Petroleum news

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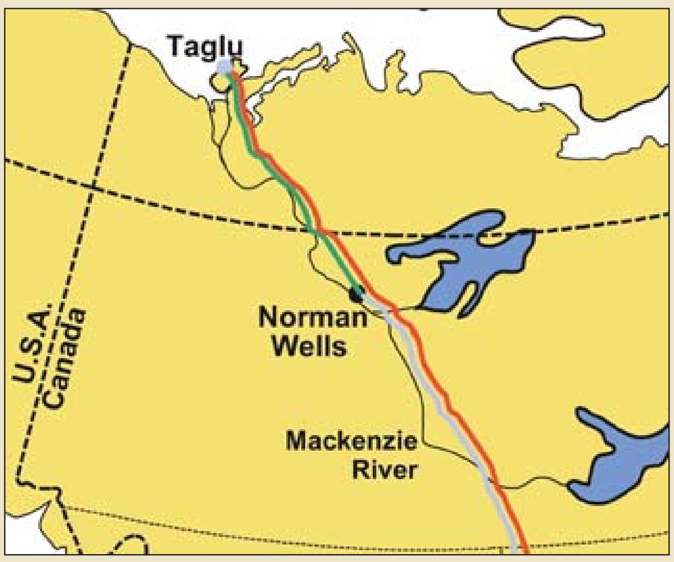
page 6 Income trusts still a hot potato: Goodale fends off accusations



Deh Cho urged to get realistic

The hold-out Deh Cho First Nations got a clear message from Imperial Oil Chief Executive Officer Tim Hearn Dec. 6 that they should not expect a better deal than other aboriginal regions along the planned Mackenzie Valley gas pipeline route.

He said the Deh Cho has a "pretty good model for what is realistic and available" from the land access and benefits agreements reached with the Inuvialuit, Gwich'in and two Sahtu communities.

At a session for analysts and reporters, Hearn said the work accomplished so far should encourage the Deh Cho "to see what is possible."

But the Deh Cho continue to cling to a demand for property taxes from the pipeline — a prospect that has been rejected by the Mackenzie consortium and Deputy Prime Minister Anne

see **DEH CHO** *page 23*

Going once … first public auction of properties in Canada; Itta makes Aiken's position permanent

THE PETROLEUM INDUSTRY'S version of a yard sale has finally found its way to Canada, where the first public auction of properties was held Dec. 1.

The novelty attracted a crowd of about 300, including 140 registered buyers and 10 sellers.

It was organized by investment banker Tristone Capital, which became affiliated with The Oil & Gas Asset Clearinghouse last year through a C$101 million merger with Petroleum Place Energy Advisors.

The clearinghouse is estimated to control about 90 percent of the auction business in the United States.

Tristone had hoped to generate about C$30 million in sales,

see **INSIDER** *page 22*

BREAKING NEWS

3 BP, Unocal execs form Cobalt: New E&P independent run by seasoned 'Dream Team;' targeting Gulf of Mexico

3 B.C. feasts off gas harvest: Province sees C$300 million impact on revenue due to higher natural gas prices

16 Alpine hits new daily high: Total North Slope crude production up slightly

COOK INLET

Boom or bust?

What will it take to prevent Inlet gas output from steep decline?

By **ALAN BAILEY**
Petroleum News Staff Writer

At first glance, things seem to be looking up in Alaska's Cook Inlet gas industry.

New gas supply contracts linked to Lower 48 Henry Hub prices have encouraged companies such as Marathon Oil Corp. and Aurora Gas LLC to explore for gas and bring new gas fields on stream — increased pricing ought to enable Cook Inlet gas exploration to compete with exploration elsewhere. A state areawide leasing program in the Cook Inlet basin has encouraged leasing. And according to the Alaska Department of Natural Resources Cook Inlet gas reserves increased from 2,032.8 billion cubic feet at year-end 2003 to 2,087.5 bcf for year end 2005.

A long-awaited resolution to a dispute regarding access to the Cook Inlet Gas Gathering System that crosses the Cook Inlet means that there's now an interconnected, regulated gas pipeline infrastructure north from Trading Bay on the west side of the Inlet and north from Ninilchik on the east side of the

see **INLET GAS** *page 12*

FORREST CRANE

The implications of a North Slope gas spur line to Southcentral Alaska particularly intrigue Mark Myers, especially if that line were to have … capabilities for bidirectional flow. A spur line could link the Cook Inlet area to North Slope gas and to the Lower 48 gas market, thus fostering a vibrant gas industry in Southcentral Alaska.

WASHINGTON, D.C.

ANWR: The home stretch

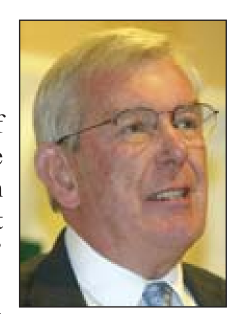
White House, congressional leaders, Stevens team to win coastal plain drilling

By **ROSE RAGSDALE**
Petroleum News Contributing Writer

As the push to open the coastal plain of the Arctic National Wildlife Refuge to oil and gas drilling nears the finish line, key supporters are speaking out in the days leading up to Congress' Christmas recess.

President Bush, who spoke on the strength of the U.S. economy in North Carolina Dec. 5, cited the need to develop ANWR's oil resource in his remarks.

"We've got to produce and refine more crude oil and natural gas here at home in environmentally sensitive ways, and we can do that. The most promising site for energy in America is the Arctic National Wildlife Refuge in Alaska," Bush told a crowd in Kernersville, N.C.



JUDY PATRICK

ROGER HERRERA

Bush has listed oil development in ANWR as a top priority of his energy policy. He reiterated the key facts in the ANWR debate, including the small, 2,000-acre footprint needed for development and little or no impact on the land or wildlife from that development activity.

"I can't tell you how important I think it is for the United States Congress to authorize a pro-growth, pro-jobs, (and) pro-environment exploration of ANWR," Bush added.

Speaking the day before the U.S. House of Representatives reconvened after the Thanksgiving recess in Washington, D.C., Bush apparently timed his

see **ANWR** *page 24*

ALASKA

Alaska lease sales deferred

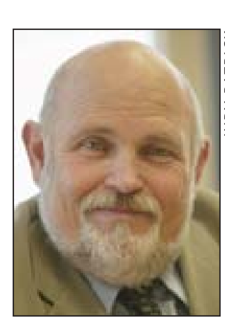
Synergies with gas pipeline contract, ANWR delay North Slope, Beaufort sales

By **KRISTEN NELSON**
Petroleum News Editor-in-Chief

The Alaska Department of Natural Resources has deferred the North Slope and Beaufort Sea areawide oil and gas lease sales, originally scheduled for October, a second time.

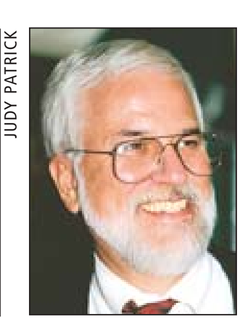
Patrick Galvin, division petroleum land manager, told Petroleum News in response to an e-mail question that Commissioner Mike Menge requested time to familiarize himself with the oil and gas leasing program "and review the proposed terms to be offered in the next North Slope and Beaufort Sea areawide sales."

Once the commissioner has completed his review and notified the division, a 90-day notice is required of the sale date, Galvin said, so the earliest the sales could be held is in March.



JUDY PATRICK

MIKE MENGE



KEN BOYD

First delay announced in July

In July the department deferred the sales to February, saying it wanted to focus industry attention on the Alaska Peninsula areawide sale, being held for the first time, and to spread the work of both participants and staff more evenly. "The Department of Natural Resources has worked hard to evaluate

see **SALES** *page 24*

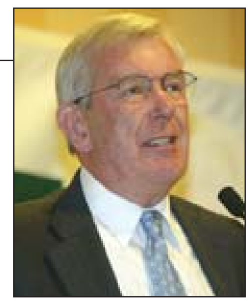
contents

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

ON THE COVER

Boom or bust?

What will it take to prevent Inlet gas output from steep decline?



ANWR: The home stretch

White House, congressional leaders, Stevens team to win coastal plain drilling

Alaska lease sales deferred

Synergies with gas pipeline contract, ANWR delay North Slope, Beaufort sales

Deh Cho urged to get realistic

OIL PATCH INSIDER

1 Going once … first public auction of properties in Canada

22 Itta makes Aiken's position permanent

22 Nabors CEO donates $750,000 to APU

22 Pirtle Bates appointed deputy director

GUEST EDITORIAL

17 DOUG REYNOLDS: Alaska's natural gas strategy

EXPLORATION & PRODUCTION

4 MMS says 31% of U.S. Gulf oil production remains shut-in due to hurricane damage

5 NOAA survey: Barge hit submerged platform

8 Slope tundra opening earliest since '95

8 **More of the same in Canada's upstream**

2005 drilling count expected to top 24,000, beating record of 22,720 set in 2004; 20,161 wells completed in first 10 months

8 Colorado approves some 1,800 new wells

14 Final Nikaitchuq permits expected soon

16 **Alaska North Slope crude output up**

Alpine hits new daily production record with completion of ACX2 facility expansion, allowing production up to 140,000 bpd

20 Canada gains 22 drilling rigs, U.S. down 31 rigs in weekly drilling survey

22 Texas oil, gas production falls; permits up

FINANCE & ECONOMY

3 **Former BP, Unocal execs form new firm**

E&P independent Cobalt looking to enter deepwater Gulf with $500M in the bank, a seasoned 'Dream Team'

6 **Income trusts still a hot potato**

Goodale fends off accusations of leaks; accountant says trusts rife with 'abuses'; others tell investors to brace for challenges

6 Energy trusts on brink of merger wave

7 **Platts: Big oil dominates global energy**

Survey shows dominance of big oil, with leaders amassing $1.9 trillion in 2004 revenues; Devon tops E&P independents

7 Permanent Fund tops $32B for first time

16 OPEC chief suggests no output change

19 Cash flow bolsters Canadian cap-ex

20 EIA says 2005 price increases reflect supply

GOVERNMENT

3 B.C. government feasts off gas harvest

5 EPA administrator foresees jump in oil, gas and mining in Alaska

5 Rumsfeld opposes more offshore drilling

10 Commission will monitor Prudhoe studies by owners

11 **Conoco compares HDD with Nigliq bridge**

Corps of Engineers requested comparison of horizontal directional drilling with company's proposed vehicle-pipeline bridge

18 Appeals court to hear Exxon Valdez case

19 RCA looks at regulating pipelines by size

INTERNATIONAL

4 Timor-Australia cut deal on Sunrise

5 ExxonMobil goes back into offshore Libya

9 International rigs up 4% from October

LAND & LEASING

18 Wyoming split-estate law to be tested

19 MMS asks for interest in '07 inlet sale

20 Big coalbed methane play up for grabs

23 BLM takes comment on Ring of Fire plan

NATURAL GAS

9 Solving the Beluga pipeline puzzle

15 **Gas negotiations: two different views**

Irwin, Rutherford, Myers say gas line talks raise concerns; governor says Legislature must approve oil tax changes, balance sought

PIPELINES & DOWNSTREAM

10 Refineries did not pollute after Katrina

● HOUSTON

Former BP, Unocal execs form new firm

E&P independent Cobalt looking to enter deepwater Gulf with $500M in the bank, a seasoned 'Dream Team'

By RAY TYSON

Petroleum News Contributing Writer

Cobalt International Energy and its high-powered team of former BP and Unocal executives have put together a nice bankroll to start accumulating oil and gas leases in the deepwater Gulf of Mexico, a particularly arduous task for an upstart E&P independent with no current acreage whatsoever.

Nevertheless, with $500 million from New York investment banks Goldman Sachs and Carlyle/Riverstone, Houston-based Cobalt is off and running with superior financial support and its dream team.

Moreover, Cobalt management anticipates two more rounds of financial bargaining that could raise an additional $125 million to $250 million from overseas investors.

Company says it expects to be competitive

"We expect that from the outset we will be competitive explorers in deepwater Gulf of Mexico and select international basins," Cobalt Chairman and chief executive Joseph Bryant, a former president of both Unocal and BP Angola, said Dec. 1. "We will immediately hire critical technical team members who are experts in the basins where we will focus."

Cobalt's other executives include Vice Chairman Samuel Gillespie, former general counsel of Unocal and Mobil; Vice President of Exploration James Painter, former vice president of exploration with Unocal and Ocean Energy; and President James Farnsworth, former vice president for worldwide exploration and technology at BP.

Last but certainly not least is Laura Munoz, Cobalt's vice president and general counsel. Munoz is what every new independent requires, an acquisition and merger specialist, the job she holds with New York law firm Wachtell, Lipton, Rosen & Katz. Munoz also holds various degrees from Harvard, Yale and the University of Cambridge, and was once a college professor teaching international relations in Mexico.

GOM, international deepwater targeted

Led by executives with vast global experience, it's only logical that Cobalt is targeting deepwater Gulf of Mexico and international hydrocarbon provinces, including West Africa.

"We believe they will create a 'super-explorer' enterprise that will deliver great results," said David Leuschen, co-founder of Riverstone Holdings and managing director of Carlyle/Riverstone Global Energy and Power Funds.

Evidently Cobalt was quick to recognize what could be the last major opportunity for a well-financed independent to latch on to some of the thousands of oil and gas leases set to expire in deepwater Gulf of Mexico.

Bryant and most of his executive team came from companies that are highly active explorers with impressive deepwater records, most notably BP's Thunder Horse discovery in Mississippi Canyon, the largest find ever in the Gulf with more than 1 billion barrels of oil equivalent. Unocal's long list of discoveries in the Gulf includes St. Malo, a large ultra-deepwater prospect that helped open the prolific Lower Tertiary play in Walker Ridge.

Unocal and BP also are experienced bidders when it comes to Gulf of Mexico oil and gas lease sales — an important attribute these former executives would bring to Cobalt's participation in

see **COBALT** *page 22*

● BRITISH COLUMBIA

B.C. government feasts off gas harvest

Province sees C$300 million impact on revenue for every $1 shift in natural gas prices

By GARY PARK

Petroleum News Canadian Contributing Writer

While a torrent of petroleum cash pours into Alberta government coffers, British Columbia is quietly reveling in its own bonanza.

Finance Minister Carole Taylor forecast that the North American spike in natural gas prices should boost royalties for 2005-06 to C$2.4 billion, up C$695 million from the original forecast.

Overall, resource revenues are expected to rise C$757 million.

But Taylor is not counting on the windfall as a sign of things to come, noting that gas prices soared after Hurricane Katrina to US$11.49 per million British thermal units from US$6, slipped back to US$6.75 in early November and have since rebounded close to US$9.

"If you're going to do prudent budgeting, you have got to be very cautious about over-estimating what the price increase will be," she told the Vancouver Sun.

"When you see a number that's so large and also so volatile, what you must discipline yourself to think about is that 'this is one time.'"

Taylor said that every $1 shift in gas prices spread over a year translates into a C$300 million impact on revenues "in either direction."

Her comments sounded as if they had come directly from the Alberta government guide for comments by cabinet ministers on resource-driven windfalls.

Alberta, having once been burned by over-estimating commodity prices, keeps its fingers out of the fire by refusing to stoke up oil and gas price projections.

B.C. replaced 210% of gas

However, there is plenty of reason to think that British Columbia is establishing a solid foundation on which to use gas prices as a key budget plank.

The latest reserves report from the Canadian Association of Petroleum Producers made B.C. the brightest spot across Canada.

For 2004, the province replaced 210 percent of the 953 billion cubic feet it produced, adding 1.05 trillion cubic feet to its reserves, boosting year-end reserves by 11.4 percent from 2003 to 10.27 tcf.

That was the largest year-over-year gain in 35 years — CAPP Vice President Greg Stringham rated it as "huge" — and, given the scale of B.C.'s gas operations, the percentage improvement was not something to treat lightly.

It reflected heightened activity in the Deep basin and tight gas plays of northeastern British Columbia, where companies such as EnCana and Talisman Energy eagerly tout the prospects and the pace of drilling has changed little this year.

Stringham said government incentives to promote year-round activity and revisions to regulatory practices have helped stimulate upstream operations, but he views the immature nature of the region, with the prospect of major finds, as even more appealing. ●

GULF OF MEXICO

MMS says 31% of U.S. Gulf oil production remains shut-in due to hurricane damage

Nearly 31 percent or 464,858 barrels of oil per day remained shut-in as of Dec. 8, and 24.4 percent or 2.4 billion cubic of natural gas was shut-in as of the same date, according to the U.S. Minerals Management Service.

Oil and gas production in the Gulf of Mexico continues to recover from damage caused by this year's harsh hurricane season. Nearly 31 percent or 464,858 barrels of oil per day remained shut-in as of Dec. 8, and 24.4 percent or 2.4 billion cubic feet of natural gas was shut-in as of the same date, according to the U.S. Minerals Management Service.

The cumulative shut-in oil production in the Gulf from Aug. 26 through Dec. 8 totaled 99.9 million barrels, or 18.2 percent of the roughly 547.5 million barrels of annual oil production. During the same period, the cumulative shut-in natural gas production totaled 516.9 billion cubic feet, or 14.1 percent of the approximately 3.65 trillion cubic feet annual gas production in the Gulf.

Additionally, evacuations equivalent to nearly 16 percent of the 819 manned platforms were not operating as of Dec. 8, while all of the 134 rigs in the Gulf were operating as of the same date, according to MMS.

—RAY TYSON

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● TIMOR SEA

Timor-Australia cut deal on Sunrise gas

Woodside appears to be pushing ahead with new Pluto field instead, until questions about Timor Sea border issues fully resolved

By ALLEN BAKER
Petroleum News Contributing Writer

Negotiators for Australia and East Timor apparently have come up with a formula for sharing cash flow from the giant Greater Sunrise gas field that sits in the Timor Sea between the two nations. But Sunrise operator Woodside Petroleum Ltd. appears to be concentrating instead on its 100 percent owned Pluto discovery, which doesn't carry international boundary complexities or partner issues.

But the development agreement reportedly has some ticklish provisions, and it might well be rejected by East Timor's legislators. Until the formal signoff by both countries, Australia's Woodside is unlikely to make any moves at all.

Australian Foreign Minister Alexander Downer told his country's parliament Dec. 1 that the two governments reached a tentative agreement on splitting the billions of dollars in royalties expected from Sunrise development.

If it goes through as envisioned, East Timor could receive $14 billion over 20 years. The country, with just three quarters of a million residents, was devastated by its long war for independence from Indonesia.

But the development agreement reportedly has some ticklish provisions, and it might well be rejected by East Timor's legislators. Until the formal signoff by both countries, Australia's Woodside is unlikely to make any moves at all.

Perth-based Woodside, a third of which is owned by Shell, put Sunrise on hold last year because of the border controversy. Still, Sunrise is a rich deposit, expected to yield something like $40 billion in natural gas and liquids.

Woodside said it welcomed the government announcement but hadn't yet seen the contents of the agreement between the two countries.

"The future of the Sunrise gas project remains dependent on several factors, including the fiscal regime under which it would operate, the cost and location of any development and the successful marketing of the resource," the company said.

Pluto LNG agreement

Meanwhile, Woodside said Dec. 1 it has North Asian buyers for 3.5 million to 4 million tonnes of LNG annually from Pluto, which was discovered just last April.

The sales number is more than half of the project's initial capacity of 5 million to 7 million tonnes. The sales would be worth somewhere around $11 billion over their 15-year terms, and there's a five-year extension option as well. A million tonnes of liquefied natural gas converts into roughly 48 billion cubic feet of natural gas.

Heads of agreements are due for signature over the next few months and firm purchase agreements by the end of 2006, Woodside said, with a final investment decision in 2007.

In addition to its Asian customers, Woodside says discussions are progressing with potential U.S. customers for additional LNG from Pluto, which sits about 120 miles off Western Australia. China, which backed away from a major commitment for Gorgon LNG, doesn't appear to be a factor in this deal.

For Woodside, the 100 percent owned Pluto deposit could be a major plum, and the company already has plenty of technical credibility from its successful operation of the one-sixth-owned North West Shelf venture, which is nearby. Pluto shipments would start in 2010 under the company's current swift timetable.

As for Sunrise, Woodside owns 33.4 percent and will have to share production there with ConocoPhillips (30 percent), Shell (26.6 percent) and Japan's Osaka Gas Co. (10 percent).

Sunrise is expected to cost about $5 billion to develop, compared with about $4 billion for Pluto.

Another Gorgon sale?

Chevron Corp. was reportedly nearing an agreement with Japan's Osaka Gas Co, for LNG from the Greater Gorgon project, according to reports from Dow Jones and Reuters.

The deal is said to involve 1 million to 1.5 million tonnes of LNG annually for 20 to 25 years starting in 2010.

That builds on major recent Gorgon sales to two other Japanese utilities, Tokyo Gas Co. and Chubu Electric Power Co. Those sales volumes are 1.2 million and 1.5 million tonnes for 25-year terms. All three Japanese companies are reportedly considering equity stakes in Gorgon.

Earlier plans for China's CNOOC to take Gorgon LNG appear to be moving off the stage. The Chinese firm backed away from its tentative deal with Chevron over the higher prices that Asian gas is now commanding.

Chevron has 50 percent of Gorgon, while Shell and ExxonMobil own a quarter each. Shell has said its share of the production will go to Sempra's Baja California terminal. Exxon's isn't spoken for.

Still, the lack of contracted supply and the long-term deals for Australian LNG call into question whether China will continue its aggressive plans to build more than a dozen LNG terminals along its coastline and boost its use of the fuel dramatically. ●

LIBYA

ExxonMobil goes back into offshore Libya

Oil and gas company Exxon Mobil Corp. said Dec. 5 it has agreed to an exploration and production sharing pact with Libya's National Oil Corp. — the company's first re-entry into that country since leaving in the early 1980s.

Financial terms of the deal were not disclosed. The agreement covers 2.5 million acres of the Cyrenaica basin in waters between 10-feet and 10,000-feet deep.

Exxon exited the country in 1981; Mobil had left in 1982, according to ExxonMobil spokesman Len D'Eramo. In 1986, the United States imposed comprehensive trade and financial bans on Libya.

Shares of ExxonMobil gained 44 cents to close at $59.51 Dec. 5 on the New York Stock Exchange.

—THE ASSOCIATED PRESS

ALASKA

EPA administrator foresees jump in oil, gas and mining permits in Alaska

A federal Environmental Protection Agency official says the demand for permits from the oil, gas and mining industries in Alaska will grow tremendously in the next few years. A gas pipeline would require permits for roads and other infrastructure, said Marcus Peacock, EPA's Deputy Administrator based in Washington.

The agency will be looking at a possible increase in the number of EPA employees in the state to handle the workload, he said.

Peacock said the agency is trying to make sure the permitting process is timely, while still protecting the environment. Peacock on Dec. 6 visited the EPA office in Alaska for the first time since his appointment in August.

With 40 people, it's the largest EPA presence in any state. In an interview with The Associated Press, Peacock also noted that the effects of a warming climate are more pronounced in Alaska than in the Lower 48. He said the agency is also working to make sure Bush villages have more access to clean running water and ways to dispose of solid waste and trash.

—THE ASSOCIATED PRESS

GULF OF MEXICO

NOAA survey: Barge hit submerged platform

A survey completed Nov. 30 by the National Oceanic and Atmospheric Administration confirmed that a barge that has leaked oil into the Gulf of Mexico after capsizing was damaged after hitting a platform that was sunk by Hurricane Rita.

The 441-foot barge was en route from Houston to Tampa, Fla., on Nov. 10 when it struck the submerged platform about 100 miles east of Galveston.

The platform, owned by Targa Midstream Services Limited Partnership, was used to support pipeline inspection and operation. It's usually above water but was damaged and sank during Hurricane Rita. The company found the platform and marked it with unlit buoys, according to the U.S. Coast Guard.

Three cargo tanks of the double-hulled tank barge were damaged and leaked oil.

Initial surveys indicate that a large portion of the 1.3 million gallons of oil in the damaged cargo tanks leaked out and settled on the ocean floor.

Responders are staging equipment to conduct sonar and video surveys of the submerged oil and are monitoring the movement, if any, of the oil on the ocean floor.

No oil has reached either the Texas or Louisiana coasts.

As of Nov. 30, work crews had off-loaded with the use of hoses and pumps more than 400,000 gallons of oil from the barge. Most of the vessel's oil will be removed before it is salvaged.

The barge's oil, a thick, heavy petroleum product known as number-six fuel oil, is heavier than water and sinks to the bottom of the sea.

The barge is not obstructing marine traffic, and all waterways were open.

—THE ASSOCIATED PRESS

TALLAHASSEE, FLA.

Rumsfeld opposes more offshore drilling

Defense Secretary Donald Rumsfeld called offshore drilling "incompatible" with military training and weapons testing in the Gulf of Mexico off Florida's shores in a letter to Senate Armed Services Committee Chairman John Warner.

The letter was touted Dec. 1 as a major development in the offshore drilling debate by U.S. Sen. Bill Nelson, D-Fla. Nelson had asked Warner, R-Va., to seek the Pentagon's view.

"It is a clear signal to drilling proponents to stop," Nelson said in a teleconference with reporters. "This is what we needed in our constant battle with the oil industry."

Rumsfeld refers in the letter, dated Nov. 30, to a line extending south from a point in the Florida Panhandle near Fort Walton Beach, or 234 miles west of Tampa Bay.

"In those areas east of the Military Mission Line, drilling structures and associated development would be incompatible with military activities, such as missile flights, low-flying drone aircraft, weapons testing and training," Rumsfeld wrote.

Some in Congress have proposed that natural gas drilling be allowed as close as 20 miles from the shores of Florida and other coastal states. Other proposals have set distances of 125 miles or 150 miles for oil and gas exploration and production.

Closer drilling proposed

Some in Congress have proposed that natural gas drilling be allowed as close as 20 miles from the shores of Florida and other coastal states. Other proposals have set distances of 125 miles or 150 miles for oil and gas exploration and production.

Such legislation would lift existing congressional and presidential moratoriums on offshore drilling that extend to well beyond 200 miles from Florida's beaches.

Rumsfeld wrote that military activities east of the military line "are especially critical" to the Defense Department.

Rumsfeld wrote that the Defense Department would evaluate its requirements and work with the Interior Department to "strike a proper balance between our nation's energy and national security goals."

Pressure to expand offshore drilling has grown in Congress since Hurricanes Katrina and Rita temporarily curtailed fuel supplies and raised prices.

—THE ASSOCIATED PRESS

CANADA

Energy trusts on brink of merger wave

Viking Energy Royalty Trust and Harvest Energy Trust gave weight to those who believe Canada's income trust sector is entering a "go big, or go home" era.

Already carrying a fair degree of individual clout, the two intermediate-sized operations are ready to merge, creating the fourth largest conventional oil and gas producer in the sector with a market value of C$3.3 billion.

If the combination agreement is concluded next March, the new entity — carrying the Harvest name — will produce about 64,000 barrels of oil equivalent per day, trailing only Penn West Energy Trust at 103,000 boe, Enerplus Resources Fund at 88,000 boe and Canetic Resources Trust at 80,000 boe. Canetic itself stemmed from the September amalgamation of Acclaim Energy Trust and Starpoint Energy Trust in what was hailed as a megatrust.

Dec. 16 debut on index

The pace could quicken as trusts face their Dec. 16 debut on the Standard & Poor's/Toronto Stock Exchange benchmark index.

Paul Charron, Acclaim chief executive officer at the time of the StarPoint announcement, said size is critical as the red-hot sector seeks to acquire new mature oil and gas fields to ensure cash flow can be directed to unit holders far into the future.

"The reality is being a bigger entity will reduce the competition for larger transactions," he said.

While C$300 million purchases could be made by "almost anyone given the strength of the capital markets," C$1 billion transactions are beyond the reach of most, Charron said.

Trusts also need to bulk up to improve their chances of bidding for rigs, which is another shift of direction as the sector resorts to the drill bit to add reserves.

Despite the Viking-Harvest deal, not everyone anticipates an early flood of consolidation.

Jeff Martin, an analyst at Peters & Co., said mergers among the 30-plus trusts will happen as weaker trusts are exposed and that will need a slump in commodity prices.

Raymond James analyst Don Short is counting on a shakeout in a sector he thinks is over-saturated, resulting in two camps: smaller trusts with output close to 10,000 boe and larger trusts able to compete for assets in Canada and internationally.

Those left in the middle will be faced with paying premium prices for a shrinking number of properties.

Based on oil prices of US$60 per barrel, the trust group should be able to acquire about C$13 billion in assets next year and there is less than C$1 billion on the market right now, Short said.

—GARY PARK

● CANADA

Income trusts still a hot potato

Goodale fends off accusations of leaks; accountant says trusts rife with 'abuses'; others tell investors to brace for challenges

By GARY PARK

Petroleum News Canadian Contributing Writer

It's the issue that just won't go away in Canada.

Whatever hopes Finance Minister Ralph Goodale might have harbored when he tried to shut down the controversy Nov. 23 by cutting tax rates on corporate dividends rather than hiking them on income trusts have been swept away in the midst of an ill-tempered federal election campaign.

Canadian Finance Minister Ralph Goodale

The political heat is on Goodale as pressure mounts to have the Royal Canadian Mounted Police and/or securities regulators investigate whether stock traders learned of the trust decision hours before its decision.

In addition:

- A study by a firm of forensic accountants says the trust sector is still overvalued by 28 percent.
- Major investors warn trusts should not assume that their tax-efficient status is free from government interference.

Timing of announcement at question

At the core of the attack on Goodale was the unseemly haste of the trust announcement Nov. 23, barely an hour after his office assured reporters there would be no new developments that day.

In the lead up to the trust ruling there was heavy trading of dividend-paying stocks, which was sufficient for Christopher Thomas, a former broker, analyst and money manager, to identify as "deviant behavior."

To the surprise of many, some trusts were able to react to Goodale's announcement 35 minutes after it was made.

Asked if he suspected any leaks from his office or other sources, Goodale declared that was "a complete falsehood."

He accused his political opponents of "character assassination" and insisted any heavy-trading of dividend-paying stocks prior to the trust ruling was based on "pure speculation" by investors.

Mounties reviewing request for a probe

The Mounties meanwhile are reviewing a request from the federal New Democratic Party to probe the trading patterns and determine whether an investigation is warranted.

But Gerry Phillips, the Ontario cabinet minister responsible for overseeing the Ontario Securities Commission, Canada's largest regulator, refused to get involved, saying that would be tantamount to political interference in the regulatory field.

Although the firm did not include energy and real estate trusts in its examination, it said less than two-thirds of the cash distributions by 50 of the biggest trusts were based on actual income. The rest was the return of investors' own capital.

While that dispute rages, a report from Accountability Research Corp., an affiliate of Rosen and Associates forensic accountants, said the C$20 billion loss in the market value of trusts during the two-month federal review of the sector did not get to grips with accounting and sales "abuses" by trusts.

Although the firm did not include energy and real estate trusts in its examination, it said less than two-thirds of the cash distributions by 50 of the biggest trusts were based on actual income. The rest was the return of investors' own capital.

It said the tax advantage of the trust structure has been overstated as the motivation for corporations to join the trust ranks and much of that overvaluation "stems from abuses in the financial reporting, valuation and marketing of business trusts."

Accountability Research said "much of the manipulation relates to the understatement of future capital spending required to maintain the capital assets of the business. Even more of the overvaluation results from the flawed methodologies being pushed by the investment banks."

The report, entitled "The Worst is Yet to Come," suggested that the "prospects for serious declines in business trusts are already evident," with the unit prices for 22 trusts down by 30 percent or more from their offering prices.

For those wondering whether the Canadian government has dropped the notion of imposing a tax on trusts, Ira Gluskin, president of Gluskin Sheff & Associates, a major trust investor, said: "Are we safe? The answer is no. There are civil servants who stay up at nights worrying about income trusts."

If there is a continuing wave of conversions, the tax treatment of trusts will quickly "move front and center again," he said.

Robert Bertram, head of investment at the Ontario Teachers Pension Plan, said the government has "not fixed the tax system" or leveled the playing field between corporations and trusts with Goodale's announcement. ●

● INTERNATIONAL

Platts: Big oil dominates global energy

Platts survey shows dominance of big oil, with leaders amassing $1.9 trillion in 2004 revenues; Devon tops E&P independents

By RAY TYSON

Petroleum News Contributing Writer

U.S.-based ExxonMobil, Chevron and ConocoPhillips and other large integrated oil and gas companies, feeding off the unprecedented rise in commodity prices, blew away the field in a Platts global survey of 250 leading energy companies, with combined revenue and profit of the integrateds soaring over the past few years.

Platts is a division of McGraw-Hill and a leading provider of energy information. This year's report, released Dec. 2, measured the financial performance of the top 250 companies in the world by examining each company's assets, revenues, profits and return on invested capital. All companies ranked in the survey had assets exceeding US$2 billion.

ExxonMobil, Chevron and ConocoPhillips were among the world's best 10 performers. ExxonMobil was ranked number one in the survey with 2004 reported revenue of nearly $264 billion, profits of $25.3 billion and assets of $193 billion.

U.S.-based exploration and production independents also dominated their sector. Oklahoma's Devon Energy was at the head of the pack in 2004 with $9.2 billion in revenues, $2.2 billion in profit and $29.7 billion in assets.

Devon ranked 38th overall, followed by Anadarko Petroleum (50), Apache (58), Burlington Resources (63), Nexen (97), Talisman Energy (102), EOG Resources (116), Kerr-McGee (128), XTO Energy (131), Newfield Exploration (156), Noble Energy (157), Pioneer Natural Resources (170) and Pogo Producing (172).

Growth in integrateds startling

The huge increase in revenues and profits among the integrated oil and gas companies was startling. Since last year's report, combined revenues for the 31 integrateds in the survey nearly doubled to $1.9 trillion, while profits rocketed 165 percent to $5.3 billion on average. Integrateds also dominated the top dozen spots with average individual assets of just over $53 billion.

"No other energy industry segment can match those numbers," said Theo Mullen, co-author of the analysis and managing editor of Platts Megawatt Daily.

The top 10 ranked companies in the survey were ExxonMobil, France's Total, Chevron, UK's BP, Netherlands' Royal Dutch/Shell, Italy's Eni, China's Petrochina, UK's Shell Tran & Trade, Norway's Statoil and ConocoPhillips.

Royal Dutch/Shell, which ranked first in last year's survey, "has had a tough time of it since," Platts said, explaining that "a huge reserves overbooking scandal, the firing of very senior officers, regulatory authority investigations in three countries, criminal proceedings, and substantial fines combined to spur a previously unthinkable radical organizational shakeup."

Other energy segments ranked in this year's Platts survey were refining and marketing, diversified utilities, independent power producers, exploration and production, commodity storage and transfer, gas utilities, and coal and consumable fuels.

The survey used the latest data from Standard & Poor's which, like Platts, is a division of McGraw-Hill. Because the survey was global and financial reports are not all filed simultaneously nor do they share a common financial reporting standard, the information used in the analysis was for full-year 2004, Platts said.

Platts noted that because this year's rankings were based on 2004 data, before oil and natural gas prices exploded in 2005 and companies began reporting record quarterly revenue and profit, the financial gap between the integrateds and the rest of the energy industry "could well widen."

Significant investment increase

On the investment front, there appear to be significant new higher levels of spending by companies searching for and producing oil and natural gas, Platts said, citing a Lehman Brothers' spending survey indicating worldwide exploration and production expenditures could jump 13.5 percent this year to $192 billion, compared to a 5.7 percent increase reported by companies queried for Lehman's 2004 survey.

In the United States alone, Lehman carved out the 2005 spending plans of 265 companies with a largely domestic focus. The survey found plans to boost U.S. exploration and production spending by 16.9 percent, up from a year-end 2004 estimate of a 7.8 percent.

Lehman said that 2006 is likely to see record E&P spending, with about 65 percent of the companies responding to its latest survey planning to spend more in 2006. And of those planning to spend more, 80 percent intend to increase spending by at least 10 percent and 38 percent plan to hike spending by 20 percent or more.

Oil prices haven't hurt demand growth

Oil prices, which have more than doubled from an average $31 per barrel in 2003, have thus far done little to hurt economic or oil demand growth, according to an International Energy Agency report cited by Platts.

"The confluence of sharply higher commodity prices that show no sign of collapsing and higher spending should soon translate into more muscular cash flow for the companies involved in the segment," Platts concluded.

In regard to commodity prices, the U.S. Energy Information Administration recently raised its price forecast for West Texas Intermediate crude to $59.17 per barrel and said monthly average WTI prices would remain above $55 per barrel for the rest of this year and next — "levels already surpassed," Platts pointed out.

"Imbalances, real or perceived, in domestic markets could cause light crude prices to average above $60 per barrel," according to EIA, the statistical arm of the U.S Department of Energy.

EIA said robust worldwide energy demand would contribute to higher oil prices through 2006, adding that demand is projected to grow at an annual average rate of about 2.1 million barrels per day to 85 million barrels in 2005 and to 87.1 million barrels per day in 2006.

In regard to global oil supply, Platts noted an International Energy Agency report saying that supply from Russia and other independent producers is rising more slowly than expected this year, putting strain on OPEC.

"That has helped prices reach a record high," IEA said in its analysis, adding that Non-OPEC oil supply in 2005 would rise by 675,000 barrels per day to 50.8 million barrels per day.

Platts commented: "The outlook points to a greater reliance on supply from the 11-member OPEC, which is already pumping crude close to full capacity."

Overall rankings are published in the December issue of Platts' Insight-2006 Global Energy Outlook publication, and are available on the Platts web site at http://www.top250.platts.com. Regions covered in the survey were Asia-Pacific Rim, the Americas and Europe. ●

ALASKA

Permanent Fund tops $32B for first time

The value of the Alaska Permanent Fund, the state's oil-revenue savings account, reached $32 billion for the first time, fund officials say.

The fund has grown $1 billion over the previous three weeks after a steep decline in October, fund officials said Nov. 25.

The growth spurt was due in part to the recent rise in value throughout global financial markets, said Bob Bartholomew, the fund's chief operating officer.

It's too early to tell whether the rise will affect the amount of the annual Permanent Fund dividend paid to each Alaska resident next fall, officials said.

The dividend is calculated on a five-fiscal-year average of the fund's profits, so a large gain in fund value will not translate into proportionately larger dividends, Bartholomew said.

So far this year, the fund has gained more than $2 billion and is on target to meet the long-term goal of 8 percent growth a year, he said.

The bulk of the fund's investments are in stocks, bonds and real estate, although overseers are planning to shift much of the money to alternative investments, such as hedge funds and venture capital projects.

The fund draws less than 10 percent of its earnings from legislatively authorized deposits of a portion of oil revenues, according to Bartholomew.

—THE ASSOCIATED PRESS

NORTH SLOPE

Slope tundra opening earliest since '95

New state standards for protection of North Slope coastal tundra have allowed the earliest start of the oil and gas exploration season since 1995, Natural Resources Commissioner Michael Menge said Dec. 7.

Menge said in a statement that the Department of Natural Resources opened the east and west coastal areas of state-owned lands on the North Slope to oil and gas exploration activity Dec. 6, based on measurement standards developed in a scientific study completed in 2004 by the department's Division of Mining, Land and Water.

> *The commissioner said new snow depth and soil temperature standards developed through the study allow the department to lengthen the oil and gas exploration winter season without increasing the impact on the tundra.*

"The division conducted its study in response to the winter oil exploration seasons becoming shorter because of warming weather and changes in measuring techniques," Menge said. "While the winter exploration season had been effectively cut in half since the early 1970s, this winter's opening is the earliest since 1995, thanks to good science and cooperative weather."

The commissioner said new snow depth and soil temperature standards developed through the study allow the department to lengthen the oil and gas exploration winter season without increasing the impact on the tundra. The study found that snowfall is more important in protecting the tundra than previously understood while ground hardness, previously the determining factor in opening the tundra, is relatively less important after a certain point. The department is now opening the tundra after the accumulation of at least six inches of snow in the coastal area and nine inches of snow in the Foothills area, and after soils reach a temperature of minus-five degrees Celsius.

The department said its monitoring of some of the early exploration activity allowed last year, followed by additional study this summer, showed that the early opening did not result in any increased impact on the tundra.

"We are confident that any seismic activity that occurs under these conditions will not cause any increased impact to the tundra," said Wyn Menefee, chief of operations for the Division of Mining, Land and Water.

"We will, however, continue to monitor the effect of exploration based on the new standards developed," Menefee said.

The department said it will continue to collect data in the Foothills to determine when opening standards have been met for that area.

—PETROLEUM NEWS

● CANADA

More of the same in Canada's upstream

2005 drilling count expected to top 24,000, beating record of 22,720 set in 2004; 20,161 wells completed in first 10 months

By GARY PARK
Petroleum News Canadian Contributing Writer

A blazing finish to Canada's 2005 drilling year is expected to push the 12-month count over the 24,000 mark, setting the stage for more of the same over the next two years.

More than 80 percent of the steadily growing fleet has been at work through the fall season, representing an average 637 rigs — 136 more than the tally for the same period last year.

That has given rise to hopes of 24,000-plus wells, easily beating the record 22,720 in 2004.

October logged 2,684 well completions, an increase of 29 percent or 604 wells from October 2004, completing the fourth successive month that topped comparable 2004 numbers.

The total for the first 10 months of 2005 was 20,161 wells, up 7.5 percent from the January-October period last year, with the four provinces in Western Canada all posting gains.

Declines in north and east

However, northern and eastern (both onshore and offshore) Canada showed a decline.

Preliminary figures for November showed more than 2,000 well completions.

Rig utilization to late November was up 29 percent in Saskatchewan to an average 50 active rigs (the highest count since 1997) and up 23 percent in Alberta to 385 working rigs (an all-time high). British Columbia had an average 73 working units.

Roger Soucy, president of the Petroleum Services Association of Canada, told the Edmonton Journal that the current drilling performance is "probably the longest run we've ever had in the industry" and is likely to continue if oil remains above US$40 per barrel and gas doesn't drop below the US$4-$5 per thousand cubic foot range.

The association has already forecast 25,290 completions in 2006, while the Canadian Association of Oilwell Drilling Contractors says there is no reason to expect any change over the next 18 to 24 months.

Training center to be expanded

To help overcome the challenge of finding trained rig hands, the two associations are among six trade groups who have financed a C$2 million expansion of Canada's main training centre near Edmonton, where classes are now taking place around the week and often until as late as midnight.

An addition of about 200 rigs to the fleet over the past two years and forecasts of another 20 in 2006 means field contractors require up to 80,000 workers to meet the demands of E&P companies.

Currently, in some of the highest demand regions, only two shifts can be filled instead of the three needed to support round-the-clock activities, intensifying the pressure to recruit and train new rig hands. ●

COLORADO

Colorado approves some 1,800 new wells

A plan approved Dec. 5 by the Colorado Oil and Gas Conservation Commission will allow companies to drill about 1,800 new natural gas wells on Colorado's Eastern Plains over the next 20 years.

It was trimmed from 81 townships to 27 townships, extending from Greeley to the outskirts of Keenesburg.

The commission agreed to exclude drilling in Longmont, Broomfield, Berthoud, Loveland, Hudson and Windsor.

Opponents say the plan does little to protect developers, who will have to set aside land for the new wells, and little to protect the environment around well sites.

—THE ASSOCIATED PRESS

● COOK INLET

Solving the Beluga gas pipeline puzzle

Bidirectional flow on pipeline and settlement of tariff dispute should help west Cook Inlet producers move gas to market

By **ALAN BAILEY**

Petroleum News Staff Writer

A Nov. 28 document filed with the Regulatory Commission of Alaska appears to signal the end of a dispute between Aurora Gas LLC and Beluga Pipe Line Co. regarding gas transportation tariffs in the Beluga pipeline on the west side of Alaska's Cook Inlet. The document, a joint unopposed motion by the parties to the dispute to set aside a Dec. 5 RCA hearing, says that "Beluga, Aurora, and Beluga's parent Marathon Oil Company have reached an agreement in principle which, among other things, will resolve all of Aurora's concerns in Docket U-04-081." U-04-081 is the RCA docket for the dispute.

And on Sept. 13 Beluga filed a request to RCA for approval to initiate bidirectional flow on the Beluga line, with an initial postage stamp rate of 25 cents per mcf in either direction. RCA approved the bidirectional flow but only permitted a restricted, interim rate, pending resolution of the Beluga pipeline tariff dispute.

Following on the heels of the Sept. 27 settlement of the dispute regarding access to the Cook Inlet Gas Gathering System (known as CIGGS), a settlement to the Beluga pipeline tariff dispute and the instigation of bidirectional flow on the line mark further progress in opening up gas pipeline access for independent gas producers on the west side of the Inlet.

Regulated utility line

The Beluga pipeline, a regulated gas utility line owned and operated by Marathon, runs from CIGGS, at Granite Point, north to the Beluga gas field, where it connects with the southern end of Enstar Natural Gas Co.'s utility line from Beluga into Enstar's Southcentral Alaska gas network. Aurora's Lone Star, Moquawkie, Kaloa and Three Mile Creek fields all export gas through the Beluga pipeline. CIGGS connects gas production facilities in the area around Trading Bay and Granite Point to Nikiski on the east side of the Cook Inlet.

In the past, gas in the Beluga pipeline has always flowed from south to north, thus limiting fields north of Granite Point to markets accessible through Enstar's pipeline system. Because Enstar has to add odorizing agents to gas passing though its system the gas becomes unsuitable for industrial applications such as LNG or fertilizer production. Agrium Inc., the owner of the fertilizer plant at Nikiski, and others have long argued for bidirectional flow on the Beluga line, to increase the marketing options for gas fields on the northwest side of the Cook Inlet. The provision of north to south flow in the Beluga line will enable fields north of Granite Point to export gas through CIGGS to industrial facilities at Nikiski.

Tariff dispute

Because RCA regulates the Beluga pipeline, third-party gas producers such as Aurora have rights of access to the pipeline for the transportation of gas, subject to certain terms and conditions. But on Sept. 2, 2004, Aurora filed a protest with RCA regarding the tariffs for the carriage of gas on the pipeline — Aurora said that the tariff rate was based on the original revenue requirements for the pipeline and that, given factors such as the depreciated value of the plant and recent low interest rates, those requirements had subsequently "become excessive." Aurora also claimed that throughput in the pipeline had "greatly exceeded" the initial projected throughput, upon which the tariff was based.

Aurora raised other issues such as allowances for federal and state income taxes, and assumptions about future pipeline abandonment.

Aurora also said that RCA, in its approval of the inception rate for the Beluga line, had stated that the inception rate was subject to future review, because none of the utilities receiving gas from Marathon directly paid the tariff for use of the line — the tariff was rolled into the transportation cost of the gas that Marathon supplied.

In response to Aurora's protest, Beluga Pipe Line Co. said that "a full-blown (tariff) investigation at this time is neither necessary nor appropriate."

The company said that in recent years throughput in the Beluga pipeline had declined well below the level that had been assumed for the original tariff determination. A decline in throughput had resulted in revenue requirements for the pipeline not being met, even allowing for a reduced cost of service based on age of the pipeline, the company said.

Beluga also said that Aurora has been able to transport gas from its Lone Creek field at a reduced "bypass rate," and that the low tariff had further worsened the economics of the pipeline. However, in its complaint, Aurora stated that the bypass rate was simply a prorated version of the full tariff, allowing for the fact that Lone Star connects to the pipeline towards the downstream end.

Beluga said that it would be premature to review the tariff because the company was in the process of assessing the possibility of enabling bidirectional flow on the pipeline. The introduction of bidirectional flow would probably result in increased throughput but would also entail significant capital expenditure.

But, if there were an investigation into the tariffs at the moment "a new rate filing at this time would doubtless result in a rate increase, not a decrease," Beluga said.

Aurora responded to Beluga's claims of lower recent throughput in the pipeline by saying that Marathon, Beluga's parent company, had bypassed the use of the pipeline by exchanging gas delivered on the east side of the Cook Inlet for gas delivered to Enstar and Chugach Electric association from the Belugas gas field on the west side. Aurora also said that plans for bidirectional flow on the Beluga pipeline must "be regarded as speculative and uncertain."

RCA investigates

On Dec. 7, 2004, RCA "found good cause to open an investigation into the rates Beluga charges for transportation on the Beluga Pipeline." Meantime, Agrium, Enstar and the state of Alaska all petitioned to intervene in the RCA docket. And the Alaska attorney general elected to participate.

RCA held a public hearing on the docket in January 2005 and subsequently heard testimony from witnesses.

Aurora and Beluga entered negotiations to seek a settlement in the case and on May 12 RCA issued a procedural schedule, leading to the public hearing on Dec. 5 that the parties to the dispute have now asked RCA to set aside.

In response to the motion filed on Nov. 28 RCA has required Aurora and Marathon to submit a formal stipulation of their agreement by Dec. 15. Otherwise, RCA will call a prehearing conference to establish a new procedural schedule.

But it does look as if the pieces of the Beluga pipeline access puzzle are finally slotting into place. ●

INTERNATIONAL

International rigs up 4% from October

The international rig count for November was 935, up 32 from 903 in October, and up 59 from 876 November 2004, Baker Hughes Inc. said Nov. 7. Including North America, the worldwide rig count for November was 3,021, up 98 from 2,923 in October and up 436 from 2,585 in November 2004.

The international offshore rig count was 267, up three from 264 in October, and up eight from 259 in November 2004.

Most rigs in Latin America

Latin America had the most rigs working, 318, up 23 from 295 in October and up from 317 in November 2004. In the Middle East 256 rigs were working, down three from 259 in October, but up from 239 in November 2004. In Asia Pacific there were 237 rigs working, up four from 233 in October and up from 202 in November 2004. Seventy-five rigs were working in Europe, up five from 70 in October and up from 69 in November 2004. There were 49 rigs working in Africa, up three from 46 in October but the same count as the 49 rigs working in November 2004.

The November land-offshore rig breakout by region was: Europe, 25 land and 50 offshore; Middle East 221 land and 35 offshore; Africa 38 land and 11 offshore; Latin America 253 land and 65 offshore; and Asia Pacific 131 land and 106 offshore.

—PETROLEUM NEWS

NEW ORLEANS

Refineries did not pollute after Katrina

Countering environmentalists, the Louisiana Department of Environmental Quality said Nov. 30 that oil refineries did not pollute after Hurricane Katrina even though they were granted waivers from environmental restrictions.

"No state or federal standard is being exceeded for any of the pollutants that we're looking at," said Jim Hazlett, a DEQ senior environmental scientist.

On Nov. 30, environmentalists said that sample results taken after Katrina by the U.S. Environmental Protection Agency showed high levels of benzene were found near refineries and other locations in southeast Louisiana. Benzene is a component in gasoline and it can cause cancer.

Anne Rolfes, the director of the Louisiana Bucket Brigade, said the high levels of benzene were the result of refineries being allowed to emit more pollutants than they usually can. EPA and DEQ issued the waivers so refineries could get back in operation sooner.

> *Rodney Mallett, a DEQ spokesman, said that if the average yearly benzene standard was applied all the time "it would impossible to light a cigarette or start a car" without violating the standard.*

John Millett, an EPA spokesman, said there is no link between the high benzene levels and the waivers.

The Bucket Brigade compared results taken by EPA mobile laboratories with Louisiana's yearly average benzene standard. The EPA laboratories were brought into Louisiana after Katrina to discover if ambient pollution was a problem.

Hazlett called the Bucket Brigade's comparison "totally inappropriate and misleading" because the EPA samples were "instantaneous readings" while the annual average standard is a composite of benzene emissions over a year.

Rodney Mallett, a DEQ spokesman, said that if the average yearly benzene standard was applied all the time "it would impossible to light a cigarette or start a car" without violating the standard. Rolfes called that statement "grossly inaccurate."

Hazlett said that regular, 24-hour sampling at the refineries since Katrina show that the plants did not at any time exceed the yearly benzene standard.

EPA's samples from mobile laboratories that detected high levels of benzene, Rolfes charged, show that DEQ's regular sampling system is "worthless."

"This just shows how crumby those systems are," she said.

Hazlett denied that, saying that DEQ's monitoring stations work well and give the public an accurate assessment of air quality.

He said EPA's high readings "could have been from a refinery or a passing vehicle," but that they should not be viewed as an indication of sustained and high levels of benzene in an area.

—THE ASSOCIATED PRESS

● ALASKA

Commission will monitor Prudhoe studies by owners

Inquiry into whether gas offtake limit should be changed closed; staff, contractors will have access to owner reservoir studies

By KRISTEN NELSON

Petroleum News Editor-in-Chief

The Alaska Oil and Gas Conservation Commission has ended its inquiry into whether rule 9 of conservation order 341D, limiting gas offtake from the Prudhoe Bay oil pool to 2.7 billion cubic feet per day, should be updated.

The commission held hearings on the issue in March and May, and said Dec. 5 that a proposed gas pipeline shipping 4.5 bcf a day would require an upward revision of rule 9. The commission also said that after reviewing the history and basis of rule 9, it "believes that there is a need to comprehensively revisit the question of the appropriate gas offtake limitation in light of several decades of reservoir development and the information that has become available since 1977, and in light of the current understanding of reservoir management and improved techniques for reservoir simulation."


JUDY PATRICK

JOHN NORMAN

To date, the commission said Dec. 5, it has not received an application from any of the owners for a revision of the gas offtake rule. But because a delay in its decision making "could disrupt the timetable for a potential gas pipeline project," the commission said it is adopting "a proactive approach to ensuring that there will be an adequate factual basis for its eventual decision on allowable gas offtake," rather than relying on information the Prudhoe Bay owners "might choose to submit in support of a future application to amend the pool rules."

Will monitor owner studies

The commission said it will monitor Prudhoe Bay working interest owner reservoir simulation studies on gas offtake issues, rather than undertake reservoir simulation studies of its own.

The commission held a public hearing Dec. 1 to take comments on a proposed report which incorporated principles that would govern monitoring by commission staff and consultants of Prudhoe owner reservoir studies. These principles ensure confidentiality of data.

Commission Chair John Norman said at the hearing that it would save time and expense for the commission to use reservoir simulations by the Prudhoe working interest owners, but the commission reserves the right, he said, to initiate its own studies if that becomes necessary.

Norman said that when hearings begin on the gas offtake rate for Prudhoe Bay, the commission will have legal rights, as will the Prudhoe Bay owners, and confidentiality will be established "issue by issue" at that time. He said the commission is concerned that enough data will be on the public record to support whatever decision the commission makes.

Commissioner Cathy Foerster said she thinks that the commission has reached an understanding with the owners which allows adequate time for staff and consultants to evaluate gas offtake; allows access to and understanding of the Prudhoe Bay reservoir model; allows the commission's technical staff to add sensitivities to model runs; and honors confidentiality during the evaluation.

Norman said data would be made available to commission staff within 30 days following the commission's signing off on the report.

Once gas offtake rate hearings begin, Norman said, the commission's bias will be toward public disclosure and having as much information in the public record as possible.

No additions to study team

Harold Heinze, chief executive officer of the Alaska Natural Gas Development Authority, told the commission in a Nov. 30 letter that he thought the commission's study would benefit if the study team included other state and federal employers "and contractors with other expertise than reservoir simulation," but Norman said the commission has a process the owners are comfortable with which includes only commission staff and contractors. He said the commission would look at including others if the working interest owners were comfortable with the inclusion. Norman said he was also concerned about policing confidentiality for those outside the commission staff and contractors.

Heinze also suggested that in addition to reservoir simulation studies, "there is a need for separate studies of potential recovery impacts in the same range as differences in recovery under differing gas off take volumes," specifically understanding: "component transportation capability" of a proposed gas pipeline system "dramatically different than 20 years ago"; a change in miscible injection slug design reflecting the availability of carbon dioxide "to allow greater marketing of ethane and propane; and alternate surface facility design, process specification and future use of existing operational capabilities" that might increase natural gas liquids recovery.

Norman said the commission would look at those suggestions. They are "subtle issues," he said, which "may have conservation implications."

At the end of the hearing Norman said the commission would keep the public advised on how the study process is going, perhaps at its monthly public meetings, but nothing confidential would be disclosed. ●

● NORTH SLOPE

Conoco compares HDD with Nigliq bridge

Corps of Engineers requested comparison of horizontal directional drilling with company's proposed vehicle-pipeline bridge

By KRISTEN NELSON

Petroleum News Editor-in-Chief

ConocoPhillips Alaska is in the process of permitting development of the Alpine West reservoir, the Colville Delta 5 Alpine satellite, CD5, and has proposed a vehicle and pipeline bridge across the Nigliq Channel of the Colville River. The bridge would provide access between the satellite and the main Alpine facilities for personnel and for three-phase crude oil (oil, gas, water), which would be processed at Alpine. Alpine is not tied into the North Slope road system, but is reached by ice roads in the winter and year-round by air.

The Corps of Engineers requested technical information from the company on an alternative crossing of the channel for the pipeline using horizontal directional drilling, the method used to cross the Colville River to take sales-quality oil from Alpine to Kuparuk.

"This is essentially a discussion about roadless vs. roaded access, as an HDD crossing would only be a consideration in a roadless development," ConocoPhillips said. The company said it cannot make a direct comparison between a horizontal directional drilling crossing and a pipeline bridge, because while horizontal directional drilling is technically feasible, it is not an alternative to a bridge.

ConocoPhillips told the agency in a Nov. 29 letter that cost estimates are $25 million for a pipeline-only bridge and $28 million for horizontal directional drilling, with an estimated $1 million to support pipelines on an existing vehicle bridge. A vehicle-only bridge is estimated at $39 million compared to an estimated $20 million to support roadless access with an air operation.

"If either a pipeline or vehicle bridge option is required, it is cost effective to install a dual duty bridge to satisfy both access requirements," the company said.

No known three-phase fluid HDD crossings

The company said "there are no known three-phase fluid HDD crossings in existence." Technical concerns include: corrosion; sedimentation; paraffin issues; leak detection; lack of visual inspection; cathodic protection; unknown slugging impacts to existing facilities; and unknown soil conditions.

ConocoPhillips included a white paper on a horizontal directional drilling crossing of the Nigliq Channel prepared by Michael Baker Jr. Inc. Michael Baker concluded that while a horizontal directional drilling crossing is "technically feasible, there are disadvantages to an HDD crossing at the Nigliq Channel. Liquid holdup and slugging can be minimized, but cannot be eliminated and will add increased stresses to the pipe, exacerbate internal corrosion, and require additional slug catching equipment at the Alpine Processing Facility."

Michael Baker also said that cathodic protection for an HDD pipeline "becomes complicated and expensive."

Horizontal directional drilling "is sensitive to geotechnical and geothermal conditions," the company said, and pipeline inspection and leak detection system are not as reliable for buried lines, "especially for the three-phase flow lines."

Installing a pipeline on a bridge "reduces the risk of an undetectable leak" as well as reducing the cost of the pipeline, Michael Baker said.

> *"This is essentially a discussion about roadless vs. roaded access, as an HDD crossing would only be a consideration in a roadless development."* —ConocoPhillips Alaska

Issues with multi-phase flow

In transporting multi-phase fluids — oil, water and gas — "fluid phase separation becomes increasingly important," Michael Baker said. Long multi-phase flow lines are "usually accompanied by large pressure drops, and rises and falls in terrain encourage this separation and the formation of slug flow."

Multi-phase flows, unlike single-phase flows, "are strongly influenced by the geometry of flow," of which the strongest influence is from pipe inclination, with an inclination of as little as 0.5 degrees having the ability to "dramatically alter the flow patterns, the boundary layer structure, and the fundamental transport mechanisms." While inclination of a horizontal directional drilling pipe under the Nigliq Channel could be reduced with long approaches, it could not be eliminated, Michael Baker said.

Sediment may also be present in multi-flow, and tends to drop out and accumulate in low spots, such as HDD river crossings, and may increase the risk of corrosion in these areas. In addition, Michael Baker said, sediment may increase erosion of pipe wall, especially at bends in the pipe. That would not be any worse in an HDD installed pipe, but erosion at submerged bends in the pipe could make addressing the issue difficult, "short of complete pipe replacement."

Michael Baker said slugging would be one of the greatest challenges to an HDD crossing of the Nigliq Channel. That occurs with phase separation. The liquid in a multi-flow accumulates in the pipe and gas pressure builds up behind the liquid, forcing it through the pipe as a slug, which can generate large forces within the pipe "due to changes in momentum as the slug negotiates abrupt changes in direction." Slug formation is sensitive to pipe inclination and would have to be studied at the Nigliq crossing, Michael Baker said: "Vertical changes in pipe alignment, especially large sags, have the greatest potential to cause liquid holdup and large slugging forces." An HDD crossing of the Nigliq Channel would require a vertical drop of some 50 feet, Michael Baker said, and while the large slugging forces would require modifications, such as slug catchers, at the Alpine facility, cathodic protection and corrosion issues are of greater concern, and traditional methods of cathodic protection do not work. The slugging forces "increase shear wall stress in the pipe," increasing the rate of internal corrosion.

If there is a road bridge at the Nigliq Channel, installing a pipe on the bridge would be "the preferred installation," Michael Baker said. ●

continued from page 1

INLET GAS

Inlet. The recent instigation of bidirectional flow in the Beluga gas line on the west side of the Inlet and the pending resolution of a tariff dispute for that line also bode well for improved access to the Cook Inlet pipeline infrastructure.

And Chevron has established gas storage facilities at Swanson River on the Kenai Peninsula and Pretty Creek on the west side of the Inlet, to alleviate supply problems during peak winter demand; Marathon also plans to instigate gas storage in the Beluga gas field.

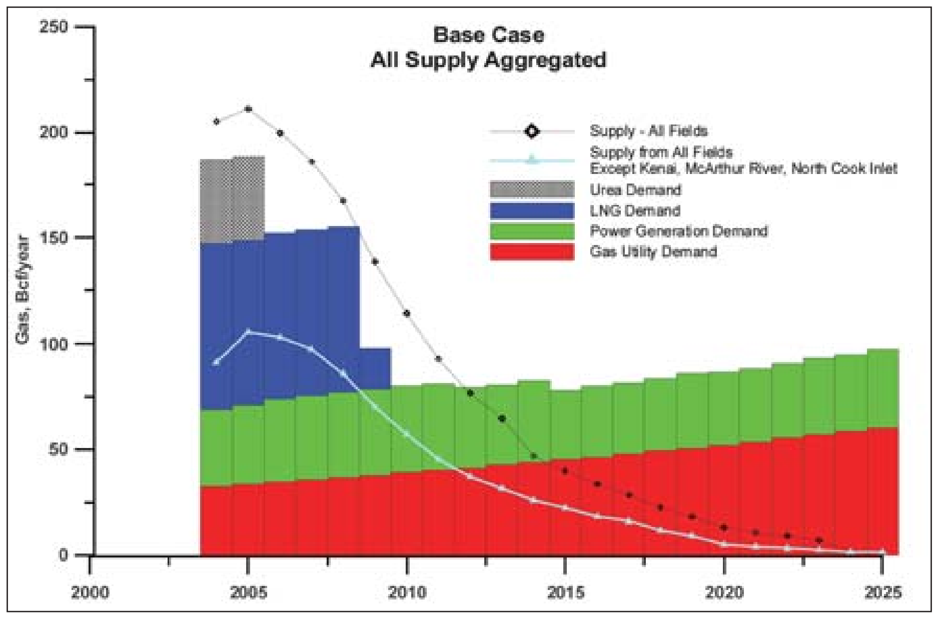
A new contract between Marathon and Enstar Natural Gas Co., the main Southcentral gas utility, should now ensure adequate gas supplies for Enstar through 2016.

The production cliff

But the residents of Southcentral Alaska have become increasingly familiar with the graph that shows projected gas production from the Cook Inlet basin dropping over a cliff within the next few years. And even if gas supplies can be assured for heating and electricity generation, the industrial facilities on the Kenai Peninsula remain under threat. Agrium's Nikiski fertilizer plant is looking to convert from the use of natural gas to the use of gas generated from coal. And, in the absence of increased Cook Inlet gas deliverability, the Nikiski liquefied natural gas plant will struggle to renew its export license in the first quarter of 2009.

So why isn't the Cook Inlet area awash with companies actively searching for gas? A 2004 U.S. Department of Energy report stated that there might be as much as 10 trillion to 14 trillion cubic feet of undiscovered, conventional natural gas in the Cook Inlet basin.

In the Resource Development Council annual conference, held in Anchorage in mid-November, Scott Pfoff, president of Aurora Power Resources Inc., and John Barnes, Marathon's Alaska business unit manager, reviewed some of the issues facing the Cook Inlet gas industry.



Total aggregated Cook Inlet gas supply (top curve) and demand in mid-2004, showing the pending production cliff at that time. The bottom curve shows total supply without the fields dedicated to industrial demand.

CREDIT: From U.S. Department of Energy Southcentral Alaska Natural Gas Study, June 2004

Difficult gas market

Pfoff focused on some of the market challenges.

"Having pounded the pavements in downtown Houston, downtown New York and in Calgary in search of private equity capital … we never had any problem selling anybody on the technical merits of looking for oil and gas in the Cook Inlet basin," Pfoff said. "… The problem came when I got up and tried to talk about the market. There is no spot market up here — you don't just find gas, hook it up to the nearest pipeline and start selling it. You've got to have contracts; you've got to have a way to sell your gas."

Pfoff said that the gas utilities establish long-term contracts with gas suppliers, because the utilities want to ensure continuity of gas supplies for their consumers. But new contracts do not then become available until the utilities enter their next round of supply negotiations, he said.

"Somebody wanting to come in today a make a major investment and find gas and put it on production is not going to have markets available to them for quite some years down the road," Pfoff said.

And David Boelens, vice president of Alaska operations for Aurora, has questioned whether long-term supply contracts are really in the best interests of gas consumers. Allowing new producers to compete in the gas market might reduce prices, he has told Petroleum News.

A plethora of gas supply contracts, all at different price levels, has led to another issue — the state's royalty and tax assessments use "prevailing value," a weighted average of gas prices from the region. That can result in a gas producer paying royalties and taxes based on a gas value that is higher than the price that the producer is actually obtaining.

"Sometimes we're being required to pay royalties and taxes on values much higher than we're able to achieve in the market. And it's issue that I think we will need to address," Pfoff said.

Barnes talked about the commercial problems resulting from extreme seasonal fluctuations in gas demand.

"Seasonal gas pricing doesn't really exist," Barnes said. "There's a significant difference in demand between summer and winter but not a lot of price difference."

Industrial uses of gas can help smooth out seasonal demand, but there's a shortage of industrial customers in the Cook Inlet area.

"There aren't enough multi-year industrial contracts," Barnes said. "… Industrial consumers are important to a successful (gas) industry."

Permitting complexity

The complexity of permitting in the Cook Inlet area compounds the commercial issues. Barnes commented on the many forms and reports that are required to drill a well in the Cook Inlet basin.

"That all takes time and can slow down projects," he said.

There are a lot of people in the agencies doing a good job, but it's a very complicated situation, Barnes said.

"There's ample opportunity, I think, for the state to work to try to improve that situation," he said.

Barnes commended the Regulatory Commission of Alaska on its efforts to streamline the process for pipeline regulation. But significant hurdles remain, Barnes said — for example the need to set a tariff before knowing what the pipeline will cost.

Veteran Alaska geologist Arlen Ehm also emphasized the permitting issues in his testimony to the Alaska House Special Committee on Oil and Gas on Nov. 21. Ehm cited situations where it proved impossible to access leased land for drilling. He also cited the complexity of the permitting paperwork.

"One of the biggest problems is the Coastal Zone Questionnaire with its myriad of questions of which only a fraction actually applies to oil and gas operations," Ehm said.

Small independent oil and gas companies also testified to the committee about the high cost of bonding and permitting in Alaska. Petroleum News has determined that the Alaska Oil and Gas Commission requires a $100,000 bond to drill a single well or a $200,000 bond to drill multiple wells. The Alaska Department of Natural Resources requires a $10,000 bond for any lease activity.

But the Alaska Department of Environmental Conservation requires proof of financial responsibility for $1.43 million to drill a well that may encounter oil — DEC waives this requirement if the operator can demonstrate to AOGCC that the well will not encounter oil. DEC proof of financial responsibility for a shallow gas well is $35,875.

Dual management

Mark Myers, ex-director of Alaska's Division of Oil and Gas, has told Petroleum News that the complexity of the permitting in the Cook Inlet area is partly a result of dual management between state and federal agencies.

"One of the things that you have to recognize in Cook Inlet is that you've got the big wildlife refuge and you've got the state critical habitat areas," Myers said. "That puts into play a dual management structure, where the permitting process is

see **INLET GAS** *page 13*

continued from page 12

INLET GAS

more complicated."

Also there's a continuing issue regarding the role of oil and gas in the Kenai National Wildlife Refuge — whether new oil and gas development should be allowed and, if so, under what conditions, Myers said.

The land ownership situation is also complex. In addition to state and federal land "you've got Native owned lands in the area and you've got a fair amount of fee simple land scattered throughout the area … and you have some split estate surface owner issues," Myers said. "You (also) have an overlap of an extreme number of different (land and water) users and types of users."

The level of concern from local residents regarding oil and gas development varies between different parts of the Kenai Peninsula and can complicate the permitting process, he said.

High risks and costs

Then you have to consider the high risk and cost of doing business in the Cook Inlet region, especially in remote areas distant from the existing natural gas and transportation infrastructures. Operations on the west side of the Inlet are particularly expensive because of the lack of road access and the need to barge equipment and supplies during the periods when the Cook Inlet is ice free.

Add those risks and costs to the marketing and permitting issues and it's not too difficult to see why more companies haven't entered the Cook Inlet gas business.

So, what needs to happen to encourage development of the trillions of cubic feet of natural gas that probably still lie in the Cook Inlet basin?

Ehm thinks that tax and royalty incentives for small independent oil and gas companies would help alleviate the cost factors.

"This could be a lowering of the state's royalty for the initial production and could be increased with time or with the increase in volume of production," Ehm said. "Severance taxes and property taxes could be lowered in a similar manner."

Myers thinks that there is scope for improvement in the permitting system. For example, the state has looked into implementing a universal, electronic permitting system — perhaps something like that could help. The Alaska Department of Natural Resources has taken a central role in streamlining the state permitting process, Myers said. Perhaps more state/federal coordination could be done and standard permit templates could be used for similar activities in the same area — Ken Boyd, another previous DOG director, has championed this type of approach.

"(But) it's complicated and how do you do it better and then how do you also respect the multiple use nature of the Kenai?" Myers cautioned.

Natural gas market is the key

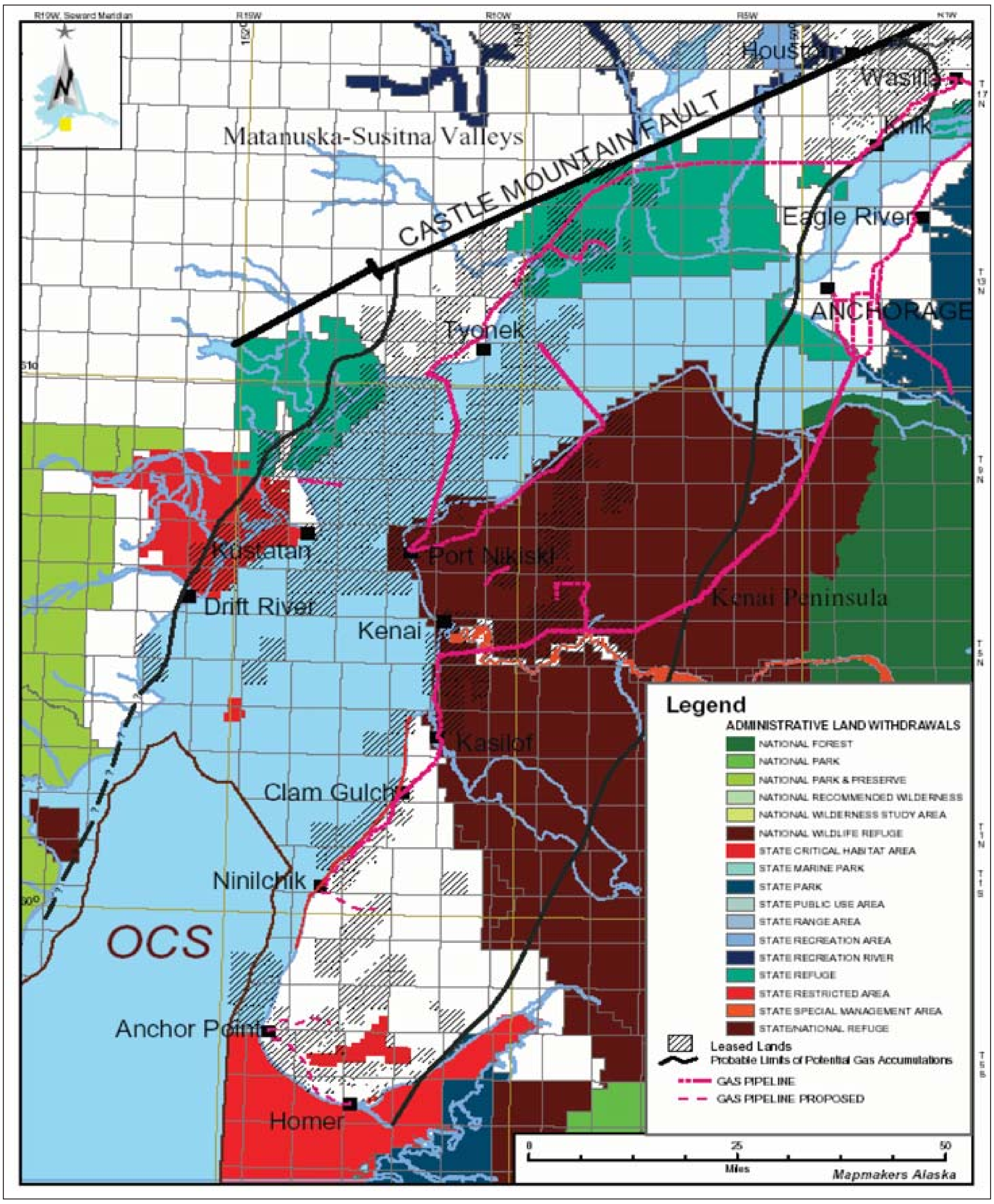
However, Myers thinks that the key to a flourishing Cook Inlet natural gas industry is the gas market. Resolve the issues that hamper the gas market and solutions to other issues will emerge.

"You have a difficult situation trying to get folks to invest capital up here," he said.

Companies need to be exploring for some of the larger opportunities, rather than just exploring on the fringes of the basin, he said. And to support that type of exploration, Myers particularly commends the proposals for state incentives to bring a jack-up rig to the Cook Inlet.

"(But) we (also) need, I think, to have a way to sell a large volume of gas into the market at higher prices," he said.

A more robust export market or a value-added manufacturing market could enable someone to monetize a larger discovery, he thinks. The Agrium fertilizer plant is limited in what it can pay for gas but LNG seems a high value export product.



Areas of administrative land around the Cook Inlet basin, showing the national park, the national wildlife refuge and state critical habitat areas. **CREDIT:** From U.S. Department of Energy Southcentral Alaska Natural Gas Study, June 2004

A bidirectional spur line

The implications of a North Slope gas spur line to Southcentral Alaska particularly intrigue Myers, especially if that line

see **INLET GAS** *page 15*

NORTH SLOPE

Final Nikaitchuq permits expected soon

In its Nov. 27 edition Petroleum News reported that Kerr-McGee did not expect to make a decision on development of its Alaska North Slope Nikaitchuq discovery before the end of the year, as company executives previously indicated would happen.

If the project was sanctioned in late 2005 the big independent would begin construction of the first of four Nikaitchuq production pads with the intention of producing first oil in March or April 2006, effectively setting a record on the North Slope for the shortest time between the discovery of a field and when it went into production.

Unlike the other three proposed production pads, oil production from wells at the first pad (Oliktok Point) would be processed through existing facilities at the nearby Kuparuk River unit, necessitating the need for a processing agreement with Kuparuk operator ConocoPhillips.

Unlike the other three proposed production pads, oil production from wells at the first pad (Oliktok Point) would be processed through existing facilities at the nearby Kuparuk River unit, necessitating the need for a processing agreement with Kuparuk operator ConocoPhillips.

In November Kerr-McGee said there were four issues that had to be resolved before its board would consider sanctioning development of Nikaitchuq:

- reservoir stimulation
- royalty relief from the state of Alaska
- pipeline and processing agreements with ConocoPhillips
- permitting

Since the Nov. 27 report Petroleum News discovered the major permit not yet issued for the Nikaitchuq project was from the U.S. Corps of Engineers.

On Dec. 7 Kerr-McGee spokesman John Christiansen told Petroleum News that the company expects "to have all the necessary permits in hand over the next couple of months, maybe sooner."

Currently the company is making good progress on "conducting reservoir stimulation studies, analyzing core data and conducting analog studies," he said.

"At the same time we're working with the State of Alaska on issues relating to royalty relief," which state officials confirmed is moving forward.

Christiansen would not comment on negotiations with ConocoPhillips, but he did say that the "sooner we resolve those issues, the sooner we will be able to move forward."

No vote to sanction will occur, he said, until Kerr-McGee has "royalty relief, permits and a third party processing agreement in hand."

Christiansen offered no new timetable for project sanctioning.

At full capacity Nikaitchuq is expected to produce 60,000 barrels of oil per day and small amounts of natural gas through 2026.

Editor's note: In September Kerr-McGee established a full-time office in Anchorage (see Oct. 9 issue of Petroleum News), a step-up from the sporadically manned office the company initially had in the ASRC building, which housed ASRC Energy Services, a Kerr-McGee contractor.

—KAY CASHMAN

● ALASKA

Gas negotiations: two different views

Irwin, Rutherford, Myers say gas line talks raise concerns; governor says Legislature must approve oil tax changes, balance sought

By KRISTEN NELSON

Petroleum News Editor-in-Chief

Two compass pieces in the Dec. 7 Opinion section of the Anchorage Daily News give a flavor of the discussion likely to take place when an agreement between the State of Alaska and the North Slope producers is reached and a gas pipeline contract becomes public.

One column was written by three former administration officials, the other by Gov. Frank Murkowski.

Tom Irwin was commissioner of the Department of Natural Resources until dismissed by the governor in late October. Marty Rutherford was one of the department's deputy commissioners and Mark Myers was director of the department's Division of Oil and Gas. They were among the six department officials who resigned after Irwin was terminated, citing concerns with the direction of the administration's gas pipeline negotiations.

TOM IRWIN

The governor has been pursuing a gas pipeline contract with the major holders of known North Slope natural gas — BP, ConocoPhillips and ExxonMobil — for two years. Negotiations have been intense since the summer and in October the state reached a basic agreement with ConocoPhillips. That contract, along with terms being discussed with BP and ExxonMobil, remain confidential, but the governor has made a number of the state's goals public. The governor also released an October memo by Irwin asking Alaska Attorney General David Marquez for legal clarification on a number of the issues under negotiation.

Oil tax structure being negotiated

In their Dec. 7 compass piece, titled "Gas line talks raise several concerns," Irwin, Rutherford and Myers said the Alaska Stranded Gas Development Act "allows for limited changes to Alaska's fiscal terms on gas only," while the proposed contract "greatly exceeds the act by making far-reaching changes to Alaska's gas and oil fiscal structure."

The governor's Dec. 7 compass piece, titled "Gas pact rests on tripod of dollars, exploring, in-state use," was written in response to questions raised by the Daily News Dec. 5, Murkowski said, questions left over from the late November forum on the gas contract sponsored by the University of Alaska Anchorage's Institute of Social and Economic Research.

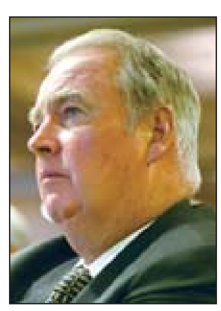
MARTY RUTHERFORD

The first question, the governor said, was: "Which is harder to negotiate, taxes and royalties for the proposed gas line or a rewrite of oil taxes?"

"Fiscal certainty on oil was not included in the Stranded Gas Development Act," the governor said, "so we will need the Legislature's authorization to include it in the gas line contract." The governor went on to say that oil tax certainty is important to the producers "because they do not want the fiscal terms they negotiate on gas effectively reduced by new taxes on oil." The producers remember, the governor said, that after construction began on the trans-Alaska oil pipeline, the Legislature "revamped oil taxes."

ELF revenue declining

The governor also said the economic limit factor formula in the state's severance tax on oil will result in the severance tax only applying to 19 percent of the barrels produced in 15 years. Murkowski said "the state needs to change oil tax laws now. We are simply taking advantage of the fact that the producers also have reason to negotiate this issue as part of the gas line contract."



JUDY PATRICK

GOV. FRANK MURKOWSKI

The governor said the state "will not agree to a change in the oil tax system that does not advantage the state today and going forward," and said the negotiations are over "the premium the state is demanding during periods of high oil prices."

Irwin, Rutherford and Myers said: "Changes in how the state manages its oil and gas should be legal (including constitutional), fair to all parties, and continue to provide the state with a stable, secure and enhanced revenue stream."

MARK MYERS

Gas in kind a concern

Irwin, Rutherford and Myers said they are concerned that the proposed contract will require the state to take its gas, both royalties and in lieu of severance tax, "as gas rather than receiving its cash value from the producers." The three said they believe the state will lose money by doing this, because it will "have to pay billions in production taxes" which it wouldn't have to pay if it took the cash value of the gas and will have to pay "over $10 billion" up front in firm transportation fees.

The state will also, the three said, have to compete with the producers in marketing natural gas "in markets they currently dominate."

The risk is compounded, they said, because the state won't control the volumes of gas it receives — the producers will control those volumes.

The pipeline is economic "without the state taking this unnecessary risk, and the state can still be a pipeline owner," the three said. They said that under the proposed contract terms the state would "surrender billions of dollars of revenue we are currently entitled to receive."

Other issues

The governor also responded to a question on how the administration was factoring in "indirect benefits and economic development in analyzing the value of a gas project, rather than just counting tax and revenue dollars?"

The governor said such other values include third-party explorer access to a gas pipeline and in-state use of gas.

He said the administration's policy "is to make sure we increase the number of North Slope explorers. If explorers cannot get their gas to market, they will not explore. Explorers who look for gas will also find oil."

"Part of the reason the negotiations are taking so long is because we have been fighting for these provisions that are clearly in Alaska's interest," the governor said.

The Federal Energy Regulatory Commission will regulate the gas pipeline and access to it, he said. "The state fought for and obtained FERC regulations unique to Alaska in order to protect explorer access. We have maintained and strengthened these provisions in the contract."

The governor said the state has "insisted on four off-take points along the line" so that Alaskans will have access to gas. And the gas will be cheaper to Alaskans than in the Lower 48 "because transportation rates will be based on mileage from the North Slope to the point of use in Alaska."

The governor said the state is "looking for that balance of dollars, explorer access and in-state use that is best for Alaska." As to why negotiations are taking so long, "the Legislature told the administration to nego-

see **VIEWS** page 22

continued from page 13

INLET GAS

were to have expansion capability and capabilities for bidirectional flow. A spur line could link the Cook Inlet area to North Slope gas and to the Lower 48 gas market, thus fostering a vibrant gas industry in Southcentral Alaska.

"You actually could see that being an export line as much as an import line, should exploration really be successful in the Inlet," Myers said.

But if implemented the wrong way, a spur line could provide a disincentive for exploration and development in the Cook Inlet.

"Access to the major (North Slope) pipeline, both intake and offtake, is a critical role," Myers said. "You need predictability in being able to do that and a tariff structure that supports it."

Then you would have full access to Lower 48 markets and Lower 48 prices, he said.

So what does all this mean? With an impending production cliff, plans for a North Slope gas line and gas exploration occurring in Alaska's Susitna and Nenana basins, the Cook Inlet gas industry seems to be heading for some significant changes. Will it fall over the cliff or really start to flourish?

"We're on the verge of something but I don't know whether it's a boom or bust," Barnes said. "The outcome is going to be determined by how the challenges are met — by the industry, by the regulatory permitting bodies, by consumers, by outside forces." ●

● ALASKA

Alaska North Slope crude output up slightly

Alpine hits new daily production record with completion of ACX2 facility expansion, allowing production up to 140,000 bpd

By KRISTEN NELSON

Petroleum News Editor-in-Chief

Alaska North Slope crude oil production averaged 892,192 barrels per day in November, up 0.9 percent from an October average of 884,080 bpd, including a new daily production record at Alpine on the western side of the slope.

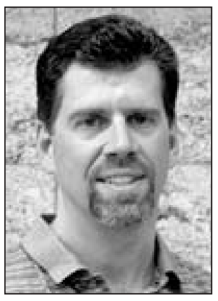
BP Exploration (Alaska)'s Milne Point field had the largest percentage month-to-month increase, up 3.78 percent to average 42,748 bpd in November, compared to 41,191 bpd in October. That level of production was a 9.8 percent decline from September, when the field averaged 45,653 bpd. The Alaska Department of Revenue said Milne had gas compressor problems Oct. 22-23. On Nov. 5 the field was shut down due to generator failure, dropping production to 13,004 barrels; the field returned to production levels in the plus-40,000 bpd range Nov. 9, and hit a one-day high for the month of 46,214 barrels Nov. 18.

BP-operated Endicott averaged 21,673 bpd in November, up 3.4 percent from an October average of 20,970 bpd. Endicott production includes Sag Delta, Eider and Badami.

Alpine hits 136,141 bpd Nov. 19

The ConocoPhillips Alaska-operated Alpine field averaged 130,597 bpd in November, up 1.9 percent from an October average of 128,114 bpd. Production hit 136,141 bpd Nov. 19 at Alpine, a one-day record at the field, ConocoPhillips Alaska spokeswoman Dawn Patience told Petroleum News.

ConocoPhillips Alaska (78 percent) partners with Anadarko Petroleum (22 percent) at Alpine. Initially projected to produce 70,000 bpd, further study of the reservoir and the decision to go with horizontal wells, waterflood and enhanced oil recovery changed the initial capacity to 80,000 bpd, John Whitehead, ConocoPhillips Alaska's vice president for the western North Slope, told Petroleum News in a June 2004 interview. But as more wells were drilled, he said, "they recognized that they had well capacity to go above the 80,000 barrels a day."



FORREST CRANE

MARK IRELAND

Operations, engineering and drilling cooperated in tweaking the original Alpine facilities, a range of activities from learning how to operate at a little higher rate to things like installing a little bigger valve, Whitehead said. For the reservoir engineers, he said, it was a matter of working on "how do we manage this reservoir correctly at a higher level."

From 2001 to 2002, de-bottlenecking increased Alpine production to 100,000 to 105,000 bpd.

And there was a "junior" capacity expansion project in the summer of 2002, upgrading transfer pumps at Kuparuk where Alpine buys seawater for injection, allowing the shipment of some 10,000 additional bpd of water to Alpine for fluid replacement in the reservoir.

> *Production hit 136,141 bpd Nov. 19 at Alpine, a one-day record at the field, ConocoPhillips Alaska spokeswoman Dawn Patience told Petroleum News.*

The first major expansion project, ACX1, was approved in 2003. That project increased produced water handling capacity from 10,000 bpd to 100,000 bpd Whitehead said, and also allowed an increased production of about 5,000 bpd of oil.

ACX2, like ACX1 about a $60 million project, was also begun in 2004 and completed in 2005. ACX2, Whitehead said, is designed to increase Alpine capacity to 140,000 bpd. Seawater injection capacity was increased to more than 130,000 bpd to compensate for increased oil production. ACX2 also includes a small increase in gas handling capacity, Whitehead said, from 160 million cubic feet a day to about 180 million.

Mark Ireland, ConocoPhillips Alaska's Western North Slope development manager, told Petroleum News this August that work on ACX2 was completed in June during a maintenance shutdown with installation of the final cooling equipment. When the field came back up, production rates began to rise, he said.

Ireland said work also began over the summer for ACX3, a condensate stabilizer which provides a cleaner break between the oil and gas leaving the facility, providing more hydrocarbon components to aid in enhanced oil recovery. ACX3, Ireland said, is geared to long-term production increases through enhanced oil recovery, rather than to immediate production increases.

Prudhoe production up

Production from the BP-operated Prudhoe Bay field averaged 424,393 bpd in November, up 1.7 percent from an October average of 417,436 bpd. Prudhoe Bay includes Midnight Sun, Aurora, Polaris, Borealis and Orion.

BP-operated Lisburne (including Point McIntyre and Niakuk) averaged 40,799 bpd in November, down 0.4 percent from an October average of 40,953 bpd.

The ConocoPhillips-operated Kuparuk River field (which includes production from West Sak, Tabasco, Tarn, Meltwater and Palm) averaged 171,998 bpd in November, down 1.2 percent from an October average of 174,014 bpd.

BP-operated Northstar had the steepest month-to-month decline, averaging 59,984 bpd in November, down 2.3 percent from an October average of 61,402 bpd. Revenue said there was a plant shutdown at Northstar Nov. 17 due to a power outage, with reports of problems restarting a compressor. Production at the field dipped to 41,566 bpd Nov. 17, but got back above the 60,000-bpd level by Nov. 21 and remained above 62,000-bpd for the last nine days of the month.

The North Slope temperature at Pump Station No. 1 averaged minus 9.6 degrees Fahrenheit for November, down from a 21.7 degree average in October. Revenue said the three-year average temperature for November is 5.6 degrees F.

Cook Inlet production averaged 18,790 bpd in November, down 4.6 percent from an October average of 19.691 bpd. ●

VIENNA, AUSTRIA

OPEC chief suggests no output change

OPEC members support keeping production at present levels, the president of the Organization of Petroleum Exporting Countries said Dec. 2, looking ahead to the organization's next ministerial meeting later in December.

The comments by Sheik Ahmed Fahd Al Ahmed Al Sabah, who is also Kuwait's oil minister, indicated that the organization will not change its output when the ministers meet Dec. 12.

"I have support to keep output unchanged," he said ahead of a meeting of European Union and OPEC ministers in the Austrian capital.

But he said the group had yet to decide if it would continue to offer an additional 2 million barrels a day spare capacity to the market, telling reporters that would be discussed at the Dec. 12 meeting in Kuwait.

OPEC offered an extra 2 million barrels above the organization's 28 million barrel daily ceiling if demand was there at its September ministerial meeting in a move to calm volatile markets. With prices moving lower in recent weeks, that reassurance may now not be needed.

Refinery tightness strains market stability

The participants said in a joint EU-OPEC statement that they "recognized ... that the serious tightness in the global refinery system would continue to strain market stability in the next few years."

"We will continue to urge consumer countries to invest in the downstream sector so as to relieve the pressure on product prices," Al Sabah said in comments prepared for delivery at the closed meeting.

The Vienna meeting is focused on coordinating oil supply and demand and planning energy strategies for the coming years.

The second meeting of the OPEC-EU Energy Ministerial Dialogue follows a first round of talks in Brussels in June. That meeting was the first at this level between the two organizations.

The European Union is represented by EU Council and U.K. Minister of Energy Malcolm Wicks; Andris Piebalgs, the European Commissioner for Energy, and Austrian Economics Minister Martin Bartenstein, OPEC said.

OPEC representatives include Al Sabah, OPEC Secretary-General Adnan Shihab-Eldin and Nigerian Oil Minister Edmund Maduabebe Daukoru, tapped to take over as OPEC president on Jan. 1.

—THE ASSOCIATED PRESS

● GUEST EDITORIAL

Alaska's natural gas strategy

By DOUG REYNOLDS, PH.D.
For Petroleum News

COMMENTARY

Alaska faces two important natural gas pipeline issues. One is the route and the other is Alaska's fiscal system. Both will determine state revenues for decades to come. First consider the route.

If Alaska wanted an All-Alaska, liquefied natural gas project of say 3 billion cubic feet a day, that would require huge liquefaction facilities in Valdez. Typically a one-half bcf LNG module — also called a train — would take two and a half years to build. Usually two trains built simultaneously takes three years. So six such trains built two at a time would take about nine years to complete. You could try to build more trains simultaneously, but given the cramped area in Valdez, that would be very risky in terms of docking collisions, bottlenecks and severe cost overruns. Constructing an infrastructure in Valdez with more roads and a huge new port to offload all the capital and equipment would take another two years. So an All-Alaska line would easily take 11 years to build, the same as Nigeria's 3 bcf Bonny Island facility. This is being optimistic since Valdez has fisheries, oil terminals, and tourists that cramp the small bay. Physical space in Valdez is extremely limited so there are likely to be bottlenecks at every turn during construction.

So if a 3 bcf pipeline to Valdez is built and made ready for the first two LNG trains then it will sit partially unused for the rest of the six years needed to finish the remaining trains. In other words all the interest paid on the initial debt to build the pipeline and the conditioning plant would accrue for those years. The end result would easily be a four or five dollar tariff for natural gas even with tax breaks. Plus the LNG will likely receive a substantially lower price on the Pacific Rim than in Chicago.

The alternative is a 4 bcf AlCan route that can be built in four years, have a two and a half dollar tariff and receive a higher price at the end of the line. Even if construction will not start in four years, the AlCan route could actually be finished before an LNG facility is fully finished. It will cost less and give Alaska a greater value increasing PFD dividends substantially.

New tax system more important

The second issue is even more important to the state yet no one is talking about it — the new tax system that Alaska is likely to negotiate. Alaska has the opportunity to negotiate a fiscal system where severance taxes can increase as oil and gas prices increase — a progressive tax. Why is a progressive tax so important? Future oil and gas prices are set to increase even more than they have in the recent past. Alaska needs to prepare for those high prices with a tax system that can extract rent from our oil and gas leases.

There are a number of reasons to expect high oil and gas prices. Mature basins such as those in the United States face declining production. Large producers such as Russia are government-owned enterprises, which will be concentrating on rent extraction rather than on developing more incentives to expand production. Therefore they will have little incentive to expand production. Also OPEC producers are at their capacity limits of production. Any new production from OPEC will now require entirely new upstream exploration and development. Again, they will not have much incentive to aggressively expand their capacities since they are already making plenty of money. Venezuela for example recently changed all oil and gas contracts retroactively to increase government revenues and reduce incentives to oil and gas companies working within their borders.

Even if construction will not start in four years, the AlCan route could actually be finished before an LNG facility is fully finished. It will cost less and give Alaska a greater value increasing PFD dividends substantially.

Interestingly most LNG producers who are in competition with Alaska are also government-owned producers. That means they will less aggressively expand their production than will privately owned gas producers. Plus since oil and gas are substitutes for each other on a number of dimensions, then oil and gas prices will follow each other closely, no matter the level of natural gas supplies. Therefore future oil and gas prices look to be high.

Progressive tax: why Norway does better than Alaska

I believe we must take advantage of these expected price spikes with higher severance taxes. That means a progressive severance tax on oil and gas. In exchange for a steep progressive upside tax, we can give tax breaks for price collapses. Such a progressive tax rate will help Alaska reap a huge windfall as oil and gas prices stay high and go higher in the future.

Oil companies might fear such a progressive tax — if too steep on the upside — will take away any incentive for expanding production. However, marginal fields only provide the state with small amounts of new revenues. There will still be plenty of incentives to aggressively exploit those fields, so why worry about an extra 5 or 10 percent of production output by giving away an extra 30 or 50 percent of revenues. It would be much better to extract more rent and not to worry about expanding production rates. Plus current reserves will naturally expand to keep the pipeline full.

What kind of progressive tax should we fight for? Start with a base price of about $5 per thousand cubic feet at the Henry Hub. Index the base price to inflation. At the base price then have a 12.5 percent royalty and a 15 percent severance tax with no economic limit factor. Then for every 10 percent increase in the Henry Hub price above the base price, increase the severance tax by 1 percent. So at a $5.50 Henry Hub price, the severance would be 16 percent and so on up to a maximum of say 35 percent at a price of $34 per mcf. In exchange, give down side tax reductions.

For oil we should start with a base price of $30 per barrel and create a similar progressive tax with no ELF where the severance tax increases by 1 percent for every 10 percent that the price increases. Also include lower severance taxes for prices below $30 per barrel.

If we look to other countries, we can see the difference. Norway for example has a substantial welfare state, yet Norway's petroleum fund is already at $150 billion, about five times bigger than Alaska's Permanent Fund even though Norway only produces about three times as much oil as we do. Part of the difference is that we are a state and the federal government takes a share. Also we have higher costs, but the bottom line is that Norway extracts a higher percent of the rent available than does Alaska. Now we can rectify this lack of revenues especially in light of the new market reality. ●

Dr. Doug Reynolds is an associate professor of energy and oil economics at the University of Alaska Fairbanks. This paper is part of Prof. Reynolds' university-required public service to the community.

GILLETTE, WYO.

Wyoming split-estate law to be tested

A Johnson County rancher will be the first landowner to use Wyoming's new split-estate law to challenge oil and gas development on his ranch.

Steve Adami is scheduled to take his case before the state Oil and Gas Conservation Commission Dec. 6 in Casper.

In a letter Nov. 2, Adami asked the commission to increase the amount of bond money Gillette-based Kennedy Oil must put up for reclamation of off-channel water pits related to natural gas wells on his ranch east of Buffalo.

In a letter Nov. 2, Adami asked the commission to increase the amount of bond money Gillette-based Kennedy Oil must put up for reclamation of off-channel water pits related to natural gas wells on his ranch east of Buffalo.

"The appeal to the Oil and Gas Commission is not whether to build the pits but whether the bonds are adequate," Adami said.

Kennedy Oil owner John Kennedy maintains Adami's claims are off-base and any reclamation will be properly done no matter the amount of bond money.

Reclamation has "always been taken care of and always will be taken care of in the future regardless of what bonds are being put up," Kennedy said.

Kennedy Oil has posted $500 of bonding with the commission under the split-estate act for the off-channel pits that will be used for water from the wells, said Ruth Reile, who operates the permit for Kennedy Oil. A split estate is when the surface land and the minerals underneath have separate owners.

Adami wants the bonding level closer to $100,000 per well, a figure Kennedy said is too high.

"The reason it's $500 is because we've already posted reclamation bonds," Reile said. "The only thing that's left out there is the value of the grazing because there's no tangible improvements or growing crops."

Adami counters that the cost of reclamation is higher. Documents Kennedy filed with the commission show reclamation costs to be $83,809.

The Oil and Gas Commission approved separate reclamation bonds for that amount on Sept. 29. It covers the cost of reclaiming the six pits.

Don Likwartz, director of the Oil and Gas Conservation Commission, said the question that will be brought before the five-member commission in December is whether the $500 blanket split-estate bond is adequate.

Adami can challenge the commission's decision to the District Court, Likwartz said.

The water pits are on hold until the issue between Adami and Kennedy is resolved, Reile said.

—THE ASSOCIATED PRESS

● ALASKA

Appeals court to hear Exxon Valdez case

Oral arguments scheduled in January before 9th Circuit Court of Appeals; spill occurred in '89; jury ordered payment in '94

THE ASSOCIATED PRESS

The long-running Exxon Valdez lawsuit will have another day in court in January.

The 9th U.S. Circuit Court of Appeals on Jan. 27 in San Francisco will hear arguments over punitive damages from the 1989 Exxon Valdez oil spill in Prince William Sound.

The court will hear oral arguments about whether plaintiffs should get $4.5 billion plus interest in punitive damages.

Attorney David Oesting said the hearing should be the final argument before the Appeals Court over punitive damages.

Plaintiff Steve Vanek, a Ninilchik commercial fisherman, is not expecting a settlement soon.

"It will be another year or a year and a half before that bloody 9th Circuit makes a decision," Vanek predicted. "I won't count on it until I see the check."

It's impossible to predict when the Appeals Court will issue a decision, Oesting said. He also expects Exxon to appeal to the U.S. Supreme Court.

"I don't know if the Supreme Court will (choose) to get involved," Oesting said.

Plaintiffs dying

Each year fewer fishermen, Native subsistence gatherers and other plaintiffs are still alive to track the court case. Oesting said he believes that around 3,000 of the plaintiffs have died while waiting for the billions in punitive damages a jury first ordered Exxon, now ExxonMobil, to pay in 1994.

More than 30,000 plaintiffs from oiled areas remain, Oesting said.

The Exxon public affairs office referred inquiries to the company's Web site. The site offers a lengthy defense of the company position.

"Despite complaints by the plaintiffs, which are designed to sway public opinion, ExxonMobil is exercising a fundamental right to appeal these damages, a right to which every American individual and company is entitled," the Web site said.

Exxon has paid more than $3 billion in cleanup costs, government settlements, fines and compensation. The $4.5 billion at issue is just for punishment, Exxon said.

Spill occurred in March 1989

The Exxon Valdez ran aground on a charted reef in Prince William Sound in March 1989, creating America's largest tanker spill. The estimated 11 million gallons of spilled oil fouled the sound, contaminated an estimated 1,300 miles of shoreline, killed marine creatures and disrupted commercial fishing.

A jury in 1994 first awarded $5 billion in punitive damages to people whose livelihoods were harmed by the spill. Exxon appealed and the 9th Circuit Court of Appeals said in 2001 that the award was too much.

The U.S. District Court trial judge, H. Russel Holland, has reviewed the amount twice at the direction of the Appeals Court. Holland made his most recent ruling almost two years ago. He said Exxon should pay $4.5 billion, an award that could amount to almost $7 billion with interest.

The judge said Exxon had "demonstrated reckless disregard for a broad range of legitimate Alaska concerns."

ExxonMobil, the world's largest publicly traded oil company, earned nearly $10 billion in the third quarter of this year. ●

● CANADA

Cash flow bolsters Canadian cap-ex

Suncor budgets C$2.5 billion for oil sands; Shell Canada investing in sands, gas; Canadian Natural Resources in Primrose

By GARY PARK
Petroleum News Canadian Contributing Writer

The payoff from a prolonged cash flow bonanza is starting to make its impact on the Canadian oil patch.

As capital spending plans start to roll out of Calgary head offices, Suncor Energy has hiked its 2006 budget by 30 percent from 2005 to C$3.5 billion, Shell Canada has pumped in an extra 60 percent to earmark C$2.7 billion and Canadian Natural Resources plans an initial investment of C$600 million in its Primrose East bitumen project in northeastern Alberta.

Suncor: C$1.8B to expansion

Not surprisingly, oil sands pioneer Suncor is pumping C$2.5 billion into its primary interest, with C$1.8 billion directed to the next phase of expansion at its Fort McMurray operations.

Although production will remain unchanged at 260,000 barrels per day next year, the company is aiming for 360,000 bpd in 2008 and 500,000 bpd in 2012.

However, Amir Arif, an analyst with Freidman, Billings & Co. in Virginia, speculated that what Suncor has allocated to the oil sands implies that the company is shooting for a 2007 completion.

Some of the capital will also go to Suncor's Firebag venture, boosting output to 70,000 bpd.

Of the remaining C$1 billion, C$250 million will lower sulfur levels at Suncor's Ontario refinery, C$225 million will produce low-sulfur fuels at the company's two Denver refineries and converting the plants to handle synthetic crude from northern Alberta and C$325 million will be spent on natural gas exploration and production.

One-fifth of Shell Canada's capital budget, C$465 million, will be spent on the first-stage expansion of the Athabasca oil sands facility, operated 60 percent by Shell, with 20 percent held by both Chevron Canada and Western Oil Sands.

The objective is to add 25,000 bpd to Athabasca production, reaching 180,000 bpd in 2009 as part of a C$7 billion plan to hit 600,000 bpd over the next decade.

Western Oil Sands is budgeting C$233 million for the oil sands in 2006, with the objective of hitting a net 120,000 bpd in the next 8 to 10 years.

Shell: C$405M to unconventional gas

Shell Canada is backing its commitment to grow gas production by pumping C$405 million into the unconventional sector.

A primary target is the Tay field in the west-central region of Alberta where an 800 billion cubic foot raw gas find last year has spurred the company's reawakening interest in the gas sector.

Shell Canada also expects to spend C$45 million on its share of the Mackenzie Gas Project, which is scheduled to enter the public hearing phase in January and get a final decision from the partner companies in late 2006 or early 2007.

Canadian Natural's plan to invest C$600 million in Primrose East underpins its goal of producing 120,000 bpd, throwing out a challenge to Imperial Oil, the region's leader at 137,000 bpd.

Current output from Wolf Lake/Primrose is 50,000-60,000 bpd, but is expected to average 80,000 bpd by mid-2006 and chase the 120,000 bpd objective in early 2009.

The independent predicts Primrose East will generate C$1 billion in capital spending and C$600 million in royalty and tax payments over 25 years. ●

COOK INLET

MMS asks for interest in '07 inlet sale

The Department of the Interior's Minerals Management Service is asking for expressions of interest by industry in a proposed 2007 Cook Inlet outer continental shelf lease sale.

Two Cook Inlet sales are included in Interior's 2002-07 five-year OCS leasing program. An environmental impact statement covering both sales was prepared and the first sale was held in 2004, but received no bids.

The second sale was proposed for 2006, but when MMS received no comments or interest from industry, it delayed the sale to 2007.

MMS is now asking if there is interest in holding Sale 199 in May 2007. "If bona fide interest from companies is received, we will proceed with the planning for the sale. If no interest is shown, Sale 199 will not be held," the agency said in the Federal Register Dec. 6.

JUDY PATRICK

JOHN GOLL

Goll: stable energy supply needed in area

"We are hopeful that companies have renewed interest in Cook Inlet given the current energy situation and the need for natural gas in the area," MMS Alaska Regional Director John Goll said in a statement. "The federal OCS in Cook Inlet remains relatively unexplored, with the last exploration well drilled in 1984. The region needs a stable supply of energy and raw materials to keep the state's economy growing. Sales in the federal portion of Cook Inlet would complement the state's strong program," Goll said.

Comments are due within 30 days. If there is interest, area identification would be in February, National Environmental Policy Act/Environmental Assessment Review (or supplemental EIS) and consistency determination would be in December 2006. A final notice of sale would be published in April 2007 and the sale would be held in May 2007.

The State of Alaska receives 27 percent of all revenues generated as a result of federal leases that lie within three to six miles offshore the Alaska coast.

—PETROLEUM NEWS

ALASKA

RCA looks at regulating pipelines by size

The Regulatory Commission of Alaska has opened a docket, R-05-11, to consider whether it should establish two or more classes of pipelines and the requirements that it should prescribe for each class.

The commission said in a Dec. 2 order that it recognizes "that the cost of regulation can be prohibitive for small, producer-owned pipelines and that full regulation of small pipelines could discourage exploration and development of Alaska's resources."

The commission said it should consider simplified regulation "if current regulation is unduly burdensome and adversely affects the development of Alaska's oil and gas resources." The commission said it also "must balance the need for such regulatory change with the public interest in open access to pipelines and reasonable transportation rates."

Can regulatory burden be eased?

The commission said it decided to open the docket at its Nov. 4 public meeting and said its focus is on whether it can ease the regulatory burden for "small, producer-owned pipelines that ship only the producer's products, while still adequately protecting the interests of unaffiliated producers, end-users and the public."

Comments on whether the commission should establish two or more classes of pipelines, and the reporting, accounting and other regulatory requirements for each category, are due Jan. 13, with reply comments due Jan. 27. The commission said it is also interested in hearing "how implementation of comments will encourage development, provide cost-effective regulation, provide open access to pipelines, and allow for reasonable transportation rates while protecting the public interest."

—PETROLEUM NEWS

● ALBERTA

Big coalbed methane play up for grabs

By GARY PARK

Petroleum News Canadian Contributing Writer

The largest coalbed methane play in North America (based on reserve size) will be put to the test Dec. 14 when Alberta holds its largest land sale in close to six years.

More than 1 million acres will be on the block, dominated by the Mannville coalbed methane seams in central Alberta.

For many industry observers, they represent a substantial gamble given that companies are still working on the technology to turn the Mannville play into a commercially viable prospect.

They caution that heavy research and development spending will be needed to develop a formation that contains a possible 300 trillion cubic feet and note that operational costs for the deeper, wet Manville coals could be three to four times greater than the C$250,000 for Alberta's Horseshoe Canyon play.

Corbett Creek project commercial

For now, Trident Exploration, with joint venture partners Nexen (40 percent) and Red Willow Production (10 percent), has declared the Mannville's Corbett Creek project to be commercially profitable and announced plans to spend C$400 million over the next 18 months.

"They obviously have something there that's encouraging," said Mike Dawson, president of the Canadian Society for Unconventional Gas, when the announcement was made in August.

But he said the resource potential in the Mannville offers a reasonable chance of kick-starting Alberta's second coalbed methane play after Horseshoe Canyon.

Nexen Chief Executive Officer Charlie Fischer said the partnership's 320,000 net acres contained about 3 tcf of gas-in-place that should produce 150 million cubic feet per day by 2011.However, Trident will not say whether it intends to be the major bidder in the Dec. 14 sale.

Coalbed methane has made rapid strides in Alberta over recent years, with production now at 200 million cubic feet per day and headed for 500 million in 2006. Coalbed methane well completions are expected to pass the 3,000-mark this year.

Although coalbed methane is a tougher challenge than conventional gas, once it comes on stream it has a longer life than a conventional well because coals have up to 20 times more gas.

FirstEnergy Capital estimates that coalbed methane needs gas prices of US$4.25 per thousand cubic feet to achieve a return of at least 10 percent. ●

NORTH AMERICA

Canada gains 22 drilling rigs, U.S. down 31 rigs in weekly drilling survey

The combined number of rotary drilling rigs operating in the United States and Canada totaled 2,113 during the week ending Dec. 2, a net increase of nine rigs from the prior week and an increase of 409 rigs when compared to the same period a year earlier, according to rig monitor Baker Hughes.

Canada's rig count at the end of the recent week totaled 653, an increase of 22 rigs compared to the previous week and an increase of 194 rigs versus the same period a year ago.

The number of rigs operating in the United States during the recent week was 1,460, a decrease of 31 rigs from the previous week and an increase of 215 rigs compared to the year-ago period. Compared to the previous week only, land rigs dropped by 28 for a total of 1,360 rigs, while offshore rigs slipped by three for a total of 78 rigs. Inland waters rigs were unchanged at 22 rigs.

1,192 U.S. rigs drilling for gas

Of the total number of rigs operating in the United States during the recent week, 1,192 were drilling for natural gas and 264 for oil, while four rigs were being used for miscellaneous purposes. Of the total, 885 rigs were drilling vertical wells, 359 directional wells and 216 horizontal wells.

Among the leading U.S. producing states in the recent week, Texas' rig count plummeted by 13 to total 658 rigs, while Louisiana's dropped by 10 for a total of 171 rigs. Colorado's rig count fell by four to total 83 rigs, while Oklahoma's declined by two to total 147 rigs, New Mexico's decreased by two to 87 rigs, and Alaska's slipped by two for a total of 10 rigs. Wyoming gained one rig for a total of 88 rigs. California was unchanged with 30 rigs.

—RAY TYSON

● WASHINGTON, D.C.

EIA says 2005 price increases reflect supply

DOE's Energy Information Administration says demand drove '04 prices; in '05 spare capacity at lowest level in three decades

PETROLEUM NEWS

Sharp increases in energy prices in 2005 were largely driven by supply concerns due to hurricane-related losses along with a reduction in world oil spare capacity, "which fell to its lowest level in over three decades," the U.S. Department of Energy's Energy Information Administration said Dec. 6 in its short-term energy outlook.

By contrast, the agency said, 2004 energy prices were largely driven up by an increase in demand.

U.S. spot prices for crude oil increased an average of 36 percent so far in 2005, while natural gas prices increased some 47 percent, but total U.S. energy demand has been flat, despite an economic growth of more than 3 percent.

Despite slower demand growth in both China and the United States, world oil prices climbed through the year, the agency said.

Total domestic energy demand is expected to increase at a 2 percent annual rate in 2006, the agency said, and prices for crude oil, petroleum products and natural gas "are projected to remain high through 2006 because of continuing tight international supplies and hurricane-induced supply loses."

It expects West Texas Intermediate to average $57 per barrel in 2005 and $63 per barrel in 2006, regular gasoline to average $2.27 per gallon this year and $2.41 per gallon next year and Henry Hub natural gas prices to average $8.88 per thousand cubic feet in 2005 and $9.30 per mcf in 2006.

The interconnectivity of the natural gas gathering system has speeded up production recovery from hurricane damage and shut-in federal Gulf of Mexico natural gas production is now expected to fall to 6.5 percent of pre-hurricane production by March. Gulf crude oil production is improving at a slower rate, and only 19 percent of pre-Katrina and Rita production is expected to be shut in by March.

World oil markets, U.S. gas markets

The agency said it expects low OPEC spare oil production capacity and rapid world oil demand growth to continue to drive world oil markets in 2006, with other factors, such as extreme weather and geopolitical instability "less certain." Demand growth slowed in 2005 from 2004 levels, "due largely to slower growth in China and the United States," but demand is expected to increase in 2006, "led by an oil demand recovery in the United States."

As both Organization of Petroleum Exporting Countries and non-OPEC supplies increase, the agency expects to see world oil spare production capacity increase in 2006.

Domestic natural gas demand is expected to remain at 2004 levels in 2005 because of high prices and to increase by 1 percent in 2006. Both residential demand and industrial demand are estimated to decline in 2005, residential use because of weak demand in the latter part of last winter and industrial demand "due to the much higher prices for natural gas as a fuel or feedstock." Natural gas use in both sectors is expected to grow in 2006.

Domestic dry natural gas production is expected to be down by 3.8 percent in 2005, mainly due to hurricane disruptions in the Gulf, and to increase by 4.8 percent in 2006, with liquefied natural gas net imports for 2005 at a 2004 level of approximately 650 billion cubic feet, then increase to an average of about 1 tcf in 2006. ●

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

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Business Spotlight

By PAULA EASLEY

FORREST CRANE

Julie Murrell, Staff Scientist

AutryRaynes Engineering and Environmental Consultants

AutryRaynes Engineering & Environmental Consultants, a division of Branches Inc., is an Anchorage-based, female-owned consulting firm specializing in comprehensive environmental studies, project management, permitting and compliance services. Company professionals have permitted Alaska mining operations, utility projects, and oil and gas facilities on the North Slope, in the Beaufort and Chukchi Seas, and in Cook Inlet.

Julie Murrell, an Alaska resident since 1976, joined AutryRaynes in 2004. Since then, she has been fortunate to work on a variety of projects. Julie started in land management in 1977 and continued in that line of work until her retirement from the State of Alaska in August 2004. She and her husband, Tom, enjoy many outdoor sports such as biking, hiking and cross country skiing.

TEXAS

Texas oil, gas production falls; permits up

Oil and gas production declined in Texas during the first nine months of the year despite high prices for the fuels.

Production of crude oil dipped nearly 5 percent, from 263.6 million barrels in the first nine months of 2004 to 250.9 million barrels in the same period this year, according to the Texas Railroad Commission.

Natural gas production fell nearly 4 percent, from 3.8 trillion cubic feet in the first nine months of last year to 3.66 tcf this year.

Production in Texas has been sliding for about three decades. An exception to the decline has been the Barnett Shale, a gas field north and west of Fort Worth. Gas production there rose 19 percent.

More recent figures show an increase in finishing wells and planning to drill new ones.

Permits to drill for oil or gas rose in October to 1,393 compared to 1,178 in the same month of 2004, the commission said. The October permits, however, were below the September figure of 1,428.

Gas well completions nearly doubled in October, to 943 from 454 a year ago, and oil well completions rose to 370 from 292 a year earlier, the commission said.

—THE ASSOCIATED PRESS

continued from page 3

COBALT

future sales when thousands of previously unavailable deepwater leases start hitting the market next year.

High number of GOM leases due to expire

With the unusually high number of Gulf deepwater leases expiring over the next three to four years, it's also no surprise that the stated mission of Bryant and company is to partake of this golden opportunity to acquire prime real estate in the region.

However, this strategy likely would be an expensive undertaking given the expected competition from much larger companies with deep pockets. More likely, Cobalt's objective would be to partner on leases with the majors and other independents, a common practice in deeper waters of the Gulf where drilling costs are enormous.

The U.S. Minerals Management Service estimates more than 2,500 of these previously leased blocks are scheduled to expire in the 2006-2007 timeframe alone, compared to just 741 leases in the 2004-2005 timeframe, a nearly four-fold increase.

These so-called "newly available" blocks consist of expiring 10-year leases dating back to the Gulf's boom years when the Deepwater Royalty Relief Act was introduced. MMS believes only about 10 percent of these leases will be explored before expiring, particularly in light of the current drilling rig shortage. ●

continued from page 15

VIEWS

tiate a business deal (not litigate) to construct the gas line," he said. What's being negotiated is "a business agreement in which each party is exchanging obligations and benefits," the governor said, adding that he looks "forward to sharing the contract with Alaskans at the earliest opportunity."

More than one contract

Irwin, Rutherford and Myers said that to ensure a gas pipeline is the "best project for Alaska," all proposals need to go to the Legislature, "including proposals by the producers, TransCanada (an independent pipeline to Alberta), and Alaska Gasline Port Authority (a liquefied natural gas project)."

The three also said that information on all the options, "including the state's analysis, and any information necessary to make a truly informed decision on the best alternative" must be made available by the administration to both the public and the Legislature.

"Without this information we may accept a proposal that takes on unnecessary risk to the state; we may not maximize our opportunities and revenues; we may not ensure equal access for new oil and gas exploration companies; and we may not facilitate in-state gas use and associated economic opportunities."

The three also recommended a minimum public comment period of 90 days, saying a proper review will take time, more time than the 30 to 45 day review period the administration envisions.

They said that because there are billions of dollars at stake, "very sophisticated spin and advertising will be used to sell the proposed producer deal. The fact is that Alaska gas is economical to produce and Alaska has choices."

They said they will remain involved as concerned citizens, and urged others to be involved: "It is your oil and gas, and the state's future hangs in the balance," the three wrote. ●

continued from page 1

INSIDER

but the final tally stalled at closer to C$18 million, with lot prices ranging from C$100 to a successful C$4 million bid by Cinch Energy, a junior E&P which produces about 1,315 barrels of oil equivalent per day.

Tristone tentatively plans three auctions in 2006 and, depending on the response, a move to monthly events in 2007.

Tristone Chief Executive Officer George Gosbee sees the trend as logical in the Western Canada Sedimentary Basin, where 8 percent of properties turn over on an annual basis, compared with just 3 percent in the United States, and where the acquisition and divestiture business often leaves marginal wells on the shelf.

He said auctions are the obvious way to deal with smaller properties, but the key is demonstrating to sellers that their holdings won't be unloaded at fire-sale prices.

The auctions can also sell royalty interests separately from working interests.

With prices expected to range from C$200,000 to C$15 million, the auctions have special appeal to smaller companies and individuals, who don't have the resources to go head-to-head with larger rivals when major asset packages come on the market, although Gosbee is counting on larger companies taking the opportunity to consolidate working interests in core areas.

To stir interest in the first auction, Tristone notified 20,000 prospective buyers across North America through a database.

Bates appointed deputy director

Pirtle Bates was appointed as the deputy director for the State of Alaska's Division of Oil and Gas, division director Bill Van Dyke told Petroleum News in early December.

Bates was a former natural resource manager for the division involved in the areawide leasing program.

Isenberg donates $750,000 to APU

Eugene M. Isenberg, CEO and chairman of Nabors Industries, has made a $750,000 personal donation to Alaska Pacific University in Anchorage, Alaska. Isenberg's gift will establish the Eugene M. Isenberg Health Service Administration Endowment Fund, to help support undergraduate and graduate programs in health services administration. One goal of the fund is to create more opportunities for Alaska Natives to receive health services training — APU offers degrees both on its Anchorage campus and through its Rural Alaska Native Adult (or RANA) distance education program.

EUGENE M. ISENBERG

"Alaska is a special place for me and an important place for our company," Isenberg said. "My donation will help support a valuable academic program at a highly-regarded Alaska university."

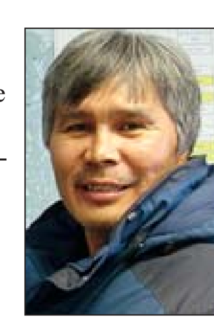
In October 2005 APU awarded Isenberg its Summa Cum Laude award, in recognition of Isenberg's donation to the university.

"The health industry, in rural Alaska and in its urban areas, needs local managers so that we do not need to import leadership," said APU President Dr. Douglas M. North. "Mr. Isenberg's gift is an impressive philanthropic act that will enable APU to educate the health leaders of the future."

Nabors Alaska Drilling, a division of Nabors Industries, has operated in Alaska since the first drilling on the North Slope in 1963.

Aiken made permanent director

Johnny Lee Aiken, a land planning manager for the North Slope Borough's land planning and permitting section, has been appointed section director by the borough's new mayor, Edward Itta.



JOHNNY LEE AIKEN

Aiken replaces Rex Okakok Sr. who retired prior to the recent mayoral election.

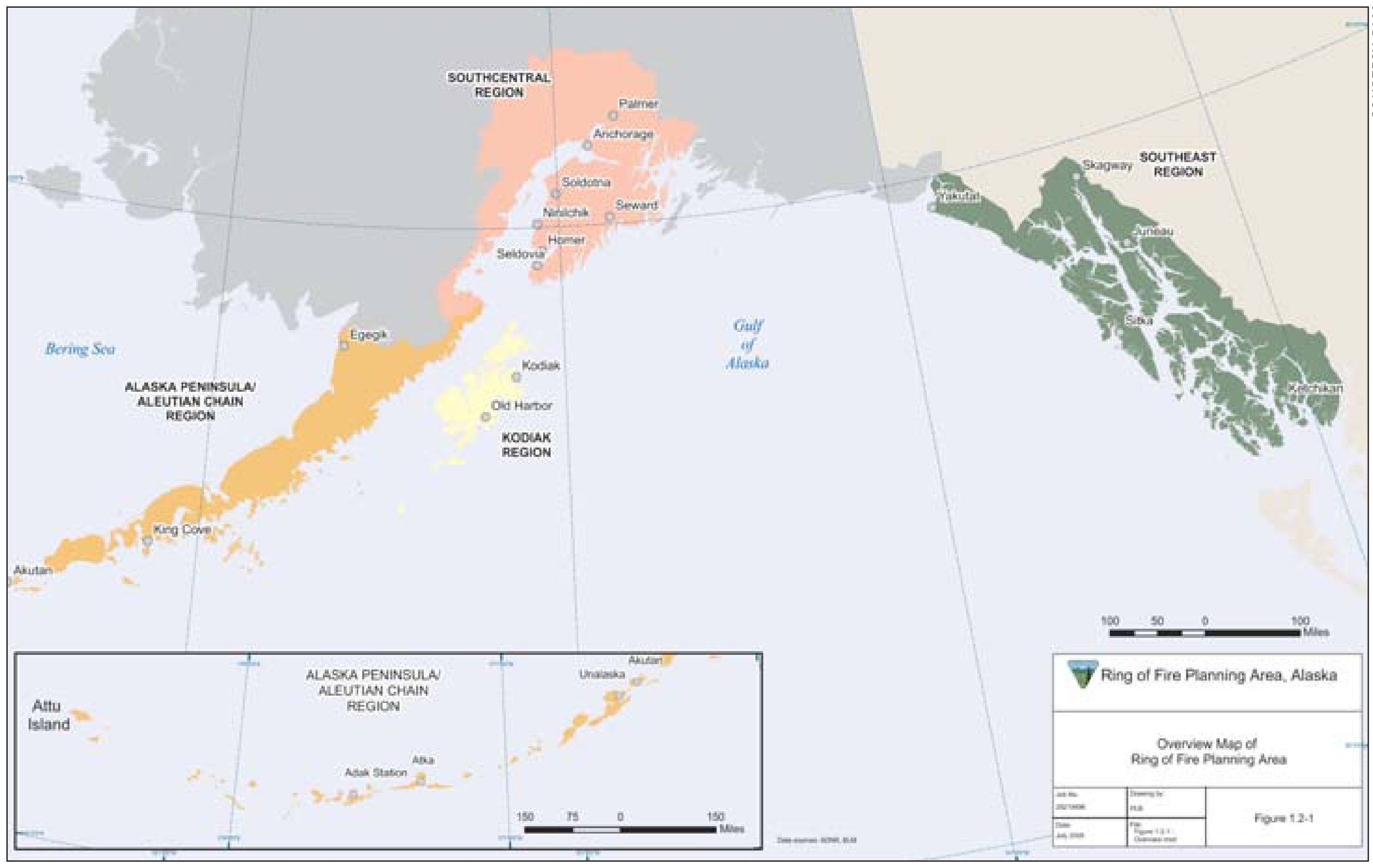
Aiken had been serving as acting director in Okakok's absence.

Oil Patch Insider was written by Gary Park, Alan Bailey and Kay Cashman. News tips should be sent to Cashman via email at publisher@petroleumnews.com or call 907 770-3505.

● ALASKA

BLM takes comment on Ring of Fire plan

Resource management plan/EIS covers 1.3 million discontinuous acres of 61.4 million acre Aleutians-Southeast planning area



COURTESY BLM

PETROLEUM NEWS

The Department of the Interior's Bureau of Land Management is taking comments on a draft resource management plan and environmental impact statement for its Ring of Fire planning area, which arcs from the end of the Aleutians to just above the Dixon Entrance in southeast Alaska, a linear distance of some 2,500 miles. The entire planning area is 61.4 million acres, although BLM lands within the planning area are only some 1.3 million acres of discontinuous lands. The agency said the largest tracts exceed 100,000 acres while the smallest tracts vary in size from several hundred acres to less than 10 acres.

> *"Most areas of high mineral potential within the Ring of Fire planning area were selected and conveyed as a result of these actions," says a mineral potential report prepared for BLM by URS Corp.*

The plan also addresses management of subsurface estate held by BLM under privately owned surface lands and under components of the National Wildlife Refuge System and the National Forest System. Within the planning area there are four regions: Alaska Peninsula/Aleutian Chain, Kodiak, Southcentral and Southeast.

Most lands with mineral potential selected by state, Native corporations

While oil and gas exploration and development is an activity considered in the plan, BLM-managed lands in Alaska have been selected by the State of Alaska and Native corporations. The state selected lands under the Alaska Statehood Act of 1959 and Native lands were designated as a result of the Alaska Native Claims Settlement Act of 1971, which provided for Native claims to traditional lands.

"Most areas of high mineral potential within the Ring of Fire planning area were selected and conveyed as a result of these actions," says a mineral potential report prepared for BLM by URS Corp.

Four alternatives considered

Alternatives being considered include A, No Action; B, Resource Development; C, Resource Conservation; and D, the Preferred Alternative. "Alternative D provides a balance of protection, use, and enhancement of resources. The majority of unselected lands and those selected lands whose selection would be relinquished or rejected, would be open to oil and gas leasing and development and mineral location, though certain unique or sensitive areas would remain closed," BLM said.

> *The entire planning area is 61.4 million acres, although BLM lands within the planning area are only some 1.3 million acres of discontinuous lands.*

BLM and the URS Corp. are holding open house-public hearings for the draft plan in Palmer Dec. 8 at the Colony High School Theater, in Kodiak Dec. 12 at the Kodiak High School Commons, in Anchorage Dec. 14 at the BLM Anchorage Field Office on Abbott Loop Road and in Kenai Dec. 15 at the Kenai Central High School Little Theater. There is an open house from 6-7 p.m. with a brief overview of the plan, followed by public comments from 7:20-9 p.m.

The draft report and EIS are available in hardcopy and on CD at the BLM Anchorage Field Office.

Call BLM at (907) 267-1246 or (800) 478-1263.●

continued from page 1

DEH CHO

McLellan.

Hearn urged the Deh Cho to deal separately with the pipeline and their attempts to negotiate a self-government and land claim agreement with the Canadian government and not attempt to use the pipeline for political leverage.

However, he said discussions have not broken off with the Deh Cho.

He hopes the agreements in principle reached with the other aboriginal regions will result in ratified deals by year's end.

Hearn also announced the latest uptick in the Mackenzie cost estimates, with the forecast now C$7.5 billion, an increase of C$500 million.

—GARY PARK

continued from page 1

SALES

and organize AP 2005, and this sale deserves our full attention this October," the department said July 25.

But notices posted on the Division of Oil and Gas Web page the last week in November for each of the sales said: "This sale has been delayed. The new sale data is to be determined."

DNR spokesman Dan Saddler told Petroleum News that the commissioner is trying to get as much familiarity with the North Slope and the Beaufort Sea leasing program as possible to see if there might be any synergies between the sales and the gas pipeline negotiations and also ANWR that would help the entire industry. Saddler said Menge envisions this process taking several more weeks, not months.

Congress is evaluating whether to open the coastal plain of the Arctic National Wildlife Refuge for oil and gas exploration.

Boyd on areawide permitting

Ken Boyd, formerly director of the Division of Oil and Gas, reviewed the areawide lease sales program at a Nov. 21 meeting of the Alaska Legislature's House Special Committee on Oil And gas.

Ten years ago, he told the committee, access to land was an issue because the leasing program was based on nominations and companies could only acquire prospects in bits and pieces — with no surety of when adjacent pieces would be offered.

Areawide leasing was passed by the Legislature 60 to nothing, Boyd said, and the bill worked.

There are five areawide lease sales: North Slope, Beaufort Sea, Foothills, Cook Inlet and the Alaska Peninsula.

In its current five-year leasing brochure the division said areawide leasing was implemented by the state to assure "stability and predictability in the leasing program, and in response to industry's request for more frequent sales."

The first areawide sale, on the North Slope, was held in June 1998. To facilitate areawide leasing the Legislature in 1996 established a 10-year life for best interest findings for the areawide sales. A call for comments is issued some nine months before a sale, requesting any substantial new information, and the Department of Natural Resources then determines whether or not a finding should be supplemented. Ninety days before a sale, the department issues either a supplement or a decision that there is no new information requiring a supplement. ●

continued from page 1

ANWR

remarks to be heard in Congress where House-Senate negotiators are set to take up budget reconciliation legislation that includes ANWR drilling.

White House spokesman Scott McClellan said at a press briefing the last week in November that the White House would fight for ANWR's inclusion in the final bill.

Talks heat up behind scenes

Though the U.S. Senate was scheduled to resume work Dec. 12, many senators returned to work early, according to pro-ANWR lobbyist Roger Herrera.

"Quite a number of the senators are here, and they're all working away," Herrera said Dec. 7. "There's a lot going on, but it's all behind the scenes."

ANWR oil development is part of the Senate's $35 billion version of a budget reconciliation package that leaders from both chambers are currently negotiating in conference. A $50 billion House version of the deficit reduction measure does not include ANWR.

A spokeswoman for the Senate Budget Committee told reporters she expects conferees will be named when the Senate returns Dec. 12, and said staff- and member-level discussions have already occurred. "We are hopeful a conference report will be voted on before Christmas break," she added. The measure would move as a stand-alone "reconciliation" bill, which is not subject to filibuster in the Senate.

Among those working to keep ANWR drilling in the bill is Alaska's powerful senior Sen. Ted Stevens. House Majority Leader Roy Blunt, R-Mo., told reporters Dec. 5 that Stevens has turned his full attention to House Democrats to gain support for ANWR drilling.

A few dozen House Democrats supported ANWR drilling in a key vote in April, but the minority party has stuck together over the past month in decisive budget votes on the House floor. If Stevens can win back this support, it could pave the way for Arctic drilling language appearing in a House-Senate budget reconciliation conference report.

"He has discussed his plan with me, and I would be pleased to see it result in some House Democrats who would like to vote for deficit reduction including ANWR," said Blunt, who avoided providing details.

A spokeswoman for Stevens confirmed that he's working toward opening ANWR through the reconciliation process but did not comment on the idea of courting House Democrats.

The solidarity of House Democrats on ANWR drilling has won them praise from the environmental community, but Blunt said the anti-energy votes could come back to hurt Democratic congressmen, especially those representing energy states.

"You can't have people from significant oil and gas areas voting against measures, like refinery reform measures, that they have always voted for," he told E&E Daily. "You can't have them doing that without having some price ultimately paid."

Herrera said the backroom negotiations now under way in Congress are typical of what happens when a controversial bill is in conference. "We're glad it's happening. It suggests that ANWR still is very much in play and that an agreement will be reached," he added. ●