset base moving from offshore to onshore." —Craig Clark, Forest's chief executive officer

"You can expect this kind of a model to be employed in the first year of operation," Keyte told analysts. "Forest's cash-cost structure should be reduced by 10 to 15 percent with the combination."

The addition of Houston Exploration would increase Forest's proved reserves from 1.340 trillion cubic feet of natural gas equivalent to 1.995 tcfe.

Capital expenditures to be decreased

Forest said it intends to decrease overall capital expenditures in the combined company and to reallocate capital expenditures being spent on Houston Exploration assets. Under Forest's pro forma business plan, 2007 capital expenditures for the combined company would be about $900 million, and 2007 estimated daily production would be around 540 million cubic feet of gas equivalent, up from Forest's current average daily output of about 313 million cfe.

The acquisition, which would add in excess of 3,200 drill sites to Forest's existing inventory, also would create a highly concentrated and complementary set of oil and natural gas assets focused in all regions of Texas. Furthermore, Houston Exploration's assets are located in tight gas sand basins in which Forest has extensive experience, the company said.

Specifically, the combined Forest-Houston Exploration positions in the South Texas and Greater Carthage Areas (East Texas) represent two premier operated core tight gas assets with significant exposure to recent horizontal drilling opportunities, Forest said.

Additionally, the new company would provide a strong production base and acreage position in the Arkoma Basin that is near the emerging Fayetteville Shale play.

Moreover, the combination increases Forest's exposure to the Rockies with a significant acreage position and about 1,900 identified drilling locations in the Denver-Julesburg Niobrara, Forest said.

Deal has unanimous approval of boards

The boards of directors of Forest and Houston Exploration have each unanimously approved the transaction. The deal is subject to regulatory and shareholder approvals, but is expected to close in this year's second quarter. Jana Partners, holder of 14.7 percent of the outstanding shares of Houston Exploration, already has agreed to vote in favor of the transaction.

Jana, said to be one of the largest "activist" hedge funds, offered to buy Houston Exploration last June for $62 a share in what analysts said appeared to be an effort to put the company into play, or generate buyer interest. However, that was before natural gas prices fell by nearly half

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● LAND & LEASING

Exxon files more Pt. Thomson paperwork

Gives court supplemental points on appeal, asking that reconsideration and original DNR commissioner's decision be reversed

By KRISTEN NELSON

Petroleum News

Exxon Mobil Corp., the Point Thomson unit operator, has filed supplemental points on appeal in its suit against the Alaska Department of Natural Resources over the department's November termination of the unit.

Acting DNR Commissioner Marty Rutherford said in a Dec. 27 reconsideration decision that Point Thomson was terminated because "DNR is entitled to terminate a unit which has been known to contain massive hydrocarbon reserves for more than 30 years, but which has never been put into production, when the lessees of the state oil and gas leases making up the unit unequivocally state that they still cannot find a way to put the unit into production."

Acting DNR Commissioner Marty Rutherford

The second primary ground for termination, Rutherford said, was failure to submit an acceptable plan of development.

Rutherford also agreed with Menge's decision that certified wells were not a basis to hold leases, calling the long-standing policy "poor policy."

"The new policy is in conformance with existing statutes, regulations and agreements. Certified wells will still play a role in appropriate circumstances," Rutherford said.

ExxonMobil filed suit Dec. 22 in Alaska Superior Court, appealing Menge's Nov. 27 finding terminating the unit.

Points in Menge's finding were appealed to Rutherford, who upheld the decision on reconsideration.

In a Jan. 5 filing, ExxonMobil asked the court to reverse the reconsideration decision, as well as the original decision, or to remand the matter to the commissioner, "with instructions to make a new and different decision."

Other major Point Thomson unit owners, BP, Chevron and ConocoPhillips, have also appealed.

Supplemental points addressed

In addition to points made in its Dec. 22 filing, Exxon made a number of supplemental points Jan. 5.

It said the DNR commissioner "erred in finding that there were no certified wells" in the Point Thomson unit, "in revoking previous certifications retroactively," in finding there were no wells in the unit "capable of producing hydrocarbons in paying quantities" and in terminating the Point Thomson unit.

Exxon said the decisions made by the commissioners "amounted to an abuse of discretion, were entirely unsupported by the evidence in the record, constituted an error of law," breached the Point Thomson unit agreement "and the covenant of good faith and fair dealing" and violated the rights of ExxonMobil and the other Point Thomson owners "under the takings, due process, equal protection and contracts clauses of the Constitutions of Alaska and the United States."

Exxon: lack of rule making

Listing specific points, Exxon said the commissioner erred in determining that the Point Thomson unit could be terminated on the grounds that it was not yet in production, and also erred in determining the unit could be terminated on the grounds that the lessees have said it could not be put into production.

State regulations deny the commissioner "the power to terminate a unit agreement without judicial proceedings if the unit contains wells certified as capable of producing oil and gas in paying quantities," Exxon said.

Exxon said the reconsideration decision admits DNR "has changed and intends to change its longstanding policy and established construction of the law with respect to certifying wells as capable of producing oil and gas in paying quantities," and said DNR "may not make such a change in the law without rule-making under the Alaska Administrative Procedure Act."

Exxon also said the reconsideration decision "admits that the principles set forth in that decision" will govern Point Thomson "but will not be applied to other leases and other units. Such a decision is fundamentally lawless, in that it seeks to apply different rules to parties who are similarly situated. It is discriminatory, lacking in due process, and a violation of the equal protection clauses of the Constitutions of Alaska and the United States."

Discretionary determination also an issue

Exxon said the reconsideration decision "indicates that whether a lease will be held beyond its primary term will depend, not on the terms of the lease which provide that it may be held if there is a well on the lease capable of producing oil or gas in paying quantities, but on the Commissioner's discretionary determination as to whether a lessee has made an 'appropriate commitment' to explore, produce or otherwise develop oil and gas leases." Exxon said this is "directly contrary" to lease terms, "and if upheld would amount to an impairment of the obligation of contract and a taking or confiscation of rights granted to the lessees under the leases, in violation of the contracts and due process clauses of the Constitutions of Alaska and the United States."

Exxon also argued that the commissioner erred in the issues properly before the commissioner for decision, erring "in holding that issues on which no appeal had been taken from the decision of the Director of the Division of Oil and Gas were nevertheless properly before the Commissioner for decision on the ground that they were discussed in public comments of entities who took no appeal from the Director's decision." ●

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FOREST

between August and October, dragging down Houston Exploration's share price. Now Jana said Forest can improve the assets.

Jana appears satisfied that it will end up with some cash plus shares in what it believes to be the better-run Forest Oil, rather than have to pay up to buy all of Houston Exploration to see its policies changed.

Upon completion of the transaction, it is anticipated that Forest shareholders would own about 73 percent of the combined company, and Houston Exploration shareholders would own around 27 percent.

Forest expected to create Houston business unit

Forest management and its board of directors will continue in their current positions with Forest, and it is anticipated that Forest will create a new business unit to be located in Houston.

Under the terms of the agreement, Houston Exploration shareholders would receive 84 cents per share of Forest common stock and $26.25 in cash for each share of Houston Exploration stock outstanding, or an estimated 23.6 million shares of Forest common stock and cash of $740 million. This represents $52.47 per share received by the Houston Exploration shareholders based on the closing price of Forest shares on Jan. 5.

The exact amount of the total cash and stock consideration to be received by each Houston Exploration shareholder would be determined by elections and an equalization formula, Forest said, adding that it is anticipated that the transaction will be tax free to Houston Exploration and the stock portion of the deal also would be received tax free.

Forest said the cash side of the acquisition is expected to be financed with a new $1.4 billion revolving credit facility underwritten by JP Morgan Chase Bank, N.A. ●

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LNG

made on the supply issue.

"We are not in any kind of talks on these projects with the sellers, and haven't made any decision," a Tepco spokesman was quoted by Dow Jones. Tepco buys 920,000 metric tons of LNG annually from Alaska, as well as 130,000 metric tons from Indonesia.

Tepco and Tokyo Gas Co. Ltd. have bought essentially all of the LNG from the Nikiski facility since it started production back in 1969.

Two ships that each carry 40,000 metric tons of LNG continually shuttle from Nikiski to Japan, taking the plant's annual production of 1.7 million metric tons of LNG, produced from the 220 million cubic feet of natural gas that flows in daily.

No shutdown plans

The owners of the Nikiski LNG plant say they aren't ready to give up on the facility, even though it's essentially outmoded and small by current standards.

"We have a contract through 2009. Nothing definitive has been determined after 2009. ConocoPhillips remains interested in extending exports if circumstances permit," said Dawn Patience of ConocoPhillips, which owns 70 percent of the plant and operates it. Its 70 percent share of the production comes from the North Cook Inlet field.

The other plant owner, Marathon Oil Co., may have a more compelling reason to want the facility to soldier on past 2009. While ConocoPhillips isn't active in Southcentral Alaska exploration, Marathon has drilled more than 50 wells in the area since 1998, and has had some notable successes.

"We've invested many millions in development and drilling activities," says Paul Weeditz, the company's director of external communications. "The Cook Inlet region, we believe, holds substantial resource potential — but it will require significant investment to realize that potential."

And that investment may be contingent on a ready market for natural gas, which the LNG plant provides by consuming more than a third of the gas produced in the region, day after day, year after year.

"It's an incredibly important part of the economy there. Beyond simple exports of LNG, it plays an important part of the industrial base of natural gas," Weeditz said. "We've been asked quite a bit about the future of the facility in 2009. What we've said is we're working with our partners to examine the facility, what our options are."

Permit problematic

But even renewal of the export license may not be easy. When the two companies went to the Department of Energy in 1999 to get an extension of the license from 2004 to 2009, objections came from utility Enstar Natural Gas Co., as well as from Aurora Gas Inc., Unocal and Fairbanks Natural Gas LLC. The export license depends on a determination that there is surplus gas beyond what is needed for domestic use, and the objecting companies disputed that.

The next round could be challenging because projections by the Alaska Department of Natural Resources indicate a steep decline in production from existing Cook Inlet fields after this year. Most of the huge fields discovered in the 1960s are starting to play out.

On top of that, there are concerns that the plant itself is reaching the end of its useful life. A report last summer commissioned by the Alaska Natural Gas Development Authority noted that the big combustion gas turbines driving the compressors have been in service for 37 years, and are likely to need replacing in the next five years. Does it make economic sense to patch the current system, build a new state-of-the-art plant, or dismantle it?

For the 58 workers at the Nikiski plant, future employment could depend on major new discoveries of gas in the Cook Inlet region, or a spur line carrying natural gas from the North Slope to Southcentral Alaska. Even a North Slope spur could be tough on the plant's economics, given the netbacks the producers would want for their gas, plus transportation to Nikiski and then to the eventual markets.

Closer suppliers

The Japanese utilities that signed the long supply contracts back in the 1960s that resulted in construction of the Nikiski plant are now diversifying their supplies, and are finding sources much closer to home. They still like dependability, however, and typically ink agreements for a fifth of a century or more.

The LNG from Nikiski accounts for just 6 percent of the 16 million metric tons of LNG consumed each year by Tokyo Electric Power. Tepco signed a 22-year contract in 2004 to buy at least 1.5 million tonnes of LNG annually, starting in 2008, from the Sakhalin 2 venture, now led by Russia's Gazprom.

It has long-term contracts with other sources, including Australia's North West Shelf project, Malaysia, Qatar, Brunei and Abu Dhabi, along with the Alaska and Indonesian suppliers. Tepco expects to need the same 16 million tonnes of LNG in 2009 that it is using this year. The utility says it already has contracts in place for the 2009 supplies.

Japan imports a total of 58 million tonnes of LNG annually, and is expected to consume 80 million tonnes by 2020. Korea is the world's second-largest LNG buyer, with current consumption of more than 22 million tonnes a year and a growth rate of about 5 percent annually. ●

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INSIDER

Begich invited Markey to visit the Arctic coastal plain and to tour "cutting-edge" oil field technologies. He also offered his services in helping to draft a "strong" national energy policy.

—ROSE RAGSDALE

Governor names Hartig to head DEC

GOV. SARAH PALIN HAS NAMED Larry Hartig as commissioner of the Department of Natural Resources.

"Larry is the perfect Alaskan for this position," Palin said Jan. 10. "His deep Alaska roots coupled with in-depth experience with environmental issues in the private sector will serve Alaskans well. I have complete confidence that Larry will serve the best interests of the state, protecting our environment, as we enter this crucial period of resource development. Larry wants to get a gas line for Alaskans and his oil and gas experience which dates back to the early 70's will add to the solid foundation of this administration."

Hartig an Anchorage attorney

Hartig is an attorney who actively practices law in the areas of environmental, natural resources, and real estate law matters. His professional legal experience includes the acquisition of exploration and mineral rights for mining and oil and gas companies, purchase agreements, leases and other transactional agreements. Hartig has also provided legal guidance relating to environmental compliance and cleanup of contamination and assisting clients in obtaining air, water, and other permits for natural resource development.

He has been in private practice in Anchorage since 1983.

"I was very pleased to get the governor's call," said Hartig. "I look forward to serving Alaskans and combining my experiences to further help guide the state in its resource development."

Hartig has been a member of the State Board of Forestry since 1994. He is a member of the Alaska Mining Association, a director of the Resource Development Council and an active board member of AMEEF, the Alaska Mineral and Energy Education Fund.

Alaska governor to speak at Meet Alaska

ALASKA'S NEWLY ELECTED GOVERNOR, Sarah Palin, has accepted an invitation from the Alliance to speak at Meet Alaska 2007.

The state's most prestigious annual energy conference, Meet Alaska will be held in on Jan. 19 at the Sheraton Anchorage Hotel.

The Alliance's president, Jim Palmer, will introduce the governor who will speak at 8:50 a.m.

For more information about the conference visit the Alliance's web site at www.alaskaalliance.com or call 907 563-2226. ●

PIPELINES & DOWNSTREAM

Trans-Alaska pipeline back in operation

The trans-Alaska oil pipeline was back in full operation Jan. 10, one day after a loose fitting on a secondary pipe caused a leak that shut down the 800-mile pipeline for hours, with some 900,000 barrels per day flowing through the line.

Two tanks at Pump Station 1 on the North Slope hold 210,000 barrels each, said Alyeska Pipeline Service Co. spokesman Mike Heatwole.

"We are running at higher rates for a little while to just get us back to the normal average of about 800,000 barrels," Heatwole said.

The pipeline was shut down for about six hours Jan. 9. The process to restart it began at 2:45 p.m., after work was completed to tighten a loose fitting on a pipe at a valve in the Brooks Range in northern Alaska.

The spill was discovered by a worker doing snow removal at Remote Gate Valve 32 south of Atigun Pass. It is one of 178 mainline valves in the pipeline system used to regulate the flow of oil and shut down segments of pipe.

About 500 gallons of oil spilled on a gravel access road at the site, Heatwole said.

Alyeska was assembling a team to try to determine how the fitting became loose. It was loose by a turn and a half, Heatwole said.

The Alaska Department of Environmental Conservation and the Joint Pipeline Office, a state and federal agency that oversees pipeline operations, were being invited to join the investigation, he said. Cleanup crews were at the site Jan. 10.

—THE ASSOCIATED PRESS

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

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

Business Spotlight

COURTESY PHOTO

Scott Stowell
Assistant Maintenance Manager

Usibelli Coal Mine Inc.

Usibelli Coal Mine, Alaska's only operating coal mine, produced some 1.5 million tons per year in 2004 and 2005 to supply coal to six Alaska power plants and for export to South Korea and Chile. Its corporate goals are to deliver a quality product on time and provide a safe, secure environment for all Usibelli employees.

Scott Stowell joined Usibelli over 30 years ago and well knows the equipment, mine, shop and warehouse. He's taken on environmental compliance work and often filled in for the maintenance manager. Scott's recent promotion to assistant maintenance manager recognizes his expertise and professionalism. Born in Alaska, Scott is married, and loves to cook and restore classic cars.

GOVERNMENT

Murkowski named ranking member of U.S. Senate energy subcommittee

Sen. Lisa Murkowski, R-Alaska, was selected to serve as the ranking member on the subcommittee on energy for the U.S. Senate committee on energy and natural resources, Murkowski's office said Jan. 11.

The subcommittee's jurisdiction includes oversight and legislative responsibilities for the following: coal and synthetic fuels research and development; nuclear and non-nuclear energy commercialization projects; nuclear fuel cycle policy; DOE National Laboratories; global climate change; new technologies research and development; nuclear facilities siting and insurance program; commercialization of new technologies including, solar energy systems; federal energy conservation programs; energy information; liquefied natural gas projects; oil and natural gas regulation; refinery policy; coal conversion; utility policy; strategic petroleum reserves; regulation of trans-Alaska pipeline system and other oil and gas pipeline transportation systems within Alaska; Artic research and energy development; and oil, gas and coal production and distribution.

Sen. Lisa Murkowski

"As we look to increase and diversify energy development in the United States, I will use my position as ranking member of the energy subcommittee to advocate for Alaska's role in meeting our energy needs," Murkowski said in a press release.

"Alaska has more to offer than oil on the North Slope. We are the Saudi Arabia of coal, and I will continue to promote investments in new clean coal technologies to find ways to bring this resource to market. Additionally, Alaska is rich in sources of renewable energy. From the wind in the west — to our tremendous tides in Southcentral — to our geothermal springs throughout the state, Alaska has potential to be a leader in alternative energy development. We must invest in the technologies necessary to develop these resources."

—PETROLEUM NEWS

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FOREST

Chief Financial Officer David Keyte said during the Jan. 8 teleconference.

The timing of the "for sale" sign going up in Alaska would appear to depend on progress with the Houston Exploration takeover — Forest hopes that the sale will be completed in the second quarter of 2007.

"Our goal is to reduce our long term debt from initial estimates of $1.9 billion to $1.3 billion by year end, but a lot of this depends on timing and when we begin to manage the (restructured) business," Keyte said.

Forcenergy purchase in 2000

Forest entered the Alaska oil and gas business in 2000 with its purchase of Forcenergy Inc. That purchase included the Redoubt Shoal and West McArthur River oil fields and a number of oil and gas prospects in the Cook Inlet basin. After valiant efforts to bring the difficult Redoubt Shoal field on line the company has been producing oil from that field through the Osprey offshore platform.

Forest is also operator for the Kustatan and West Foreland fields, and has a 53.2 percent working interest in the Chevron-operated Trading Bay field. The company owns a 20.79 percent interest in Aurora Gas's Three Mile Creek gas field. All of these fields lie on the west side of the upper Cook Inlet.

In addition to Redoubt Shoal, some acreage acquired from Forcenergy lay offshore in the central upper Cook Inlet.

On the east side of the inlet, near Anchor Point in the southern Kenai Peninsula, Forest has a 12.5 percent interest in the offshore Cosmopolitan prospect, where operator Pioneer Natural Resources is evaluating possible oil and gas production.

Forest also holds a small working interest in the Prudhoe Bay field on the North Slope.

The company inherited from Forcenergy an interest in a state exploration license in the Copper River Valley. Part of that license area was subsequently converted into an oil and gas lease, in which Forest holds a 50 percent interest. Operator Rutter & Wilbanks has been testing for gas in a well drilled near Glennallen in that lease.

Growth opportunities

Despite disappointing production results from the Redoubt Shoal field Forest was continuing to seek growth opportunities in Alaska, Leonard Gurule the company's senior vice president for Alaska operations, told Petroleum News in October 2003. In fact, the company had just acquired two exploration licenses in the Susitna basin.

In November 2004 Forest purchased 17 tracts on the west side of Cook Inlet west of Point MacKenzie in an Alaska Mental Health Trust lease sale. The company also picked up some tracts in the State of Alaska's Cook Inlet areawide lease sale in May 2005.

In February 2005 Forest announced that it had two successful gas wells onshore in the Cook Inlet area of Alaska, the West Foreland No. 2 and the Aurora Gas-operated Three Mile Creek Unit No. 1.

"These wells are the first of our new onshore gas focus in the Cook Inlet area," Clark said. "We enjoy a large acreage position surrounding these discoveries so we have a lot of running room. The Cook Inlet acreage is near existing infrastructure, so the time and cost it takes to hook up to sales is minimal."

And in 2005 the company drilled the Middle Lake unit 1A re-entry well in one of its Susitna basin license areas. That well was completed and suspended in 2006.

In a March 2006 analysts' conference Clark confirmed a strategy of expanding Forest's Alaska onshore natural gas production. Clark said that his company sees Cook Inlet onshore natural gas as one of its "up and comer" areas where there is current production, but where further exploration is needed. Alaska's Susitna Valley fits within the company's pure exploration areas, termed "flyers," Clark said.

Gurule said that a comprehensive study of geologic information from existing wells and from seismic data had resulted in Forest making substantial changes to its Cook Inlet lease position, with a policy of only holding onshore acreage with leads and prospects.

"When we started 18 months ago we had an onshore acreage position that was about 30,000 acres," Gurule said. "Today we have an onshore acreage position that's 101,000 (acres) — 96 percent of that's undeveloped."

That's a turnover in acreage of about 98 percent, he said.

"We basically got rid of everything we had and acquired almost all new land onshore," Gurule said.

Offshore interests

But Forest still holds some offshore Cook Inlet acreage. In addition to acreage acquired with the purchase of Forcenergy in 2000, Forest made the highest per-acre bid at a state Cook Inlet oil and gas lease sale in May 2006, bidding $45.51 an acre,

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FOREST

a total of $116,505.60, for a tract at North Middle Ground Shoal.

And Forest applied to Alaska's Division of Oil and Gas to form a unit at its offshore Corsair prospect. Corsair lies on the same anticline as ConocoPhillips' North Kenai gas field, the known oil pool in Renaissance Alaska's Northern Lights prospect and Escopeta's Kitchen prospect.

In its Corsair unit application Forest said it had "identified large seismic amplitude anomalies located in the center of the Upper Cook Inlet approximately 12 miles southwest of the North Cook Inlet field." The prospect occurs in a feature some 2.5 miles wide and nine miles long that

In 2003 Forest said that pre-drill analysis indicated Corsair could contain 137 million barrels of oil, 79 million barrels in the Tyonek formation and 58 million barrels in the Hemlock formation, along with as much as 480 billion cubic feet of natural gas.

"lies on structural trend with the North Cook Inlet field."

In 2003 Forest said that pre-drill analysis indicated Corsair could contain 137 million barrels of oil, 79 million barrels in the Tyonek formation and 58 million barrels in the Hemlock formation, along with as much as 480 billion cubic feet of natural gas.

The exploration of offshore prospects such a Corsair would require a jack-up rig, something Escopeta and Forest propose in their unit exploration plans. Danny Davis, president of Escopeta, has been working to bring a jack-up rig to Cook Inlet.

But plans for Corsair and other Forest prospects are now set to pass to some other company.

Although, with the ink barely dry on Forest's Jan. 9 announcement of its plans for Alaska divestiture, it's too early to do more than speculate on who might be interested in purchasing Forest's Alaska portfolio. There are some obvious contenders with existing positions in the Cook Inlet area. Perhaps XTO, with its strategy of buying and developing known hydrocarbon pools, might be interested in the more mature field positions. Or a company like Renaissance Resources Alaska might see an opportunity to build on its Alaska interests. And then Chevron seems set on expanding its Cook Inlet operations.

That all remains to be seen. ●

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MORATORIUM

Last sale in 1988

The last North Aleutian lease sale occurred in 1988. But in the wake of the Exxon Valdez oil spill in Prince William Sound and amid concerns about potential impacts on the prolific Bristol Bay salmon fishery, the federal government bought back the leases.

In 1998 President Bill Clinton withdrew several offshore regions, including the North Aleutian and central Gulf of Mexico areas, from consideration for oil and gas leasing until 2012.

Starting in the early 1980s Congress included language in the annual Department of the Interior appropriations bill that prevented the department from conducting leasing in areas under federal moratorium. President Bush signed legislation in 2003 that removed the U.S. Congress objections to oil and gas drilling in the federal waters of Alaska's Bristol Bay. However, the presidential moratorium on Bristol Bay leasing remained in effect at that time.

President Bush's Jan. 9 action has modified President Clinton's 1998 withdrawal, to release the North Aleutian and central Gulf of Mexico areas from the moratorium.

Prospective basin

The North Aleutian basin, also known as the Bristol Bay basin, that lies under the area now targeted for an MMS lease sale contains somewhat similar geology to the petroleum province of the neighboring upper Cook Inlet. The Bristol Bay basin shows a high potential for the discovery of natural gas, with the potential for some oil resources in the deeper sections.

In a 2006 assessment of the offshore components of the basin MMS geologists estimated the possibility of 753 million barrels of technically recoverable oil and condensate, and 8.6 trillion cubic feet of technically recoverable natural gas in the basin.

Decline in fishery

Since the placement of the federal moratorium on Bristol Bay oil and gas leasing, the salmon fishery in the region has declined. And the need to generate new income has caused the Bristol Bay communities to take a renewed interest in the potential for an oil and gas industry in the region. But the importance of fishing both to the cash economy of the region and to the traditional subsistence way of life caused continued opposition to offshore development. Communities have, however, favored onshore development.

In October 2005 the State of Alaska held an areawide lease sale onshore the Alaska Peninsula and in state waters on the north side of the peninsula, along the south side of Bristol Bay. At that sale Shell and Hewitt Mineral Corp. purchased some leases near Port Moller, adjacent to the deepest part of the Bristol Bay basin.

And since the sale Shell has expressed an interest in offshore exploration in the Bristol Bay area (MMS has also indicated that several other companies are interested in the area).

"One area that could provide relatively direct access to the U.S. and Asia-

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MORATORIUM

Pacific LNG market is Bristol Bay," said Rob Ryan, Shell Exploration and Production's vice president for corporate affairs, in January 2006. "We look forward to the opportunity to one day acquire seismic and explore in the shallow ice-free waters of this prospective basin. We believe it can be done with no adverse impact on the fisheries or the marine mammals."

In February 2006 MMS announced that it would include a study of the North Aleutian basin in its draft 2007-2012 outer continental shelf leasing plan. And, in response to requests from Bristol Bay communities, the agency subsequently agreed to reduce the area that would be available for leasing from the 33 million acres of the complete North Aleutian planning area to an area of about 5.6 million acres northwest of Port Moller. That reduced area includes the deepest and most prospective part of the Bristol Bay basin.

Guarded local support

And communities close to the area that would be open for leasing seem to support the lease sale plan, albeit with some strong caveats about protecting the environment and the fisheries. Bob Juettner, administrator for the Aleutians East Borough, has told Petroleum News that the reduction in the proposed sale area is a key factor in local support for oil and gas leasing.

A lease sale in the North Aleutian planning area will require an environmental impact statement specific to that sale.

"This is a wonderful opportunity for us to stabilize our economy and bring jobs to the region," Juettner said in a press release from the borough. "But keep in mind our families have centered their lives around commercial and subsistence fisheries for thousands of years. We can't let anything threaten our traditional way of life. Our assembly has been very clear that it will withdraw support if it doesn't feel confident that things will be done right."

In a November resolution, the Aleutians East Borough set out its expectations for safe offshore petroleum development. Those expectations include items such as no offshore loading of tankers, and the prevention of "conflicts with local commercial, subsistence and sport harvest activities."

Juettner also told Petroleum News that the Aleutians East Borough, the Bristol Bay Borough and the Lake and Peninsula Borough are in the process of establishing a memorandum of understanding, setting out the requirements of the three boroughs.

"We want an active engagement in the process," Juettner said

Jeff Currier, borough manager for the Lake and Peninsula Borough, told Petroleum News that his borough also guardedly supports offshore leasing. Currier said, however, that his borough prefers onshore development, because of the potential for increased tax revenues and local employment. Onshore development would also eliminate the possibility of an on-water oil spill.

"We strongly support onshore development," Currier said. "We are guardedly optimistic that offshore development may be doable. … We remain open minded. We want to see this thing progress."

Currier said that the good environmental record of the Cook Inlet oil industry, even using 40-year-old technology, demonstrated that the oil industry can co-exist with fishing. But the borough wants to see what is determined in a Bristol Bay environmental impact statement, he said.

Palin support

Alaska Gov. Sarah Palin's comments on the lifting of the moratorium also included a caveat about protecting the Bristol Bay fisheries.

"It is gratifying that the federal government is again looking north to Alaska to provide the energy our nation needs," Palin said. "Development in the Bristol Bay region could provide the jobs, economic diversification and energy the people of this region need. If we can be sure it will not threaten the fisheries that are the foundation of the region's economy and way of life, I'm all for it."

"We think that it's a very positive move for Alaska and the whole energy picture in the United States," said Judy Brady, executive directory of the Alaska Oil and Gas Association. Brady cited the Cook Inlet, the Gulf of Mexico and offshore Norway as areas where the oil industry has successfully co-existed with the fishing industry. It is possible for Alaska to say yes to both fisheries and oil, Brady said.

But Brady also commented on the importance of the Bristol Bay fishery and pointed out that the lifting of the moratorium marks the beginning of a long environmental process, and that during that process much would be learned about the impact of a lease sale.

Storm of criticism

The president's action has met with a storm of criticism from environmental groups. In addition to Bristol Bay's fish habitat, the region supports marine mammals such as the walrus, harbor seal and sea otter, as well as endangered species including stellar sea lions, humpback whales, fin whales and right whales.

"I am very disappointed with the president's action today," said Bill Eichbaum, managing director and vice president of the marine portfolio at World Wildlife Fund. "Bristol Bay should be off the table for drilling. World Wildlife Fund will now work with Congress to override the president's action and re-instate the Congressional moratorium on oil and gas development in Bristol Bay which was allowed to expire in 2004."

"Opening Bristol Bay to offshore oil and gas development could have devastating impacts to the marine environment and coastal economies," said Eric Sly, executive director of the Alaska Marine Conservation Council.

Environmental process

MMS spokesman Gary Strasburg told Petroleum News Jan. 10 that the agency has involved local communities, as well as local, state and federal politicians in its decision making process.

"We will do whatever is required in the environmental process," Strasburg said. "… We're aware of those concerns."

Strasburg said that MMS would shortly issue a final proposal for its five-year leasing program, including a proposal for North Aleutians lease sales in 2010 and 2012.

"We'll do a final proposal and that should be done fairly soon," Strasburg said. "It will sit for 60 days before Congress and then providing they don't take any actions it will go into effect on July 1 of this year."

A lease sale in the North Aleutian planning area will require an environmental impact statement specific to that sale. Strasburg also confirmed that any pre-sale seismic surveying in the area would have to at least go through an environmental assessment. ●