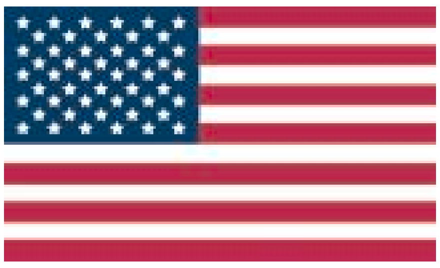
PETROLEUM NEWS ALASKA



"By sacrificing human life to serve their radical visions — by abandoning every value except the will to power — they follow in the path of fascism, and Nazism, and totalitarianism. And they will follow that path all the way, to where it ends: in history's unmarked grave of discarded lies."

—PRESIDENT GEORGE W. BUSH, SEPT. 20, 2001

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Drilling continues at Cosmopolitan

Lin Reid, Eagle Eye Helicopter Inc.

Drilling continues at Phillips Alaska Inc.'s Cosmopolitan project near Nikiski, Phillips spokesman Natalie Knox told PNA Nov. 15. This aerial photo was taken Sept. 29, prior to spudding the first well in mid-October. The Hansen No. 1 is being drilled by Nabors Rig 273, one of the largest land-based drilling rigs in North America. Knox said it took 70 truckloads to transport the rig from the Lower 48 to Alaska's Kenai Peninsula. Drilling is being done from private land on a bluff overlooking Cook Inlet. The sidetrack will extend up to 18,500 feet (3.5 miles) to reach an offshore bottom hole at approximately 7,000 vertical feet. Drilling is expected to be complete by mid-December, Knox said.

Northwest Territories leader makes case for federal pipeline aid

Nellie Cournoyea, one of the Arctic's most formidable and persuasive lobbyists, is turning up the heat on the Canadian government to provide financial support for a Mackenzie Valley gas pipeline.

The chair of the Aboriginal Pipeline Group, which is negotiating on behalf of most aboriginals along a pipeline route with the Mackenzie Delta Producers Group, said the Aboriginal Pipeline Group needs up to C$50 million to work on the project definition stage and C$1 billion to secure aboriginal ownership in a pipeline.

Bill Gwozd, manager of gas services at Calgary-based Ziff Energy Group, said there is now "a lot of push" in the Delta to get a Mackenzie Valley pipeline built before a pipeline out of the North Slope.

As leverage, she is using history — in particular the billions of dollars the government poured into exploration and development of Newfoundland's offshore oil.

The government, in fact, still holds 8.5 percent of the Hibernia field, which produces about 135,000 barrels per day and has a long-term goal of raising that to 200,000 barrels per day.

"Perhaps the federal government could use the proceeds from the sale of its interests in the heavily subsidized Hibernia oilfield, now that it is doing well," Cournoyea, a former Northwest Territories premier, told a Calgary conference the week of Nov. 5.

see AID page 18

I N S I D E

■ ARCTIC GAS

Major pipeline companies sign MOU to build Alaska Highway gasline

Nine firms will build, own and operate the pipeline; Foothills said coalition expects to submit plans to the North Slope producers by the end of the year

By Gary Park & Kay Cashman
PNA Canadian Correspondent & Publisher

Six powerhouse United States energy firms and Canada's three dominant gas pipeline companies are pulling out the stops to ensure North Slope gas is delivered to Canada and Lower 48 markets by 2008.

In a benchmark deal announced the morning of Nov. 15, Calgary-based Foothills Pipe Lines Ltd. said the memorandum of understanding represents a

"Once agreement is reached with the producers, the companies intend to move forward with the project," setting 2008 as the start-up target, Foothills said.

"giant step forward" for the Alaska Highway pipeline.

It said the companies are proceeding immediately with firming up the long-standing proposal for

see MOU page 16

■ COOK INLET

Unocal budgets $112 million for exploration, pipeline 2001-2003

Three exploration wells drilled this year, two more planned; eight wells for 2002 including Deep Creek, Anchor Point

By Kristen Nelson
PNA Editor-in-Chief

Unocal Alaska has budgeted $112 million for Cook Inlet gas exploration and pipeline work from 2001 through 2003, Dan Thomas, manager of gas marketing Alaska for Unocal Global Trade, told the Alaska Legislature's Joint Committee on Natural Gas Pipelines Nov. 8.

For this year, the figure is $8 million; in 2002 it is $49 million and in 2003 $55 million.

The company has also applied for two new Kenai Peninsula units, Thomas said (see story page 9), has drilled three exploration and innovative step-out wells on the Kenai Peninsula this year and has two more exploration wells planned for this year.

Without Regulatory Commission of Alaska approval of the Enstar contract, Thomas said, the

see UNOCAL page 17

Judy Patrick

Unocal first discovered natural gas in the Cook Inlet basin onshore in 1959. Today, the company operates 10 platforms in Cook Inlet and is the largest oil and gas producer in the region. In 1966, Unocal installed the world's first single-legged monopod platform, pictured here, to produce oil from the Trading Bay field. The design utilizes a single leg support for the structure which guards against and reduces exposure to ice and high tides.

■ ARCTIC GAS

Economic conditions shift window for Arctic gas out a year to 2009-10

Recession through 2004 would shift window even farther, possibly to 2015, Ed Small of Cambridge Energy Research tells committee

By Kristen Nelson
PNA Editor-in-Chief

The economy and natural gas prices are down — and that is pushing out the window of opportunity for frontier gas, Ed Small of Cambridge Energy Research Associates told the Legislature's Joint Committee on Natural Gas Pipelines Nov. 7.

Cambridge Energy expects to see some recovery from the current economic weakness in the mid-part of next year, certainly in the second half, but in the meantime, Small said, there is "quite a strong demand softness" for gas, now and for the first half of 2002.

Asked by committee chair Sen. John Torgerson how Cambridge Energy now feels about the windows it previously saw for frontier gas in 2008 and 2010, Small said:"I think the window of opportunity has shifted in time, probably by a year."

"And I think that's a combination of the demand destruction that we've seen this year — the recovery from that just shifts the world by a year going forward. You push the demand down, it takes a while to get back up to previous levels

see CONDITIONS page 19

Alaska Rig Report

The Alaska Rig Report as of 11/14/01, active drilling companies only listed.

Contractor/ Rig Type	Rig No.	Field/Platform	Field Operator
North Slope			
Doyon Drilling Inc.			
Dreco 1250 UE	D14 (SCR/TD)	Prudhoe Bay	BP
Sky Top Brewster NE-12	15 (SCR/TD)	Stacked/Endicott Is.	Available
Dreco 1000 UE	16 (SCR)	Prudhoe Bay	BP
Dreco D2000 UEDB	19 (SCR/TD)	Alpine	Phillips
OIME 2000	141 (SCR/TD)	Meltwater	Phillips
Nabors Alaska Drilling			
Trans-ocean rig	CDR-1(CT)	Stacked/Prudhoe Bay	Available
Dreco 1000UE	2-ES(SCR)	Prudhoe Bay	BP
Mid-Continent U36A	3-S(CT)	Prudhoe Bay	BP
Oilwell 700-E	4-ES(SCR)	Milne Point	BP
Dreco 1000UE	9-ES(SCR/TD)	Prudhoe Bay	BP
Oilwell 2000 Hercules	14E (SCR)	Prudhoe Bay	Pending/Anadarko
Oilwell 2000 Hercules	16E (SCR/TD)	Kuparuk	Phillips
Oilwell 2000	17E (SCR/TD)	Stacked/Pt. McIntyre	Available
Emsco Electro-hoist-2	18-E(SCR)	Stacked/Deadhorse	Pending/Phillips
OIME 1000	19E (SCR)	Idle/Prudhoe Bay	Pending/Phillips
Emsco Electro-hoist Varco TDS3	22-E(SCR/TD)	Stacked/Milne Point	Available
Emsco Electro-hoist-2 Canrig 1050E	27-E(SCR/TD)	Milne Point	BP
Emsco Electro-hoist-2	28-E(SCR)	Stacked/Deadhorse	Available
Oilwell 2000	33-E(SCR/TD)	Idle/North Star Island	BP
OIME 2000	245E (SCR/TD)	Kuparuk	Phillips
Nordic/Calista Services			
Superior 700UE	1 (SCR/CT)	Prudhoe Bay	BP
Superior 700UE	2 (SCR)	Stacked/Kuparuk	Available
Ideco 900	3 (SCR/TD)	Kuparuk	Phillips
Cook Inlet Basin-Onshore			
Kuukpik / H & R Drilling			
Rigmasters 850	9	Pretty Creek	Unocal
Inlet Drilling Alaska			
Taylor Rig	Glacier Rig 1	Grassom Oskolkoff #2	Marathon
Inlet Drilling Alaska/Cooper Construction			
Kremco 750	CC-1	Stacked/Tyonek	Available
Nabors Alaska Drilling			
National	154	Stacked/Kenai	Available
Wilson 120	158	Stacked/Beluga	Available
National 110-UE	160 (SCR)	Stacked/Kenai	Available
Continental Emsco E3000	273	Anchor Pt.	Phillips
Cook Inlet Basin-Offshore			
XTO Energy (Inlet Drilling Alaska Labor Contractor)			
NA	CT-A	Mid. Grd. Shoal	XTO Energy
NA	CT-C	Idle/Mid. Grd. Shoal	XTO Energy
Nabors Alaska Drilling			
IDECO 2100E	429 (SCR)	Osprey Platform	Forest Oil
Unocal (Nabors Alaska Drilling Labor Contractor)			
Oilwell 2000E	51	Idle/Steelhead Platform	Unocal
National 1320UE	54	Idle/Grayling Platform	Unocal
National 1320UE	55	Idle/Grayling Platform	Unocal
Oilwell 860	56	Monopod Platform	Unocal
Drawworks Removed	57	Idle/Granite Pt. Platform	Unocal
National 1320UE	58A	Idle/King Salmon Platform	Unocal
Drawworks Removed	58B	Idle/Granite Pt. Plat.	Unocal
OIME SD8M	60	Idle/Bruce Platform	Unocal
National 1320UE	76	Idle/Dolly Varden Plat.	Unocal
National 1320UE	77	Idle/Dolly Varden Plat.	Unocal
Ideco 2100E	428	Stacked/Baker Platform	Avail.
Bering Sea-Port Clarence			
Seatankers, Inc.			
Dreco 147	SDC-1	Stacked/Port Clarence	
Fairweather			

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

The Rig Report was prepared by Dan Wilcox

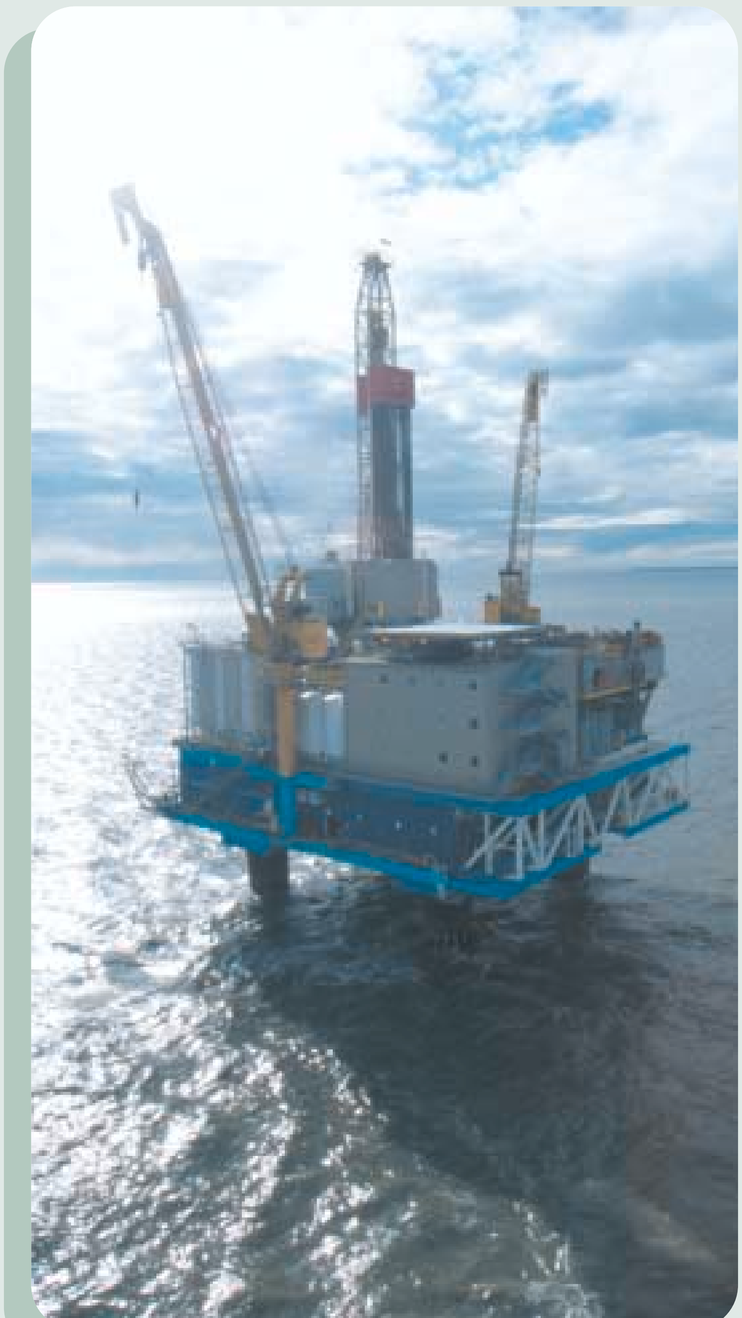

Photo of the Osprey Platform courtesy of Judy Patrick

Rig startups expected in the next 6 months:

Akita Equtak
Rig 63 startup expected Dec. 15 on Mackenzie Delta-Onshore
XTO Energy (Inlet Drilling Alaska Labor Contractor)
Rig CT-C expected to resume Dec. 2001 at Mid. Ground Shoal
Nabors Alaska Drilling
Rig 33E expected to resume November 2001 at Northstar
Unocal
Rig 54 startup expected March 2002 on Grayling Platform
Rig 58A startup expected June 2002 on King Salmon Platform

■ EXPLORATION & PRODUCTION

Exxon's Point Thomson will be North Slope's first high-pressure condensate field

By Kristen Nelson
PNA Editor-in-Chief

The state has been talking to the Point Thomson unit owners about developing the eastern North Slope field for years. This year, in conjunction with an expansion of unit acreage, the major owners (field operator ExxonMobil Production Co. and BP Exploration (Alaska) Inc., Chevron U.S.A. Inc. and Phillips Alaska Inc.) agreed to field development, in late August, as reported by PNA.

The companies applied for expansion-contraction early this year. In response, the state asked for "sustained commercial production" by 2008. The unit's 18th plan of development, submitted in September, was accepted by the state. That 18th plan of development commits field owners to continuous drilling by 2006. The expansion-contraction agreement commits field owners to the completion of seven development wells by 2008.

A different kind of field

What kind of a field is Point Thomson? PNA talked to petroleum manager Bill Van Dyke and petroleum reservoir engineer Mike Kotowski — both with the Department of Natural Resources Division of Oil and Gas — about Point Thomson.

"Ninety-five percent of it's going to be gaseous stuff that's going to have to go back in the ground if there's no gas sale. And only about 5 percent will be the liquids that you're going to sell. So you have to put 95 percent of it back in the ground — if you do a gas cycling project." —Bill Van Dyke, Division of Oil and Gas

Point Thomson is a high-pressure condensate reservoir. It's different from a field like Alpine, which is a traditional black oil reservoir, said Van Dyke.

And different than fields that have been developed up until now on the North Slope Kotowski said.

"Because of the high pressure, the wells will be relatively more expensive to drill because they'll probably be an extra

see FIELD page 4

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PETROLEUM NEWS ALASKA

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FINANCE & ECONOMY

Mexico ready to cut oil production

Mexico will cut oil exports up to 100,000 barrels per day in 2002 as part of OPEC's efforts to reduce oversupply in the world market, the Energy Ministry said the night of Wednesday, Nov. 14.

The decision comes after the Organization of Petroleum Exporting Countries agreed Wednesday afternoon in Vienna to cut its quotas by 1.5 million barrels a day beginning Jan. 1, a move the group says is dependent on Mexico and other non-OPEC producers following its lead. The cut represents a 6 percent production cut for the cartel.

OPEC officials said they wanted 500,000 bpd in non-OPEC cuts to avoid their members losing market share by bearing the full weight of the reductions. Until Mexico made its announcement, no major non-OPEC producers except Russia seemed willing to cooperate with the cartel. And Russia had pledged only token support with a 30,000 bpd reduction, representing less than 0.5 percent of its production. Russia is the world's second biggest exporter after OPEC member Saudi Arabia.

Mexico is the third leading exporter of oil to the United States behind Saudi Arabia and Venezuela.

Energy Ministry officials said Mexico's decision to cut exports is also dependent on other non-OPEC producers joining the effort.

Mexico's state oil monopoly Petroleos Mexicanos, or Pemex, exports 1.65 million bpd, out of its total production of 3.1 million bpd.

"Mexico considers that there has been an important imbalance in supply and demand in the world oil market in recent weeks," the ministry said in a statement.

OPEC supplies about a third of the world's oil. Its goal is to keep the price of crude within the $22 to $28 a barrel range.

The cartel has cut production three times this year, most recently on Sept. 1.

Bush gives prices modest boost

President Bush gave a modest boost to prices Nov. 13 when he announced the U.S. government would put more oil into the U.S. Strategic Petroleum Reserve, America's emergency stockpile.

Bush said the reserve, which currently has 544 million barrels of oil, is to be filled "in a deliberate and cost-effective manner" up to its full capacity of 700 million barrels.

—The Associated Press

continued from page 3

FIELD

string or two of casing set and the tubing will be rated for higher pressure, the well heads will be rated for higher pressures," Van Dyke said.

The drilling mud will also be more expensive, Kotowski said, "because it will take heavier materials to contain the reservoir pressure."

Even the surface flow lines will have to be rated for higher pressure, Van Dyke said.

The Point Thomson owners are talking about doing a gas cycling project, he said, extracting condensates — gas liquids — from the gas and then reinjecting the gas.

Bill Van Dyke, Division of Oil and Gas

With reservoir pressures at Point Thomson at some 10,000 pounds per square inch, compared to about 4,000 pounds at Prudhoe Bay, "they'll need compressors that can handle those higher pressures," Van Dyke said.

"And the bottom line is, compression horsepower is very expensive," Kotowski said, both to buy and to run.

Some gas could be sold

If gas wasn't reinjected at Point Thomson, reservoir pressure would drop and condensates would fall out in the reservoir, limiting recovery of liquids. But if the gas sales project goes forward, Van Dyke said, "they can sell some of the gas, then they won't have to reinject it all, which would probably make the economics look better."

Most of the production at Point Thomson will be gas, with condensate in it, Van Dyke said. The Point Thomson condensate liquid is high quality, lighter components — NGLs, gasoline and kerosene weight — not too much heavy oil, he said, pretty valuable compared to Prudhoe Bay crude

"Ninety-five percent of it's going to be gaseous stuff that's going to have to go back in the ground if there's no gas sale. And only about 5 percent will be the liquids that you're going to sell. So you have to put 95 percent of it back in the ground — if you do a gas cycling project."

Van Dyke said that when you produce Point Thomson, you have to produce gas, and then do something with it: sell it, take it to Prudhoe Bay and store it there or reinject it.

If you didn't need to maintain reservoir pressure, "you could just send that whole stream to Prudhoe Bay and process it over there," recover the liquids and send them down the oil pipeline and put the gas into the Prudhoe reservoir or send it down a gas pipeline.

If the gas went to Prudhoe, Kotowski said, the owners would "just make a gas balancing agreement that would account for the gas."

Economic analysis, as well as physical

Kotowski said the Point Thomson owners will probably do "an economic and physical analysis of what's going to be the loss in gas as well as liquid reserves if they don't reinject as compared to the compression cost of reinjection." Cost of horsepower injection will be compared to the liquid loss to determine "the most economic depletion plan," he said.

Gas cycling will recover most of the Point Thomson liquids in the condensate, Van Dyke said, and that will be balanced against the cost of building and running the project.

Point Thomson is probably not any different than a condensate field elsewhere in the world, Van Dyke said, "the liquids are valuable and it makes sense to make that investment, to strip out all those liquids first, and then you come back 10 or 20 years later and sell the gas."

"I think a better way of characterizing it — it's no different than any other condensate field in the world except for its higher pressure. …that's the big difference," Kotowski said. "It's no different than any other condensate reservoir. Other than it's high pressure and its remote location." ◆

■ COALBED METHANE

Evergreen Resources plans coalbed methane wells in 2002

Company acquired 48,000 acre Matanuska-Susitna Borough Pioneer unit in May; will bring own drilling, cementing and completion equipment to Alaska

By Kristen Nelson
PNA Editor-in-Chief

Mark Sexton, president and CEO of Evergreen Resources Inc. of Denver, told the Legislature's Joint Committee on Natural Gas Pipelines by phone Nov. 8 that the company plans to drill at least six wells — and perhaps as many as eight or 10 — in the Pioneer unit in the Matanuska-Susitna Borough in 2002. The wells, Sexton said, will be in two pilot areas.

Mark Sexton, president and CEO, Evergreen Resources Inc.

The company will bring its own drilling, cementing and completion equipment — currently in Ireland — to Alaska for the work, he said. Sexton said the equipment is state of the art and was built specifically for coalbed and shallow gas development.

After the wells are completed, Evergreen will begin testing the productivity of the coals and Sexton said those tests will give the company information on how best to develop the resource.

Evergreen acquired the Pioneer unit, a coalbed methane play, from Ocean Energy Inc. and Unocal Alaska in May of this year. Evergreen has a 100 percent working interest in 48,000 acres. An Enstar 20 inch gas line runs across the bottom of the unit and two coalbed methane wells, one water disposal well and one gas re-entry well have been drilled in the unit.

At least 1 trillion cubic feet at Pioneer

Sexton said Evergreen believes coalbed methane has the potential to replace declining conventional gas reserves in Cook Inlet. The company has not yet determined that Pioneer development will be economic, he said, but conservative estimates show the unit contains reserves of at least 1 trillion cubic feet. Sexton said the reserves could be several times that large.

Six prior attempts to produce coalbed methane in the north Cook Inlet area have been unsuccessful, and Sexton said that after reviewing the well histories, "we are not surprised that none of the wells produce gas."

In Alaska, gaining surface access for mineral development "may become the major obstacle to development" and Evergreen believes legislation "must be passed that encourages the surface owner to cooperate with the gas companies wanting to develop natural gas on their lands."
—Mark Sexton, Evergreen Resources Inc.

He said that Evergreen knows, through experience, that "slight variations in drilling, cementing, completion and production practices" spell success or failure in coalbed methane wells. It is for that reason, he said, that Evergreen has invested in its own service company, Evergreen Well Service, its own gas marketing and gathering company, Primero Natural Gas, and its own operating company, Evergreen Operating Corp.

Evergreen, along with several other parties, has also applied for shallow gas leases in the vicinity of Pioneer, and Evergreen said once the leases are granted it will negotiate with the lessees and then unitize the acreage.

If a unit can be established in 2002, he said, exploration activities could begin that year on the new acreage and wells could be drilled as early as 2003 or 2004.

He said that Evergreen's proposed Southcentral drilling budget is $5 million for 2002. If drilling is successful, Sexton said he expected the pace to "accelerate prudently" in subsequent years.

Legislative issues

Sexton said that coalbed methane drilling is different than the drilling Alaskans are used to. In the Raton Basin in southern Colorado where Evergreen has extensive operations, the company drills, logs, cements, completes, equips and places on line a new well every 72 hours.

"Doing this type of development requires streamlining the permitting and regulatory processes" and there may be bills proposed in Juneau to address this, he said.

But Sexton said the greatest challenge in Alaska coalbed methane development is the split estate issue. The areas with the most potential for coalbed methane production, he said, are areas where the state owns the subsurface rights and the surface is owned by an individual. Split estates are manageable when a few wells are drilled in an area, Sexton said, but in Alaska the plan is to drill "several dozens of wells" in close proximity.

In Alaska, gaining surface access for mineral development "may become the major obstacle to development," Sexton said, and Evergreen believes legislation "must be passed that encourages the surface owner to cooperate with the gas companies wanting to develop natural gas on their lands." ◆

ARKANSAS

Earnings drop at Murphy Oil

Profits were sliced by more than half at Murphy Oil Corp. in the third quarter. The company reported net income of $41.7 million, down 54 percent from the $90.1 million the El Dorado, Ark., company made in the same period a year ago.

The big hit was in exploration and production, where higher exploration expenses teamed with lower prices to cut E&P earnings to $26.7 million from $82 million. Increased exploration expenses, $45.5 million in the recent quarter compared with $20.9 million a year ago, contributed to that.

Better margins pushed refining and marketing profits to $19.6 million from $12.9 million, a gain of 52 percent. Liquids production averaged 64,779 barrels a day, up 5 percent from 61,852 a year earlier, but the average price per barrel dropped nearly $4 a barrel to $23.37. Natural gas sales volume rose 39 percent to a record figure of 295 million cubic feet daily due to production from the Ladyfern field in Canada. But the average gas price dropped 34 percent to $2.75 per thousand cubic feet.

Revenues slid to $1.14 billion from $1.25 billion a year earlier, a drop of 9 percent.

Murphy executives expect profits to decline further in the fourth quarter.

Murphy is a leaseholder on Alaska's North Slope. It is a minority owner of the Northstar field with operator BP Exploration (Alaska) Inc.

OIL COMPANY EARNINGS

Third Quarter 2001

3Q 2001 profits, % change from 3Q2000
3Q revenues, % change from 3Q 2000,
3Q daily production, % change from 2000

		profits	%	revenues	%	production	%
Alberta Energy	AEC	C$190	-21	C$1518	-4	1.4BCF	+27
Agrium	AGU	$17	--	$410	+8		
Anadarko	APC	-$270	--	$1743	-4	558,000BOE	+29
BP	BP	$3049	-20	--	--	1,883,000BBL/8,319MCF	-1/+7
Chevron	CVX	$1168	-24	$11909	-12	309,000BBL/1.444BCF	-3/-11
Evergreen	EVG	$7.1	+196	$25.6	+86	85.8MCF	+59
ExxonMobil	EOM	$3180	-29	$53009	-10	2,481,000BBL	-1
Foothills		not yet available					
Forest	FST	$1.5	-96	$201.1	-13	291.4MCF	-7
Marathon	MRO	$193	+60	$8336	-10	200,200BBL	+1
Murphy	MUR	$41.7	-54	$1139	-9	64,779BBL	+5
Petro Canada	PCZ	C$125	-35	C$2072	-15	190,800BOE	-6
Phillips	P	$364	-15	$6159	+8	780,000BOE	-1
Semco	SEN	-6.6	--	$81	+15	---	---
Tesoro	TSO	$32.8	+31	$1412	+1	---	---
Unocal	UCL	$102	-46	$5489	-14	506,000BOE	+8
Williams	WMB	$221	+83	$2810	+21	---	---
XTO	XTO	$70.3	+121	$197	+23	426MCF	+25

Dollar figures in millions

BCF: billions of cubic feet of natural gas
BBL: barrels of crude oil or oil and condensate
BOE: barrels of oil equivalent
MCF: millions of cubic feet of natural gas

SAN FRANCISCO

ChevronTexaco supports Dynegy-Enron merger

ChevronTexaco Corp. said Nov. 9 it has committed $2.5 billion of new equity in Dynegy Inc. to support Dynegy's planned merger with Enron.

ChevronTexaco currently owns approximately 26 percent of Dynegy's outstanding common stock, and will invest $1.5 billion in convertible preferred shares in Dynegy to fund Dynegy's equity infusion into Enron. The $1 billion balance of ChevronTexaco's equity purchase of Dynegy common stock would be made upon closing of the Dynegy-Enron merger.

Following closing of the merger, ChevronTexaco would maintain its 26 percent of Dynegy's outstanding common stock, and would maintain its three seats on the Dynegy board. ChevronTexaco will be granted warrants to purchase an additional $1.5 billion of Dynegy common stock over a period of up to three years from the merger.

If the Dynegy-Enron merger falls through, ChevronTexaco can redeem its convertible preferred shares for $1.5 billion in cash or convert to common shares. In the latter event, ChevronTexaco would own an approximate 36 percent equity interest in Dynegy.

—Steve Sutherlin

STATEWIDE

Regulators begin analysis of pipeline spill response

Regulators have begun working on an analysis of the spill response to last month's shooting of the trans-Alaska oil pipeline.

Government officials have so far praised Alyeska Pipeline Service Co.'s response to the 285,000-gallon spill. Daniel Carson Lewis, 37, is accused of the Oct. 4 shooting north of Fairbanks near Livengood.

Government officials have so far praised Alyeska Pipeline Service Co.'s response to the 285,000-gallon spill. Daniel Carson Lewis, 37, is accused of the Oct. 4 shooting north of Fairbanks near Livengood.

Rhea DoBosh, a spokeswoman for the federal-state Joint Pipeline Office, said Nov. 5 that the report could identify areas for improvement.

Critics have said the response was too slow. It took 36 hours for the company to clamp the hole and stop the leak.

Alyeska said it took that long because of the need to ensure that the clamp operation was guaranteed to be safe and effective.

DoBosh said the environmental regulators will look at whether other equipment, such as more clamps, or additional training could make such a spill response go smoother.

The final report is scheduled to be released in mid-January.

—The Associated Press

PETROLEUM NEWS
ALASKA

FINANCE & ECONOMY

DENVER

Evergreen profits take off

Evergreen Resources Inc. showed improved results for the third quarter. Profits for the coalbed methane producer were $7.1 million; nearly triple the $2.4 million the company made in the same quarter of 2000.

Gas sales jumped to 85.8 million cubic feet daily, a 59 percent increase from 54.4 million a year ago.

Average price was also higher, unlike most companies in the industry, with Evergreen collecting $3.21 for each thousand cubic feet of gas, compared to $2.71 a year ago. That was a gain of 18 percent. Revenues rose 86 percent to $25.6 million, from $13.8 million the prior year.

Evergreen drilled 52 coalbed methane wells in the Raton Basin in the third quarter alone, boosting sales gas sales during the quarter by 8 percent over the second period. The drilling brought the company's total wells connected to a pipeline to 646 at the end of the quarter, compared with 473 a year earlier.

The Denver-based company boosted its working interest in 17,800 acres of coalbed methane properties in the basin in July, bringing its interest in those properties to about 80 percent. That purchase from Shenandoah Operating Co. cost the company roughly $20 million.

—Allen Baker

Forest oil net declines

Earnings at Forest Oil Corp. dropped in the third quarter as lower prices combined with increased investment in Alaska infrastructure to deal with new production. The company earned $1.5 million in the quarter, down from $33.8 million in the same quarter a year earlier. That's a drop of 96 percent, though special items had some impact.

Besides the $4 million spent to upgrade pipelines to take increased flow from a big new strike in the McArthur River field, Forest booked several big "unusual items" in the quarter, notably $11 million in foreign currency translation losses and losses from derivatives, along with $2.3 million in merger expenses from the acquisition of the former Forecenergy.

Still, volumes were down. Natural gas production was 291.4 million cubic feet daily, a 7 percent reduction from the 314 million a year earlier.

Liquids production slipped 5 percent from 31,200 barrels a day to 29,600 barrels. Prices for those products dropped as well, as they did for all the oil companies.

Denver-based Forest said the decrease in volumes reflects the effects of property sales, a reduction in drilling activity, and a shifting of investment dollars to Alaska, where Forest's Osprey platform is showing a lot of promise that won't be turned into a flow of oil and dollars until the end of next year. Forest is predicting production will continue to decline in the fourth quarter of this year.

Revenues for the third quarter were $201.1 million, down 13 percent from $230.5 million for the year-ago period.

—Allen Baker

■ CANADA

Oil patch tax relief not in cards in upcoming Canadian budget

Canadian Association of Petroleum Producers and Alberta's lobbying for tax equity has failed due to economic slowdown and costs of beefed up security

By Gary Park
PNA Canadian Correspondent

A sore point between Canada's petroleum industry and the federal government threatens to become even worse, with upwards of C$30 billion worth of oil sands projects on the line.

For the past 18 months, the Canadian Association of Petroleum Producers and the Alberta government have been lobbying for what they see as tax equity.


Canada's Natural Resources Minister Ralph Goodale

They want Finance Minister Paul Martin to reduce the corporate tax rate for resource companies to 21 percent from 28 percent in a budget expected in early December — the same reduction given to all other industries last year.

But the combination of economic slowdown and the costs of beefed up security and military needs mean "large tax changes ... in the tax system would be difficult to accommodate," said Natural Resources Minister Ralph Goodale.

"There's clearly a squeeze on flexibility at this time," he said, ruling out the prospect of even phased-in tax cuts.

A Canadian Association of Petroleum Producers study has estimated that extending the 21 percent marginal tax rate to oil and gas companies would cost the federal government about C$700 million this year.

However, without the change the industry has warned that it will be even more difficult to attract investors, especially for the multi-billion dollar megaprojects planned for Alberta's oil sands.

The government has insisted that to ensure fairness with other industries, the resource sector would have to accept "improvements to the tax structure."

That would involve a detailed examination of existing resource tax breaks, including a 100 percent deduction in eligible exploration and development expenses, accelerated write-offs for some capital assets and an accelerated capital cost allowance.

For the industry, giving up incentives is viewed as a regressive move. "They also forget that we pay royalties," said Charlie Fischer, chief executive officer of Nexen Inc. and a former Canadian Association of Petroleum Producers chairman. "They have more work to do on this issue and that's fine. But we do expect it to be dealt with ... and not just ignored."

Anxious to avoid conflict with the Alberta government at a time when it is trying to rebuild political strength in Western Canada, the federal government is eager to explore a solution, said a spokesman in the Department of Finance. "Negotiations haven't yet hit a wall," he said. ◆

■ SAN FRANCISCO

Appeals court rules in Exxon's favor

By The Associated Press

A 9th Circuit Court of Appeals panel ruled on Nov.7 that the $5 billion in punitive damages awarded by an Anchorage jury against Exxon Mobil was excessive. The panel ordered a lower court to reduce that amount.

A federal jury in Anchorage ordered Exxon to pay $5 billion in 1994 to thousands of commercial fisherman, Alaska Natives, property owners and others harmed by the 11 million-gallon oil spill.

In its ruling Nov. 7, the Court of Appeals in San Francisco said some damages were justified to punish the company for its harmful behavior, but that $5 billion was excessive. The appeals court said that for every dollar in compensatory damages, the jury awarded more than $17 in punitive damages — a ratio that would not get by the U.S. Supreme Court.

The appeals court noted the high court in 1991 ruled that a 4-to-1 ratio was "close to the line" between a constitutionally acceptable and unacceptable jury verdict.

The state was not part of the lawsuit but reached a negotiated agreement with the federal government and Exxon in 1991. Gov. Tony Knowles said Nov. 7 that he will attempt to bring the two sides to a negotiated settlement, saying the case has dragged on too long. ◆

REDOUBT SHOAL

Redoubt Shoal recoverable estimates keep going up

Forest Oil Corp. is still officially showing recoverable oil from the Cook Inlet Redoubt Shoal field as more than 50 million barrels.

That's the number that Gary Carlson, senior vice president of Forest's Alaska business unit, has said in the past would make him happy.

Forest Oil told analysts after completion of the field's second well (a third has now been completed) that it estimated the field holds 450 million barrels of original oil in place. Carlson told PNA in October that you'd expect a 25 percent recovery rate with water flood, which will be used at Redoubt Shoal.

Twenty-five percent of 450 million is 113 million barrels recoverable.

The state is looking at a higher number.

The "field is bigger than originally thought," the state said. … It is estimating up to 193 million barrels recoverable.

In a Department of Natural Resources Division of Oil and Gas presentation Nov. 8 to the Legislature's Joint Committee on Natural Gas Pipelines, geologist Tim Ryherd showed the committee a Cook Inlet exploration summary which included Redoubt Shoal.

The "field is bigger than originally thought," the summary said.

Much bigger than 50 million barrels recoverable: the state is estimating up to 193 million barrels recoverable.

If the original oil in place is still pegged at 450 million barrels that's a 43 percent recovery rate — a rate similar to the 40 percent Carlson said is being obtained from the McArthur River field with water flood.

—*Kristen Nelson*

■ NINILCHIK

State approves Ninilchik unit

Marathon Oil operator of 25,167 acres onshore and offshore between Clam Gulch and Ninilchik; Unocal other major owner

By Kristen Nelson
PNA Editor-in-Chief

The Department of Natural Resources Division of Oil and Gas has approved an application by Marathon Oil Co. for formation of the Ninilchik unit.

Marathon is the unit operator, Unocal is the other majority working interest owner.

The unit consists of approximately 25,167 acres, both onshore and offshore, between Clam Gulch and Ninilchik. It includes some 18,999 acres of state lands (10 state oil and gas leases and approximately 420 acres of unleased state lands), approximately 222.67 acres of federal land, 661.35 acres of University of Alaska lands, 1,528.17 acres of Cook Inlet Region Inc. lands and 3,336.34 acres of patented fee lands.

The state said that Ninilchik unit acreage surrounds the Ninilchik anticline, which stretches for more than 16 miles along the coastline from near Clam Gulch to just north of Ninilchik.

One of the state leases would have expired Dec. 1 if the unit had not been formed; five state leases would have expired Dec. 31.

The state leases have a 12.5 percent royalty.

Unit surrounds Ninilchik anticline

The state said that Ninilchik unit acreage surrounds the Ninilchik anticline, which stretches for more than 16 miles along the coastline from near Clam Gulch to just north of Ninilchik.

The structure was recognized as an exploration target in the late 1950s and mapped in the subsurface with the seismic, gravity and magnetic tools available at the time. In 1960, the Socal Falls Creek 1 well was drilled to test the anticlinal trap. Although the objective of this well was oil, it was completed as a gas well in 1961 in four sandstone zones within the Tyonek formation. It has been shut-in because the size of the accumulation did not justify the cost of facilities.

The small Falls Creek unit, also operated by Marathon, lies in the northern third of the Ninilchik unit, completely surrounded by Ninilchik unit acreage.

Union Oil Co. of California drilled the Union Ninilchik 1 well in 1962 and tested gas in two Tyonek zones. The Mobil Ninilchik 1 well was drilled in 1964 and abandoned as a dry hole. Between 1968 and 1979, five exploration wells were drilled with oil and gas objectives: the Socal Falls Creek 2, Falls Creek 43-6, Brinkerhoff Ninilchik 1, Union Clam Gulch 1 and Texaco Ninilchik 1. Of the five, only the Texaco Ninilchik 1 flow tested gas from one Tyonek zone. Marathon drilled the Corea Creek 1 well in 1996 and drill stem tested four zones within the Tyonek, recovering minimal gas with water.

The state said that results of the Corea Creek well verified the size of the Falls Creek accumulation.

Marathon has reexamined area

The state said that Marathon has reexamined the area with new seismic and drilling technology. Marathon drilled and logged the Grassim Oskolkoff 1 well in 2000 and plans to test the Tyonek interval late this year. By the end of 2001, Marathon also plans to work over the Socal Falls Creek 1 well so that the well can be re-completed when facilities are in place to produce gas from the well.

Marathon plans to drill the Grassim Oskolkoff 2 well in 2002 as a southern offset to the Grassim Oskolkoff 1. Marathon also plans to re-enter the Union Ninilchik 1 well and attempt to establish a sustainable completion in the Tyonek reservoirs.

Future unit plans include a well on the northern fault block of the Ninilchik anticline to delineate gas potential within both the Tyonek and overlying Sterling reservoirs.

The first plan of exploration extends through 2004. In the second plan of exploration, or the first plan of development, whichever follows the initial plan of exploration, the division will require additional drilling, further exploration activities, sustained commercial production and/or a demonstration of efforts to proceed to further development and production within the unit area.

Majority of area held by Marathon and Unocal

Marathon and Unocal control approximately 85.43 percent of the unit area and the next largest interest group is the uncommitted individual mineral interest owners with approximately 9.102 percent. Under the Ninilchik unit joint operating agreement, any party with at least 30 percent interest can propose and cause the drilling of exploratory or development wells.

The state said that despite the fact that less than 100 percent of the lease are committed to the unit, Marathon has demonstrated that a reasonable effort was made to obtain joinder of all proper parties within the proposed unit area. And, with 85.43 percent of the working interest ownership, Marathon and Unocal hold sufficient interest in the unit area to give effective control of unit operations. ◆

■ KENAI PENINSULA

Unocal applies for two new units on Kenai Peninsula

South Ninilchik unit adjacent to Marathon's just-approved Ninilchik unit; Deep Creek unit some five miles inland from Ninilchik

By Kristen Nelson
PNA Editor-in-Chief

Unocal has applied for two new units on the Kenai Peninsula: the South Ninilchik unit — uplands and tide and submerged lands northeast of the town of Ninilchik and bordered on the east by the Ninilchik River — and the Deep Creek unit — uplands that parallel the Cook Inlet coastland approximately five miles inland from Ninilchik and Happy Valley.

Both units would be jointly managed by the state and Cook Inlet Region Inc. and would have two-year terms.

Unocal proposes to drill gas wells in each of the units in 2001-2002, and to acquire seismic over the units in 2002-2003.

Deep Creek

Unocal has 100 percent working interest ownership in the Deep Creek unit, 40 percent of which is on state leases and 60 percent of which is on Cook Inlet Region Inc. leases. Unocal told the state that Phillips Alaska Inc. has an option to elect to become a working interest owner or royalty owner in the Deep Creek unit and is a potential party to the Deep Creek unit joint operating agreement, but currently has no record title in any property located within the proposed unit outline.

The proposed Deep Creek unit covers approximately 22,216 acres in all or portions of the following lands (all of which are in the Seward Meridian): sections 1-2, 10-12, 13-16, 20-23 and 27-34 of T2S-R13W; sections 5-8 and 18 of T3S-R13W; and sections 1-3, 10-15 and 24 of T3S-R14W.

Unocal is proposing a two-year work program. In 2001-2002, the company would drill one new exploration well offsetting the original Socal Deep Creek Unit 1 well — drilled to 12,253 feet in 1958 in section 15 T2S-R13W, SM — to prove-up hydrocarbon potential of this trend. The Socal Deep Creek well had some gas in drilling mud and water in two drill stem tests.

Unocal's proposed exploration well would be a vertical hole with a proposed depth of 11,200 feet measured depth. The well would be 510 feet from the west line and 272 feet from the south line of section 11 T2S-R13W, SM.

In 2002-2003, Unocal would acquire new proprietary two-dimensional and/or three-dimensional seismic data within the proposed unit area to enable mapping of the adjacent structures.

If the initial well is successful, Unocal said it may wish to drill one or more appraisal or development wells in 2002-2003 to support the economic viability of a pipeline.

Unocal said that although the proposed plan is only for two years, the company currently envisions drilling at least one more exploration well on one of the other structures in the proposed unit area in 2004-2005.

As with the Deep Creek area, Unocal said currently available seismic for the South Ninilchik unit is of relatively poor quality and structural interpretation of the trend is by no means complete an final.

There is relatively poor seismic data currently available for South Ninilchik, Unocal told the state, so structural interpretation of this trend is by no means complete and final. Additional seismic data may reveal that the other structures are not present as currently mapped. For that reason, Unocal said, it is not prudent to commit to additional exploratory drilling in the proposed unit at this time.

South Ninilchik

Unocal has a 97.02 percent working interest in the South Ninilchik unit; the remaining acreage is unleased. Approximately 55 percent of the unit is on state leases and 24 percent is on CIRI leases.

The remaining royalty ownership is divided among the Kenai Peninsula Borough, the Bureau of Indian Affairs, and numerous estates, trusts, and private individuals.

The proposed unit covers approximately 9,328 acres in all or portions of the following lands (all Seward Meridian): sections 16-20 and 29-31 of T1S-R13W and sections 23-26 and 35-36 of T1S-R14W.

The initial plan of exploration includes one new exploration well offsetting the Mobil Ninilchik unit 1, drilled in 1964 in section 24 T1S-R14W, SM, to a depth of 12,724 feet.

Unocal's proposed exploration well is a vertical hole with a proposed depth of 9,200 feet to prove up the hydrocarbon potential of the structure. The well will be 1,970 feet from the west line and 1,570 feet from the north line of section 24 T1S-R14W, SM.

In 2002-2003, Unocal would acquire new proprietary 2-D and/or 3-D seismic data within the proposed unit area to enhance mapping of the structure and the unit area.

If the initial well is successful, Unocal may drill one or more appraisal or development wells in the South Ninilchik structure.

As with the Deep Creek area, Unocal said currently available seismic for the South Ninilchik unit is of relatively poor quality and structural interpretation of the trend is by no means complete an final. ◆

CENTRAL NORTH SLOPE

Chevron, BP plan delineation well at Northwest Eileen

Chevron U.S.A. Inc. and partner BP Exploration (Alaska) Inc. are planning a 2001-2002 single-well winter exploration program at Northwest Eileen.

The exploration well will be drilled in the first quarter of 2002 from an ice pad.

The surface location will be in section 20, T12N-R11E, UM, on state lease 047446.

This is a tract operation. Chevron holds a 50 percent interest in the lease, Phillips Alaska Inc. an 18.3 percent interest, ExxonMobil an 18.4 percent and BP 13.3 percent.

Chevron has requested that BP operate the well.

The proposed well is in the northwest Prudhoe Bay unit adjacent to Milne Point unit along the Milne Point road, approximately 4 miles north of the intersection of the Milne Point and Spine roads.

Ice construction will begin in late December of early January; drilling in early February. The well may be tested in late March to mid-April.

■ NORTH SLOPE

Phillips asks for ACMP review for Kuparuk Uplands wells

Paperwork filed with the state indicates the company requested a coastal zone review to avoid permitting delays for the project

By Petroleum News • Alaska

Phillips Alaska Inc. has asked the state to initiate review of Kuparuk Uplands exploratory well locations "as if they are subject to the ACMP in order to avoid potential future delays to the project," the company told the Department of Natural Resources Division of Oil and Gas in late October.

The exploration prospects, Heavenly and Supercub, are on state and private land east of the Colville River and south of the Kuparuk River unit and will be drilled during or beyond the 2001-2006 winter drilling seasons.

A DGC official told PNA … the agency was considering expanding the coastal zone to include all of the North Slope, which would mean all slope oil and gas projects would be subject to the ACMP review administered by DGC.

The Division of Governmental Coordination is still determining whether this project — outside the current coastal zone boundary — is subject to the Alaska Coastal Management Program. A DGC official told PNA in an October interview the agency was considering expanding the coastal zone to include all of the North Slope, which would mean all slope oil and gas projects would be subject to the Alaska Coastal Management Program review administered by DGC.

Proposed locations for the wells are: Heavenly 1 on Arctic Slope Regional Corp. lands in section 4 of T4N-R8E, Umiat Meridian; Heavenly 2 on state land in section 19 of 5N-8E, UM; Supercub 1 on state land in section 18 T5N-R7E, UM.

Phillips told the Division of Oil and Gas that "if DGC confirms our determination of non-applicability (of the Alaska Coastal Management Program), then DGC will notify the affected agencies and application review will continue as if the ACMP process had never been started."

In addition to a 500 foot by 500 foot ice drill pad and some 35.5 miles of ice road, Phillips would also build a 300 foot by 300 foot ice pad and temporary camp facility to support ice road construction. ◆

PETROLEUM NEWS
ALASKA

ARCTIC GAS

CANADA

Gas pipeline race update: Foothills, Kaska Nation strike deal

Foothills Pipe Lines Ltd. has reached a "cooperation agreement" with Yukon and northern British Columbia first nations — a key step towards ensuring economic benefits for aboriginal communities if a gas pipeline is built along the Alaska Highway.

The agreement is the first of three phases leading to a formal economic benefits pact covering Native jobs, benefits, business opportunities and ownership structure.

Stone said there is growing optimism in the Kaska Nation that the unresolved land claims and governance issues can be sorted out by the deadline.

The negotiations are expected to be completed by March 31, 2002, a federal government deadline for the settlement of six outstanding land claims, self-government and trans-boundary agreements with the Kaska Nation.

Peter Stone, chief executive officer of the Kaskas' Kayeh Nan Petroleum, described the cooperation deal as a "major step" towards achieving economic benefits for aboriginals.

He said it opens a door for the Kaska to pursue business opportunities, such as the provision of goods and services, and to discuss how they could be involved in a pipeline.

Stone said there is growing optimism in the Kaska Nation that the unresolved land claims and governance issues can be sorted out by the deadline.

Foothills executive vice-president John Ellwood said the Calgary-based company — a joint venture of TransCanada PipeLines Ltd. and Westcoast Energy Inc. (which is being taken over by Duke Energy Corp.) — is hoping to enter other, but not necessarily identical, agreements with all first nations along the pipeline right of way.

The Kaska Nation includes five of 24 first nations groups in the Yukon and British Columbia with whom Foothills is discussing the pipeline.

Just a month ago, the Mackenzie Delta Producers Group and the Mackenzie Valley Aboriginal Pipeline Corp. signed a memorandum of understanding, setting the stage for one-third aboriginal ownership of a pipeline through the Northwest Territories, as well as other economic benefits.

That deal was hailed by Northwest Territories Energy Minister Joe Handley as a crucial step in helping an all-Canadian pipeline from the Arctic get the jump on a highway line.

"It means everybody is serious in looking at the pipeline," he said. "Now the producers can get seriously on to a feasibility study."

—Gary Park

■ NORTH SLOPE

Alberta Energy, Anadarko looking for space in gas pipeline

Companies want to purchase a portion of state's North Slope royalty gas to ensure product to ship before they have gas of their own to put into pipeline

By Kristen Nelson
PNA Editor-in-Chief


Mark Hanley, Anadarko Petroleum

Anadarko Petroleum Corp. and Alberta Energy Co. Ltd. subsidiary AEC Oil & Gas (USA) Inc. have 3 million acres of North Slope exploration acreage between them — a combination of state, federal and Arctic Slope Regional Corp. lands, much in the gas-prone foothills — and a correspondingly large interest in gaining access to any gas pipeline from the North Slope.

The companies have been talking to the state about the state's royalty North Slope gas, and told a meeting of the Alaska Royalty Oil and Gas Development Board Nov. 13 that they support a state North Slope royalty gas sale.

Both Mark Hanley of Anadarko and Alan Sharp of AEC Marketing said access to a gas pipeline was a requirement for continuing exploration on gas-prone acreage in Alaska.

If the companies were simply to nominate shipping space with pipeline owners in open season they could end up paying $150 million to $200 million a year for the space if they were not ready to ship gas when the pipeline started up. With 30 trillion cubic feet of proven reserves on the North Slope, a 4 billion cubic foot a day pipeline could be at capacity for 20 years if the explorers do not nominate space in the open season.

If they purchase state royalty gas, they can then

see SPACE page 17

■ CANADA

Older is better in Canada, say U.S.-based arrivals

Dominant supply basin still has untapped potential, say industry executives, but National Energy Board chairman warns of little scope for growth

By Gary Park
PNA Canadian Correspondent

United States-based companies which have swarmed across the 49th parallel into Canada in the last two years in pursuit of natural gas riches are agreed on one thing: The best hope for growth lies in the oldest supply region.

A round-table discussion by executives of Apache Canada Ltd., Anadarko Petroleum Corp., Burlington Resources Inc. and Conoco Inc. at a Ziff Energy Group conference rated the Western Canada sedimentary basin as one of Canada's most enticing exploration targets.

But Ken Vollman, chairman of Canada's National Energy Board, told the same conference that the Western Canadian sedimentary basin, which accounted for 98 percent of all Canadian oil and gas output in 2000, is fully mature with little scope for growth.

While "there's lots of life ahead" for the basin, the industry shouldn't be expecting much production growth, he said.

"This is as good as it gets ... maybe a slight increase, but we're sort of at that adult, mid-life phase," Vollman said.

Western Canadian basin undervalued

Jim Emme, Anadarko's vice president of exploration and former president of Anadarko Canada Corp., said the Western Canadian sedimentary basin is "comparatively undervalued in terms of its growth" when stacked up against the "huge" potential of Canada's Arctic and East Coast.

He said trillion-cubic-foot discoveries are "out there and there is multi-pay potential that is not limited to only one horizon."

see BASIN page 12

continued from page 11

BASIN

Floyd Price, president of Apache Canada, said his company sees a strong future in deeper plays in the basin's under-explored areas.

On the downside, he cautioned that if the Canadian government delivers on its commitment to ratify the Kyoto Accord aimed at slashing greenhouse gas emissions and unless First Nations land claims are resolved, the Canadian oil and gas industry will be placed at a disadvantage.

We have to start looking for new sources of gas supply to augment the western basin," including the East Coast, the North and coalbed methane.
—Ken Vollman, chairman, Canada's National Energy Board

Noting that Mexico, Venezuela, Nigeria and Saudi Arabia are exempt from the Kyoto deal, while the United States does not intend to sign, Price said the added cost of doing business in Canada must be "taken into account."

He said the issues will not cause anyone to "run out of Canada," although it could become a "less hospitable place to do business."

Growth in deeper, tighter plays

Tommy Nusz, vice president of acquisitions and divestitures at Burlington Resources, which recently acquired Canadian Hunter Exploration Ltd., said deeper, tighter plays in Western Canada will provide much of the short-term growth, but "there are a lot of opportunities in some of the shallow and unconventional plays as well."

Sig Cornelius, treasurer of Conoco Inc., which purchased Gulf Canada Resources Ltd., said his firm likes all areas, with the Western Canadian sedimentary basin viewed as "bread and butter" and the North as a long-term growth prospect.

Vollman said the bottom line is that the basin will not by itself be able to meet growing gas demand in North America.

"We have to start looking for new sources of gas supply to augment the western basin," including the East Coast, the North and coalbed methane, he said.

Others believe the Western Canadian sedimentary basin still has room to expand. Bill Gwozd, gas services manager at Ziff Energy Group, predicted peak deliverability from the basin will occur around 2020 and could be as much as 4 billion cubic feet per day greater than now.

Ernie Sapieha, chief executive officer of mid-sized Compton Petroleum Corp., said the basin will play a greater role over the next five years as companies drill deeper into the foothills of the Canadian Rockies. "There's a lot of upside with the deep gas plays," he said.

Reserves have fallen in last decade

The Western Canadian sedimentary basin — which stretches from northeastern British Columbia across much of Alberta and southern Saskatchewan and Manitoba — lived off drilling successes in the 1970s and 1980s, but over the last decade reserve additions have fallen far short of meeting production levels.

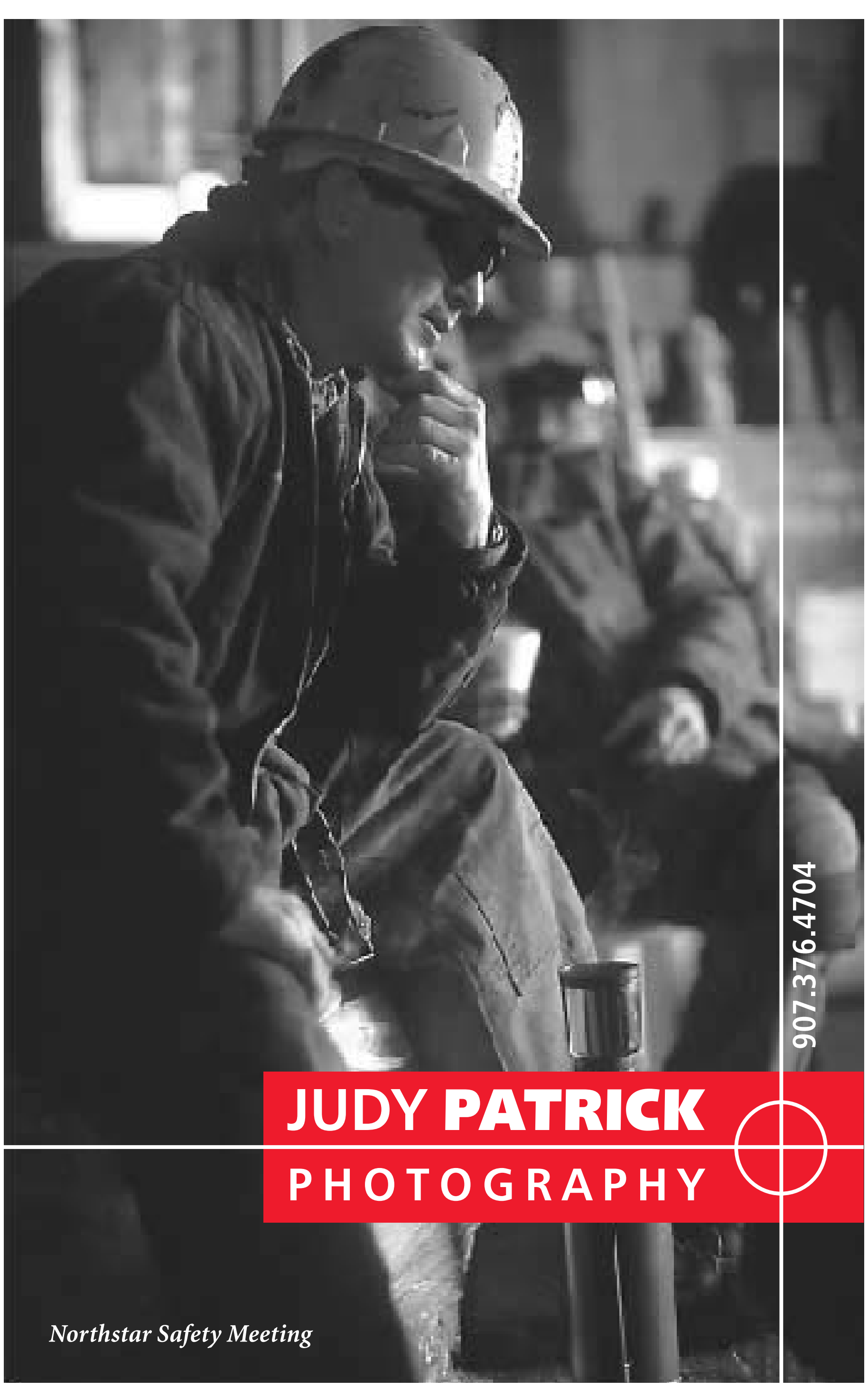
However, the Canadian Gas Potential Committee, in a report released two months ago, placed the basin's gas endowment at 423 trillion cubic feet, up 11 percent from 1993 estimate and 71 percent of Canada's conventional gas endowment.

So far, the report said, 28,770 gas pools containing 277 trillion cubic feet have been booked in the basin.

New gas supplies will come from undiscovered potential of 133 trillion cubic feet in place in 203,207 pools, plus 12.5 trillion cubic feet appreciation in existing pools.

The committee estimated the undiscovered potential includes 156 pools larger than 64 billion cubic feet each — three of them holding in excess of 1 trillion cubic feet each. Another 3,353 pools are larger than 4 billion cubic feet.

At the current success rate per exploratory well, about 200,000 exploratory wells will be needed to find 68,000 pools — more than double the number of wells drilled so far, the committee said. ◆



LAND & LEASING

STATEWIDE

MMS sets public meetings on five-year program

The Minerals Management Service will hold public hearings on the draft environmental impact statement for the Department of the Interior's proposed outer continental shelf oil and gas five-year program, 2002-2007.

Hearings on the proposals for offshore oil and gas lease schedules will be held in Anchorage, Kenai/Soldotna, Homer, Kodiak, Kotzebue, Nome and Barrow. Public comment will be taken on the draft environmental impact state issued in

see MMS page 19

Potential State and Federal Oil and Gas Lease Sales

Agency	Sale and Area	Proposed Date
DNR	Cook Inlet Areawide	May 8, 2002
DNR	Foothills Areawide	May 8, 2002
BLM	NPR-A	June 2002
MHT	Cook Inlet	Fall 2002
DNR	North Slope Areawide	October 2002
DNR	Beaufort Sea Areawide	October 2002
MMS	Sale 186 Beaufort Sea	2003
MMS	Sale 188 Norton Basin	2003
DNR	Cook Inlet Areawide	May 2003
DNR	Foothills Areawide	May 2003
DNR	North Slope Areawide	October 2003
DNR	Beaufort Sea Areawide	October 2003
BLM	NPR-A	2004
MMS	Sale 191 Cook Inlet/Shelikof Strait	2004
MMS	Sale 193 Chukchi Sea/Hope Basin	2004
DNR	Cook Inlet Areawide	May 2004
DNR	Foothills Areawide	May 2004
DNR	North Slope Areawide	October 2004
DNR	Beaufort Sea Areawide	October 2004
MMS	Sale 195 Beaufort Sea	2005
DNR	Cook Inlet Areawide	May 2005
DNR	Foothills Areawide	May 2005
DNR	North Slope Areawide	October 2005
DNR	Beaufort Sea Areawide	October 2005
MMS	Sale 199 Cook Inlet/Shelikof Strait	2006
MMS	Sale 202 Beaufort Sea	2007
MMS	Sale 203 Chukchi Sea/Hope Basin	2007

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

■ WASHINGTON, D.C.

Energy security bill sidetracked again

Stalled $73 billion economic stimulus bill probably won't have energy amendment, energy discussion unlikely in Senate until after Thanksgiving

By Steve Sutherlin
PNA Managing Editor

The slow and excruciating path of energy security legislation was twisted twice Nov. 14 as strategies to launch an energy discussion on the U.S. Senate floor imploded in both the Senate and the U.S. House. The energy discussion and a Senate vote on drilling in the coastal plain of the Arctic National Wildlife Refuge will likely be delayed until after the Thanksgiving recess, PNA was told Nov. 15 by Arctic Power in Washington, D.C.

In the Senate, a Democrat-proposed $73 billion economic stimulus package, widely seen as a potential vehicle for an energy bill amendment, ground to a halt as Senate Republicans and the White House called its spending levels too high and its tax cuts too low. At this point both sides will be reluctant to complicate stimulus package negotiations with additional amendments, Arctic Power said.

In the House, pro-ANWR drilling members sought to attach the House energy bill HR4, which contains a provision approving exploration and drilling in ANWR's coastal plain, to a defense appropriation bill. In essence, this move would have had the House voting on a measure it has already passed because in August it voted open the coastal plain of ANWR for oil and gas exploration.

When the defense bill moved to the Senate, the attached HR4 would have forced the Senate to consider energy issues. But a number of lawmakers saw the same bill as a mule for their own favored amendments, prompting the committee chairman to nix amendments to the bill. The White House also warned against loading amendments onto the defense bill because of national security

see BILL page 16

■ WASHINGTON, D.C.

Stevens urges Senate to pass energy bill

Senator cites instability in producing nations and treaty obligations as reason to fast-track energy bill in Senate

By Steve Sutherlin
PNA Managing Editor

Political instability in oil producing countries and the United States' treaty obligations to provide for the energy needs of Israel in times of shortage are grounds to move quickly on an energy bill, Sen. Ted Stevens said in a speech on the Senate floor Nov. 9. Stevens said he hoped the bill would be brought up as an amendment to the economic stimulus package, which moved out of the Senate Finance Committee on Nov. 8. The House-passed version of the energy bill contains a provision to allow for oil development on 2,000 acres of the 1.5 million acre ANWR coastal plain.

Sen. Ted Stevens

"At $20 per barrel, Americans will send over $5 billion to Iraq by Christmas," Stevens said. "We must begin to explore for oil in our own country, and we know where the largest potential supply of oil is. It is on the coastal plain of Alaska."

ANWR oil could replace the quantity of oil the United States buys from Iraq, Saudi Arabia or Venezuela, Stevens said, adding that instability in Venezuela has led President Bush to recall the U.S. ambassador to that country for consultations. The recall was the result of statements in support of Afghanistan made by Venezuelan President Chavez.

President Bush called Nov. 8 for Congress to send an energy bill to his desk, to reduce dependence on foreign oil.

Stevens said there is national support for the president's policy, "Yet today we still do not have a commitment from the leadership to bring up and complete action on this bill.

"If we act now, our men and women serving overseas will know that we stand behind them. Passing this bill before we go home for the Thanksgiving holiday will tell families from New England to Minnesota that the oil they burn in the future is American oil, not oil from Saddam Hussein or any of these unstable sources." ◆

CANADA

Three calls for nominations north of 60 degrees

The Minister of Indian Affairs and Northern Development has called for nominations for lands north of 60 degrees in the central Mackenzie Valley, Beaufort Sea/Mackenzie Delta and Arctic Islands of Nunavut.

Individuals and companies requesting posting of a parcel are expected to submit bids in response to the call for bids and the minister reserves the right to refuse future posting requests from those individuals and companies if a bid is not submitted.

The minister is not obliged to proceed with a call for bids for any lands posted.

Central Mackenzie Valley posting requests are due Dec. 10; minimum size is one section; exploration licenses issued in a subsequent call for bids would be for eight years, two consecutive periods of four years each.

Beaufort Sea/Mackenzie Delta posting requests are due Dec. 17; size of parcels posted differs according to area; term of exploration licenses issued in a subsequent call for bids would be nine years — two consecutive periods of five and four years.

Arctic Islands of Nunavut posting requests are due Jan. 7; size of posting varies by area. Term of exploration licenses to be issued in a subsequent call for bids would be nine years consisting of two consecutive periods of six and three years.

Fax the Northern Oil and Gas Directorate for more information at (819) 953-5828; or phone (819) 997-0877 or (819) 953-8529; or visit the directorate's web site: http://www.ainc-inac.gc.ca/oil.

GULF OF MEXICO

Anadarko and BP team up on deep water Gulf prospects

Anadarko Petroleum Corp. and BP Exploration & Production Inc. have formed a joint venture to explore 95 BP South Auger area deep water blocks in the Garden Banks and Keathley Canyon areas of the Central Gulf of Mexico, the companies said last month. Most of the targets are deep, sub-salt objectives in water depths of 3,000 to 6,000 feet.

The joint venture agreement gives Anadarko the option to earn a 33 percent to 66 percent working interest in the blocks. Anadarko will fund the licensing and reprocessing of 3-D seismic data and pay a disproportionately larger share of the first four wells drilled.

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"By partnering with BP in this area, we can leverage our sub-salt, shallow water expertise with BP's deep water experience to provide a greater range of drilling discovery opportunities for both companies," John Seitz, Anadarko president and CEO said in a statement. "We're already participating in drilling a deepwater Gulf of Mexico exploration well, Blues Image, with BP under a separate agreement, and we have partnered with them in other exploration areas, such as the foothills of Alaska and offshore Nova Scotia."

Also as part of the deal, BP has agreed to assign Anadarko its rights in eight blocks in the Green Canyon area near Anadarko's Marco Polo discovery on Block 608.

— Steve Sutherlin

■ CANADA

Coalbed methane projects stirring to life in Canadian Rockies

Sector trails United States in commercial development, but PanCanadian Energy executive believes the potential could be a "phenomenal story"

By Gary Park
PNA Canadian Correspondent

Interest in coalbed methane ventures is quickening along the Rocky Mountains, as Canada follows the lead of the United States in exploring what some industry officials think could be a greater resource than conventional gas.

Although the sector is still in its infancy in Canada, there have been a series of developments in the past two weeks and more are in store with the British Columbia government promising a new royalty regime for coalbed methane by year's end.

Don Wallette, Rockies regional director for Phillips Petroleum Co., said the appeal of coalbed methane is the reduced exploration cost, which he said is much less expensive than an offshore project.

A partnership of PanCanadian Energy Corp. and MGV Energy Inc. announced Nov. 7 that its current exploration program in southern Alberta will be expanded, while Alberta Energy Co. Ltd. said it will proceed with an experimental coalbed methane project in southeastern British Columbia.

In addition, Burlington Resources Inc., which recently acquired Canadian Hunter Exploration Ltd. and currently operates coalbed methane projects in the San Juan Basin of New Mexico, said it has identified a number of prospects in Canada and will spend up to C$5 million this year on test wells.

"This is a significant resource which obviously is dependent upon economics, but we won't have the feel for the true potential until we capture some real data," said Burlington vice-president Tommy Nusz.

Terry Lawrence, executive vice president of PanCanadian, told a Ziff Energy Group conference Nov. 6 the full potential of Western Canada's gas prospects may lie in coalbed methane programs just getting under way. "I just think at the end of the day it will prove to be a phenomenal story," he said.

Palliser coalbed methane drilling largest in Canada

PanCanadian and MGV, a subsidiary of Fort Worth, Texas-based Quicksilver Resources Inc., reported they have drilled 23 of 25 planned exploration wells in the gas-rich Palliser block of southern Alberta and 24 of a planned 75 pilot wells within the block.

The remaining 51 pilot wells should be completed by mid-2002, giving the partnership a total of 112 exploratory and pilots wells — 100 in the block and 12 outside.

The plans to expand outside the Palliser block and "aggressively" pilot some promising wells in Palliser, puts the joint venture "on track to develop this important resource in Alberta and Canada's natural gas future," said PanCanadian senior vice-president of new ventures, Gerry Protti.

MGV chairman and chief executive officer Mike Gatens said the Palliser drilling is the largest coalbed methane exploration and pilot in Canadian history. "The encouraging exploration results there have prompted us to accelerate our schedule and expand our exploration activity to other areas of Alberta," he said.

AEC, after quietly assembling a land position in southeastern British Columbia over the last three years, has drilled or licensed seven wells, but is keeping the details confidential.

Based on lease sales in recent months, AEC has purchased almost 38,000 acres, representing a contiguous block almost 40 miles long on the western slopes of the Rockies.

In addition, Burlington Resources Inc., which recently acquired Canadian Hunter Exploration Ltd. and currently operates coalbed methane projects in the San Juan Basin of New Mexico, said it has identified a number of prospects in Canada and will spend up to C$5 million this year on test wells.

Suncor Energy Inc. and Anadarko Canada Corp. have been identified as other buyers of coalbed methane prospects in the region.

In a new study of its oil and gas potential, the British Columbia Oil & Gas Commission has estimated the coalbed methane potential in the Elk Valley field, where AEC is operating, at 7.7 trillion cubic feet, while the Crowsnest region to the south is rated at 12.2 trillion cubic feet.

Environmentalists raising concerns

To date, the U.S. gross coalbed methane reserves are estimated in excess of 700 trillion cubic feet, while the more lightly explored Western Canada is placed at 200 tcf.

First developed on a commercial scale 20 years ago in the San Juan Basin of New Mexico and Colorado, coalbed methane development has spread to Colorado and Wyoming.

Don Wallette, Rockies regional director for Phillips Petroleum Co., said the appeal of coalbed methane is the reduced exploration cost, which he said is much less expensive than an offshore project.

But, as the Bush administration moves to open up more of the Rockies to exploration, environmentalists are raising concerns, especially about the disposal of saline water that is released as a byproduct of coalbed methane production. ◆

Courtesy of Central Trading Systems and SovinFormsputnik

A satellite picture of Fisherman's Wharf in San Francisco

■ NEW YORK

High-resolution satellite images of Alaska now available on CD

Russian black and white satellite images cover about half of Alaska and depict ground details as small as two meters

By Alan Bailey
PNA Contributing Writer

Modern satellite technology has made it possible to photograph large areas of the earth's surface in stunning detail. Satellite images, with ground resolutions as fine as one meter, can provide a wealth of useful information when exploring or developing remote regions such as Alaska, Mike Laserson, president of Central Trading Systems Inc. told PNA in a recent interview.

Russia has become a prime source of these high-resolution images. Years ago, the Soviet government used satellite imagery as part of its military program. Nowadays, Russia operates its satellite imagery program as a commercial business.

Russian images

In an interesting twist of history, Russia has become a prime source of these high-resolution images. Years ago, the Soviet government used satellite imagery as part of its military program. Nowadays, Russia operates its satellite imagery program as a commercial business.

Central Trading, based in Huntington, N.Y., markets the Russian images in the United States. The company supplies the images on CD ROM, which can be viewed on a computer.

"The imaging we sell is entirely from Russia," Laserson said. "Unlike anyone else, we do have archive imagery over Alaska."

Increasing resolution

When Central Trading went into business in 1990, it sold only the five-meter resolution images, most of which went to energy exploration geologists. Other potential applications required finer resolution, which was not available at that time.

The resolution of the images has advanced steadily during the past decade, to a point where they now reveal the kind of surface detail required for development and construction projects, Laserson said.

"Over time the products have gradually improved," he said. "We started selling two meter data in 1993 and about a year and a half ago we started selling one meter data."

3-D pictures of Alaska

Laserson said Alaska presents some difficult challenges for satellite photography. The snow cover during many months of the year limits the time available to shoot usable pictures.

The state's location relative to satellite orbits causes further time restrictions, Laserson said.

The Russian imagery, all of which was shot in the 1990s, includes two-meter resolution pictures of about half of the state. The images are black and white.

Although individual images display a flat picture of what is on the ground, overlapping, adjacent images snapped from slightly different angles by the satellite make it possible to view the terrain in three-dimensional relief. These so-called stereoscopic pictures allow the elevation of the terrain to be calculated for plotting on maps.

Laserson said that stereoscopic imagery at a 10-meter resolution exists for about two-thirds of Alaska.

And with the introduction of color imagery planned for 2003, Central Trading's satellite photography program continues to develop.

With uses ranging from mapping and environmental studies to development planning, high-resolution satellite images provides a cost-effective alternative to conventional maps and aerial photographs, Laserson said.◆

ANCHORAGE

Security Aviation secures contracts

Security Aviation Inc. landed a General Dynamics contract for air support of military site projects, inked a two-year renewal of a long-standing Air Force contract, and renewed an FAA contract to carry maintenance workers to various sites, the company said in a statement Nov. 9. All three contracts are for personnel and freight transport in Alaska. The company will be able to fulfill the contracts with its existing fleet, said Mike O'Neill, company president.

Security operates a twin-engine fleet of a Cessna Citation II jet, two Cessna Conquest II prop-jets, a Piper PA-31-350 Chieftan and a Cessna T-310R from its base at Ted Stevens Anchorage International Airport. Aircraft and crews are available for 24-hour charter. The company has operating authority throughout Alaska, Canada, the contiguous 48 states and Eastern Russia.

McKay president at Northwestern Arctic Air

Dave McKay has been named president of Northwestern Arctic Air Inc., the company said Nov. 1. Northwestern provides charter services and operates a fleet of Gulfstream, Hawker, Learjet and King Air aircraft from its base at Ted Stevens Anchorage International Airport. The company was recently authorized to fly for Phillips Alaska Inc. and BP Exploration (Alaska), McKay told PNA Nov. 7.

The company can fly its 16-passenger Gulfstream jet to Sakhalin from Anchorage non-stop in seven hours, and has made a number of flights to the island for oil companies and oil service companies, McKay said. Northwestern has a Hawker business jet stationed in Moscow, and has considerable experience operating in Russia and the Far East, he said. Most of its flights in that region are medi-vacs; in fact, the company is the fixed-wing provider of medi-vac flights for the Providence Alaska Medical Center Lifeguard program.

With 27 jets available at bases nationwide, the company can match the range and payload to the needs of the mission for greater speed and efficiency, McKay said.

The company is a subsidiary of Northwestern Aircraft Capital Corp., but it is based, and its operating certificate originated in Anchorage, McKay said, adding, "Our headquarters is in Anchorage and our director of maintenance is here."

Because Anchorage is such a strategic location, most of the company's flights in the Pacific Rim land in Anchorage for fuel and customs. Oftentimes with advance notice the firm can hold a specialized plane passing through for an Anchorage-originating flight to eliminate the cost of positioning the aircraft from another base.

McKay was previously Northwestern's executive vice president; he worked for Era Aviation Inc. in the 1970s and 1980s.

—Steve Sutherlin

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BILL

concerns.

An agricultural bill favored by Senate Majority Leader Tom Daschle scheduled for markup on Nov. 15 might encounter an energy security amendment, but if that happens it is unlikely that debate would begin until after Thanksgiving, Arctic Power said.

Arctic Power and its supporters are devising several new strategies to introduce energy discussion in the Senate, despite Senate Democratic leadership committed to stalling the issue.

In the aftermath of the spirit of cooperation that existed in Congress following the Sept. 11 terrorist attacks, full-out partisan squabbling and maneuvering seems to have returned, Arctic Power said.

In other words, business as usual.◆

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MOU

transporting Alaska gas and expect to submit their plans to the North Slope producers by year's end.

"Once agreement is reached with the producers, the companies intend to move forward with the project," setting 2008 as the start-up target, Foothills said in a statement.

The deal, which a Foothills spokesman said has been "in the works for several months," is aimed at the nine companies building, owning and operating a highway delivery system.

The partners are subsidiaries of The Williams Companies, Duke Energy, Sempra Energy International, Enron (which is being taken over by Dynegy), PG&E Corp. and El Paso Corp. — a galaxy of the major U.S. pipeline and broad-based energy companies.

The Canadian companies are Foothills and its joint owners, TransCanada PipeLines and Westcoast Energy (which has scheduled a Dec. 15 shareholders' meeting to approve a takeover by Duke Energy).

Foothills chief executive officer Dennis McConaghy, said all of the MOU signatories, including their predecessor companies in some cases, have been "involved in developing the Alaska Highway project at one point.

"Through this agreement, the companies are demonstrating their intent to renew their commitment to the commercialization of vital natural gas infrastructure from the Alaska North Slope to Canada and the Lower 48 states," he said.

The Foothills statement said the MOU establishes the "key principles for re-enlisting" in the partnership to build the Alaska portion of the highway project.

It said a "key element" is that current and re-enlisting companies "are committed to eliminating historic and other commercial barriers to construction" of the pipeline.

ANS producers receptive

"They have not contacted the producers as of yet. Or, I should say, this is the first I have heard of it. … They have not contacted our project team," Curtis Thayer told PNA Nov. 15, minutes after the Foothills announcement. Thayer is a spokesman for the Alaska Gas Producers Pipeline Team, a joint study group representing the North Slope's three major producers, BP, ExxonMobil and Phillips.

Foothills' announcement, Thayer said, "does not affect what we are doing here and what we expect to accomplish by years' end.

"But one thing we have said from day one is that we have made no conclusions or assumptions about who would ultimately own a gas pipeline. That discussion has not taken place. We would welcome anyone who can bring value to the table," he said.

Later the morning of Nov. 15, BP spokesman Ronnie Chappell told PNA, "We see this as welcome news and a positive development in the effort to move Alaska gas to market. The more people and companies working this project, the better. We wish them success in developing a competitive project."

BP, he said, has no "preconceptions on pipeline ownership. … If we go forward, we would seek out pipeline companies" as potential partners.

"If other companies develop a competitive project, BP would ship its gas on that pipeline," Chappell said.

The deal comes at a time when the gas study group has estimated that a highway pipeline would cost more than going "over-the-top" with a line from the North Slope, under the Beaufort Sea and connecting with Mackenzie Delta gas in a delivery system through the Mackenzie Valley, although Thayer has said the gas team is still examining the economics of the two routes as part of studying the feasibility of developing Alaska gas.

Meanwhile, the Mackenzie Delta Producers Group and First Nations occupying the bulk of the Mackenzie Valley right-of-way have reached their own agreement setting the stage for an aboriginal equity stake in stand-alone Canadian pipeline, plus economic benefits, creating a growing sense among analysts that the Delta could come on stream before the North Slope.◆

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SPACE

commit to pipeline space and use that space to ship state royalty gas until they have gas of their own ready for the pipeline.

AEC says no risk for state

Anadarko and AEC are partners in acreage and are interested, AEC's Sharp told the board, "in purchasing state royalty gas to backstop, if needed, any potential nominations for capacity during an open season." The companies would nominate space in a pipeline separately, but make a joint bid for state royalty gas.

"Without some assurance concerning pipeline capacity, continued investment in new Alaska gas exploration is unlikely." —Alan Sharp, AEC Marketing

Sharp also said that with the volumes of discovered gas, neither new explorers nor the existing producers would need to explore for 20 years.

AEC has 1.1 million acres in the foothills — state and Native lands — and is looking for non-associated gas (gas that is not part of an oil field) in the area, Sharp said.

Because existing gas would fill the pipeline for 20 years, he said, AEC is concerned that if it doesn't nominate space in the first open season, it might never be able to acquire pipeline capacity.

"Without some assurance concerning pipeline capacity, continued investment in new Alaska gas exploration is unlikely," he said.

"We believe," he told the board, "the state should leverage its gas volumes of tomorrow to support gas exploration projects of today. The state has no risk, as this is a natural hedge.

"If the pipeline does not proceed, the state would have no obligation to deliver contracted future royalty gas volumes under those circumstances.

"The benefits are greater exploration and greater revenues…"

Encourage exploration

Anadarko's Hanley told the board that holding a state royalty gas sale will encourage additional exploration. Anadarko, he said, has 1.9 million acres of state, federal and Native land on the North Slope, is shooting seismic over the gas-prone foothills and hopes to do gas drilling next winter.

Transportation of gas is crucial for us, he said, if we can't get pipeline capacity, we can't spend money to find oil.

The risk for Anadarko, if it just took gasline space in an open season, is that based on an estimate of one-half billion cubic feet it could be charged $150-$200 million a year for the space if it had no gas ready to ship — and that could be for a 20-year contract.

"A $200 million a year risk without any gas would be a huge risk," Hanley said.

"If we don't have gas, we night not nominate — it's a huge risk and I can't say we'd take it — it's a fairly watershed event for us."

And without pipeline capacity, Anadarko might not go forward with exploration in the foothills sales area, he said.

State wouldn't see all its royalty gas

Bonnie Robson, deputy director of the Division of Oil and Gas, said the state wouldn't sell all of its North Slope royalty gas. It needs to take some of the gas in value to establish a base price — royalty-in-kind gas, by law, must be sold for more than royalty in value brings in — and would also want to have some gas available for instate sales and for purchasers who aren't ready to come forward now. The state would probably be interested in selling 50-80 percent of its royalty gas, Robson said, although she noted that at the end of the sale process the decision may be to sell no gas at all. For a 4 billion cubic foot pipeline, the state's one-eighth would be 500 million cubic feet, so 50 percent of its gas would be 250 million cubic feet a day.

The state is looking at a three-part sale price including the base price, which can't be less than the royalty-in-value price. Robson said the second part would be a bonus bid, a fixed dollar amount, probably $1 per thousand cubic feet. For a three-year supply, she said, this would come out to 1/10 of a cent per thousand cubic feet — for a 15-year supply, it would be 1/50 of a cent per mcf. So the amount, she said, would be fairly small on an mcf basis, but would cover the cost of the sale and would ensure that only serious bidders participated.

The third part of the bid would be a premium, and the bidder would decide what premium to offer. Robson said examples of a premium include an extra cent per mcf, instate investment or a floor rate for the price.

Miscellaneous additional terms

Additional terms that the state is looking at include flexibility to renegotiate some of the specifics if gas markets or the gasline develop in ways other than what we now anticipate, Robson said. The state might require a security for payment of any future price adjustments. Robson said the final royalty-in-value price may be higher after audits or litigation, requiring an increase in the royalty-in-kind price. In the past the state has had a problem with its royalty-in-kind oil sales — by the time the royalty in value is finally determined buyers are unable or unwilling to pay the additional amount to the state. A security for payment would be one solution to that problem, or the contract might provide an incentive for full payment of the royalty in value either through extra interest or payment of state's attorney fees if the buyer challenges the price.

Robson said that the public comment period ends Nov. 30 and that the state's goal is to have a final best interest finding and solicitation for bids out in mid-December.

Other provisions could prevent the state from being locked into a contract if the gasline is not built by a certain date, or if an open season is not held within two years or if the pipeline does not go to the Lower 48.

Mid-December goal for contract

Robson said that the public comment period ends Nov. 30 and that the state's goal is to have a final best interest finding and solicitation for bids out in mid-December. Bidders will have 30 days to submit bids, which will be opened in public in mid-January.

If there is an open season in progress when the bids are opened, the state will accelerate a work on the bids, which may need negotiation before going to the royalty board and then to the Legislature, which will need at least one month and probably two to hold hearings and consider the bids.

Because there are a number of variables, the state needs the right to negotiate and nail down terms but, Robson said, the bidders won't have the right to improve their bids. ◆

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UNOCAL

additional wells would not have been drilled — nor would the eight exploration wells the company has planned for 2002. (See RCA contract approval story in Nov. 4 issue of PNA.) That contract price for Cook Inlet natural gas is based on Henry Hub gas prices.

Without Regulatory Commission of Alaska approval of the Enstar contract, Thomas said, the additional wells would not have been drilled — nor would the eight exploration wells the company has planned for 2002.

Thomas said Cook Inlet started out with a 100-year supply of natural gas and average utility prices for Cook Inlet gas have reflected a blend of contracts from wells discovered in the 1950s and 1960s.

Higher price cost of exploration

A higher gas price is necessary if there is going to be exploration because it costs more to do business in Alaska — the Cook Inlet area is not known the way the area is, for example, in West Texas, Thomas said. There are environmental issues, Cook Inlet must complete for capital with project worldwide and the royalty value is uncertain.

By 2003, Thomas said, there will be gas shortages in Cook Inlet on the very coldest days of winter. Unocal is looking now at gas for the next 15 to 20 years. But, he predicted, there will be shortages in Cook Inlet before a North Slope pipeline is built.

In a move to deal with seasonal shortages, Unocal has begun gas storage in Cook Inlet to meet peak needs on cold winter days, Thomas said. We injected all summer, he said, and are now withdrawing.

This is a first for Cook Inlet, although companies have discussed the need for gas storage in Cook Inlet in the past. The Alaska Oil and Gas Conservation Commission approved a Unocal application for gas injection into the Tyonek formation of Swanson River unit well 43-28 in mid-June.

Kenai to Kachemak pipeline

The Kenai-Kachemak pipeline project, from the Kenai gas field south to Homer, is expected to take two years to construct, Thomas said, with gas reaching the southern end of the line by the end of 2003.

Unocal, Marathon Oil Co., Enstar and a Homer Electric Association subsidiary are the partners in the pipeline project, which began permitting for route selection this fall.

Along the pipeline route are the Marathon-operated Ninilchik unit, in which Unocal is a partner (see story page 8) and Unocal's South Ninilchik prospect. Unocal's Deep Creek prospect is a few miles east. Farther south is Unocal's Anchor Point prospect, also along the proposed pipeline route.

The pipeline is planned to be 16 inches in diameter, but with numerous wells yet to be drill, we hope it will end up at 20 inches, Thomas said. ◆

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AID

Goal is assistance in financing

But she insisted the Aboriginal Pipeline Group is not holding out its hand for a subsidy.

"Instead, we're asking for assistance in financing our part of the partnership," she said, referring to an agreement that would give the group a one-third stake in the C$3 billion pipeline, provided it can negotiate shipments of up to 500 million cubic feet per day.

Nellie Cournoyea

"We'd like to see (government) assistance in helping us raise the one-third needed for our share of the pipeline," she said. "It could be, in part, a loan guarantee."

But the obstacles to landing a deal are already substantial. In October, federal Indian Affairs Minister Robert Nault said the government has no plans to provide aboriginals in the Northwest Territories with loan guarantees.

Bill Gwozd

At the same conference, Ken Vollman, chairman of Canada's National Energy Board, said the federal regulator will be positioned to handle an Arctic pipeline application by the end of this year. He said the objective would be to complete all regulatory and environmental assessment within 30 months.

Although there has been no indication when an application might be filed, Vollman said one is likely by early 2002.

Bill Gwozd, manager of gas services at Calgary-based Ziff Energy Group, said there is now "a lot of push" in the Delta to get a Mackenzie Valley pipeline built before a pipeline out of the North Slope.

"The industry likes smaller steps," he said. "Smaller in this particular case is better."

—Gary Park

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CONDITIONS

before you can go beyond that."

Cambridge now sees a window in 2009-10, and probably another in 2012 to 2014, he said.

Rep. John Davies asked about the effects of a slower recovery.

"We do have a scenario that calls for a recession that lasts through 2004 and it obviously shows much lower prices, prices that would stop at $3 — between $2.50 and $3 — through the entire period," Small said.

"What that means in the contest of Arctic gas, obviously, is it pushes that window of opportunity well beyond 2010 and possibly out to '15."

There are a myriad of proposals for new LNG projects, and like power generation proposals there will probably be at least a 50 percent mortality rate, "but we do see LNG being an integral part of the new supplies in the Lower 48 in the second half of this decade."
—Ed Small, Cambridge Energy Research Associates

Demand is down

Natural gas demand is down in all sectors, Small said, and fuel switching that occurred in the first half of this year will offset some of the return of demand expected in the second half of 2002. Conservation is also a big factor, especially in residential and commercial sectors in the west where local conservation programs and higher prices have had a big impact.

In power generation, where long-term growth in natural gas demand is expected, there is now a question of when that growth will occur: When you push demand down, Small said, it takes longer to get back to the original point and then to start growing again. New gas-fired power generation is coming on in 2002 and 2003, he said, but "if the economy has not recovered, you won't have those facilities running at capacity."

There is a similar demand decline in Canada. Small said recovery of demand growth will be slower there, partly because the Canadian economy lags the Lower 48, but also because the demand for power generation in Canada is not growing at the same magnitude as in the United States.

Storage in Lower 48 almost full

Small said that natural gas storage is almost at capacity in the Lower 48 and it would take an extremely cold winter to draw that storage down a significant amount, so during 2002 less gas will be required for storage.

"In our estimate it's roughly 2 billion cubic feet a day less injection required next year to reach the same full level by the end of the injection session," Small said. The story in Canada is very similar.

Drilling has been impacted by lower natural gas prices in the Lower 48, and Small said Cambridge expects to see reserve additions of only about 400 million cubic feet a day in the Lower 48 for 2001 and declines in 2002 of about 500 million cubic feet a day.

Drilling has been declining for three months, he said, and unless prices get back up to a sustainable $2 level, drilling probably won't recover until later 2002, especially since the 500 million a day decline is 2002 is more than offset by gas in storage.

In Canada, winter drilling with deep rigs will continue because those rigs were contracted last year on a two- to three-year basis, Small said, and since producers have to pay for the rigs whether they use them or not, odds are they will use them. Much summer drilling in Canada is shallow and "more than economic at today's prices — we shouldn't see a big drop there, either," he said.

Because of the economic slowdown in Canada, pretty well all of the supply growth in natural gas will be going to export markets — the Lower 48. That means that decline in Lower 48 supplies will be more than offset by Canadian growth next year, Small said.

Prices expected to stay at $2.75 through winter

Small said that factors affecting the natural gas price this winter are the demand decline, high storage and incremental or increased Canadian export. Cambridge expects, he said, that Henry Hub prices will be around $2.75 through the winter.

There is a typical demand softness in the spring, Cambridge does not expect the economy to have fully recovered by then and injection requirements will be lower, probably pushing spring and early summer prices down to the $2.25 level.

Assuming the economy recovers and with summer power generation demands, prices in the third quarter should get back up to the high $2 level. By the end of next year, in conjunction with economic growth, Cambridge expects the Lower 48 price to get back up to $3, maybe even $3.25, for the 2002-2003 winter season.

That price level, Small said, "should bring back fairly robust drilling activity in 2003."

In 2002, the Henry Hub price could average $2.71.

Longer term, Small said, "there are drivers there to keep prices from sliding down below $2… there are drivers there to keep prices long-term from being much over $3… what that suggests is longer term, there's probably a band of prices in the $2.50 to $3.50 range … there is going to be volatility. We are seeing shorter cycles, but the … range we see now… is $2.50 to $3.50…"

LNG greenfield facilities expected

Torgerson asked about liquefied natural gas and Small said the four existing LNG facilities in the Lower 48 are coming back on stream, with three now active and the fourth coming back on next year. Cambridge anticipates growth in 2003-2005 and expects to see greenfield LNG facilities built in the second half of the decade.

There are a myriad of proposals for new LNG projects, and like power generation proposals there will probably be at least a 50 percent mortality rate, Small said, "but we do see LNG being an integral part of the new supplies in the Lower 48 in the second half of this decade."

Torgerson said he views LNG as Alaska gas's biggest competition.

Small said Cambridge defines frontier gas as Arctic, including Alaska, offshore East Canada and LNG.

"And of those, the two that are now plugged in are LNG imports and growth in the offshore east Canada, the offshore Nova Scotia, Sable Island areas. So we see growth in those areas. The question becomes one of, as you put quite correctly, what are the competitive forces of LNG and how does Arctic gas compete with that and can Arctic gas compete successfully with that." ◆

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MMS

October.

Lease sales proposed in the Alaska Region include three in the Beaufort Sea, two in Cook Inlet, two in the Chukchi Sea/Hope Basin and one in Norton Sound.

MMS said the proposed sales provide companies the opportunity to search for new sources of oil, but also offer areas believed to contain excellent potential for natural gas.

The Alaska hearings are all scheduled from 7-9 p.m.:

Anchorage, Dec. 3, Wilda Marston Theater

Soldotna, Dec. 4, Kenai Peninsula Borough Conference Room

Kotzebue, Dec. 4, Northwest Arctic Borough Assembly Room

Homer, Dec. 5, City Council Chamber, 491 E. Pioneer Ave.

Nome, Dec. 5, Northwest Campus University of Alaska

Kodiak, Dec. 7, Kodiak Island Borough Assembly Chambers.

Barrow, Dec. 7, North Slope Borough Assembly Room.

MMS said it will hold a teleconferenced hearing in early January for villages that border the proposed sale areas.

Comments will be accepted through Jan. 24.

The final EIS and the proposed final program are slated for release in April.


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