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page 5 BP's David Robertson provides Alaska GTL update

North Slope Exploration Report

JUDY PATRICK

Page 11 of this issue contains a new column — the North Slope Exploration Report. It will appear in Petroleum News twice a month.

Hurricane Rita takes toll on Gulf of Mexico drilling rigs

Hurricane Rita, coming on the heels of Katrina and contributing to all the havoc her sister hurricane doled out, appears to have taken a heavy toll on the Gulf of Mexico's offshore drilling fleet.

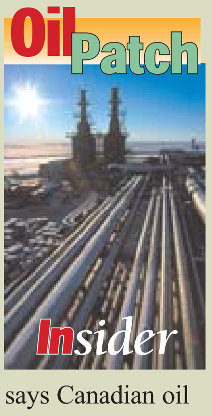
Rita and Katrina, both category four and five hurricanes before coming ashore, also crippled offshore oil and gas facilities, with the lion's share of Gulf production shut-in as of Sept. 29, some five weeks after operators first evacuated platforms and drilling rigs ahead of Katrina.

Production was not fully recovered when Rita came along, forcing yet another mass evacuation of offshore facilities. In fact, more than half of the oil and a third of daily natural gas production in the Gulf remained off line before Rita's untimely arrival.

According to the U.S. Minerals Management Service, 98.59 percent or 1.48 million barrels of daily oil production and nearly 80 percent or 7.98 billion cubic feet of daily gas production were shut-in as of Sept. 29.

see **RIGS** *page 16*

Tax breaks urged for Canada's energy sector



OVER DECADES, British- and U.S.-based companies bought up and sold countless billions of dollars of Canadian petroleum assets and were welcomed by the federal Conservative party as a vital source of financing for the industry.

Over a few months this year, France's Total and three of China's state-owned companies moved into Alberta's oil sands and they are seen by the Conservatives as a threat to Canada's energy security.

The party's deputy leader Peter MacKay says Canadian oil and gas companies need additional tax breaks to put them on a competitive footing with global companies that are becoming "more and more aggressive" in their hunt for assets.

Canada is "at a crucial point … the natural advantage and

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BREAKING NEWS

7 No nukes are good nukes: Alberta premier views nuclear power plants for oil sands developers as 'least acceptable' option

7 Anadarko to invest $1.85B to secure rigs: Long-term contracts over six years will secure rigs in tight deepwater market

10 Settlement in sight for CIGGS: After 3 months of negotiations, parties file with Alaska agency on Cook Inlet gas gathering system

CANADA

Grappling with a genie

Canadian government slows conversions to trusts, flags impact on economy

By GARY PARK

Petroleum News Canadian Contributing Writer

Coincidence or not, the Canadian government has followed two blockbuster energy-related income trust transactions by slamming the brakes on one of the hottest North American investment vehicles.

In the process it has caused turmoil in the stock market by raising fears that it plans to change the trust tax regime in next year's federal budget.

Finance Minister Ralph Goodale has made no effort to ease those concerns, explaining that he has become uneasy about the frenzied atmosphere around trusts and the impact on the wider economy.

He downplayed the lost tax revenues, which his

see **TRUSTS** *page 18*

Government sidesteps U.S. 'factor'

Canadian Finance Minister Ralph Goodale

The unmentioned aspect of income trust review under way in Canada is the role U.S. investors are playing in the drain on tax revenues and whether they might become part of the solution.

When dividends flow out of Canada, the

see **SIDESTEP** *page 18*

WASHINGTON, D.C.

Hurricane bills on tap

U.S. House committees approve legislation to open ANWR to oil and gas drilling; speed Alaska gas pipeline construction by limiting loan guarantee

By ROSE RAGSDALE

Petroleum News Contributing Writer

Rep. Edward Markey, D-Mass

Rep. Richard Pombo, R-Calif.

Proposals to open Alaska's arctic coastal plain to oil and gas drilling and to place a two-year sunset on federal loan guarantees for the Alaska Natural Gas Pipeline are part of new energy packages adopted Sept. 28 by U.S. House committees on Resources and Energy and Commerce.

Congress is revisiting various energy proposals in response to the havoc wreaked by recent hurricanes on the nation's energy supplies. With crude oil prices expected to rise 34 percent this winter and natural gas costs expected to jump 71 percent, the lawmakers seek to increase domestic energy supplies and prevent supply disruptions like those seen after hurricanes Katrina and Rita in August and September.

The House Resources Committee approved "The National Energy Supply Diversification and

see **BILLS** *page 19*

NORTH SLOPE

Anadarko wants big plays

Looking for 'anchor opportunities' in Alaska to form building blocks for future

By ALAN BAILEY

Petroleum News Staff Writer

GREG HEBERTSON

A commitment to finding large, long-term prospects in remote areas of northern Alaska underlies Anadarko Petroleum's strategy in the state, Greg Hebertson, Anadarko's Alaska/Canada frontier project manager, and Mark Hanley, the company's Alaska spokesman, told Petroleum News in late September. The company wants to develop large fields that can then form hubs for the development of smaller prospects.

"We've had a very focused type of exploration program over the years — we're looking for primarily anchor-type opportunities," Hebertson said. "These are opportunities that are standalone, that don't necessarily need existing infrastructure and we feel like that's the kind of exploration that is going to benefit Anadarko and our shareholders, as well as the state."

Anadarko believes that large oil and gas fields remain to be found in northern Alaska. And the company's strategy has caused Anadarko to amass one of the top exploration land positions in the state.

"We've been in Alaska since 1993 and we've been continually investing in Alaska ever since that time," Hebertson said.

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contents

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

Alaska - Mackenzie Rig Report

Alaska Rig Status

North Slope - Onshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Doyon Drilling			
Dreco 1250 UE	14 (SCR/TD)	Workovers, Milne Point F-Pad, MPF-93	BP
Sky Top Brewster NE-12	15 (SCR/TD)	Kuparuk 1C-28	ConocoPhillips
Dreco 1000 UE	16 (SCR)	Workovers Well Z-31	BP
Dreco D2000 UEBD	19 (SCR/TD)	Alpine CD2-11	ConocoPhillips
OIME 2000	141 (SCR/TD)	Kuparuk 1J-154	ConocoPhillips
Nabors Alaska Drilling			
Trans-ocean rig	CDR-1 (CT)	Stacked, Prudhoe Bay	Available
Dreco 1000 UE	2-ES (SCR)	Prudhoe Bay J-17C	BP
Mid-Continent U36A	3-S	Prudhoe Bay Z-02	ConocoPhillips
Oilwell 700 E	4-ES (SCR)	Prudhoe Bay 1E-117	BP
Dreco 1000 UE	7-ES (SCR/TD)	Prudhoe Bay W-17	BP
Dreco 1000 UE	9-ES (SCR/TD)	Niakuk, L-215	BP
Oilwell 2000 Hercules	14-E (SCR)	Staged at Cape Simpson	Available
Oilwell 2000 Hercules	16-E (SCR/TD)	Stacked, Prudhoe Bay	Available
Oilwell 2000	17-E (SCR/TD)	Stacked, Point McIntyre	Available
Emsco Electro-hoist -2	18-E (SCR)	Stacked, Deadhorse	Available
OIME 1000	19-E (SCR)	Stacked, Deadhorse	Available
Emsco Electro-hoist Varco TDS3	22-E (SCR/TD)	Stacked, Milne Point	Available
Emsco Electro-hoist	28-E (SCR)	Stacked, Deadhorse	Available
OIME 2000	245-E	Stacked, Kuparuk	Available
Emsco Electro-hoist Canrig 1050E	27-E (SCR/TD)	Stacked on 12-acre pad	Kerr-McGee
Nordic Calista Services			
Superior 700 UE	1 (SCR/CTD)	Prudhoe Bay, DS 2 well 17-b	BP
Superior 700 UE	2 (SCR/CTD)	Kuparuk,1B-15	BP
Ideco 900	3 (SCR/TD)	Kuparuk, stacked 1Q pad	Kerr-McGee

North Slope - Offshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Nabors Alaska Drilling			
Oilwell 2000	33-E (SCR/TD)	Cold stacked on NorthStar Island	BP

Cook Inlet Basin – Onshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Aurora Well Service			
Franks 300 Srs. Explorer III	AWS 1	Kaloa #4	Aurora Gas
Pioneer Natural Resources			
Wilson Super 38	96-19	Stacked in Wasilla yard	Pioneer Natural Resources
Kuukpik	5	Workover BRU 224-13	ConocoPhillips
Marathon Oil Co. (Inlet Drilling Alaska labor contractor)			
Taylor	Glacier 1	Beaver Creek #16	Marathon
Nabors Alaska Drilling			
National 110 UE	160 (SCR)	Stacked, Kenai	Available
Continental Emsco E3000	273	Stacked, Kenai	Available
Franks	26	Swanson River, 414-04	Chevron
IDECO 2100 E	429E (SCR)	Stacked, removed from Osprey platform	Available
Rigmasters 850	129	Stacked in Kenai yard	Available

Cook Inlet Basin – Offshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Cudd Pressure Control	340K	Stacked	Available
Unocal (Nabors Alaska Drilling labor contractor)			
Not Available			
XTO Energy (Inlet Drilling Alaska labor contract)			
National 1320	A	Idle	XTO
National 110	C (TD)	Idle	XTO

Mackenzie Rig Status

Mackenzie Delta-Onshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
AKITA Equtak			
Dreco 1250 UE	62 (SCR/TD)	Stacked, Tuktoyaktuk, NT	EnCana (Available)
Dreco 1250 UE	63 (SCR/TD)	On barges moving to the Central MacKenzie Valley for a well, winter 2005-2006.	Husky Oil
National 370	64	On barges moving to Hay River & then on trucks to Alberta.	Available

Central Mackenzie Valley

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
AKITA/SAHTU			
Oilwell 500	51	Working in Alberta	Apache

Yukon Territories Rig Status

Yukon

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
AKITA/Kaska			
National 80UE	58	Re-entering well K-29 in Fort Liard, NT area	Paramount Resources
Ensign Resources Svc. Grp.			
Jackknife Double	55	Racked in Ft. Nelson	

The Alaska - Mackenzie Rig Report is sponsored by:

The Alaska - Mackenzie Rig Report as of September 28, 2005. Active drilling companies only listed.

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

This rig report was prepared by Alan Bailey

JUDY PATRICK

Baker Hughes North America rotary rig counts*

	Sept. 23	Sept. 16	Year Ago
US	1,451	1,436	1,239
Canada	426	443	291
Gulf	89	85	83

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

*Issued by Baker Hughes since 1944

UNITED STATES

Re-submit MMS five-year comments by mail

The Minerals Management Service said Sept. 26 that anyone using the Internet to submit comments on its proposed five-year leasing plan on or after Aug. 26 should resubmit those comments in writing.

MMS' Internet-based public comment system is hosted on computers in New Orleans, La., the agency said, and Hurricane Katrina and its aftermath disrupted the system. The agency said Sept. 26 that it does not know long it will take to restore the system.

BREAKING NEWS

MMS said it was able to receive comments submitted through its Internet Public Connect system before Hurricane Katrina hit New Orleans on Aug. 29, but is advising anyone who submitted comments through the system on or after Aug. 26 to re-submit comments by mail to: Renee Orr, 5-year program manager, Minerals Management Service (MS-4010), Room 3120, 381 Elden St., Herndon VA 20170. Comments are due Oct. 11.

E-mail regarding the preparation of the EIS should be sent to fiveyreiscomments@mms.gov and e-mail regarding any other aspect of the five-year leasing program besides the EIS should be sent to fiveyrplcomments@mms.gov.

Note: Among the federal offshore areas in Alaska that are part of the proposed five-year leasing plan are Bristol Bay, Chukchi Sea and Lower Cook Inlet.

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NORTH SLOPE

BP shuts in 70 wells identified as risky

Some 20,000 bpd taken offline; 75% of wells expected to be back online by mid-2006; most productive will be worked first

By KRISTEN NELSON
Petroleum News Editor-in-Chief

BP Exploration (Alaska) has shut-in some 70 wells at the Prudhoe Bay and Endicott fields on Alaska's North Slope following a review of all wells at the fields, taking some 20,000 barrels per day of production offline until identified risks at the wells have been remedied.

"This is a review that's been going on for the last few months," Andrew Van Chau, BP Exploration (Alaska)'s vice president of external affairs, told Petroleum News Sept. 29. He said experts from BP and its partners, ConocoPhillips Alaska and ExxonMobil Production, "literally reviewed all the wells that we had up there, producing and injection."

The focus of the evaluation was on managing risk, Van Chau said.

They looked at the potential for the release of hydrocarbons or produced water in well houses. They looked at operating, start up and shut in conditions: "what elements raise and lower the risks of those activities."

They looked at what contributes to a release, including the range of weather conditions from extremely cold in the winter to warm in the summer.

They looked at controls to mitigate risk, at the equipment on the wells itself and at administrative controls, the "processes and procedures employees follow" in starting up, operating and shutting down wells.

And they "looked at where could things go wrong" inside the well, such as the potential for corrosion in tubing or valve failure.

Of the 2,000 or so wells at Prudhoe Bay and Endicott, the review looked for wells with the potential for risk higher than acceptable. Seventy or so wells were identified; about 30 of those were already shut in; the balance of the wells are being shut in now, Van Chau said.

Shutting those wells in is the "right thing" to do, he said, because of focus on the workforce and on the safety of BP's operations.

The next step is to look at what is needed to refurbish the wells, whether maintenance or equipment replacement, because the company plans to operate on the North Slope for decades to come. The focus, he said, is on "maintaining and enhancing reliability … and the safety of our operations."

The priority will be on "bringing high-production wells back online sooner rather than later," he said. Each well will be looked at individually to see what is needed. At least 75 percent of the wells are expected to be back online by mid-year 2006, Van Chau said.

Work on these wells will have to be balanced with the work program to drill new wells, he said.

Decisions on which wells to shut in were driven by "safety considerations" for BP's workforce, and by operational experience both from the North Slope and from worldwide operations. Van Chau said BP also consulted with agencies such as the Alaska Oil and Gas Conservation Commission, the state agency responsible for downhole operations. ●

OSLO, NORWAY

Norway OKs North Sea field development

The Norwegian government on Sept. 23 approved development of a North Sea oil and natural gas find near Norsk Hydro ASA's existing Oseberg field.

Even though the Oseberg Delta find is relatively small by Norwegian standards, it is in keeping with a government drive to maintain the nation's production levels by encouraging development of moderate finds.

"I am very glad the Oseberg license holders have decided to develop Delta," said Oil Minister Thorhild Widvey. "This project will help maintain production levels in the Oseberg area in the years to come."

Norway is the world's third-largest oil exporter, after Saudi Arabia and Russia, with a capacity of about 3 million barrels per day, plus natural gas.

However, production has begun to decline at some aging fields, and the government is looking to small finds, such as Delta, and the frontier provinces of the far north to help supply a world hungry for petroleum.

Widvey said this was the ninth offshore development approved by the government so far this year, with total expected investment of about 45 billion kroner (US$7.1 billion). Delta, discovered in 1998, is about 95 miles west of Bergen, the main city on Norway's west coast. It has estimated reserves of 63.2 billion cubic feet of natural gas, and about 17 million barrels of oil and natural gas liquids.

The 1.8 billion kroner (US$286 million) project will use so-call "subsea" technology, with all production equipment on the seabed and link the find to the Oseberg D offshore platform by pipeline. Norsk Hydro, based on the outskirts of Oslo, is one of Norway's largest companies, with about 35,000 employees in 40 countries.

—THE ASSOCIATED PRESS

● ANCHORAGE

BP wants to be serious player in GTL

New vice president leads global effort that includes continuing work at Nikiski testing facility, as high oil prices boost prospects

By ALLEN BAKER
Petroleum News Contributing Writer

High crude prices and low-cost supplies of natural gas around the world have put plans for turning gas into an easily transported liquid back on the front burner.

BP Exploration & Production made its move last December, picking David Robertson as the new vice president charged with commercializing the company's GTL technology.

"Natural gas continues to offer value compared to crude oil," says Robertson, whose title is vice president, gas to products. "My responsibility is to develop a portfolio of technology that will allow monetization of natural gas through syngas."

Syngas in the product of the initial step in GTL technology. That step "reforms" methane into a mix rich in hydrogen and carbon monoxide — the building blocks for more complex hydrocarbons.

Many products

Among the products that can come from that mix are diesel fuel, naphtha, lube stocks, methanol and acetic acid. BP is already a partner in the largest methanol plant in the world, a Trinidad facility that turns natural gas into 5,000 tons of methanol a day. It's also a leader in producing acetic acid from gas.

"If people believe the value of crude oil will remain elevated compared to historical numbers, then products that didn't look attractive before look a lot more attractive. There's a broad range of opportunities there," he said.

Robertson was in Alaska Sept. 29 for a meeting of his global team, inviting "internal customers" from BP business units to hear what his engineers can offer. Nikiski was a natural site for the meeting, since BP has been testing aspects of the process at its GTL pilot plant there since 2002.

That testing was expected to last a year to 18 months, but engineers are continuing to tinker with aspects of the design.

Nikiski plant plugs on

"Nikiski continues to be a demonstration plant. We haven't finished the program yet," Robertson told Petroleum News. "We're considering some further modifications to it."

The GTL plant ran most of second quarter, but it's been shut down for further modifications. Once it's started up again, Robertson anticipates it will run for the rest of the year. About 15 people work at the facility.

The plant was originally expected to cost $86 million and turn about 3 million cubic feet of gas daily into a token 300 barrels of synthetic crude. It was sited in Alaska, instead of closer to BP's UK research facilities, as part of the antitrust deal when ARCO was swallowed up and BP was looking to mollify state authorities.

BP has spent $120-$130 million at Nikiski, Robertson estimates, with total company spending on gas-to-products research in excess of $300 million.

"We want to be considered a serious player," he said. "(Nikiski) is a fantastic facility."

One of BP's big hopes for the Nikiski test was its compact design for the reformer that produces the syngas. Unlike much of the rest of the plant, the reformer was built to commercial scale.


DAN WILCOX
David Robertson, BP

"We've had very good success with the reformer. We definitely see opportunities to improve reliability." Still, "it's not proven. Until we're comfortable with something we've demonstrated at scale, we won't go ahead with it. At the moment we're not considering a commercial project using a compact reformer."

Colombian GTL project

The company does have its eye on a field in Colombia for development using a more traditional reformer along with BP technology for turning the syngas into liquid fuels using a modern version of the Fischer-Tropsch technology developed by German scientists in the 1930s.

Colombia, with a startup date of 2011, "is going to be the first big project we'll be developing using this technology," Robertson said. "We're looking at early studies for a GTL project in Colombia, to monetize the gas that's being reinjected."

As for Alaska's huge North Slope gas reserves, BP remains focused on sending that gas to the Lower 48 through a dedicated pipeline.

Various studies over the years have speculated that producing GTL liquids on the North Slope and sending them down the oil pipeline could be a viable option if crude prices are high enough, and there's likely enough gas to feed both a major gas pipeline and a giant GTL plant. But it's an expensive gamble, with costs that run into the billions of dollars.

"The big risk element is that we don't know what the price of oil is going to be in five years when these plants come on line," he notes.

Sasol a leader

While major oil companies including ExxonMobil and ConocoPhillips have plans for big GTL facilities in Qatar, Robertson figures South Africa's Sasol and Shell have the lead in the technology.

> *"Natural gas continues to offer value compared to crude oil," says Robertson, whose title is vice president, gas to products. "My responsibility is to develop a portfolio of technology that will allow monetization of natural gas through syngas."*

Sasol makes 160,000 bpd of liquids from synthetic gas derived from coal, and is set to begin operation of its 34,000 bpd Oryx operation in Qatar next year. The company got its start on GTL when South Africa was under an economic blockade during the apartheid era.

Shell has been producing liquid fuels at its Bintulu plant in Indonesia for a decade. It has awarded a $6 billion-plus contract to Japan's JGC Corp. and Halliburton's KBR for a Qatar plant that will produce 140,000 bpd at full capacity in 2010.

"ExxonMobil has a fantastic number of patents. They're smart people. They have a plan and they've worked it through," Robertson said. "But Shell and Sasol have a proven track record.

"It's all very well designing the chemistry. But running it is the big challenge. You have to be in this for a long time. You have to be persistent and learn your lessons."

Costs rising

While the economics of a GTL plant will benefit if the price of oil remains high, costs for steel and other construction materials are also rising.

"People have talked about $27,000 per installed barrel (daily)," Robertson said. "I think everybody is going to struggle to hit that one." High capital costs are a big reason GTL plants haven't been proliferating.

Engineers also are hoping for a breakthrough on overall efficiency, the main motivator for developing the compact reformer. Most operations lose about a third of the energy in the gas in the conversion, though some of it can be recycled to produce steam and electricity. ●

NORTH AMERICA

Rig count down by two to 1,877; U.S. picks up 15 rigs, Canada loses 17

The number of rotary drilling rigs operating in the United States and Canada during the week ending Sept. 23 totaled 1,877, down two rigs from the previous week but up 347 rigs compared to the same weekly period last year, according to rig monitor Baker Hughes.

Canada's rig count for the recent week was 426, a decrease of 17 rigs from the prior week but an increase of 135 rigs when compared to the year-ago period.

The number of rigs operating in the United States during the recent week totaled 1,451, up 15 rigs from the previous week and up 212 rigs from the same period last year. Compared to the previous week only, land rigs increased by 10 to 1,336, while offshore rigs increased by five to 94. Inland waters rigs remained unchanged at 21.

Rig count prior to Rita

The Baker Hughes rig count was issued prior to Hurricane Rita's arrival along the Texas-Louisiana coast. The storm earlier swept through the Gulf of Mexico as a category four and five hurricane, seriously damaging a yet undetermined number of evacuated offshore drilling rigs on the continental shelf and in deeper waters of the Gulf.

Of the total number of rigs operating in the United States during the recent week, 1,239 rigs were drilling for natural gas and 205 for oil, while seven rigs were being used for miscellaneous purposes. Of the total, 904 were vertical wells, 348 directional wells and 199 horizontal wells.

Among the leading U.S. producing states, Texas picked up six rigs compared to the previous week for a total of 633 rigs. Louisiana picked up three rigs for a total of 188 rigs. Wyoming gained three rigs for a total of 86 rigs. California picked up two rigs for a total of 29 rigs. And New Mexico gained one rig for a total of 90 rigs. Alaska's rig count declined by two for a total of four rigs, while Oklahoma's declined by two rigs for a total of 152 rigs. Colorado's rig count was unchanged at 79 rigs.

—RAY TYSON

Editor's note: According to Ron Wilson, the top executive at Doyon Drilling in Anchorage, Alaska, Baker Hughes's rig number for Alaska is incorrect. Wilson told Petroleum News Sept. 28 that Doyon and Nabors Alaska Drilling each have five rigs working on the North Slope and Nordic has two for a total of 12 working rigs in northern Alaska. In Cook Inlet, the working rigs include one belonging to Kuukpik Arctic Drilling, one owned by Marathon Oil, one owned by Unocal (now part of Chevron) on a platform (operated by Nabors), and one owned by Aurora Gas. "At least 15 or 16 are currently working that I am aware of," Wilson said. (See latest rig report for Alaska on page 2 of this issue.)

● ANCHORAGE

Comments to RCA largely support ANGDA

Flint Hills favors proposed repeal of sections of Alaska Pipeline Act; Anadarko largely in agreement; Enstar wants to know more

By KRISTEN NELSON

Petroleum News Editor-in-Chief

Comments received by the Regulatory Commission of Alaska largely support a request by the Alaska Natural Gas Development Authority (ANGDA) for repeal of two sections of the Alaska Pipeline Act.

The commission held a hearing Sept. 8 on the request (see stories in Sept. 4 and Sept. 18 issues of Petroleum News), which is for repeal of sections on intrastate transportation and on how intrastate service shall be regulated by the commission, and also provided an opportunity for written comments.

Flint Hills Resources Alaska told the commission Sept. 19 that it agrees with the concerns ANGDA expressed "that the statutes proposed for repeal, as currently written, may create an impediment to the expansion of the intrastate (gas shipped within Alaska) North Slope natural gas market" as well as limiting the ability of the commission "to protect the public interest."

Flint Hills said it agrees with the criticism of AS 42.06.240(f). A portion of a natural gas pipeline "should be available to serve the needs of intrastate shippers," the company said, but "requiring shippers and customers to enter into three-year take-or-pay commitments is a very heavy burden on the customer."

Concern for later intrastate gas needs

Flint Hills also said that requiring the carrier to specify amounts of intrastate gas when it applies for a certificate "leaves out of the North Slope natural gas market those customers who, at the time of initial tender, either could not make such commitments or did not have a need for or have physical access to North Slope natural gas."

"Finally, as the statute is written, carriers would have no obligation to increase intrastate capacity," Flint Hills said, leaving those who did not initially secure space on a pipeline with "no redress, and no market access, except by soliciting the carrier" for RCA approval to expand the line. Which, Flint noted, "the carrier has no obligation to do."

Flint concluded that "the statute is a real impediment to growth of the intrastate North Slope natural gas market, and leaves the discretion to increase the market to the carriers."

The commission, Flint said, "must be granted greater authority to meet the public demand," and repealing AS 42.06.240(f) "is a step in that direction."

Statute limits discretion of commission

As for the second provision, AS 42.06.370(c), Flint said it agrees with ANGDA that as written the statute, "which requires regulating North Slope natural gas pipeline rates according to the public utility rather than the common carrier rubric, limits the discretion of the RCA and limits the capacity of carriers, shippers, and customers to propose, debate, and develop creative rate models which encompass not only the considerations specific to the North Slope natural gas market but also the lessons learned in other rate-setting environments."

Flint recommended to the commission that "any rate setting model be detailed and specific, so as to mitigate ambiguities." Unclear rate models, the company said, leave room for interpretation and lend themselves "to frequent regulatory complaints and litigation. Rate certainty benefits both carriers and shippers, and ultimately natural gas customers, by providing an essential stability (rather than a moving target variable) upon which business and financial decisions can be based," Flint told the commission. The company also recommended limiting retroactive rate adjustments as another factor in "the same desired outcomes of certainty and limiting system disputes and costs…"

Anadarko, Enstar also comment

Anadarko Petroleum, commenting through counsel Brena, Bell & Clarkson, said it understands the proposed repeals "will serve to clarify the Pipeline Act and will give the Regulatory Commission of Alaska greater discretion in the resolution of issues related to the intrastate transportation of North Slope natural gas," and based on that understanding, supports the ANGDA proposal.

Enstar Natural Gas, commenting through attorneys Ashburn & Mason, said "it appears to be ANGDA's general contention that repeal of these two statutory provisions would make development of North Slope natural gas and its availability to Alaska customers more likely." Enstar said it "is keenly interested in the prompt and efficient development of North Slope natural gas," but "is not ready to comment on this specific proposal at this time."

Enstar said "interrelationships between the statutory and regulatory provisions that will govern development of North Slope natural gas are not simple," and before it takes a position, Enstar said it "would like to hear a better explanation of both the need for repeal of these sections and the consequences for the RCA's regulatory oversight over future gas pipelines from ANGDA." ●

● ALBERTA

No nukes are good nukes for oil sands

Alberta premier views nuclear power plants for oil sands developers as 'least acceptable' option; Total stifles speculation

By GARY PARK

Petroleum News Canadian Contributing Writer

It's the oil sands option that won't go away, with reports circulating that Total is ready to use nuclear power rather than natural gas at an oil sands project in Alberta, which it controls by 84 percent.

Just as quickly, the French oil giant snuffed out the reports that were doing the rounds in New York and Toronto, declaring its preference for gas, while Alberta Premier Ralph Klein put nuclear power at the bottom of his list of fuel options.

He said that if environmentalists "go nuts" over the construction of a hydro-electric dam, how would they react to a nuclear plant.

Klein cast his vote in favor of hydro power from the Northwest Territories or Alberta's vast thermal coal deposits, or the gasification of oil sands byproducts such as coke over the contentious nuclear option.

Christophe Margerie, president of Total's global exploration and production business, told reporters in Calgary Sept. 22 that his company is not clear "what nuclear can bring to the extraction of bitumen. It's certainly not something that Total will work on. We're not experts in the nuclear industry."

However, Total has not flatly ruled out the use of nuclear energy at the Joslyn project, which it now controls following a successful bidding war to take over Deer Creek Energy for C$1.67 billion.

A company spokesman said that choice is likely to be 15 to 20 years away.

In the meantime, he said it would be foolish not to consider the option.

For now, efforts to find substitutes for costly natural gas are focused on several new innovations.

Standing offer from Atomic Energy of Canada

But there is still a standing offer from Atomic Energy of Canada Ltd., a federal government agency, to build a nuclear plant for oil sands producers using its Candu reactor, 34 of which are completed or under construction in North America, South America, Europe and Asia.

It commissioned the Canadian Energy Research Institute to undertake a report comparing the costs and benefits of using a new generation of small reactors over making power and steam with natural gas and the advantages of reduced air pollution and greenhouse gas emissions.

The institute, jointly funded by industry and governments, said the "raw economics" supported the atomic agency's proposal.

"We need to lessen the reliance on natural gas, which is a diminishing energy source," argued Jerry Hopwood, the agency's general manager of advanced nuclear applications, noting that 25 percent of the energy content of a barrel of synthetic crude is consumed in the extraction process.

A spokesman for the agency, which has reportedly been involved in backroom talks with industry representatives on a nuclear power plant, said the option remains "part of our long-term strategy."

But the Alberta Chamber of Resources, whose members include all of the leading oil sands companies, has argued there is more at stake than just cost.

"Nuclear energy still has issues around societal acceptance, particularly in terms of the perception of safety risks and the disposal of nuclear wastes," the chamber said.

Its report said more work is required "on an economically attractive scale" for oil sands nuclear power and steam plants. ●

● HOUSTON

Anadarko to invest $1.85B to secure rigs

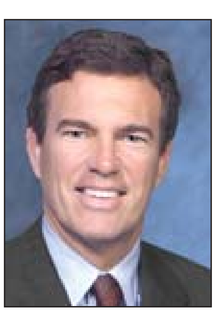
Long-term contracts over six years will secure drilling rigs in tight deepwater market; includes share of new $312M rig

By RAY TYSON

Petroleum News Contributing Writer

Anadarko Petroleum, not wanting to be left out of an ever-tightening deepwater rig market, has committed $1.85 billion to various long-term rig contracts over the next six years, including a hefty time share of a new $312 million deepwater semi-submersible rig to be commissioned by contract driller Ensco International.

Nearly two-thirds of total rig time under the contracts will go to delineate and develop existing discoveries, with the remaining one-third set aside for "high potential exploration" in the Gulf of Mexico, West Africa, Georgia and Gabon, Anadarko said Sept. 26.



James Hackett, Anadarko president & CEO

"A review of our worldwide deepwater drilling inventory, along with the tightening deepwater rig market, led us to lock in the equipment and services we need to execute upon our strategy," said James Hackett, Anadarko's president and chief executive officer.

Industry observers believe that day rates for fifth-generation, high-specification deepwater drilling rigs in the Gulf of Mexico will surpass $400,000 next year, well above the current $200,000-plus daily average, as companies attempt to secure rig contracts in a tightening deepwater market supported by lofty oil and gas prices. In fact, some analysts are modeling day rates of $500,000-$600,000 to as high $1 million per day.

Moreover, the loss of drilling rigs to hurricanes Rita and Katrina, along with six jack-ups expected to leave the Gulf for more lucrative markets abroad, likely will put even more upward pressure on day rates in the Gulf.

Four-year lease for deepwater semi-submersible

Anadarko, along with fellow offshore explorers Kerr-McGee and Dominion Exploration & Production, signed a four-year time-share agreement under which Ensco will build the deepwater semi-submersible rig with a target delivery date of mid-2008. Anadarko committed to 50 percent of the rig time at a cost of $200 million. Dominion and Kerr-McGee each committed 25 percent.

Separately, Anadarko signed a three-year contract to secure the Belford Dolphin drillship at a cost of $459 million. The vessel is expected to be released to Anadarko in mid-2007.

In addition, multi-year contracts valued at about $1.19 billion are being concluded to extend Anadarko's existing contracts and to secure incremental rigs, Anadarko said, noting Anadarko currently has two deepwater rigs under contract.

Anadarko has multiple Gulf projects

Anadarko's current deepwater Gulf development projects include K2, K2 North and Genghis Khan in the Green Canyon area. All are satellites of Anadarko's first deepwater Gulf discovery and development, Marco Polo.

Company development projects also include seven natural gas fields in the ultra-deep waters of the Eastern Gulf. The project, expected to come on line in 2007, is part of a multi-company effort known as "Independence Hub," a central production facility that will take gas from numerous discoveries in the Eastern Gulf area.

Anadarko also has working interests in several non-operated exploration wells currently in progress in the Gulf, including the announced Knotty Head commercial discovery, which needs to be delineated and developed, the company said.

In addition to existing discoveries and planned developments, Anadarko said it has "multiple additional prospects" to explore throughout deepwater Gulf.

"The company's expanded rig position could provide leverage into additional opportunities, if further tightening of the deepwater rig market materializes." Anadarko said.

see ANADARKO page 8

● WHITEHORSE, YUKON

Devon: Pipelines could bring Yukon boom

Huge independent looks past territory's rough edges to attractive prospects for oil, gas reserves; says infrastructure needed

By ROSE RAGSDALE

Petroleum News Contributing Writer

Getting oil and gas producers to sink investment capital into Yukon Territory won't be easy, but it can be done, says an executive with Devon Canada Corp. The Canadian arm of Oklahoma-based Devon Energy Corp. has spent $40 million to drill one gas well and an undisclosed sum to drill another in this remote region since August 2004.

"We operate the only gas field in production in the Yukon, and we're the only company to drill oil and gas wells in the Yukon in recent years, said Michel Scott, a speaker at "Opportunities North 2005," a conference and trade show held in Whitehorse Sept. 20-22.

"Yes, there's been some activity in oil and gas in the Yukon, but it's going to be difficult to get more activity until we do something to get more access to markets," observed Scott, who serves as Devon Canada's vice president for government and public affairs.

> *"We need both the Mackenzie pipeline at the northern end of the territory, and we need the Alaska Highway pipeline at the southern end. Other basins like the Whitehorse Trough will need to wait on the Alaska pipeline."*
>
> **—Michel Scott, vice president for government and public affairs, Devon Canada**

Yukon Territory has abundant petroleum resources to attract investment, including an estimated 20 trillion cubic feet of natural gas, according to government geologists.

But only 73 wells have been drilled in the territory since 1958. "The total is less than what's drilled in Alberta on a slow day," Scott said. One of North America's largest independents, Devon has 29 percent of its roughly 2 billion barrels of oil equivalent and 26 percent of its 600,000 barrels a day of oil and 2.268 billion cubic feet a day of gas production in Canada.

Most of Yukon's wells were drilled in the 1970s after Prudhoe Bay was discovered in Alaska in 1969. Gas output peaked in the territory in 1999 at 60 million cubic feet a day.

Scott observed that as things stand today, southern Yukon presents the best opportunities for oil and gas activity.

Exploration yields mixed results

Devon Canada drilled a gas well last August in the southern region of Yukon Territory, the first such penetration in the territory in 24 years. The well is in the Kotaneelee field, which contains 213 bcf of raw gas, according to Scott. Nearby Devon operates a 70 million cubic feet per day gas plant that sends gas to British Columbia via the Duke Energy pipeline system.

The new well joined two others on line, contributing enough gas to boost Devon's declining Yukon gas production to 29 million cubic feet per day from 12 million cubic feet, Scott said.

However, that single well was expensive, costing about $40 million once tied into the pipeline. "It cost about twice what it would have in a green area of B.C.," he said.

Devon also drilled an unsuccessful exploratory well in February on its 270,000-acre leasehold near Eagle Plains in the northern region of the territory. Completing this 1,278-meter well took 41 days and presented unexpected logistical challenges resulting in high costs, Scott said. In short, there were few local businesses to hire services, which meant extensive planning and importing manpower and equipment from more populated areas to the remote well site, Scott explained.

Though he declined to say how much Devon spent on the Eagle Plains well, he did say it cost five times what a comparable penetration would have cost in a green area of B.C. "The Eagle Plains well is close to the Dempster Highway, but it still presented a challenge, and we underestimated that challenge," Scott explained. "We think it's possible to chop costs in half next time with better planning."

Devon is not alone in expressing interest in the Eagle Plains area. Northern Cross, a small oil and gas independent, owns three producing oil wells in the region near the Dempster Highway.

"We're hoping to market oil production from them locally as diesel and other fuels using trucks," David Thompson, president of Northern Cross Energy Ltd., told Petroleum News Sept. 21. Yukon Territory is believed to contain a resource of at least 920 million barrels of oil.

Government has work to do

But the Yukon government will have to improve local business conditions to bring more oil and gas producers to the territory, according to Scott.

"Until we see solid movement on the Mackenzie Valley pipeline, it's not worth it for us," he told an audience of 200 gathered at the High Country Inn Convention Center Sept. 21.

Among areas Scott says need attention in the Yukon:

- Ability to compete on a world scale for capital;
- "You've got to be concerned how your royalty regimes match up," he explained. "High energy prices bring new sources of competition. This means you also will be competing with unconventional gas plays south of the 60th parallel. Still exploration is moving north."
- Clarity and timeliness in regulatory requirements;
- Surface and subsurface access on known and sustainable basins for at least 20 years: "Access to land is critical, and that's crown land and First Nations land," he said.
- Adequate infrastructure — but that will come with increased oil and gas activity, he said; and
- Access to markets.

"Mobilization costs for one well are tough to stomach when you don't know when or how you're going to get your production to market," Scott said.

"We need both the Mackenzie pipeline at the northern end of the territory, and we need the Alaska Highway pipeline at the southern end," he said. "Other basins like the Whitehorse Trough will need to wait on the Alaska pipeline." ●

continued from page 7

ANADARKO

Ensco 8500 enhanced version of 7500

Meanwhile, the new Ensco deepwater semi-submersible rig to be shared by exploration and production independents Anadarko, Kerr-McGee and Dominion actually will be built for Ensco by Keppel FELS Ltd. of Singapore, Ensco said, adding that the rig will be named Ensco 8500.

Ensco 8500, an enhanced version of the company's first deepwater semi-submersible rig, Ensco 7500, will be capable of drilling in water depths up to 8,500 feet and can be upgraded to operate in 10,000 feet of water, the company said. Enhancements to the new rig include a 2 million pound quad derrick, offline pipe handling capability, increased drilling capacity and greater variable deck load.

"Ensco 8500 is expected to provide a cost-effective deepwater water drilling solution to a consortium of important oil company customers, while expanding Ensco's deepwater capability," said Carl Thorne, Ensco's chairman and chief executive officer.

Ensco said its new rig should cost about $312 million, roughly $73 million less than the $385 million the drilling company expects to generate in contract revenues over four years from Anadarko, Kerr-McGee and Dominion. About $20 million is due on delivery of the rig during the second quarter of 2008, Ensco said.

Under terms of the agreement with the three producers, Ensco is to be reimbursed for rig mobilization and other start-up costs, and day rates are to be adjusted for future variances in operating costs. ●

● RIFLE, COLO.

Energy industry faces worker shortage

Looming retirements face oil and gas industry; rigs also an issue, with equipment sought for U.S. work in China, Italy and Norway drilling

By ERIN GARTNER
Associated Press Writer

Brian Barclay makes a 275-mile commute across Colorado every week to work near the dusty little town of Rifle, drawn by a natural gas boom that has added trucks, cranes and hundreds of people to the rocky landscape.

Asked why he travels so far for work, the former soldier from Colorado Springs grinned and answered: “The money, and it’s better than getting shot at.”

Forest Bommarito said he had seven job offers before graduating, and his wife received her first job offer a full year before she graduated. Husband and wife signed contracts in October to work for ConocoPhillips and BP, respectively, in Anchorage, Alaska, with starting salaries around $79,000

The natural gas industry has swamped parts of the Rockies with workers and equipment. But despite the surge in population, the energy industry is desperate for labor in the high deserts of Colorado, New Mexico, Utah and Wyoming.

At least one company is helping American oil and gas developers bring in drilling rigs and crews from China, while others are recruiting engineering students before they graduate from college.

Experts say the oil and gas industry will lose more than half of its skilled work force to retirement within 10 years, even as companies consider resurrecting oil shale mining in the sparsely populated land north and west of here.

“We’re in the midst of a gas boom right now, and it’s beating us up,” said John Loschke, the mayor in nearby Parachute. “And to talk about oil shale on top of it? Whew.”

Foreign rigs coming in to U.S.

Presco Inc. imported a Chinese-built rig


JUDY PATRICK

this summer and began operating the equipment in early August near Rifle. The crew is American, said Kim Bennetts, Presco’s vice president for exploration and production.

“We only went to China because we were having trouble finding equipment here,” Bennetts said, adding that rigs from Italy, Norway and other countries also are being sought by U.S. oil and gas companies.

The proposed use of foreign labor has upset Rep. John Salazar, a Democrat representing much of western Colorado, and some unionized workers. Salazar suggested providing grants to local colleges or allowing Colorado workers to train with Chinese workers.

“The rig work out there is not a highly skilled criteria. It is dangerous and it’s hard work, but for that kind of money you can’t tell me there aren’t local workers,” said Henry Solano, business manager for the Pipefitters Local Union No. 208 in Denver.

Others disagree.

“I’m sure with the wages the way they are, people will be recruited but not at the rate that’s needed,” said Bob Woodworth, a partner in Denver-based Western Energy Advisors, which helps North American

The number of petroleum engineers in the United States dropped by more than 50 percent between 1983 and 2001... The number of college students pursuing petroleum and mining degrees dropped by 80 percent over a similar span.

companies work with the China National Petroleum Co.

Looming retirements

Oil and gas companies are dealing with some alarming labor statistics: About half the entire work force will soon be eligible for retirement because the average age for members of the Society of Petroleum Engineers/American Association of Petroleum Geologists is 50 years old, according to a study by the University of Texas at Austin.

The number of petroleum engineers in the United States dropped by more than 50 percent between 1983 and 2001, according to the U.S. Bureau of Labor Statistics. The number of college students pursuing petroleum and mining degrees dropped by 80 percent over a similar span.

Forest and Olivia Bommarito, both 24, were among 11 students who graduated with master’s degrees in petroleum engineering in May from the Colorado School of Mines.

Forest Bommarito said he had seven job offers before graduating, and his wife received her first job offer a full year before she graduated. Husband and wife signed contracts in October to work for ConocoPhillips and BP, respectively, in Anchorage, Alaska, with starting salaries around $79,000.

“Right now times are great, but there have been times in the past and probably times in the future that haven’t been so good,” Forest Bommarito said. “But it’s going to take a long time, if ever, for the petroleum industry to phase out and for another energy source to become dominant.” ●

TEXAS

Port Arthur refinery plans expansion

A Port Arthur, Texas, oil refinery plans an expansion that would double its capacity, making it one of the nation’s largest, city officials said.

Motiva is planning a $3.8 billion expansion that would increase the refinery’s capacity from 285,000 barrels per day to as much as 570,000 barrels, Port Arthur Mayor Oscar Ortiz said.

That would make the refinery larger than ExxonMobil’s Baytown refinery, which is the biggest in the United States.

A Motiva spokesman couldn’t confirm details of the expansion, but said the company is starting a process engineering study to find a Gulf refinery to expand.

Motiva is a joint venture between Royal Dutch Shell and Saudi Aramco.

—THE ASSOCIATED PRESS

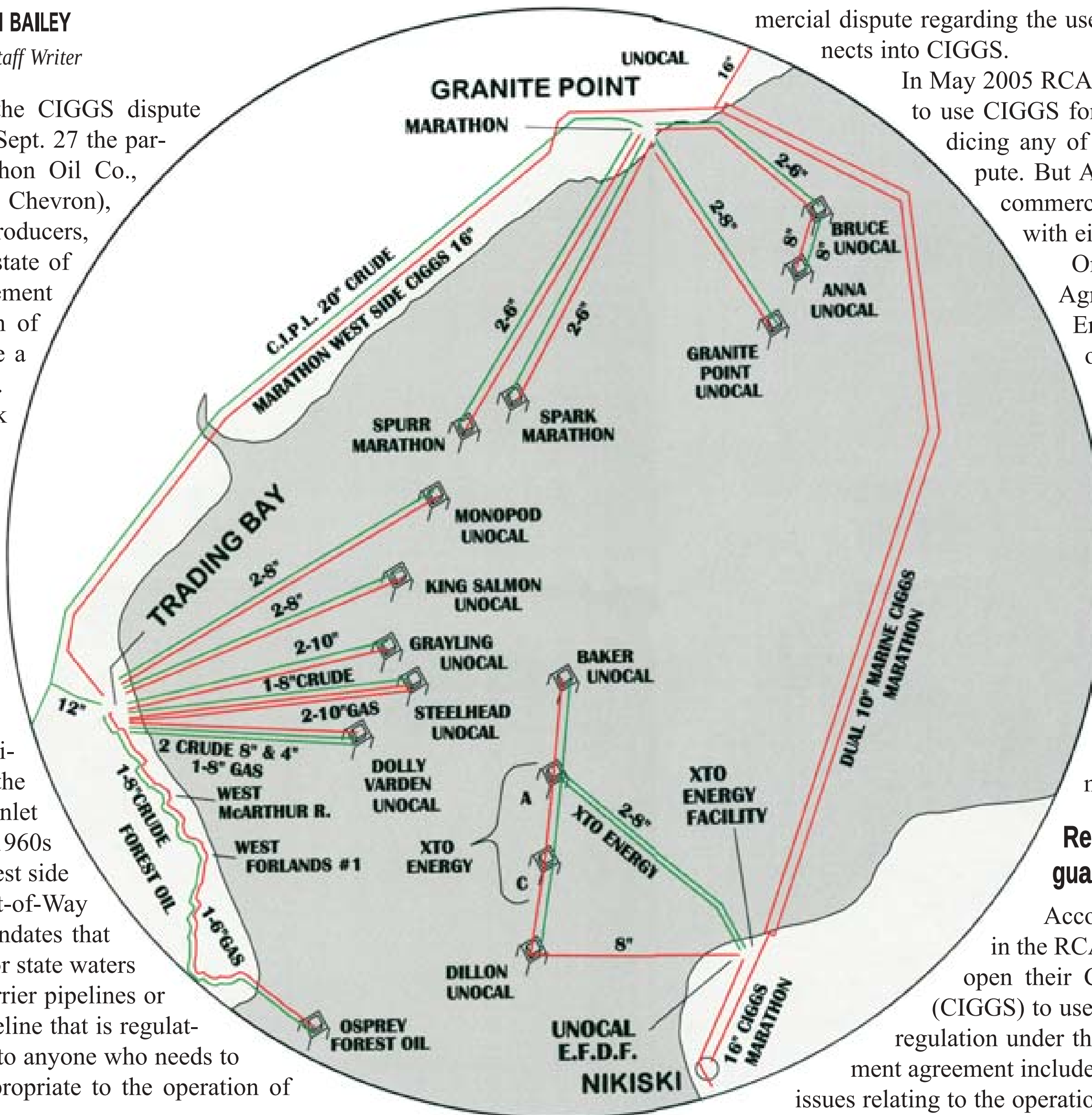
● COOK INLET

Settlement in sight for CIGGS dispute

Following nearly three months of negotiations, parties file agreement with Alaska commission on Cook Inlet gas gathering system

By ALAN BAILEY

Petroleum News Staff Writer



Is the long-running saga of the CIGGS dispute about to come to an end? On Sept. 27 the parties to the dispute — Marathon Oil Co., Unocal Corp. (now part of Chevron), Agrium, the Cook Inlet gas producers, Enstar Natural Gas Co. and the state of Alaska — filed a settlement agreement with the Regulatory Commission of Alaska. RCA now needs to make a ruling on the proposed settlement.

The privately operated Cook Inlet Gas Gathering System, or CIGGS, transports gas from oil and gas fields in the Trading Bay area on the west side of the Cook Inlet to the fertilizer and LNG plants on the east side of the inlet. Marathon and Unocal jointly own CIGGS, while Agrium owns the Nikiski fertilizer plant.

CIGGS has operated as a private, unregulated system since the companies operating the Cook Inlet oil fields built the system in the 1960s to ship out excess gas from the west side of the inlet. The Alaska Right-of-Way Leasing Act, passed in 1972, mandates that all pipelines crossing state lands or state waters must be regulated as common carrier pipelines or gas utility lines. In general, a pipeline that is regulated in this way must offer service to anyone who needs to transport petroleum products appropriate to the operation of the pipeline.

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

Agrium petitions

Since early 2004 Agrium has filed two petitions with the Regulatory Commission of Alaska to regulate CIGGS. The commission dismissed Agrium's first petition but the second petition, filed in October 2004, remains open. Agrium argued that the private operation of CIGGS was an obstacle to getting new industrial gas supplies to Nikiski. As a result of gas supply problems the Nikiski fertilizer plant is under threat of closure.

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

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

In May 2005 RCA granted Aurora interim permission to use CIGGS for Nicolai Creek gas without prejudicing any of the arguments in the CIGGS dispute. But Aurora has been unable to agree to commercial terms for the use of CIGGS with either of the CIGGS owners.

On May 26, 2005, Marathon, Unocal, Agrium, the Cook Inlet gas producers, Enstar Natural Gas Co. and the state of Alaska entered mediation, to negotiate a resolution to the CIGGS dispute.

On June 24 the parties to the dispute notified RCA that they had executed a comprehensive agreement in principle "setting forth the principal settlement terms intended to resolve all outstanding rate and tariff issues." Since then the parties have been hammering out the detailed commercial arrangements that they have now published in the settlement agreement filed with RCA.

Regulated with guaranteed capacity

According to a joint statement included in the RCA filing "Marathon and Unocal will open their Cook Inlet Gas Gathering System (CIGGS) to use by the public and will submit it to regulation under the Alaska Pipeline Act." The settlement agreement includes provisions that address numerous issues relating to the operation of the system.

The CIGGS owners have guaranteed a minimum capacity of 40 million cubic feet per day for common-carriage service for third party shippers. The owners will retain firm rights to use the remaining capacity "subject to the terms and conditions set out in the settlement agreement," so that the owners can continue to use the system for its present purposes.

Provisions relating to operating pressures address concerns of CIGGS owners about potential adverse impacts of third party shipper usage on operating pressures at the Steelhead production platform. The agreement allows the CIGGS owners to operate the system at pressures that "they deem necessary to optimize their production," subject to meeting the obligation to maintain a guaranteed capacity for common carriage and a stated maximum pressure.

Self-policing of imbalances

The agreement recognizes that the CIGGS metering and control facilities were not designed for a common carriage system and that the system has little ability to withstand imbalances between how much gas a shipper puts into the system and how much a shipper takes out. As a result the parties have settled on a tariff regime that "relies heavily, in the first instance, on self-policing" to control imbalances. The CIGGS owners will, however, retain the ability to enforce compliance with system operating rules.

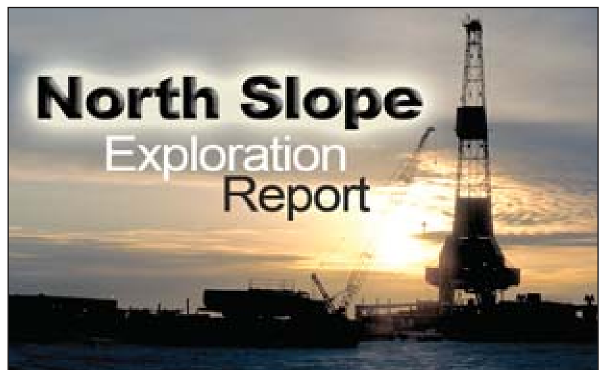
Shippers must meet rules governing the gas control and monitoring facilities required for connecting facilities. There are also circumstances under which the CIGGS

see CIGGS *page 12*

● NORTH SLOPE

Numerous wells under discussion but….

Pioneer, Talisman's FEX and maybe ConocoPhillips and Anadarko plan exploration drilling on Alaska's North Slope



By Kay Cashman | Petroleum News Executive Editor

Some call the upcoming drilling season the lull before the storm on Alaska's North Slope with expectations that Pioneer Natural Resources and Kerr-McGee will sanction their developments at Oooguruk and Nikaitchuq, respectively, by the end of the year.

The demand for drilling rigs is starting to get tight, with some competition coming from producers increasing in-field drilling, as well as from companies looking to contract rigs for this season and for the following winter drilling season, 2006-07.

The big unknown for this winter is ConocoPhillips, the most active explorer on the North Slope to date – or at least the company that spends the most money on exploration. ConocoPhillips has been very quiet about its plans to operate any exploration wells in the winter of 2005-06, although it has done some well site staking in the national Petroleum Reserve-Alaska. The company was looking at drilling a well at its Iapetus prospect northwest of the Alpine field but told the Alaska Division of Oil and Gas in July that it had canceled those plans.

Pioneer has several wells in works

With the new Arctic Fox No. 1 drilling rig currently under construction by JV partners Doyon Drilling and Akita Drilling and due to arrive this winter for use on Pioneer Natural Resources' North Slope leases, Pioneer is talking about drilling several exploration wells this winter, including Hemi Springs State No. 2 and Hailstorm 1 in the proposed Storms unit, a state official said.

JUDY PATRICK

Rolligon at sunset in the NPR-A

In unit paperwork filed with the State of Alaska, a Hailstorm prospect is identified on lease ADL 390472, in section 2 of township 9 north, range 13 east, Umiat Meridian. Pioneer told the state the first Storms exploration well would be on that lease; the second would be on ADL 389096, ADL 389097 or ADL 390492.

Farming in at Antigua and Cronus

In a recent pre-application meeting with the state Pioneer also discussed drilling exploration wells at Antigua and Cronus, both North Slope prospects where Pioneer said it had a farm-in agreement with leaseholder ConocoPhillips.

In August 2004, ConocoPhillips notified state regulators that it planned to drill "one or more" Antigua wells south of its Kuparuk River unit last winter. Those plans fell through, presumably because its Alaska projects were not competitive with other opportunities around the world. The four wells, ConocoPhillips said, would require ice pads and 20 miles-plus of ice roads.

Antigua No. 1 is in township 10 north range 10 east, Umiat Meridian; Antigua No. 2 is in T9N-R11E, UM; Antigua No. 3 is in T9N-R10E, UM; and Antigua No. 4 is in T9N-R10E, UM.

In July, ConocoPhillips filed a two-lease exploration unit application with the state for Cronus prospect (just west of Meltwater) and said it would drill an exploration well this winter.

Pioneer did not give the state any specifics in its pre-application meeting but in its July 27 unit application to the state ConocoPhillips said the Cronus well would be drilled on state lease ADL 389161 to depths sufficient to penetrate the Albian Torok sand interval correlative to that found in the Nanuk No. 1 well between 6,140 feet to 6,300 feet measured depth, or 6,100 feet to 6,300 feet subsea true vertical depth, whichever is less. (That accumulation is being developed as an Alpine satellite, with production planned to begin at the end of 2006 from both Nanuq and Kuparuk sands.)

ConocoPhillips told the state that the Cronus unit "encompasses all or part of a potentially oil-bearing reservoir in the Albian Torok formation."

One of a group of exploration prospects ConocoPhillips was looking at west of Kuparuk early in the decade the Cronus prospect was originally part of the larger SE Delta exploration unit approved by the state in 2001 and eventually dissolved because ConocoPhillips did not meet a work commitment to drill the Cronus well by June 2002.

Anadarko's plans uncertain

Anadarko Petroleum told state officials in a recent pre-application meeting that it is looking at drilling its Ayak oil prospect in the old Slugger unit south of Badami and near the company's Jacob's Ladder oil prospect this winter — and possibly a second well next winter. But drilling could depend on a partnership deal coming together for Anadarko. (See Anadarko's Alaska update on page 1 of this issue.)

Eni wells for next year

Three of the wells initially under discussion as possibilities for this winter were ENI Petroleum's at its proposed Rock Flour unit, but the company told the state in its unit plan this fall that those wells will be drilled next winter, not this coming winter.

FEX drilling two in NPR-A

Two companies are talking about drilling exploration wells in the National Petroleum Reserve-Alaska this winter – ConocoPhillips and Talisman Energy's wholly-owned U.S. subsidiary, Fortuna Exploration, which has changed its name to FEX L.P. In a July 28 conference call, Talisman Energy executives said the Calgary-based independent would be drilling two exploration wells in NPR-A this winter, as opposed to a single well previously mentioned by company executives.

On Sept. 26, the State of Alaska began its Alaska Coastal Management Program consistency review of FEX's exploration drilling project in Northwest NPR-A, a three-year program in which FEX is looking at drilling up to eight exploration wells. (One of the proposed drill sites — the Aklaq-1 site — lies within the statutorily defined coastal zone and therefore requires review under ACMP.)

The company has already identified 11 possible locations for those wells, BLM records show.

Supplies and equipment were barged to Cape Simpson from West Dock this past summer. Mobilization via low-pressure vehicles (LPVs) from Barrow, Cape Simpson, Deadhorse and possibly Inigok to the drill sites will proceed when tundra travel conditions allow.

ConocoPhillips stakes near Kokoda

ConocoPhillips has staked locations for four wells near its NPR-A Kokoda prospect where it drilled last winter – Nugget 2, Noatak 2, Hornet 1 and 2 — and it recently filed a notice of staking with the Bureau of Land Management for the Aviullaavik 1 and 2, which lie between the notice of stakings for FEX's wells Aklaq 2 and Aklakyaaq 1. Word on the street is that the deal on the rig ConocoPhillips was hoping to use in NPR-A fell through.

CANADA

Oil sands start-up forages for prospects

CanWest Petroleum plans 12 wells this winter at Alberta oil sands prospect; also testing Saskatchewan oil sands extension

By GARY PARK

Petroleum News Canadian Contributing Writer

Surrounded by a hungry pack of oil sands giants chasing scarce prospects in northern Alberta, start-up CanWest Petroleum, and its stable of subsidiaries, is sinking its teeth into some promising morsels.

In its latest acquisition, CanWest, through wholly owned Township Petroleum, made a successful bid of C$864,000 for the 23,040-acre Eagle Nest prospect in the Athabasca region of northwestern Alberta.

The company is now gearing up to spend about C$2.3 million on 12 wells this winter to test an Alberta Energy and Utilities Board estimate that the property has an initial in-place resource of 3.4 billion barrels of crude bitumen.

Independent consultants have told CanWest that seven previous exploration wells on the prospect point to a net bitumen pay of 46 feet at a depth of 1,700 feet.

That indicates a commercial operation would lend itself to the fast-evolving steam assisted gravity drainage technology, which injects steam under pressure, melting the bitumen, which can then flow to the surface.

Company also working Saskatchewan

CanWest is also poised to blaze trails in Saskatchewan, to test the eastern extension of the oil sands and study the feasibility of oil shale as a source of petrochemical feedstocks.

It has a controlling interest in 1.4 million acres in the Firebag East project and is now developing an exploration program, including geophysical surveys to delineate and prioritize prospective targets before drilling to test the prospective pay zones.

Firebag East is adjacent to a host of major projects, including Suncor Energy's Firebag operations which expect to yield 140,000 barrels per day; Synenco's Northern Lights project which is targeting 150,000 bpd, with China's Sinopec as a 40 percent partner; the Kearl leases where Imperial Oil and ExxonMobil Canada may invest C$6.5 billion to achieve peak output of 200,000 bpd; and Petro-Canada's 60,000 bpd Lewis project.

As CanWest moves ahead with its plans it is being closely followed by major companies in the area, a spokesman for CanWest told Petroleum News.

In total these projects hold reserves of 14 billion barrels of recoverable bitumen.

Closest bitumen production 30 miles away

The closest bitumen production is Suncor's Firebag operation, just 30 miles from the permit boundary of CanWest's unit Oilsands Quest, which recently completed a C$4.4 million equity financing with CIBC World Markets to fund its 2005 exploration program on 13 permits covering 850,000 acres in northwest Saskatchewan.

As CanWest moves ahead with its plans it is being closely followed by major companies in the area, a spokesman for CanWest told Petroleum News.

Rounding out CanWest's current plans, the company has an agreement with Nova Chemicals to jointly study the feasibility of Saskatchewan's Pasquia Hills oil shale project as a potential source of petrochemical feedstock.

Nova has the right to purchase any future feedstock production, leaving CanWest as the owner of any project. ●

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CIGGS

owners can operate control valves at interconnection points.

The agreement also includes the detailed terms of a gas quality waiver that will allow Forest Oil Corp. to ship gas with a relatively high nitrogen content through CIGGS to Agrium's fertilizer plant at Nikiski. The waiver will protect the interests of all businesses that receive gas from the system.

Prepayments and tariffs

Agrium and Aurora have agreed to make specific prepayments to the CIGGS owners, in recognition of costs incurred by the owners in the transition of CIGGS operation to a public service and as assurance of interest in shipping gas through the system.

The rate base for the use of CIGGS will be valued at the owner's original investment cost and there is settlement rate methodology for calculating rates. The initial tariff rate will be $0.152 per mcf shipped, but after the first year of regulated service this rate may be modified if there is a "substantial and material" change in gas throughput in the system.

The agreement includes provisions permitting third party shippers to fund expansions to CIGGS and "contemplating streamlined procedures for transferring the facility to a willing third party or for abandoning it from public service at some time in the future." ●

● JOHANNESBURG, SOUTH AFRICA

Saudi Arabia's oil minister says more refineries needed

ExxonMobil head says conservatively 2 trillion barrels of oil remain, more than twice oil so far recovered

By TERRY LEONARD
Associated Press Writer

Saudi Arabia's oil minister said Sept. 27 that world oil reserves are more than enough to meet rising future demand but that without new refineries prices will remain high and markets volatile.

"These are turbulent times for oil markets. Prices are under pressure because the petroleum industries infrastructure is stretched thin," Ali Naimi told the 18th World Petroleum Congress in Johannesburg. "Most of the spare capacity of the 1980s and 1990s has disappeared, resulting in a system that has a much smaller margin for error."

Naimi said the havoc and disruptions caused recently by hurricanes Katrina and Rita in the Gulf of Mexico offered visible examples of the fragility of the energy delivery system.

Concerns about refining capacity, heightened by the hurricanes, have pushed the price of oil beyond US$60 a barrel.

During periods of low prices, Naimi said low cost fuel encourages consumption but causes investors to turn to other industries that offer greater returns. If prices are too high, global growth suffers and the petroleum industry suffers from reduced demand.

Price attracts investment

"The current price level is providing the returns needed to attract adequate investment," said Naimi. "We believe spare crude oil production capacity will grow sufficiently in the next three to four years to restore some margin of safety to world crude markets."

However, he said higher prices were not enough to assure the necessary investment. He said environmental impact issues and contentious planning regulations will make it more difficult to overcome the bottlenecks in the current energy delivery system. He said an uncoordinated proliferation of regulations was complicating investment decisions and clouding the future.

Rex Tillerson, president of Exxon Mobil Corp., said the damage from hurricane Rita was still being assessed but that hurricane Katrina had destroyed 40 oil platforms in the Gulf of Mexico and damaged others. It also briefly knocked out 95 percent of the oil production in the Gulf of Mexico and 90 percent of natural gas production there.

"There was a rapid, market-driven recovery. Within two weeks, all but 15 percent of oil and 6 percent of gas production was restored.

The hurricanes, he said, underscored the global interdependence of the oil industry and made it clear that no country can be truly energy independent.

Exxon: at least 2 trillion barrels

Tillerson said global energy demands would increase by 50 percent in the next 25 years and about 80 percent of that increase will come from the developing world.

"We must invest wisely and continue to make technological innovation to meet the challenge of the next generations energy demand," said Tillerson.

He said although some estimates were as high as 7 trillion, by conservative estimate there were at least 2 trillion barrels of oil yet to be recovered.

"That is more than twice all the oil recovered up to now in all of human history," said Tillerson.

Naimi said talk of oil scarcity reminds him of the 1970s, when people also thought the end of the age of oil was at hand.

"But in the intervening years, when we were supposedly facing a precipitous decline, world oil reserves more than doubled," said Naimi. The increase was noteworthy because the world consumed 800 billion barrels during the period.

Proven oil reserves in Saudi Arabia in 1970 totaled 88 billion. Today, he said they are conservatively estimated at 264 billion barrels despite 91 billion barrels have been produced over the 35 years.

New technology as well as new discoveries has raised world oil reserves. He said new technology would soon boost proven reserves in Saudi Arabia by 200 billion barrels. He said a technology that allows the country to recover just 1 percent more from its fields would add a full year to production.

Naimi said in an effort to stabilize prices and reduce volatility in the markets, Saudi Arabia will maintain at least 1.5 million barrels a day in spare capacity. He said for decades the overcapacity had reached as high as 15 million barrels a day, but those days are gone because of rising oil demand produced by a vibrant global economy.

Saudi Arabia, he said will continue efforts to expand capacity across the supply chain. He said it would meet current requirements by offering additional crude as needed, and would pursue an aggressive exploration program, expand production capacity from 11 billion to 12.5 billion barrels a day by 2009, expand and upgrade refineries in the kingdom and overseas, build new export refineries, add tankers to its fleet and invested in new advanced technologies. ●

QUITO, ECUADOR

Ecuador prepares to renegotiate contracts

President Alfredo Palacio's government will ask the French Institute of Petroleum to assist in renegotiating contracts with foreign oil companies to give the Andean nation a greater share of petroleum profits, his energy minister said.

With the help of the French Institute, Ecuador hoped that the country might begin contacting oil companies in October to schedule talks.

Palacio has said he wants to increase Ecuador's share of royalties and income tax on petroleum profits from the current 20 percent to 50 percent.

Rodriguez pledged the government would "respect legal security in a negotiation that will not be traumatic, a negotiation of mutual accord."

"To that end, we have had preliminary negotiations with representatives of the petroleum companies to let them know our desire is to do a very objective, very professional job," he added.

High oil prices not in current deals

He said the deals currently in place do not take into account record-high world oil prices.

In the same press conference, the president of state-run Petroecuador, Luis Roman, said that it was impossible to say whether Ecuador would be able to achieve a 50-50 split that Palacio's government seeks, given the complexity of renegotiating deals with some 19 transnational companies that operate in the country.

Ecuador produces about 535,000 barrels of crude daily, taking into account state and private production. Oil income provides about 43 percent of the government's operating budget.

—THE ASSOCIATED PRESS

● POINT THOMSON

Port Authority says Pt. Thomson in default

Authority demands state terminate unit, give natural gas to authority; threatens legal action if public hearing not scheduled

By KRISTEN NELSON

Petroleum News Editor-in-Chief

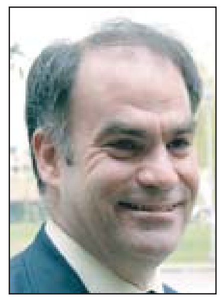
In August the Alaska Gasline Port Authority told the State of Alaska it expects to ship royalty North Slope natural gas as part of its proposed liquefied natural gas project.

It also said it would expect state assistance in obtaining natural gas.

In September the authority got specific about the kind of help it expects from the state: it wants the Point Thomson unit terminated and wants the state to provide it with the natural gas from that unit.

The port authority's Aug. 22 Alaska Stranded Gas Development Act filing with the state is based on shipping the state's royalty gas, but also proposes that the state assist the port authority with third-party negotiations for other gas; "diligently enforce" any rights the state has to cancel leases or unit agreements; "bring suit against leaseholders" or unit working interest owners for "failure to meet a duty to develop or market ANS gas" to either compel the sale of gas to the port authority or forfeiture of the leases; and support legislation "to clarify" the port authority's "right to exercise the use of eminent domain to acquire needed gas."

In mid-September the port authority sent an "Agency Demand Regarding the Point Thomson Unit" to the Alaska Division of Oil and Gas, demanding that the division notify the working interest owners at Point Thomson that they are in default of the unit agreement and of state regulations, telling unit owners that the unit will terminate in 90 days and also demanding "that gas from Point Thomson be made available" to the port authority as described in its Aug. 22 proposal.


FORREST CRANE

Mark Myers, Division of Oil and Gas


JUDY PATRICK

Jim Whitaker, port authority chairman

The demands were filed Sept. 16 by port authority attorney Bill Walker on behalf of the port authority and Jim Whitaker, the authority's chairman, described in the demand as "a citizen-taxpayer of the State of Alaska…"

The authority's demands would seem to run counter to one of the division's demands of plans from the Point Thomson owners. The owners want to focus on gas development; the division is opposing that focus, saying it also requires a plan on how liquids would be produced from the unit, since an initial focus on gas production could potentially leave liquids stranded in the reservoir.

Public hearing demanded

In a Sept. 23 supplement, the port authority demanded that the division hold a Point Thomson public hearing not later than Oct. 31. At that public hearing, Walker told the division, ExxonMobil and the other Point Thomson working unit owners would justify the terms of their proposed 22nd plan; explain why no production has occurred from the unit; explain why all wells in the unit are currently plugged and abandoned; explain when and how unit production is expected to occur; "report all inquiries they have received to purchase gas from the Alaska North Slope generally" and specifically from the Point Thomson unit; and explain why they have requested a delay in development drilling.

The port authority said in its Sept. 16 demands that in April it "made a detailed offer to purchase Alaska North Slope gas and transport it to market," an offer "distributed to" ExxonMobil, ConocoPhillips, BP, Chevron "and others." The major producers declined to sell gas to the port authority, "or even to discuss prices or terms," the authority told the division.

The authority said it has also "intensified its correspondence and meetings" with ExxonMobil about Point Thomson gas, and asked ExxonMobil in August to present information on a gas sales agreement it would find acceptable. The authority said ExxonMobil's response is that it would need to do an analysis of the project from the wellhead to market to access the project's viability, and has asked for information for its analysis.

Also opportunity for comments

The port authority said that in addition to testimony from ExxonMobil, the port authority "and other interested parties" would be able to comment at the public hearing on whether or not it is in the state's best interest for the division to approve a 22nd plan of development, "and if so under what terms," and to comment on issues raised in the authority's Sept. 16 agency demand, and in general whether it is in the public interest for the state to extend or terminate the Point Thomson unit agreement, thereby terminating leases within the unit.

Walker said if the authority did not receive confirmation of a public hearing by Sept. 27, it would "seek judicial intervention to bring this about."

Division Director Mark Myers said in a Sept. 26 letter to Walker that it would "consider your demands and requests as we evaluate Exxon's proposed plan." The division, he said, intends to issue a decision on the 22nd plan of development before the 21st plan expires Sept. 30.

Point Thomson plan under review

Point Thomson is on the eastern edge of the state's North Slope lands, abutting the coastal plain of the Arctic National Wildlife Refuge. The main Point Thomson reservoir, discovered in the 1970s, contains high-pressure natural gas and condensate, hydrocarbons which are liquids at normal pressure. There are also shallower conventional oil reservoirs within the unit.

The Point Thomson unit was formed in 1977 and requires a state-approved plan of development. There are also requirements related to a 2001 unit contraction and expansion agreement in which the state agreed to add acreage to the unit in exchange for development drilling by June 15, 2006, and completion of seven development wells by June 15, 2008.

The division and Point Thomson unit operator ExxonMobil Production (major working interest owners are ExxonMobil, BP Exploration (Alaska), Chevron USA and ConocoPhillips Alaska) are in the process of negotiating the next plan of development, discussions which have been ongoing for some months.

The original unit agreement required a well to be drilled each year. This occurred through 1982, with several wells certified by the state as capable of producing in paying quantities. In 1980, however, state officials said that a well a year within the unit was no longer crucial, as delineation wells drilled outside of the unit might be more appropriate.

In 1982 the first unit plan was approved without a drilling requirement, and also in 1982 Division Director Kay Brown agreed with Exxon's assertion to Commissioner of Natural Resources John Katz that the unit should be extended beyond the initial five years because it contained discoveries recognized by the state.

Plan had been gas cycling

In recent years the unit owners have proposed a gas cycling project at Point Thomson: liquids would be produced; a pipeline would take those liquids to the trans-Alaska oil pipeline; and gas would be reinjected into the reservoir for sales once there was a gas pipeline from the North Slope.

But in late 2003 ExxonMobil told the state that further work evaluating Point Thomson had "resulted in a significant reduction in liquid resources," and said the owners could not "identify a viable gas

see POINT THOMSON page 15

ALBERTA

Bidding for oil sands getting ‘aggressive’

What companies are prepared to pay for oil sands rights in Alberta’s Athabasca region seems far from peaking.

Synenco Energy, with China’s Sinopec as a 40 percent partner, forked over a record C$76 million for 23,000 acres at the Alberta government’s latest bi-monthly land auction Sept. 22, just two weeks after an unidentified company paid a benchmark C$45.2 million for a similar sized parcel.

The scramble to secure prospects is forcing companies to “aggressively pursue and acquire properties,” Michael Supple, Synenco chairman, said in a statement.

Reinforcing that outlook, Scott Land & Lease, operating for an undisclosed client, purchased 6,000 acres near the Synenco parcel for C$15.3 million.

With three-quarters of the land sales year gone, the Alberta government has collected C$223 million for oil sands rights, C$50 million ahead of the previous 12-month record in 1997. Overall land sales now tally C$1.31 billion, beating the comparable record, also set in 1997, by C$160 million.

The Synenco land is on the western edge of its Northern Lights property, where Sinopec (officially China Petroleum & Chemical Corp.) paid C$105 million in May for a 40 percent stake. However, Synenco said it has sole ownership of the latest purchase, although most observers believe the Chinese company is involved in setting a strategy.

Privately owned Synenco raised C$60 million in August from investors, at C$14 a share, to expand its oil sands portfolio.

Northern Lights is a C$4.5 billion mining and upgrading venture, which hopes to start commercial production in 2009 at 50,000 barrels per day and possibly triple over time. That lease has an estimated 2.5 billion barrels of recoverable bitumen.

—GARY PARK

GILLETTE, WYO.

Anadarko applies for Wyoming shale leases

Anadarko Petroleum is seeking federal permission to study the feasibility of getting oil out of shale in southwestern Wyoming.

An estimated 2.6 trillion barrels of oil permeate shale deposits in Utah, western Colorado and southwestern Wyoming. That’s 20 times the nation’s traditional oil reserves. With Congress’ recent lifting of a moratorium on oil-shale research, the U.S. Bureau of Land Management has received 18 applications to study oil shale development in Colorado and Utah.

So far, only Anadarko has applied in Wyoming, where the company holds vast oil shale reserves intermixed with federal holdings, according to company spokesman Rick Robitaille. The company wants to focus on an area 35 miles southeast of Rock Springs. “We are wanting to conduct some tests to explore some different sciences and analyze the potential resource base that might exist in the area,” Robitaille said.

Technology to extract oil from shale has so far been too inefficient for feasible production, but high oil prices have renewed interest for the first time since the 1980s.

Colorado and Utah hold more oil shale, but Robitaille said southwestern Wyoming is already suited to handle oil-shale development.

“In southwest Wyoming there is a very definitive mining culture,” he said. “Those folks have mined coal and mined trona for years. The infrastructure is there for moving production to market. So there are a lot of positives.”

The BLM plans to consider 10-year leases on 160-acre parcels. Federal regulators and governors plan to evaluate the lease applications in October and some research could begin early next year.

—THE ASSOCIATED PRESS

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POINT THOMSON

injection project under current fiscal terms.”

With a smaller condensate resource, ExxonMobil said the owners tried to identify a smaller gas injection project which would be viable, but were not able to identify enough cost reductions.

This June the unit owners told the division they wanted development of the field tied to a natural gas pipeline from the North Slope with development drilling to begin three and a half years before field startup, rather than by June 2006. Terms of the expansion agreement call for expansion acreage to be contracted out of the unit if development drilling did not begin by June 2006, or if seven development wells were not completed by June 2008, with the owners paying the state $20 million at the first default date or $27.5 million at the second.

Myers told ExxonMobil in a July letter that the division “is not inclined” to accept the extension of development drilling, and said the division “does not intend to relieve” the owners of the drilling play they committed to in the unit expansion in 2001. He told ExxonMobil the division would enforce the terms of the expansion agreement — contracting expansion acreage out of the unit — if the owners failed to meet the work commitment. Myers said, however, that the division would accept an exploration/delineation well in lieu of development drilling.

Owners would apply for conservation order

A revision of the 22nd plan, submitted by ExxonMobil Aug. 31, remained focused on gas development, but acceded to the division’s concerns that the field owners describe plans to develop all hydrocarbon reserves, not just natural gas.

As for the exploration well, ExxonMobil instead proposed a joint planning effort with the state to define the value of information which would be gained from a well. The division had asked for a well to delineate the Thomson reservoir west of the Point Thomson Unit No. 1, in lieu of deferring the start of development drilling for one year. Myers told ExxonMobil that the state would enforce the expansion agreement if the owners failed to meet the work commitment, contracting 2001 expansion acreage out of the unit.

ExxonMobil said the owners would agree to apply to the Alaska Oil and Gas Conservation Commission for a conservation order for field gas off take for Point Thomson, and would also prepare a schedule of activities to prepare permits. ●

MADISON, WIS.

It’s Big Oil vs. Big Corn in Wisconsin

A major political fight is shaping up over a plan in the Wisconsin Legislature that would require all gas sold in the state to contain 10 percent ethanol by July 2006, a mandate that supporters say will benefit farmers while reducing gasoline prices and dependence on foreign oil.

Democratic Gov. Jim Doyle and key Republicans in the Legislature say the state should join Minnesota, Montana and Hawaii in mandating such a requirement.

“I would just rather have the farmers of the Midwest making the profits instead of the sheiks of the Mideast,” said Rep. Stephen Freese, R-Dodgeville, a sponsor of the measure.

Coalition opposes plan

But the push is running into intense opposition from an unlikely coalition of oil companies, the state’s powerful business lobby and environmental groups usually at odds with both of them.

Ethanol advocates say the mandate would reduce gas prices by about 5 cents per gallon while increasing the price of corn by 10 cents per bushel. Critics say the plan will have no effect on gas prices, but instead will lead to more smog.

Gas prices soared to more than $3 a gallon for the first time ever in Wisconsin after Hurricane Katrina disrupted the nation’s oil supply before dropping to $2.72 per gallon, according to the AAA.

The debate over ethanol may play out in other states as lawmakers look for ways to ease the pinch of rising gas prices. In Michigan, Democratic lawmakers proposed a similar plan in August.

In Wisconsin, a coalition of farm groups is mounting a major campaign to push the bill to approval in both chambers of the Legislature so that Doyle can sign the measure into law.

—THE ASSOCIATED PRESS

continued from page 1

RIGS

Moreover, between Aug. 26 and Sept. 29, a cumulative total of 39.36 million barrels or 7.19 percent of annual oil production and 188.54 billion cubic feet or 5.17 percent of annual gas production remained shut-in.

Offshore rigs hard hit by Rita

As damage reports began trickling in after Rita, it became apparent offshore drilling rigs were particularly hard hit by the hurricane's 175 mph winds and the huge waves generated by that storm.

The Financial Times of London concluded that Rita caused more damage to offshore drilling rigs than any other storm in history and would force companies to delay exploring for oil and gas in both the United States and overseas. The newspaper noted that the path Katrina took was through mature areas of the Gulf where there are mainly production platforms. But Rita came to the west where there is lots of exploratory drilling.

Contract drilling company Noble reported that four of its semi-submersible rigs operating in the Gulf's Green Canyon area — Therald Martin, Paul Romano, Amos Runner and Max Smith — broke from their moorings and sustained varying damage. The rigs were found between 75 and 123 miles from their original locations.

Noble said its Lorris Bouzigard semi-submersible also broke at least one of its 10 mooring lines, with the remaining lines holding the unit in position nearly a mile from its original location, and the submersible Joe Alford moved about eight miles off its original location. Noble's Jim Thompson already was undergoing inspection for damage caused by Katrina.

Transocean Marianas forced off location

Transocean said its moored semi-submersible rig Marianas was forced off its drilling location during Hurricane Rita and was grounded in shallow water at Eugene Island Block 133 about 140 miles northwest of its pre-storm location.

"An initial assessment of the rig indicates significant damage to the unit's mooring system, but a more complete rig inspection is ongoing," Transocean said.

Additionally, the company said its semi-submersible Deepwater Nautilus, which sustained damage to its mooring system during Katrina and was undergoing repairs, was set adrift when a tow line failed. The rig was being towed out of the path of Rita when the line broke.

Workers aboard Nautilus used the rig's thrusters to navigate the rig to a location about 40 miles south of Grand Isle, La., where the rig remains grounded, Transocean said.

GlobalSantaFe, Diamond, Rowan also report damage

Other contract drilling companies hurt by Rita include GlobalSantaFe, Diamond Offshore and Rowan.

GlobalSantaFe said two of its oil and gas drilling rigs, the GSF Adriatic VII and GSF High Island III, could not be found on their drilling locations during a preliminary search by fixed-wing aircraft on Sept. 25, noting that the two missing jack-ups had a combined net book value of $22.2 million and were insured for $125 million.

However, there were "no signs" of major damage to the company's other rigs, GlobalSantaFe said, adding that the company's "ultra-deepwater" drillship GSF C.R. Luigs was safely moved off location before Rita's arrival.

Diamond said drilling rigs Ocean Saratoga and Ocean Star also broke free from their moorings as Rita passed west of the semi-submersible, but the company said both rigs were eventually found because they were tracked during the storm by onboard locator beacons.

The Saratoga was found grounded in about 35 feet of water on Vermilion Block 111, about 100 miles northwest of the rig's original location on Green Canyon Block 157, Diamond said. The Star went aground in about 35 feet of water on Eugene Island Block 142, also about 100 miles north of the unit's original location on Green Canyon Block 768, the company said, adding that start-up crews re-boarded the rigs to assess their condition.

However, initial fly-bys of other Diamond rigs in the path of Rita indicated no significant damage, but the company said it would not be able to make a complete assessment until workers re-boarded the rigs.

More jack-up rigs missing

Rowan also reported jack-up rigs Odessa and Halifax missing following the storm, and said the hull of jack-up rig Louisiana apparently detached from its legs and was aground offshore Louisiana. Additionally, the company said it was also unable to account for the rig Fort Worth during a high-altitude aerial survey.

The Odessa, Halifax and Louisiana were operating under contracts that provided for total revenues of about $210,000 per day. The rigs were insured for an amount exceeding their value, but Rowan noted that the company does not carry insurance against loss of revenue.

Meanwhile, Chevron said its Typhoon tension leg platform, located in 2,000 feet of water in the Green Canyon area, was severed from its mooring and suffered severe damage during Rita. The facility was said to be secured, but the company provided no additional details.

ConocoPhillips said assessment teams returned to the four Gulf fields it operates following Rita. The company's largest offshore asset in the Gulf, Magnolia, suffered minimal damage and production was expected to resume soon, contingent on resumption of operations at related onshore infrastructure such as pipelines and utilities, the company said.

Initial assessments of ConocoPhillips' three smaller fields found some damage, but the production impact was not expected to be significant, the company said.

Enbridge said it natural gas pipelines in the Gulf were still shut down on Sept. 26 with crews only starting to assess facilities following Rita. Company pipeline systems Garden Banks and Stingray were located in the path of Rita.

Widespread damage from Katrina

Before Rita, Katrina had caused widespread facility damage and major supply disruptions across offshore Gulf.

Shell Oil reported damage to four of its offshore platforms following Katrina, with production down to 160,000 barrels of oil equivalent per day, well short of its usual 450,000 barrels per day. Shell is the largest operator in the Gulf and alone accounted for 30 percent of the Gulf's entire 1.58 million barrels of daily oil output prior to the hurricane. Katrina caused severe topside damage to Shell Oil's Mars production platform, which was expected to keep Mars crude output down until early next year.

Other large Gulf producers were ready to pump following Katrina but couldn't get their production ashore because of damage to key pipelines and onshore storage facilities. Big Gulf producer BP was said to be considering options, including barging, tankering, and bypassing third-party operated pipelines to get its production to market.

—RAY TYSON

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

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

Petroleum news

Business Spotlight

By PAULA EASLEY

FORREST CRANE

Mike Mortensen, Purchasing and Sales

Alaska Rubber & Supply

Alaska Rubber supplies Alaska with industrial, hydraulic, and automotive hose, fittings, belts, conveyor belts, pumps and lube equipment. The company's philosophy has been that it can provide the highest level of customer service only if it has the needed product in stock. Consequently Alaska Rubber has the largest in-state stock of all its product lines.

Mike Mortensen says he's one of the new guys, and he's been with Alaska Rubber 12 years. After working in sales for eight years, Mike has recently been transitioning to purchasing. He and wife Kelly have two daughters, Kayla and Malia, and celebrated their tenth anniversary last December. Mike considers himself a golf addict who also loves outdoor family activities and travel.

continued from page 1

TRUSTS

own department estimated at C$300 million in 2004 and Toronto-Dominion Bank chief economist Don Drummond believes has now doubled to C$600 million.

In effectively freezing future deals, Goodale said he wants time to understand the "implications of a business vehicle that essentially pulls off a revenue stream, leaving little flexibility for reinvestment in future growth and development.

"There's a long-term implication about whether or not you could be embedding a kind of sluggishness in the economy," Goodale said.

He said the government wants to know whether there is an inherent unfairness in the treatment of conventional corporations and trusts.

No more advance tax rulings

To allow "good, solid consultations to continue" in an atmosphere of calm, he has ordered an end to advance tax rulings for companies planning to convert to trusts — a practice that is not required, but has given companies certainty regarding the tax implications of a transaction.

Federal Industry Minister David Emerson made more of an effort to placate the trust world by insisting that Ottawa has no intention of driving away investment through possible tax changes.

He told reporters Sept. 22 that neither he nor Goodale "is going to be comfortable with driving investment away," but the Finance Department is also anxious to ensure that Canadians are not motivated "largely or solely by tax considerations," when the loss of that tax revenue could squeeze out investment in plants and equipment.

Drummond thinks there is a 50 percent chance that Ottawa will trim the trust advantage by lowering the effective tax rate on corporate dividends before an election, expected by late winter or early spring.

Otherwise, he said it is possible the government may limit the ability of trusts to deduct interest as an expense and, finally, that it could tax trust distributions.

Other factors could underlie concern

There could be many factors underlying government concern, not least the ballooning cash flow of trusts.

Scotia Capital analysts Brian Ector and Grant Hofer estimate the free cash flow of conventional oil and gas trusts could reach C$2.7 billion in 2006 if oil prices hold steady at US$40 a barrel, climbing to C$4.8 billion at US$50 oil, C$6.9 billion at US$60 and a mind-boggling C$11 billion if ever oil hits US$80.

And that doesn't include CanadianOilSands Trust, the largest partner in the Syncrude Canada consortium, whose free cash flow could surpass C$1 billion next year.

Although not prohibiting the formation of trusts, the government said it hopes companies will postpone conversions or spin offs.

Intended or not, the immediate response was to spook the markets, with shares of some companies that are proceeding with conversion strategies tumbling by as much as 16 percent.

"We've seen more than C$700 million worth of value in our company eroded," said Stephen McPhail, chief operating officer of CI Fund Management, Canada's second largest mutual fund company.

Shareholder pressure to convert

Over the last couple of years, E&P, pipeline and oilfield service companies have been caving in to pressure from shareholders and switching to trust ranks.

Until then they were obscure and much-scorned vehicles used by small oil and gas producers as a tax-efficient way to spread cash flow to investors.

Conventional companies distribute cash to equity holders in the form of dividends. But those dividends and the revenues are both taxable, whereas only the cash distributed to trust unit holders is taxed.

As a result, trusts in unpopular mature industries are able to raise capital at a lower cost, giving them an opportunity to expand, acquire, innovate and create jobs.

Instead of being a short-term fad, as many had predicted, the trusts have gained momentum and finally exploded this year as companies across a wide spectrum have caved in to the option of not paying taxes, building an asset class with a market value of C$170 billion, equivalent to 10 percent of the Toronto Stock Exchange's overall value.

While Goodale has temporarily slowed the proliferation of trusts until he decides sometime next year whether to overhaul the tax system, the ban on tax rulings has spread confusion among investors and punished those companies that did not act quickly enough to convert.

Big energy deals in September

In the oil patch, the two big deals in September involved a merger of StarPoint Energy Trust and Acclaim Energy Trust which negotiated the largest trust transaction to date in Canada, with a market value of about C$4.5 billion, and the long-anticipated conversion of Precision Drilling, Canada's largest driller with a market capitalization of over C$7 billion.

Known for the time being as New Trust, the StarPoint-Acclaim entity will produce 75,000 barrels per day of oil equivalent, placing it third among conventional trusts behind Penn West Energy Trusts at 100,000 boe and Enerplus Resources Fund at 78,000 boe.

Acclaim Chief Executive Officer Paul Charron said New Trust will be listed on both the Toronto and New York stock exchanges, giving it an edge in scooping up more mature oil and gas fields.

"Being a bigger entity will reduce the competition for larger transactions," he said. "The reality today is C$200 million or C$300 million deals can be achieved by almost anyone, given the strength of the capital markets, but the C$1 billion deals are not so easy to do by smaller organizations."

The merger was consistent with earlier predictions by StarPoint Chief Executive Officer Paul Colborne, who expects four years of consolidation as trust cost structures climb and producing assets decline.

"When consolidation comes, and it will, that will be our opportunity," he predicted in May.

Colborne, described as a deal junkie, has stitched together four deals in the past five months carrying a combined value of almost C$6 billion in turning a small junior explorer into a giant trust.

Assuming the StarPoint-Acclaim merger is concluded — and the two trusts say the federal intervention does not affect their plans — Colborne will start again as chief executive officer of a new junior explorer the combined trust plans to spin off, with production of 1,000 bpd of production and reserves of 3 million barrels.

But some analysts doubt that the StarPoint-Acclaim transaction signals a wave of new deals.

Jeff Martin of Peters & Co., in a review of the sector earlier in September, said major consolidation can't occur until oil and gas prices fall, exposing the weaker trusts.

Tax rulings freeze won't deter Precision

Precision, with Chief Executive Officer Hank Swartout an outspoken critic of the trust impact on upstream activities, said Sept. 22 that it will not be deterred by the freeze on tax rulings.

The company said that given published Canada Revenue Agency policy and prevailing law it does not think a ruling is necessary and will, therefore, proceed with its trust conversion.

Swartout might also have helped prod the government to take action by observing that trusts have "more cash than we know what to do with."

He also sits on the board of Harvest Energy Trust, whose annual payout to unit holders has been raised twice this year for an overall increase of 75 percent, consistent with Harvest President Jake Roorda's view that "we are not in the business of hoarding cash. We are in the business of distributing money to our unit holders. That is our No. 1 priority."

The trust review by Peters & Co. said the "stage is set" for higher distributions, which now average 55 percent of cash flow compared with 90 percent several years ago.

"Many of the energy trusts have not increased distributions at the same rate at which their respective underlying cash flows have been growing," the firm said, predicting that energy trusts "will likely be forced to raise distributions to keep the underlying structure non-taxable."

Trilogy Energy Trust, Crescent Point Energy Trust and Petrofund Energy Trust have all announced higher payouts in September and Canaccord Capital has forecast they will soon be joined by Vermilion Energy Trust, C Energy Trust, Viking Energy Royalty Trust and Daylight Energy Trust.

In addition, to sustain their oil and gas production, trusts have been forced to divert more of their cash flow from acquiring properties to spending more on exploration and development, Peters & Co. said. ●

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SIDESTEP

government collects only a 15 percent withholding tax.

Finance Minister Ralph Goodale tried plugging that hole in early 2004 by proposing a limit on foreign ownership.

But a furious response saw Goodale back down, allowing American investors to pick up where they left off and buy as many units as they wished.

However, Pengrowth Energy Trust took action to protect itself, offering A units to foreigners and B units to Canadians.

The A units now trade at a 40 percent premium as conclusive proof of their popularity among U.S. investors.

Although it did not follow the Pengrowth example, Enerplus Resources Fund, one of the top three trusts, recently estimated that non-Canadians own 73 percent of its units.

Senior Vice President Eric Tremblay said Enerplus has no reason to believe that Ottawa is unduly concerned about foreign ownership.

But some observers warn that it would be less painful politically for the government to discourage international investors than punish Canadians who hold small numbers of units in their retirement plans.

—GARY PARK

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INSIDER

the prosperity we should be achieving (from natural resources) won't be there forever," he said. MacKay argued Canada has to learn from its mistakes as an exporter of raw materials.

"We need to improve the manufacturing sector and that includes the energy field," he said.

"We don't want to see lost control over that industry. We want to make sure we are maximizing the benefits in terms of jobs and investment (at a time when) the Chinese and other countries are taking a very interested look at our energy sector."

But MacKay emphasized he was not proposing limits on foreign ownership — "a dangerous line to cross" — although he warned Canada could lose control of the industry if the government didn't improve the tax position of Canadian companies.

"Right now we have a tax structure which punishes investment, that holds back Canadian investors and companies who are trying to compete on the international stage," he said.

Tax breaks, not subsidies, would remove an impediment to exploration and development of offshore Nova Scotia, which is crumbling under the weight of drilling failures and abandoned leases, MacKay suggested.

The corporate tax rate for the energy sector has dropped from 28 percent and will be 21 percent in another two years, the same as for the rest of corporate Canada. Federal Finance Minister Ralph Goodale has reportedly indicated to the Canadian Association of Petroleum Producers that he is now considering a further cut to 19 percent.

—GARY PARK

Rolling the dice on oil prices

In the space of a few days in September, two of Canada's largest banks were wildly at odds over the near-term future of oil prices.

CIBC World Markets Chief Economist Jeff Rubin bet on an average US$84 per barrel in 2006 and US$93 in 2007, with the price breaking the US$100 barrier by the end of 2007; TD Bank Financial Group economists are betting on a rollback to US$45 by early 2007, although they don't rule out US$80 if "further unanticipated supply disruptions occur."

However the ball bounces, industry executives in Canada are worried about the impact of fast-rising world energy consumption and laid out their concerns at a conference in Banff, Alberta.

Shell Canada Chief Executive Officer Clive Mather said the urgent need is to get back to an "orderly market as quickly as we can," instead of panic gasoline buying on fears of further hikes.

He said that sort of jittery response by consumers, regardless of how understandable, contributes to supply shortfalls.

Mather said a far greater concern than SUVs in North America is the demand for energy in the developing world, especially in China, India and other parts of Asia, where consumption will double and possibly triple in the next 20 to 30 years.

Gwyn Morgan, EnCana chief executive officer, doubts the tight supply-demand outlook will ease any time soon.

He said the "single biggest reason" for soaring oil prices is the unprecedented economic growth rates of 8 to 9 percent in Asian countries with combined populations of more than 2 billion people.

But the demand growth in China, India and South Korea is putting the focus on unsustainable levels of consumption in North America, where millions of cars caught in traffic jams burn fuel "when there is a better way."

Morgan practices what he preaches, occupying a condominium within walking distance of his downtown Calgary office and pursuing a vigorous fitness regime as a runner, cyclist and cross-country skier.

—GARY PARK

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BILLS

Disruption Prevention Act" on a 27-16 vote.

The draft version of the bill included a provision to explore the 1002 Area of the Arctic National Wildlife Refuge for oil and gas.

"Part of the reason we're here today is there are signs of stirring in the other body as if they are finally realizing their position opposing these measures is ridiculous," said Resources Chairman Richard W. Pombo, R-Calif.

Pombo cited passage of a budget bill that included ANWR drilling on a 51-50 vote last spring as evidence that the proposal has gained favor in the Senate.

Rep. Edward Markey, D-Mass., offered an amendment to strike drilling on the arctic coastal plain. Markey said ANWR likely contains 2.5 percent of the world's oil supplies, but he opposed drilling there because it does nothing to really solve the nation's energy problems.

"Drilling in the Arctic refuge would result in oil being transported to California to be put into largely inefficient vehicles," without anything being done to make those vehicles more efficient, he said. The amendment failed 14 to 28.

Two-year limit on loan guarantees proposed

The House Energy and Commerce Committee approved the "Gasoline for America's Security Act of 2005," a bill designed to fix the price spikes and dry gas pumps that drivers encountered nationwide after the hurricanes shut down many Gulf Coast oil refineries.

"It is unfortunate that it takes a hurricane to show us just how acute that problem is," said the panel's chairman, Rep. Joe Barton, R-Texas.

The measure, which passed on a voice vote, encourages expeditious construction of the Alaska Natural Gas Pipeline by placing a two-year sunset on loan guarantees that Congress authorized for use in building the $20 billion pipeline last fall.

Barton said the nation needs the abundant natural gas supplies that the 4.5-billion-cubic-feet-a-day Alaska pipeline would carry to the Lower 48. The clock would start ticking when Barton's bill becomes law.

The Energy and Commerce bill also directs the Federal Trade Commission to launch an investigation into price gouging, cuts the number of "boutique" fuels currently required for different parts of the country from 19 to six, and encourages carpooling to conserve gasoline.

Also royalty reductions for federal deep gas onshore

The Resources committee approved an amendment offered by Rep. Steve Pearce, R-N.M., that provides royalty reductions for onshore deep gas wells on federal land. The Secretary of Energy will have the discretion to determine the standards for the eligibility of wells and to place limits upon the royalty incentives based upon market conditions.

Pearce said the amendment is aimed at helping small independents engage in more costly deep gas plays.

The Resources legislation also includes language to allow states to opt out of a federal ban on offshore oil and natural gas drilling, a proposal that faces strong Senate opposition. The bill would expedite the development of renewable energy projects on federal lands, an idea dropped during energy conference talks this year because of Senate concern.

Environmentalists and Democrats oppose most of the proposals. They are supporting alternative legislation, including a bill by Science Chairman Sherwood Boehlert, R-N.Y., and Markey, D-Mass., that would boost the average fuel efficiency standard from 25 miles per gallon to 33 miles per gallon by 2016.

The full House is expected to vote on energy legislation in October. ●

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ANADARKO

Anadarko has participated in proprietary seismic with its partner ConocoPhillips and has operated 2-D and 3-D seismic programs in the eastern North Slope and Brooks Range foothills. The company has only operated two exploration wells (the Altamura well in the National Petroleum Reserve-Alaska and the Hot Ice well in the central North Slope) but has participated in approximately 35 exploration wells, predominantly in NPR-A, Hebertson said.

Remote areas and partnerships

The remoteness of the areas in which the company prefers to explore drives a need to find large oil or gas accumulations.

“We’re looking for the hundreds of millions of barrels, and because they are far from infrastructure and because of the infrastructure that’s needed to bring those fields online they need to be a substantial size,” Hebertson said.

But exploring for large petroleum accumulation far from existing infrastructure entails higher than average risk. To mitigate those risks, Anadarko works with partners that can share the costs, risks and rewards.

“Obviously in those types of situations … you really have to have the right kind of partnership in place, and that’s what we’re continually trying to do is find that right partner,” Hanley said, likening the process to dating.

Anadarko seeks partners that have similar exploration objectives and that can handle the commercial risks. The company has enjoyed a fruitful relationship with ConocoPhillips Alaska (previously ARCO Alaska) that stretches back to the discovery of the Alpine field by an ARCO-operated partnership in 1994. Anadarko continues to partner with ConocoPhillips in the development of Alpine and its satellites, and the company maintains a joint venture with ConocoPhillips for exploration in NPR-A.

The 430 million barrel Alpine field (Colville unit) and the satellite fields that surround it exemplify the type of opportunity that Anadarko seeks.

Success at Alpine has acted as a springboard for frontier exploration west into NPR-A. The ConocoPhillips-operated partnership with Anadarko drilled the Puviaq prospect in the winter of 2003-04 and the Kokoda prospect in the winter of 2004-05. The wells at Puviaq and Kokoda remain tight holes.

From The Explorers

This story on Anadarko Petroleum is an abbreviated version of an article that appears in The Explorers 2005, an annual magazine published by Petroleum News. The Explorers, devoted to coverage of the search for oil and gas in Alaska, will be released in November.

Exploring in the foothills

Anadarko is also pleased with its Brooks Range foothills partnership with Petro-Canada.

“Our … joint venture with Petro-Canada I think is a good example of a good, successful relationship,” Hebertson said. “We’re very aligned technically in the (foothills) area and we see the area similarly in terms of its resource potential and our commitment to the area.”

Anadarko is operator for the exploration of more than 1.5 million acres of state and Arctic Slope Regional Corp. land in the Brooks Range foothills. The company pooled this acreage with Petro-Canada under the terms of the partnership between the two companies.

“We’ve got a very deep portfolio of opportunities in the foothills. The vast majority of those are gas opportunities, but they’re not exclusively gas opportunities,” Hebertson said. “We have people doing geologic fieldwork this summer up there. Potentially we could be acquiring some seismic … there in the future with our new partnership.”

Gas drilling in 2007

However, drilling in the gas-prone foothills area will depend on progress with plans for a gas pipeline from the North Slope: Anadarko needs assurances on the availability of capacity for shipping gas before incurring the significant cost of foothills drilling. The two key gas line issues are access for explorers and expandable space, Hanley said.

“Based on our current planning we’d like to be drilling in 2007 in that area,” Hebertson said. “Obviously that’s contingent upon Anadarko feeling that access issues have been rectified with respect to the pipeline.”

Anadarko is, however, happy with the Federal Energy Regulatory Commission’s rules for open season on the gas line: “We were pretty pleased with how that came out — we think that went a long ways to addressing the issues,” Hebertson said.

The company would like a second partner for foothills exploration.

However, “not having (another) partner wouldn’t necessarily preclude us from moving ahead,” Hanley said. “I think we’re happy with our current partnership. Ideally we’d like to bring somebody else in, but conceivably we could go ahead if we don’t find anybody.”

Jacob’s Ladder and Ayak

Anadarko is also looking for a partner for its Jacob’s Ladder prospect, in the central North Slope, 20 miles southeast of Prudhoe Bay. Meantime the company is unitizing the Jacob’s Ladder acreage.

“We’ve had a lot of interest in Jacob’s Ladder recently and I’m encouraged that we might be able to put something together in the next six to twelve months,” Hebertson said.

The company also has a 100 percent interest in the nearby Ayak prospect.

“Ayak is another prospect we have in the Jacob’s Ladder area that could be drilled in the near future if a partnership comes together,” Hebertson said.

Although Hebertson stressed Anadarko’s commitment to Alaska he also pointed out that exploration opportunities in the state have to compete with the company’s portfolio of opportunities elsewhere. However, Alaska offers significant resource potential and a stable political environment.

“You’ve got a governor and a Legislature and congressional delegates who are very supportive of the oil and gas industry,” Hebertson said.

“I think the resource potential is there in Alaska. It’s never been a resource issue — the challenges in Alaska are commercial much more than they are from a resource perspective,” Hebertson said. “We’ve always been committed to Alaska. I think we’re going to be here for the long term.”

And plans for this winter?

“We’re going to continue to be active this winter just like we have been,” Hebertson said. “I think you’ll see Anadarko be involved with additional seismic acquisition in our focus areas and hopefully we’ll be participating in some drilling this winter, but that’s yet to be determined.” ●