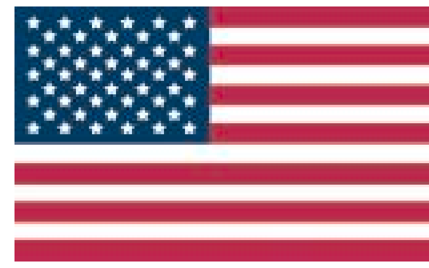
PETROLEUM NEWS
ALASKA



"The American temptation is to believe that foreign policy is a subdivision of psychiatry."

—HENRY KISSINGER, YEARS OF UPHEAVAL, 1982

Vol. 7, No. 9 $1 • www.PetroleumNewsAlaska.com *Alaska's source for oil and gas news* **Week of March 3, 2002**

INSIDE

Canada's Far North edges back into exploration spotlight

Canada's exploration interests are shifting back to the Far North, now that the East Coast offshore is stalled and possibly in decline.

With hopes of a gas pipeline from the Mackenzie Delta higher than they have ever been, the potential of the region's 13 exploration basins is again being taken seriously.

Gerry Reinson, of Reinson Consultants Ltd., told a Calgary seminar in February that once a pipeline is in place the Arctic will be "highly economical."

> ***Hunt Oil Co., from its midpoint between the two pipeline routes, could work with either an Alaska Highway or Mackenzie Valley pipeline. —Chris Wickens, Hunt Oil***

In particular, the gas prospects are the major current magnet. Current estimates of the region's potential range as high as 175 trillion cubic feet, compared with 270 trillion in the Western Canada Sedimentary Basin.

For all of Canada reserves are placed at 594 trillion cubic feet, of which 121 trillion have so far been produced, 105 trillion have been found and 368 trillion are yet to be discovered.

Using figures from a study by Sproule Associates Ltd., Reinson said 102 trillion cubic feet are in the Arctic, with 62 trillion in the Mackenzie/Beaufort Sea region and 11 trillion in mainland Northwest Territories fields. In addition, discovered oil reserves are rated at 1.29 billion barrels, with undiscovered oil estimated at 5.74 billion barrels, dominated by the Beaufort at 767 million (discovered) and 4.35 billion (undiscovered) and the Mackenzie Delta at 248 million (discovered) and 1.05 billion (undiscovered).

On the gas front, the Beaufort resources are estimated at 4.08

see EXPLORATION page 12

Response to bullet hole in pipeline called success

The response to the trans-Alaska pipeline bullet hole oil spill was efficient and successful, according to a joint report released Feb. 27.

Alyeska Pipeline Service Co.

Some 6,800 barrels of Alaska North Slope crude hit the ground about 45 miles north of Fairbanks between the time a bullet punctured the trans-Alaska oil pipeline at about 3 p.m. Oct. 4 and 3 a.m. Oct. 6 when a hydraulic clamp sealed off the spill.

Application of the hydraulic clamp was a successful means of controlling the oil spill, but the report said ideas to reduce pressure and/or stop the leak at the site should be investigated for effectiveness.

While safety controls are in place to reduce exposures to hazards and prevent serious explosions, injuries, fires or similar disasters, future exercises should include community fire departments. Both in-state and out-of-state expertise and resources that could enhance fire prevention and fire suppression should be identified.

see RESPONSE page 15

■ EXPLORATION & PRODUCTION

Phillips targets West Sak

If this year's viscous wells prove successful, company will submit 50-well development at Kuparuk for board approval at end of year; $100 million Alpine facility expansion to go to Phillips' board in third quarter

By Kristen Nelson
PNA Editor-in-Chief

Phillips Alaska Inc. is not doing any major projects on the North Slope in 2002, but the company is preparing to take two projects in the hundred-million-dollar range for board approval in the third and fourth quarter.

1999, 2000 and 2001, said Kris Fuhr, manager of Phillips Alaska's project group, "were extremely busy years both for ourselves and BP," with billion-dollar projects at Alpine for Phillips and at Northstar for BP and Phillips' Meltwater development at a couple of hundred million.

Forrest Crane

Kris Fuhr, Phillips Alaska Inc.

Those big projects created an abnormal capital spend compared to what it has been over the last 20 years, Fuhr said Feb. 20 at the Pacific Rim Construction, Oil and Mining Expo, and Phillips expects the next couple of years will be a more normal spending pattern for the company, with capital expenditures in the $550-$600 million range, excluding tanker fabrication.

"The $550-$600 million this year is about evenly split between drilling capital and surface facility capital," he said.

He also said that cost management will continue to be rigorous for North Slope work. The oil basins on the North Slope are pretty mature and margins are low so a "$15-$16 a barrel oil world is very tough for us to generate acceptable returns…

see PHILLIPS page 13

Phillips begins NPR-A winter exploration

Phillips Alaska Inc.'s 2002 exploration effort is probably more focused than last year, Kris Fuhr, Phillips Alaska Inc. manager projects group said at PacCom Feb. 20. The company looked at a lot of different areas last year, he said, and "we're going to go back and we're going to look at a couple of those opportunities from our NPR-A work."

Dawn Patience, Phillips Alaska spokeswoman, told PNA Feb. 27 that the company will drill eight to 10 exploration wells this winter season, about half in the National Petroleum Reserve-Alaska. Three of the wells are wildcats, she said, Hunter in the National Petroleum Reserve-Alaska, and Grizzly and Heavenly in the Kuparuk Uplands.

Phillips received a drilling permit for Hunter A Feb. 15 in section 30, township 9N range

see NPR-A page 13

■ EXPLORATION & PRODUCTION

AEC investing $32M in Alaska in 2002

Company has North Slope acreage position of 1.3 million acres acquired through eight transactions including farm-ins, acreage swaps and lease sales

By Kristen Nelson
PNA Editor-in-Chief

Alberta Energy Co. subsidiary AEC Oil & Gas (USA) Inc. came to Alaska in 1999 to look at the proposed disposition of part of the Alpine field when BP planned to purchase all of ARCO, AEC Vice President Guy James told the House Special Committee on Oil and Gas Feb. 21.

Since then, the company has acquired 1.3 million exploration acres and this year, James said, AEC will participate in two onshore exploration wells, shoot a full season 3-D seismic program in the Foothills and operate the McCovey offshore exploration well.

> ***The Alaska gas industry is "where Alberta was in the 1950s. We've had 50 years of sustainable gas growth in Alberta."… Alaska should have 50 years of gas, too: "… when you factor in such things as possibly hydrates it could be much more than 50 years." —Guy James, AEC Oil & Gas (USA) Inc.***

BP didn't purchase ARCO's Alaska assets, but on that visit AEC talked to ARCO (now Phillips Alaska Inc.) about possible involvement in "any significant quality oil prospects" that they might have in the future, and, James said, "about 60 days later we were in their offices evaluating technical on two opportunities that they put on the table for us."

It was a beginning that has grown into an acreage position of 1.3 million acres.

In 2000 and 2001 the company spent $35 million, "primarily on seismic and land" and participated in one well south of Kuparuk which was unsuccessful, James said.

"And we plan to spend $32 million this year" on drilling and seismic programs, he said.

This year AEC is participating in Phillips-operated exploration wells at Grizzly and Heavenly, shooting 3-D seismic with Anadarko Petroleum Corp. over acreage the companies acquired in partnership in the Foothills and will operate the offshore McCovey exploration well later this year.

The company also plans to be more visible in Alaska, James said:

"We are in the process of attempting to acquire office space in Anchorage right now to open an office in Anchorage and we have just hired our first Alaska-based employee."

Eight Alaska transactions

The first prospect AEC looked at in Alaska was

see AEC page 13

■ ARCTIC GAS

Knowles: U.S. Senate Majority Leader Daschle agrees to submit gasline amendments to energy bill

Southern route mandated, along with interstate access to gas and pipeline access for future discoveries, financial safety net

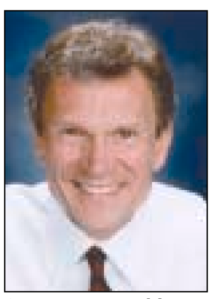
By Petroleum News • Alaska

U.S. Senate Majority Leader Tom Daschle has agreed to introduce three amendments to the national energy bill that the governor believes will both serve Alaska's economic needs and help spur development of an Alaska gas pipeline from the North Slope to the Lower 48, Gov. Tony Knowles said Feb. 27.

Gov. Tony Knowles

Knowles released a statement from Daschle's office in which the South Dakota senator said he would offer amendments to S. 517, the Energy Policy Act, that would:

■ mandate that the project follow the "southern route" from Prudhoe Bay to Fairbanks along the trans-Alaska pipeline right of way and the Alaska Highway through Alaska and British Columbia to Alberta;



Sen. Tom Daschle

■ provide access to the gas for residential and business purposes in Alaska and access to the pipeline for future discoveries and production of natural gas; and,

■ provide a financial safety net for investors against future volatility in the natural gas market.

The portions of Daschle's existing energy bill that relate to the North Slope gasline project were written from recommendations submitted to the U.S. Senate by Alaska's big three oil and gas owners — BP, ExxonMobil and Phillips. The companies' recommendations were requested by U.S. Senate members and were closely adhered to in the drafting of the Democrats' energy bill.

"This is, I think, a significant step forward for the project," Knowles said in a news conference.

BP, ExxonMobil and Phillips have spent $100 million over the past year studying the feasibility of piping natural gas from the North Slope to markets in the Lower 48.

Chuck Kleeschulte, a spokesman for U.S. Sen. Frank Murkowski, said the senator has also proposed amendments mandating the highway route and in-state access to the gas.

While final reviews of that study from the individual producers have not been announced, preliminary analysis questioned whether the project would return enough profit — i.e. be competitive with other investment opportunities around the world.

Phillips encouraged by news

Following the Feb. 27 announcement, Phillips Alaska Inc. spokeswoman Dawn Patience said the company is encouraged by Daschle's announcement, although officials there haven't seen the proposed amendment. She could not say whether those provisions would ultimately lead to a project going forward.

"This project is very large and has a lot of challenges ahead of it," Patience said.

A spokesman for BP said he could not comment on Daschle's announcement without seeing the proposed legislation.

Knowles asked Daschle to support Phillips' request that federal tax credits if gas prices fall too low, with those credits to be repaid if prices rise above a certain level.

Daschle's statement did not specify what would be in the "financial safety net" he agreed to support, and Knowles said a specific trigger price for tax credits had not been determined.

Phillips is seeking federal tax credits if the price of gas dropped below about $3.75 per million BTU.

Phillips is the only one of the three producers that has come out in support of the Alaska Highway route.

The producers have looked at two possible routes: the "over-the-top" route that would run from the North Slope under the Beaufort Sea into Canada, largely bypassing Alaska; and one that follows the trans-Alaska oil pipeline to Fairbanks and then the Alaska Highway south.

Alaska politicians oppose the northern route, saying it would not provide Alaskans the jobs and access to natural gas for in-state uses that the highway route would provide.

Purchase of U.S. steel not included

Chuck Kleeschulte, a spokesman for U.S. Sen. Frank Murkowski, said the senator has also proposed amendments mandating the highway route and in-state access to the gas.

Murkowski has also proposed amendments to the energy bill that would mandate the constructors of a North Slope gasline to use organized labor and buy U.S. and Canadian pipe for the line. Although Daschle's statement mentioned creating jobs and helping the U.S. steel industry, he did not propose amendments to buy North American pipe or use organized labor.

Both Daschle, a Democrat, and Murkowski, a Republican, support requiring access to the pipeline for future discoveries of gas.

A version of the national energy bill that passed the U.S. House prohibits the Beaufort Sea route, but does not include the tax credit provisions.

If the measure passes the Senate with the proposed amendments, differences would likely be ironed out in a conference committee.

—The Associated Press contributed to this report

GOVERNMENT

Bill would make shallow gas program commercial

Senate Bill 319, changing the state's shallow natural gas leasing program to allow individuals to hold up to 100,000 acres and including gas below 3,000 feet as long as a portion of a field is above 3,000 feet, received support from large and small oil and gas companies and was strongly endorsed by the Department of Natural Resources' Division of Oil and Gas.

The bill, sponsored by Sen. John Torgerson, R-Kasilof, chairman of the Senate Resources Committee, was heard and passed out of Senate Resources Feb. 27.

Division of Oil and Gas Director Mark Myers told the committee the proposed changes make the shallow gas leasing program an effective commercial program.

The original intent of the program, Myers said, was to provide energy for villages in rural Alaska. But the pattern of leases under the program has been in clusters near high population areas. Myers said the division worked with industry on the proposed changes. The Alaska Oil and Gas Association, the Red Dog mine (Teck Cominco, operator Red Dog, holds shallow gas leases), Evergreen Resources Inc., Unocal, Dave Lappi and Ken Boyd (director when the program was enacted) all testified in support of the bill.

The bill also increases the application fee for a shallow gas lease from $500 to $5,000 and the rent from 50 cents an acre to $1 an acre. The time requirements for the division to public notice lease applications is removed. Myers said the division has to do title work because private parties can't get title insurance for subsurface title work. The title work is also one reason for the $5,000 application fee: title work is costing the division $2,000 a lease.

The bill also requires a bond against "damages that may be caused … related to a shallow natural gas lease." Myers said the bonding is because private surface owners are concerned about damage to land and the bond, required when a person applies for a lease, would assure surface owner protection.

—Kristen Nelson

Index

PETROLEUM NEWS ALASKA

Kay Cashman, *PUBLISHER*

Dan Wilcox	CHIEF EXECUTIVE OFFICER
Kay Cashman	PUBLISHER
Kristen Nelson	EDITOR-IN-CHIEF
Steve Sutherlin	MANAGING EDITOR
Gary Park	CANADIAN CORRESPONDENT
Alan Bailey	CONTRIBUTING WRITER
Allen Baker	CONTRIBUTING WRITER
Judy Patrick Photography	CONTRACT PHOTOGRAPHER
Mary Craig	CHIEF FINANCIAL OFFICER
Wadeen Hepworth	ASSISTANT TO THE PUBLISHER
Amy Armstrong	STAFF WRITER
Susan Crane	ACCOUNT EXECUTIVE
Forrest Crane	ACCOUNT EXECUTIVE
Steven Merritt	PRODUCTION DIRECTOR
Tom Kearney	ADVERTISING DESIGN MANAGER
Brian Feeney	PRODUCTION ASSISTANT
Tim Kikta	CIRCULATION REPRESENTATIVE
Dee Cashman	CIRCULATION REPRESENTATIVE
Heather Yates	ADMINISTRATIVE ASSISTANT

Petroleum News • Alaska and its supplement, Petroleum Directory, are owned by Petroleum Newspapers of Alaska LLC. The newspaper is published at weekly. Several of the individuals listed above work for independent companies that contract services to Petroleum Newspapers of Alaska LLC or are freelance writers.

P.O. Box 231651
Anchorage, AK
99523-1651

Editorial
907 522-9469
Editorial Fax
907 522-9583
Editorial Email
edit@gci.net
Bookkeeping & Circulation
907 522-9469
Bookkeeping & Circulation Fax
907 522-9583
Circulation Email
circulation2@gci.net
Advertising
907 245-2297
Advertising Fax
907 522-9583
Advertising Email
adsales@gci.net

Petroleum News Alaska, ISSN 10936297, Week of March 3, 2002
Vol. 7, No. 9
Published weekly. Address: 5441 Old Seward, #3, Anchorage, AK 99518
(Please mail ALL correspondence to:
P.O. Box 231651, Anchorage, AK 99523-1651)
Subscription prices in U.S. — $52.00 for 1 year, $96.00 for 2 years, $140.00 for 3 years.
Canada / Mexico — $165.95 for 1 year, $323.95 for 2 years, $465.95 for 3 years.
Overseas (sent air mail) — $200.00 for 1 year, $380.00 for 2 years, $545.95 for 3 years.
"Periodicals postage paid at Anchorage, AK 99502-9986."
POSTMASTER: Send address changes to Petroleum News Alaska, P.O. Box 231651, Anchorage, AK 99523-1651.

ARCTIC GAS

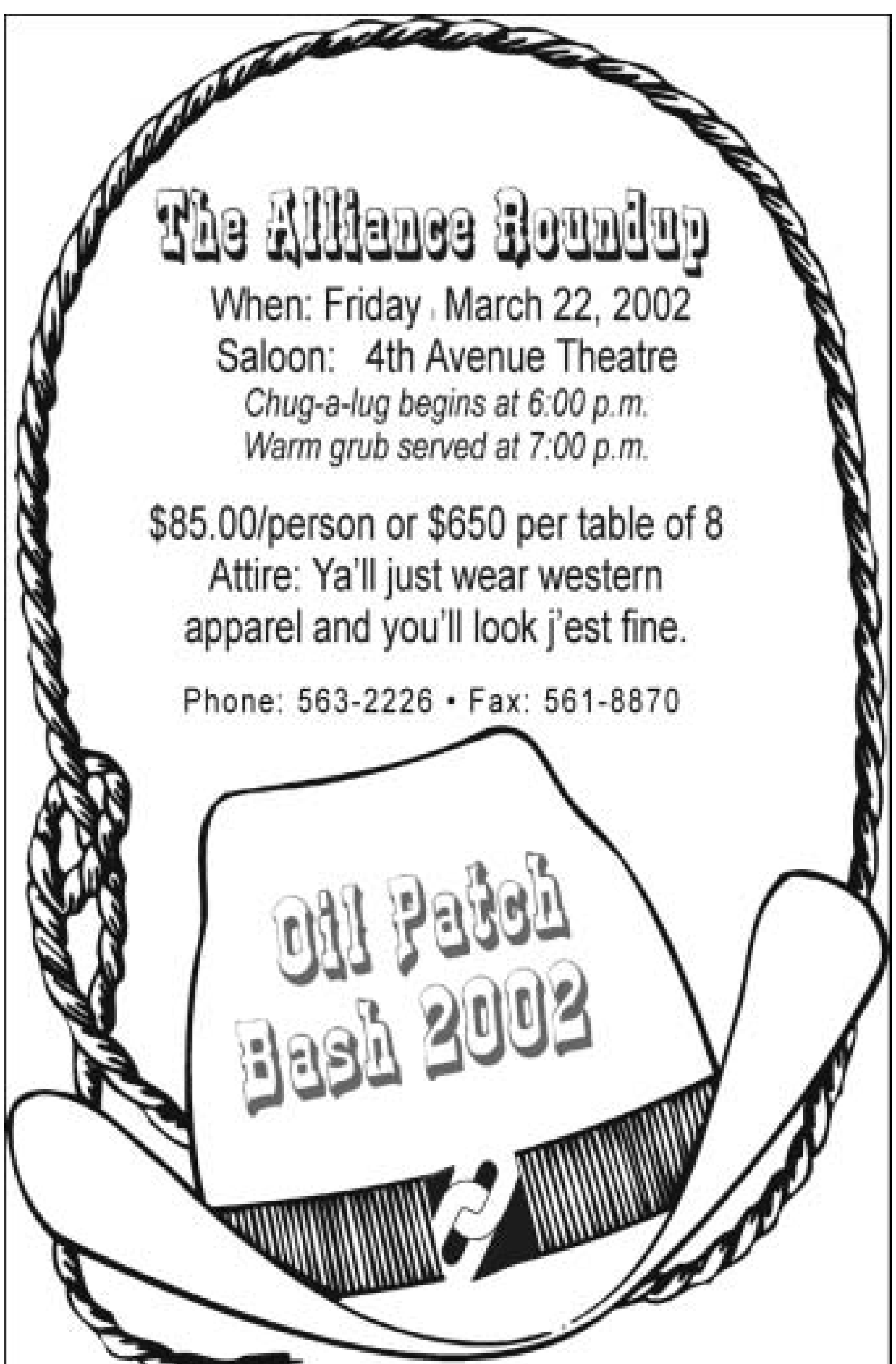
Energy bill calls for study of government owned gasline

The energy bill introduced to the U.S. Senate by Majority Leader Tom Daschle Feb. 15 calls for study of a government owned gasline, as reported by the Dow Jones news service. The bill would require the secretary of energy to study "the feasibility of establishing a government corporation to construct an Alaska natural gas transportation project, and alternative means of providing federal financing and ownership (including alternative combinations of government and private corporate ownership) of the project."

Another section calls for the government to find ways to encourage the pipeline if private sector companies don't proceed within six months of the bill's enactment.

The bill would remove regulatory and legal obstacles in order to speed construction of the project. The U.S. Federal Energy Regulatory Commission would be lead agency for environmental reviews, which would have an 18-month completion deadline. The U.S. Court of Appeals for the District of Columbia would have exclusive U.S. jurisdiction for legal claims arising from the project.

—Steve Sutherlin



■ WORLD OIL

Making a fortune in B.C., spending the money in Alberta

British Columbia Energy Minister Richard Neufeld estimates province has lost 45,000 petroleum jobs in past decade; Alberta offers lowest income taxes and no sales tax

By Gary Park
PNA Canadian Correspondent

The rich get richer and British Columbia is trying to figure out why. Once Canada's wealthiest province, British Columbia is now left with the oil and gas industry as its main hope to reverse an economic tailspin that threatens to leave it with a record C$4.4 billion budget deficit in 2002-03.

> ***"It's interesting to know that although activity has increased dramatically in the northeast, employment has gone down."***
> ***—British Columbia Energy Minister Richard Neufeld***

But as fast as the petroleum sector expands, the benefits are washing over the border into Alberta, Canada's economic stronghold.

British Columbia Energy Minister Richard Neufeld estimates his province's flourishing northeastern gas region has in fact generated 45,000 jobs in the past decade for Alberta residents.

Exploration and production workers choose to live in Grande Prairie and Peace River, in northwestern Alberta, and merely commute across the border to jobs in places such as Fort St. John and Fort Nelson.

Low income tax

The reasons are simple: Alberta has Canada's lowest provincial income tax and is the only one of 10 provinces that has no sales tax, while British Columbia is about to raise its provincial sales tax to 7.5 percent as it scrambles for new sources of revenue.

Speaking to a conference in Fort St. John on Feb. 24, Neufeld said British Columbia has yet to see any measurable benefits from a 600 percent increase in gas drilling over the past 10 years to a record 493 wells in 2001.

"It's interesting to know that although activity has increased dramatically in the northeast, employment has gone down," he said.

"And it's a very good example of people leaving B.C. o go to other jurisdictions to call that home, but wanting to work in B.C. because there's work here."

While ruling out any legislative measures to keep workers in British Columbia, he said the problems reinforces his government's commitment to reduce bureaucratic delays in approving exploration and development and to deliver on aggressive tax-cutting initiatives.

Call for infrastructure

Hank Swartout, president and chief executive officer of Precision Drilling Corp., Canada's largest driller with 37 percent of the fleet, urged the British Columbia government to accelerate its plans for building infrastructure to allow year-round work in the northeast.

He told the conference that until that happens, Precision will continue to pull rigs out of British Columbia and ship them to fields in Alberta during the summer.

An oil and gas initiative launched by the predecessor to Neufeld's government committed more than C$100 million to all-weather northeastern roads and an injection of a further C$113 million of oil and gas revenues over 10 years into northeastern communities.

The spending is all part of a program to double the province's oil and gas output by 2008 and attract C$25 billion of new investment over the next decade. ◆

FINANCE & ECONOMY

Agrium shows loss for quarter, year; Argentine devaluation pulls down results

Agrium Inc. showed a loss of $80 million for the fourth quarter as problems in Argentina complicated an already difficult year. Earnings were $22 million in the fourth quarter of 2000. Calgary-based Agrium owns the fertilizer plant in Nikiski.

For the year, the company lost $42 million, compared with a profit of $82 million for 2000. Though the company is based in Canada, it reports results in U.S. dollars.

Weather problems reduced sales last spring, and then high inventories depressed prices. The global economic slowdown reduced industrial demand later in the year.

Even so, "Agrium would have ended the year with a modest net income of $4 million had our results not been further decreased by the devaluation and forced conversion of U.S. dollar assets in Argentine," said John Van Brunt, Agrium's president and CEO. He said 2002 was looking up, however.

North American earnings before interest and taxes totaled $31 million for the year, down 81 percent from a year earlier.

Net sales for the fourth quarter were $469 million, down 3 percent from a year earlier.

Annual earnings up 10 percent

For the year, Agrium racked up sales of $2.06 billion, up 10 percent from the figure for 2000. That reflected the results from owning the Nikiski plant for the entire 2001 year.

Agrium bought the facility from Unocal at the end of September 2000.

—Allen Baker

FINANCE & ECONOMY

HOUSTON

Nabors to buy Enserco in $287 million deal

Nabors Industries Inc. and Enserco Energy Service Co said Feb. 26 that Nabors has agreed to buy Enserco for $287 million including debt assumption. Nabors said it undertook the transaction primarily to better serve its customers that are expanding oil and gas operations in Canada.

Nabors wants to expand in Canada

"Enserco's assets are relatively new, in excellent condition and well suited for the increasingly important role that Canada is playing in the North American natural gas supply picture," said Gene Isenberg, Nabors' chairman and CEO.

The transaction will increase Nabors' activity in Alaska as well, adding Enserco's Kuukpik/H&R Drilling joint venture, which is drilling for Unocal at Ninilchik.

The transaction will increase Nabors' activity in Alaska as well, adding Enserco's Kuukpik/H&R Drilling joint venture, which is drilling for Unocal at Ninilchik. At PNA press time, Nabors Alaska Drilling Inc. officials were unsure how or if the Ninilchik operation would be integrated into local operations.

H&R in Alaska is headed by Dale Larsen, former general manager of Pool Alaska Drilling. Pool Alaska was absorbed into Nabors' Alaska operations after being acquired by Nabors in the 1999 purchase of Pool Energy Services Co. of San Angelo, Texas.

Analysts generally positive

Canadian oil and gas stocks notched a record high close Feb. 27, partially because the Nabors/Enserco deal sparked investor's expectations of additional merger and acquisition activity in the market, analysts said.

Analysts following Nabors were generally positive on the deal. Morgan Stanley said the drilling assets were acquired at an attractive price and Goldman Sachs raised its price target for Nabors stock from $50 to $53, saying the deal should boost earnings in 2002 and 2003.

Standard & Poor's said Feb. 26 that the transaction would not affect Nabors' credit rating.

Nabors is offering C$15.50 per Enserco share in cash or exchangeable shares in a Nabors subsidiary, plus 6 percent interest from Feb. 26 to closing. The offer represents a premium of 5 percent above Enserco's Toronto Stock Exchange closing price of C$14.81 on Feb. 25.

Enserco is Canada's third-largest oil field service firm and will add 193 service rigs and 30 drilling rigs to Nabors' fleet of more than 500 land drilling and 740 land workover and well-servicing rigs worldwide, including 52 in Canada.

The deal has a C$17 million break fee if it falls through, and Nabors has the right to match any competing bid.

—Steve Sutherlin

■ FORT WORTH, TEXAS

XTO earnings dip 17 percent in quarter; profits for year up 116 percent

Decline small compared to other companies; XTO did well because of increased gas flow, higher than spot market prices because it hedged its gas production

By Allen Baker
PNA Contributing Writer

XTO Energy Inc. posted earnings of $41.2 million for the fourth quarter, down just 17 percent from the same period a year ago. Most of the industry showed much bigger declines, but XTO prospered due to 24 percent higher gas production and hedging much of its gas production so it received higher than spot market prices.

XTO, based in Fort Worth, is the former Cross Timbers. The company has two producing platforms in Cook Inlet purchased from Shell in 1998.

For the year, XTO had profits of $248.8 million, up 116 percent from the 2000 figure, with cash flow up 59 percent to $549.6 million.

Gas production up 24 percent

In the fourth quarter, XTO boosted gas production to a record 455 million cubic fee daily, 24 percent higher than the 366 million cubic feet a day in the same quarter in 2000 with drilling activity in East Texas and the Arkoma and San Juan basins. The company is projecting an average flow of 480 million cubic feet or more daily in the cur-

see XTO page 7

Judy Patrick

XTO Energy's Cook Inlet platform.

■ BARTLESVILLE, OKLA.

Phillips replaces 135 percent of production; Conoco boosts reserves

Phillips says its Lower 48 discoveries cost $5.08 per barrel, $5.15 in Alaska and $6.80 for non-U.S. reserves; pumped more oil in Alaska than added to its reserves

By Allen Baker
PNA Contributing Writer

Phillips Petroleum Co. replaced 135 percent of its 2001 oil and gas production with proved reserves of 433 million barrels of oil equivalent, the company announced.

Future partner Conoco did even better, but that was mostly due to the acquisition of Gulf Canada. Conoco's reserves rose by 1.2 billion equivalent barrels, 432 percent of what the company produced during the year.

Factoring out Gulf Canada and other purchases and sales, the replacement figure was a more modest 113 percent of 2001 production of 281 million BOE. Conoco's year-end proved reserves were

see PHILLIPS page 6

BP replaces 191% of production; Forest Oil 259%

Other companies also have announced major success in replacing reserves, with much of the industry in high gear after prices rose in 2000. Among them:

• BP replaced 191 percent of production, booking 2.2 billion barrels of oil equivalent through extensions, discoveries, revisions and improved recovery. It was the eighth straight year replacement exceeded production.

• ExxonMobil added 1.8 billion barrels of oil equivalent to its reserves, replacing 110 percent

see RESERVES page 6

Companies in the news

Companies which appear in the articles in this issue of Petroleum News • Alaska are listed below. The page number indicates where the story starts, not where it continues.

continued from page 5

PHILLIPS

3.58 billion barrels of oil equivalent, including Canadian syncrude. Of that, 85 percent was outside the United States.

New oil finding cost up in 2001

For Phillips, the new oil came with a finding and development cost of $5.97 per BOE in 2001. The company's three-year average cost is $3 per barrel, but that figure includes the acquisition of ARCO Alaska Inc.'s assets in 2000.

Phillips pumped more oil in Alaska than it added to its reserves. The company says it replaced 99 percent of its reserves in the United States, but 128 percent of production in the Lower 48.

New reserves in Alaska cost a bit more as well.

Alaska discoveries cost $5.15 per barrel

For the Lower 48, Phillips says its discoveries cost $5.08 per barrel, while the overall total for the United States, including Alaska, was slightly higher at $5.15. Non-U.S. reserves cost even more, however, at $6.80 per BOE.

Worldwide, Phillips increased proved reserves 2.3 percent to 5.3 billion barrels of oil equivalent, while producing 321 million BOE. With no more discoveries, the proved reserves would last 16 years.

Worldwide, Phillips increased proved reserves 2.3 percent to 5.3 billion barrels of oil equivalent, while producing 321 million BOE. With no more discoveries, the proved reserves would last 16 years.

Drilling success was up in 2001, Phillips reported.

"Overall, we completed 42 exploration and appraisal wells with a success rate of 62 percent, up from 45 percent in 2000 and 38 percent in 1999," said Dodd DeCamp, senior vice president of worldwide exploration.

This year, Phillips is concentrating its efforts in deepwater off Angola, the Caspian Sea, Alaska, and the Atlantic Margin of northwestern Europe, he said. ◆

continued from page 5

RESERVES

of production. The company has more than 13 years worth of reserves at current production rates, with 21.6 billion barrels of reserves.

• ChevronTexaco added 1.2 billion barrels to its reserves in 2001, or 120 percent of production. The additions came principally in the international arena.

• Anadarko replaced 221 percent of its production. Excluding sales and acquisitions, the figure was 173 percent. Proved reserves stood at 2.3 billion BOE at the end of the year, split equally between gas and liquids. Worldwide finding costs were $8.53 per barrel.

• Unocal replaced 222 percent of production, boosting its reserves 15 percent to 1.8 billion barrels of oil equivalent. Finding and development costs were $5.39 per barrel. Discoveries, extensions and improved recovery added 241 million barrels of reserves, more than the 2001 production of 193 million barrels.

• Petro-Canada pushed proved reserves up 2 percent to 821 million barrels of oil equivalent, replacing 103 percent of its natural gas production with exploration and development work at a cost of $1.52 (Canadian) of 94 cents U.S. per thousand cubic feet of gas equivalent.

• Forest Oil replaced 259 percent of production, ending the year with 828 billion cubic feet of natural gas reserves and 120 million barrels of liquids, all in North America.

—Allen Baker

OIL COMPANY EARNINGS

Fourth Quarter 2001

4Q 2001 profits, % change from 4Q 2000
4Q revenues, % change from 4Q 2000,
4Q daily production, % change from 4Q 2000

		profits	%	revenues	%	production	%
Alberta Energy	AOG	—					
Agrium	AGU	-$80	—	$2,063	+10	—	—
Anadarko	APC	-$188	—	$1,379	-41	529,000BOE	+9
BP	BP	$2,204	-46	__	__	2,017,000/8,764MMCF)	+4/+2
ChevronTexaco	CVX	-$2,522	—	$21,460	-33	2,014,000BBL/4,371MMCF	0/-1
Conoco	COC	$127	-77	$8,491	-18	891,000BOE	+32
Evergreen	EVG	—					
ExxonMobil	EOM	$2,680	-49	$47,300	-26	2,527,000BBL/11,373MMCF	-3/+1
Forest	FST	-$29.7	__	$174	-44	297MMCF/30,600	-5/0
Marathon	MRO	-$1,074	—	$6,846	-15	192,300BBL	-1
Murphy	MUR	$28.8	-69	$849	-33	70,687BBL	+7
Petro-Canada	PCZ	C$71	-75	C$1,772	-39	205,000BOE	-3
Phillips	P	$162	-78	$10,000	+59	836,000BOE	0
Semco	SEN	-$5.4	__	$132.5	__	__	__
Tesoro	TSO	$4.0	-84	$1,279	-11	—	—
Unocal	UCL	-$29	—	$1,263	-55	497,000BOE	+5
Williams	WMB	—					
XTO	XTO	$41.2	-17	$183.3	-11	455MMCF/13,761BBL	+24/+7

Dollar figures in millions

BOE: barrels of oil equivalent
BBL: barrels of crude oil and condensate
MMCF: billions of cubic feet of natural gas

The fourth quarter information about the companies in the chart above is either included in news briefs and stories in this section of PNA or was reported in the February issues of PNA.

■ BARTLESVILLE

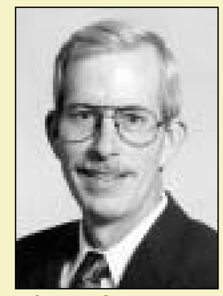
ConocoPhillips senior management positions announced

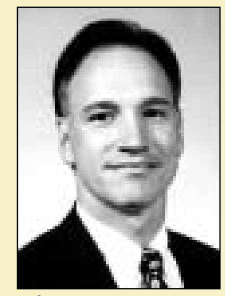
By Petroleum News • Alaska


Jim Mulva


Robert McKee III


Jim Nokes


John Carrig


John Lowe


Rick Harrington

Phillips Petroleum Co. and Conoco have named the initial members of the ConocoPhillips global management team that will take office after the completion of their proposed merger of equals announced in November.

As previously announced, the companies said Feb. 26, Jim Mulva, currently chairman and chief executive officer of Phillips, will become president and CEO of ConocoPhillips.

The following officers of ConocoPhillips will report directly to Mulva.

Robert McKee III, 55, executive vice president exploration and production for Conoco since 1996, will hold the same position with ConocoPhillips. McKee joined Conoco in 1967 and has held senior positions in the United States and Europe, including vice president, refining and marketing, North America; senior vice president, administration; and executive vice president, corporate strategy and development.

Jim Nokes, 55, executive vice president, refining, marketing, supply and transportation for Conoco since 1999, will hold the same position with ConocoPhillips. Nokes joined Conoco in 1970, was named vice president of Conoco's North American refining and marketing operations in 1994 and president of North American refining and marketing in 1998.

John Carrig, 50, senior vice president and chief financial officer for Phillips since 2001, will become executive vice president, finance, and chief financial officer for ConocoPhillips. Carrig joined Phillips in London in 1978 as a tax attorney, was elected treasurer in 1995 and vice president and treasurer in 1996. In 2000, he was elected senior vice president and treasurer.

John Lowe, 43, senior vice president, corporate strategy and development for Phillips since 2001, will become executive vice president, planning and strategic transactions for ConocoPhillips. Lowe joined Phillips in 1981, and held a number of managerial positions in finance and controllers. He was elected vice president of planning and strategic transactions in 1999 and senior vice president of planning and strategic transactions in 2000.

Rick Harrington, 57, will become senior vice president, legal, and general counsel for Conoco since 1998, will hold the same position with ConocoPhillips. Harrington joined DuPont in 1979 as a senior attorney and subsequently served as vice president and general counsel for Consolidation Coal Co., at that time a DuPont subsidiary. He was named vice president and general counsel for Conoco in 1994. ◆

continued from page 5

XTO

rent year. Oil production was 13,761 daily barrels, up 7 percent from a year earlier.

XTO also pumped 4,567 barrels of natural gas liquids a day, roughly the same as the figure for the 2000 quarter.

Revenues up 40 percent in 2001

Like the rest of the industry, XTO got lower prices for its products, with gas bringing an average of $3.67 per thousand cubic feet, down 20 percent from $4.56 a year earlier, but hedging activities helped. The company has a guaranteed price of $3.88 per thousand cubic feet for 80 percent of its expected gas production in 2002.

Oil averaged $17.97 per barrel in the fourth quarter, down 39 percent from $29.63. Gas liquids showed the biggest drop, to $9.85 per barrel from $22.82.

Total revenues for the quarter were down 11 percent to $183.3 million. For the year, revenues rose 40 percent to $838.7 million. ◆

■ CANADA

EnCana eyes British Columbia offshore as possible new venture

Driving forces behind new company prepared to unload up to C$1 billion in assets, but Alberta Energy's Gwyn Morgan wants EnCana to take advantage of buyers' market

By Gary Park
PNA Canadian Correspondent

British Columbia's offshore beckons as a new exploration target for EnCana Corp., the company to be created from the merger of Alberta Energy Co. Ltd. and PanCanadian Energy Corp.

In presenting an EnCana organizational structure to investors Feb. 21, the West Coast was cited as one of a number of new ventures projects.

While neither AEC nor PanCanadian holds any acreage in the region, they have registered interest just as the British Columbia and Canadian governments are giving their most serious consideration in 30 years to removing exploration bans on 54 million acres.

In a series of roadshow presentations and conference calls, AEC and PanCanadian executives talked more about growth than shrinkage beyond the April 5 target they have set for completion of the merger.

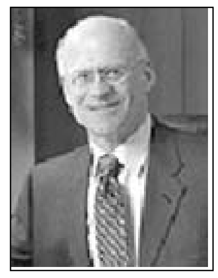
But, at the same time, the long-time leaseholders — Shell Canada Ltd., Petro-Canada and Chevron Canada Ltd. — are maintaining a strict arm's length view of the offshore, suggesting that even an end to the government moratoriums would be unlikely to spark their interest.

Gas a target

In a series of roadshow presentations and conference calls, AEC and PanCanadian executives talked more about growth than shrinkage beyond the April 5 target they have set for completion of the merger.

But they did say EnCana will be ready at the outset to unload C$500 million to C$1 billion of midstream processing and pipeline assets, but will just as quickly be hunting for upstream gas buys, especially in the U.S. Rocky Mountains, Alberta and British Columbia.

AEC also announced on Feb. 22 it has hired Waterous & Co. as its exclusive agent to seek proposals for the sale of certain oil and gas producing assets in Alberta and Saskatchewan. The properties produced 9,500 barrels of oil equivalent per day in 2001, generating net operating income of C$69 million.



Gwyn Morgan, CEO of EnCana Corp., the company to be created from the merger of Alberta Energy and PanCanadian Energy

"This is a time of many sellers and not many buyers for (upstream) assets that are on the market ... and we are sure in a position to take advantage of that opportunity," said AEC chief executive officer Gwyn Morgan.

Cash generation

In his upbeat message to investors and employees, he said EnCana will "generate a tremendous amount of cash. We're not only going to be able to grow this business with our cash flow, we're going to have extra money for acquisitions."

In releasing fourth-quarter 2001 results, AEC had an 83 percent drop in profit from a year earlier to C$80 million and PanCanadian was off 74 percent at C$91 million — not out of line with their North American peers and an indication, Morgan, said of how EnCana will perform.

"That's going to be the toughest quarter that the industry is going to go through for a long time," he said.

For the full year, AEC has profits of C$824 million, second only to its C$922 million in 2000, PanCanadian notched a record C$1.3 billion, up C$300 million from 2000.

Weak demand cited

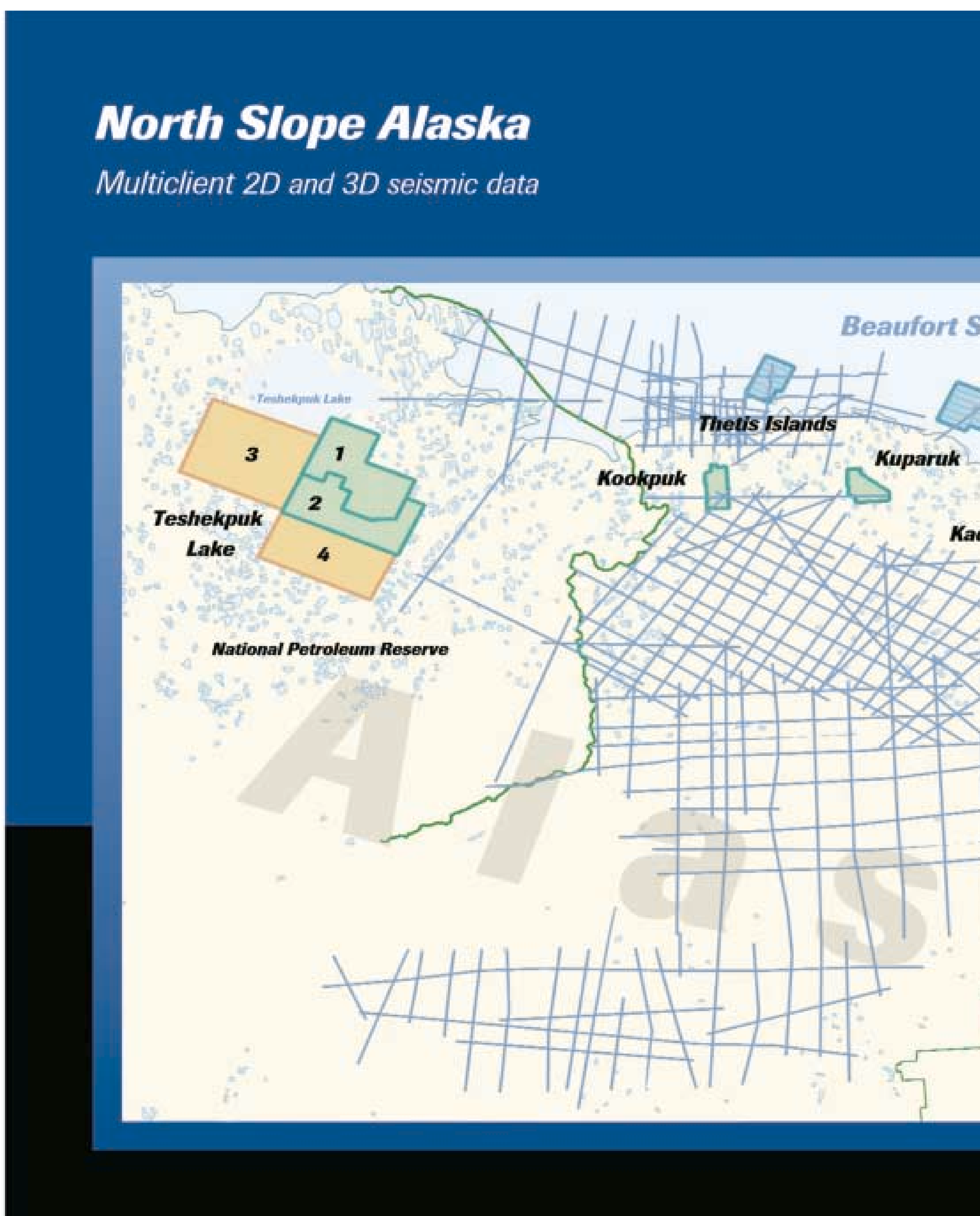
PanCanadian said it believes weak demand, excess OPEC capacity and rising non-OPEC production will keep benchmark oil prices at $20 a barrel this year, while natural gas prices will remain soft due to sluggish industrial demand and high inventories.

That outlook for gas in particular has prompted Lehman Brothers analyst Thomas Driscoll to question EnCana's ability to meet its targeted capital spending of C$3.8 billion for 2002 through internally-generated funds.

EnCana will "generate a tremendous amount of cash. We're not only going to be able to grow this business with our cash flow, we're going to have extra money for acquisitions." —Gwyn Morgan, Alberta Energy Co. Ltd.

Morgan said continuing low gas prices will only delay capital spending in the second half of 2002, but will "not affect our ability to come back very strongly ... once we get the right kind of conditions. (EnCana) has a lot of flexibility in term of ability to adapt."

He is optimistic that EnCana will maintain production at its forecast level for this year of 721,000 barrels of oil equivalent per day, largely based on relatively small incremental capital requirements per unit of growth. ◆



■ NIKISKI

GTL experiment may hold key; tests could pioneer North Slope plant

Overall conversion of energy in Nikiski plant's process could be as high as 75 percent; a major improvement over the 60 to 66 percent conversion rate achieved in past, says BP's Steve Fortune

By Allen Baker
PNA Contributing Writer

A pilot plant in Nikiski to convert natural gas to liquid fuel could provide a major step toward making the long-sought technology commercial. If the predictions of BP's scientists pan out, BP could spend billions of dollars on a big North Slope plant that would produce 30,000 to 100,000 barrels of synthetic crude, or more, every day.

Forrest Crane

Steve Fortune

The overall conversion of energy in BP's process could be as high as 75 percent, said Steve Fortune, engineering manager for the facility. That would be a major improvement over the 60 to 66 percent conversion rate that engineers have used as a rule of thumb in the past.

BP Exploration (Alaska) Inc.

BP's GTL plant under construction in Nikiski. Photo taken Feb. 12.

The $86 million testing facility in Nikiski, expected to produce 300 barrels a day, is 93 percent complete and should be working sometime in April, Fortune told the PacCom conference Feb. 20.

"One of the key things we have to do is prove the technology works," he told PNA in an interview. "Then we'll do some optimization work."

Design breakthrough?

Much of the improvement in efficiency comes from a compact reformer that BP has designed for the first stage of the three-stage conversion process, Fortune said. The reformer, which converts methane to carbon monoxide and hydrogen, is one-fortieth the size of a conventional unit, he said.

"With the much more compact design, you can be more thermally efficient," as well as cutting production and transportation costs, Fortune said. The reformer represents about 60 percent of the overall cost of a GTL plant.

Recycled heat

BP's process also recycles heat and water generated in the various steps.

"Where you're going to get efficiency gains is how you integrate different parts of the plant," he said. "At the end of the day, there's nothing magical about it."

After the natural gas is converted to carbon monoxide and hydrogen in the reformer, it's run through a process that makes long-chain paraffins from the "syngas." Those paraffins are then cracked in a conventional refinery process to make liquid fuels.

Diverting streams from various stages of the process could allow production of methanol, olefins, polyethylene and ethers as well.

If waste heat is used to generate electricity or steam for other purposes, the thermal efficiency of the process — how much of the energy is left in the final product — could go a bit higher, he said, but it'll be tough to reach the 88 percent thermal efficiency of the liquefaction process.

GTL versus gas line

For North Slope purposes, though, GTL has a competitive edge over other methods of moving natural gas to market because there's already a system in place that can transport liquids though the pipeline and tankers.

The production from a GTL plant could move down the pipeline, probably in separate batches since it would likely command a significant premium.

The product is free of sulfur and some other impurities, giving it an advantage over regular crude.

Design is ready

BP has already done much of the design work for a commercial-size facility, Fortune said, and could be ready to go to work on one in as little as two years.

The 30,000-daily-barrel size "is probably the smallest we'd want to build," he said. "We believe we'd have no problem scaling up to that size," which is similar to the capacity of a project being built in Nigeria by Sasol, the South African company that was a pioneer in the process, and ChevronTexaco.

"We've done a number of engineering studies for a 30,000 barrel-per-day plant," he said. "They give us a very good idea of what tests we need to do" at the Nikiski plant, expected to run for five years or so.

At Nikiski, BP can "plug in" different components to see how they operate at that scale. The facility is adjacent to three other Nikiski plants, but mostly shielded from view by a curtain of trees.

Part of the design challenge for a commercial operation involves looking at transportation issues, he said, since the modules would have to be shipped to the North Slope and assembled there.

The same transport issue would likely confront other uses of the technology, which

see GTL page 11

VALDEZ

Terminal closed to visitors this summer

Alyeska Pipeline Service Co. says the public will not be allowed to tour its terminal this summer.

"We explored alternatives to continue public tours under heightened security screening, but couldn't satisfy ourselves," Richard Ranger, with Alyeska's Valdez business unit, told The Valdez Vanguard. "We acknowledge the significance of the fact and are in the process of looking at alternatives to meet curiosity and interest."

Alyeska also will close to the Alyeska Marine Terminal to family tours and has tightened restrictions on all visitors to the terminal, Ranger said.

Security has increased in and around all aspects of the pipeline since the Sept. 11 terrorist attacks. Public access to the North Slope has been restricted and public access to pump station 7 in Delta Junction is closed. Ranger said the decision to restrict access to the terminal is consistent among other energy providing facilities around the country. The closure will likely hit Valdez Tours the hardest. The tour company, which shuttles cruise ship passengers from the dock to town, also contracts with the terminal and shuttles in visitors on a daily basis from May through September. Last season, 20,000 people visited the terminal through public tours.

—The Associated Press

■ VALDEZ

Alyeska continues maintenance and upgrade program

Work this year will roughly equal that of last year — shift towards larger number of smaller projects in Valdez as loading berth projects conclude

By Steve Sutherlin
PNA Managing Editor

Alyeska Pipeline Service Co. is pursuing a program of refurbishment and upgrades "to continue to operate its assets in a manner that assures protection of equipment and people," said Richard Ranger, Alyeska's Valdez business unit adviser. Expenditures system wide will be roughly equivalent to the amounts spent each year for the last two years, he said, but he declined to say what the company's total maintenance and upgrade spending would be for the year.

Forrest Crane

Richard Ranger, Alyeska's Valdez business unit adviser

In Valdez there's a shift toward a greater number of smaller dollar projects, Ranger told PNA Feb. 20. More than anything else, he said, the shift has to do with the work progress on refurbishing of the company's two principal loading berths, berths four and five.

The company will continue with the cycle of tank maintenance, cleaning and corrosion inspection and repair, Ranger said. A tank project can cost several million dollars, and can be more costly if there is an accumulation of oil-saturated sediments, such as were encountered in a primary receiving tank the company cleaned last year.

"As North Slope production advances to farther and farther reaches of the fields, we have more and more impurities in the oil that we receive," he said.

Alyeska also will continue its project to reline its fire system, a network of seawater distribution mains that supplies hydrants and fire monitors throughout the terminal, Ranger said. The company lined more than one-third of the system last year.

The company is in a major maintenance cycle for the ballast water treatment system, including the network of pipelines that move ballast water, and those that carry oil recovered from ballast water back to the storage tanks.

There is some additional work planned for the incinerators, powerhouse, and various systems and controls.

"We have continued relationships with the companies that have been supporting our project effort both in the design phase and also in the conduct of the labor, and we've added a couple as well," he said. "It's going to be a busy year. At times last year we had as many as twelve or thirteen hundred people passing through our gate on a given day."

"It's going to be a busy year. At times last year we had as many as twelve or thirteen hundred people passing through our gate on a given day." —Richard Ranger, Valdez business unit adviser, Alyeska Pipeline Service Co.

For its operations in Valdez the company has between 700 and 800 workers, including spill response workers, he said.

Streamlining for efficiency

The company is striving to make operations more efficient, Ranger said. Now oil vapors that are captured as a safety precaution are burned to supplement the power needs of the operation.

Alyeska bought five new escort tugs and has made an investment in telecom upgrades. A new 48,000 square foot office building is nearing completion.

Streamlining operations for the company is an ongoing challenge. When changes are made the company must update 400 manuals.

"The solution can sometimes be more complicated than the problem it was meant to solve," Ranger said.

The need to upgrade and renovate physical assets is just a part of the challenge the company faces as it prepares for the next 25 years of pipeline operation. As Alyeska looks to the future, it must address the fact that its workforce is aging, and the company is making it a priority to transfer the company's knowledge and experience to the next generation of workers, Ranger said.

Ranger said it's been a challenging winter from an oil movement standpoint because of rough seas. Alyeska has had to manage around delays, primarily of tankers coming north, he said.

Snow has also been a challenge this winter. Ranger said the terminal experienced 81 inches of snow on the week of Feb. 11.

Strong safety record

In addition to operating the marine terminal, Alyeska's Valdez operations include tanker escort duties and spill response. The company's Valdez functions fall under the scrutiny of the Joint Pipeline Office and the Prince William Sound Regional Citizen's Advisory Council.

Alyeska actually funds the oversight it receives. The RCAC receives $2.5 mil-

see ALYESKA page 12

■ JUNEAU

Committee passes bill to eliminate ACMP project petition right

Bill does not address other permitting issues; AOGA's Brady says industry has no way of knowing what will be required to get a permit for an oil and gas project — or how long it will take

By Kristen Nelson
PNA Editor-in-Chief

The House Special Committee on Oil and Gas heard testimony on House Bill 439 Feb. 21 and Feb. 26 from both Phillips Alaska Inc. — which had permits for five project delayed by petitions to the Coastal Policy Council — and the attorney representing the North Slope resident who filed those positions.

Both testified in favor of the bill, which eliminates the right to petition the Coastal Policy Council over individual consistency determinations. (See story in Feb. 24 issue of PNA.)

Not surprisingly, their reasons for supporting the bill were different.

But the individual consistency determination petition is not the only permitting issue of concern to industry. Judy Brady, executive director of the Alaska Oil and Gas Association, said AOGA supports HB 439, and is also working on a list of proposals addressing permitting issues. The problem, Brady said, is that under the state's permitting system industry has no way of knowing in advance what will be required to get a permit for an oil and gas project — or how long it will take to get that permit.

House Oil and Gas passed the bill out of committee Feb. 26. It now goes to House Resources.

Nancy Wainwright, an active Alaska environmentalist and the Anchorage attorney who represented the petitioner, told the committee that there is more than enough frustration with this process to go around. The Alaska Coastal Management Program process doesn't work for the public and needs to be fixed, she said.

Wainwright blamed the Division of Governmental Coordination, which manages the Alaska Coastal Management Program. DGC's regulations are a failure, she said: DGC and its regulations are the problem.

As for the five petitions filed this year, Wainwright denied that those petitions delayed Phillips' projects: the delays, she said, were caused by DGC.

Her client is not opposed to development, she said, but concerned about private property. The family owns property listed on the National Register of Historic Places, she said, and has family grave sites in the area. They want compensation for prior damage and guarantees of no further damage, she said, and they want payment for access to their land.

Multiple problems

Judy Brady of AOGA said the organization supports HB 439. The legislation is "very clear" and "very focused on the petition process itself," she said.

But the petition process is only one problem with permitting, she said, and AOGA is "going to be concentrating over the next few months in putting together a package of things

see BILL page 15

continued from page 9

GTL

at this point is only competitive for "stranded" natural gas that can't easily be transported to market.

BP's plant could be expanded by building several 30,000-barrel "trains," but there would be little additional economy of scale other than common support facilities, Fortune said.

The Nikiski plant will be used to test some new catalysts that BP has developed, particularly for the reformer stage, Fortune said. Making those catalysts in commercial quantities can be different from cooking small batches in the lab, he said.

Bringing down the cost of the facility has been the big challenge for the GTL technology, which has never really been commercially successful.

It was developed originally in Germany in the 1920s and was used to provide fuel for Hitler's army.

The process was taken off the shelf again in the 1950s when South Africa built a plant to produce fuels after that country faced a world boycott over its racial policies.

Shell has had a facility operating in Malaysia since 1993, now producing specialty chemicals and waxes.

The industry standard for GTL facilities is about $25,000 per daily barrel, Fortune said, and that's too high to be workable. With BP's compact reformer, the company expects to get down to around $20,000 per daily barrel.

That's not far from the $17,000 per daily barrel that would make the process competitive with some other uses of natural gas, such as LNG, he said. At $11,000 or $12,000, the process could compete with a new-build crude refinery, producing fuels and chemical feedstocks.

A study by the federal Department of Energy in the mid-1990s indicated that crude prices of about $30 a barrel would be needed to make a North Slope GTL plant commercially feasible with the technology available at that time.

With capital costs of about $20,000 per daily barrel, that component alone would amount to roughly $5 per barrel, about the same as the $4 to $5 a barrel in estimated operating costs. That leaves little room for paying for the gas, which can run up to $10 per barrel, or for transportation. The Sasol-ChevronTexaco plant in Nigeria will use gas that otherwise would simply be flared.

But the industry has been experimenting with the technology in recent years, trying various catalysts and altering other components to cut the overall costs.

ExxonMobil has proposed a 100,000-barrel-a-day plant in Qatar, and Sasol a 30,000-barrel project.

Shell and new player Syntroleum, in Tulsa, have also done substantial research.

BP has been involved in GTL technology since the early to mid-80s and has spent about $300 million on it, Fortune said.

BP even inherited a pilot plant at an ARCO refinery in Washington state when that company was acquired, but the project used licensed Syntroleum technology and BP didn't get access to that, Fortune said.

BP's work was concentrated at laboratories near London. ◆

continued from page 1
EXPLORATION

trillion cubic feet (discovered) and 40.7 trillion (undiscovered); Mackenzie Delta 4.96 trillion (discovered) and 12.6 trillion (undiscovered); and Liard 1.28 trillion (discovered) and 4.07 trillion (undiscovered). The rest are concentrated in the Mackenzie Plain, Colville Hills, Peel Basin and Eagle Plains areas of the Northwest Territories and Yukon.

Typical of the regions that Reinson said would benefit from more intensive exploration is the Peel Basin, just north of the Mackenzie Plain and sitting astride the Northwest Territories-Yukon border, where 72 wells have been drilled with no discoveries. The estimated potential is placed at 4.4 trillion cubic feet of gas and almost 50 million barrels of oil.

Eagle Plain, west of Peel in the Yukon, has reported discoveries of 11.7 million barrels of oil and 83.7 billion cubic feet of gas from 33 wells. In the undiscovered category, the potential is estimated at another 28.2 million barrels of oil and 1 trillion cubic feet of gas.

But Reinson gave his highest rating to Mackenzie Delta/Beaufort Sea, where almost two-thirds of the gas resource is undiscovered, although 53 discoveries have yielded 1 billion barrels of oil and 9 trillion cubic feet of gas.

Successful Hunt bid

One sign of growing Arctic interest was the successful C$1.16 million bid by Hunt Oil Co. of Canada Inc. for 100,000 acres in Peel Plateau, which a resource assessment of the area by the National Energy Board said holds a potential 2.26 trillion cubic feet of gas and 21.3 million barrels of oil. The Yukon's two previous calls for bids yielded successful bids from only Anderson Exploration Ltd., which was taken over last fall by Devon Energy Corp. Hunt senior geologist Chris Wickens said his company, taking its first foothold in the area, is confident it has identified some "significant" gas prospects, but will not decide on any drilling until it has reprocessed some seismic data and awaits developments on the Arctic pipeline front. He said Hunt, from its midpoint between the two pipeline routes, could work with either an Alaska Highway or Mackenzie Valley pipeline.

For now, the company is giving priority to building a relationship with the Tetlit Gwich'in First Nation and the Nacho Nyak Dun First Nation. Wickens said Hunt will explain its plans and timing, hear the concerns of the aboriginals and develop access and benefits agreements.

Meanwhile, the Yukon government is anxious to cash in on the prospects by pushing ahead with its next oil and gas rights disposition slated for this spring.

—Gary Park

■ WASHINGTON, D.C.

Reduction of ANWR exploration acreage unlikely

Anonymous remark puffs up into national news story, Interior says no such proposal forthcoming at this time

By Steve Sutherlin
PNA Managing Editor

A Feb. 26 New York Times Story stirred up discussion on both sides of the issue of oil exploration in the Arctic National Wildlife Refuge by suggesting an impending proposal to cut by two-thirds the proposed drilling acreage. The story, with the headline "Bush May Scale Back Alaska Drilling Plan," said the Interior Department is considering narrowing the acreage to get the drilling plan through the Senate, but the department told PNA Feb. 27 no such proposal exists.

"The option is one of several options that are out there but there is nothing on the table right now," said Eric Ruff, director of the department's office of communications. "This has not been proposed."

Ruff said the department strongly supports the adoption of the House energy bill approved last year, which contains a provision to open ANWR to exploration.

Katherine Q. Seelye, the New York Times reporter that wrote the story told PNA that she was told by a source in the department who spoke on the condition of anonymity that an acreage reduction was under consideration, but she said the story made it clear the idea had not been proposed to the White House.

"It's in the talking stages at the Department of the Interior," Seelye said.

While the story did say officials cautioned that the new proposal was one of two or three under consideration and had not been adopted by the White House, a later paragraph in the story suggested otherwise.

"Officials said the administration's goal with the new proposal was to win approval of a package that would allow some drilling, giving proponents an edge when the Senate meets with the House on final legislation to send to the president," the story said.

The story, which was picked up by newspapers nationwide, said, "Limiting the scope of oil exploration is a direct pitch to win over six moderate Republicans who have said they are likely to oppose drilling in the refuge…"

However a follow-up piece by the Associated Press reported little enthusiasm for the idea on the part of drilling opponents, who said any drilling in ANWR is too much. Drilling advocates said cutting the acreage would unacceptably limit the nation's energy options.

Energy bill discussed in Senate

A spokesman in the Washington office of pro-ANWR development group Arctic Power told PNA discussion of the energy bill, which began Feb. 27, is likely to occupy the Senate for two weeks or more because of a wealth of contentious issues it contains. He said nuclear power, ethanol, electricity policy, pipeline safety, fuel economy standards, bio-waste, hybrid vehicles and other items would be a challenge for the senators to work through. ◆

continued from page 10
ALYESKA

lion each year from Alyeska, while the JPO gets $5.5 million to offset the cost of pipeline regulation.

The terminal and its operations are continuously under scrutiny by the media as well, said Ranger.

The company is proud of the safety record it has achieved. Even with its high levels of activity last year, the company's record able incident rate was only one per 200,000 man-hours worked, Ranger said.

"In 2001 we reinvigorated a nine year old procedure where every employee is empowered to stop work if he or she observes an unsafe condition," he said. ◆

continued from page 1

PHILLIPS

"We've been rigorous about cost for 10 years and that's not going to change," he said.

Alpine facility expansion

The biggest near-term project Phillips is working on is Alpine facility expansion, Fuhr said.

"We're very fortunate. We've actually located this field where the reservoir is

Phillips is currently producing about 7,000 barrels a day out of West Sak and expects "to be producing about 50,000 barrels per day from West Sak by the end of the decade." —Kris Fuhr, Phillips Alaska Inc.

exceeding our expectations. It will provide a key stepping stone as we look to monetize other opportunities both around Alpine and even farther west," he said.

Alpine was designed to be an 80,000 barrel a day plant.

"We started bringing wells on, they exceeded our expectations," Fuhr said, and early de-bottlenecking at the plant has brought it up to 95,000 barrel a day capacity.

Third quarter this year Phillips Alaska expects to ask for board of director approval for a $100 million project to do additional de-bottlenecking, Fuhr said, to take the plant up to some 130,000 barrels a day. That work would be done in 2003 and 2004.

Fuhr said core Alpine production "would keep that facility full even at those extended rates for a couple of years. And then it does help us accelerate the opportunity around some additional satellites and resources in the near area."

Kuparuk projects

There are probably over a billion barrels of additional reserves remaining to be produced at Kuparuk, Fuhr said, but there is a "tremendous amount of work to do in the old core, anchor fields.

"We've gotten all the easy barrels. We've gotten all the cheap barrels.

To produce additional barrels at Kuparuk, Phillips is extending enhanced oil recovery—natural gas liquids from Prudhoe blended with Kuparuk residue gas and injected as miscible flood "to sweep through the reservoir and mobilize oil that didn't move when we water flooded it.

"We've been very aggressive; and we're doing that again this year; about $15-$20 million spend on a yearly basis to expand this to new pads," Fuhr said.

Gas handling capacity is also being expanded at Kuparuk, he said, and that project, which will increase gas throughput capability, is about midway to completion.

The other Kuparuk project this year is the 3S pad, which will allow production from the Palm discovery. This satellite follows Tabasco, Tarn and Meltwater development and "helps flatten decline" in Kuparuk production, Fuhr said, and keep Kuparuk lifting costs competitive.

Monetizing West Sak

The largest unmonetized oil reserve on the North Slope is probably West Sak, Fuhr said. It's been well known for more than 25 years "and we've essentially been working this problem now for 20-some years," he said.

Multi-lateral wells, with "two or three penetrations through the reservoir horizontally from one well bore… are helping to make these wells produce at competitive rates," Fuhr said, and if this year's drilling program is successful, the company hopes to take a significant West Sak development to its board of directors at the end of the year.

The company has done a fair amount of West Sak work in the pad 1C and pad 1D areas at Kuparuk, he said, and sees opportunity at the 1J pad.

Phillips is currently producing about 7,000 barrels a day out of West Sak, Fuhr said, and expects "to be producing about 50,000 barrels per day from West Sak by the end of the decade."

Fifty wells possible

In the last couple of years, Fuhr told PNA, West Sak development has been at Kuparuk drill sites 1C and 1D, with 10 to 20 well developments "trying to prove up technology and cost" and looking at well productivity "so you can get a complete economic picture."

The next major development step — if the numbers prove up — will be a 50-well project at pad 1J. Fuhr said 1J is an existing Kuparuk pad and there is room on the gravel for 50 wells.

"From a facility cost perspective, it's not that expensive a deal — the well cost is a big deal," he said. If the production is there, he said, then you have to look at Kuparuk infrastructure. Do you need more pumps to move water? Do you need more power?

"But you need to bring rate on before you start investing in that… So it's a challenge," he said. ◆

Westward expansion proves challenging

There are costs and challenges associated with expanding westward from existing North Slope oil and gas development, says Kris Fuhr, manager of Phillips Alaska Inc.'s project group.

There are "some significant technical challenges… to figure out ways to address all the environmental concerns including minimize footprints, including minimize impact to our neighbors out there" because development is now "in the neighborhood of Native surface owners," he said Feb. 20 at the Pacific Rim Construction, Oil and Mining Expo. And satellite operations away from infrastructure, "are not cheap developments." Taking western North Slope discoveries to commercial projects presents challenges, "and we saw this at Alpine, where you don't have roads," Fuhr said.

Alpine development "validated that … there are some costs associated with not having the logistics and the infrastructure that Prudhoe or Kuparuk does — and we're finding out now what those real costs are."

Even with Kuparuk satellites "the challenge is to try to develop these small satellite resources 15-20 miles away from the anchor fields," he said.

"There are some costs associated with not having the logistics and the infrastructure that Prudhoe or Kuparuk does and we're finding out now what those real costs are. And we will apply that on a going-forward basis to help us decision or make the right decisions commercially," Fuhr said.

Part of that cost is the addition of ice roads to project costs and part of it is the planning. If you want to work around a pad outside of the winter season, he said, "you need to have the foresight to have that material on the pad before your ice road melted" or else you're going to have to fly material in, "and depending on how big the materials is, some of these flights you're looking at $200,000-$300,000."

—Kristen Nelson

continued from page 1

NPR-A

1W, Umiat Meridian. Hunter is the farthest east of Phillips' NPR-A prospects and is due west of Anadarko Petroleum Corp.'s Altamura winter exploration prospect.

NPR-A work will also include two appraisal wells and a test well, Patience said.

Other Phillips drilling permits for NPR-A issued recently include: Mitre No. 1, permitted Feb. 19, section 2 township 1N range 2E UM; Lookout No. 2, permitted Feb. 22 in section 25 township 11N range 2E UM.

Lookout No. 1 was one of five discovery wells announced by Phillips and partner Anadarko in May. The companies said five wells and a sidetrack, all targeting the Alpine producing horizon, encountered oil or gas and condensate.

Phillips has already plugged and abandoned one Cirque exploration well from the Tarn pad on the western edge of the Kuparuk River unit, and has permitted a second Cirque well.

—Kristen Nelson

continued from page 1

AEC

McCovey, an offshore prospect that "we believe is potentially a legacy quality asset, that means it could be a cornerstone, if it was successful, of our development of oil and gas in Alaska," James said. AEC has a one-third interest in McCovey, scheduled to be drilled in the fourth quarter this year.

At the same time, March of 2000, AEC acquired a 20 percent interest in the Grizzly prospect, an interest that was increased to 30 percent in December.

James said AEC generally looks to have an interest of at least a third in prospects.

In July of 2000, AEC "engineered a swap with Anadarko whereby we gave up half of our interest in two large blocks in the Mackenzie Delta for one-third interest in their Foothills' lands with the ASRC. This netted AEC approximately 1 million net acres south of the Umiat baseline," James said.

At about the same time, AEC, Phillips and Chevron U.S.A. Inc. announced a joint venture at McCovey and Grizzly Gomo "whereby AEC would earn a 32.5 percent interest in roughly 70,000 acres by shooting a 30D in the first quarter of last year."

Then in November, AEC picked up additional lands in the Canning area at the state lease sale.

"And we hope that this just as Grizzly and McCovey form part of this year's drilling program, Canning will form part of next year's program. At the same land sale with Anadarko our partner we picked up lands on a Foothills project that we call Kavik-Kemik or K-squared and we shot a 3D seismic program over this, this time last

see AEC page 15

ADVERTISER INDEX

Companies involved in Alaska's oil and gas industry

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

PETROLEUM NEWS ALASKA

Business Spotlight

Forrest Crane

Jack Potter, Training Coordinator

Nabors Alaska Drilling Inc.

Nabors Alaska Drilling Inc. is involved in drilling and oil exploration on the North Slope, Cook Inlet and the Kenai Peninsula. Nabors, which has one of the best drilling safety records in the industry, is currently conducting annual safety refresher courses for all personnel.

Jack Potter, Nabors' training coordinator, is one of the people who make sure the company's policies and procedures reflect its commitment to a safe work environment.

Potter and his wife, Terri, an Alaska Airlines customer service agent, live in Anchorage and have four children: Lucas, who graduates from the University of Alaska Southeast in the spring with a degree in environmental science; Shanna, who works in Anchorage's restaurant industry; Garrett, 13, who plays competition soccer; and Brea, 10, a student at Lake Hood Elementary School.

Forrest Crane

Larry Watt, Area Manager-Alaska

PGS Onshore

PGS Onshore does geophysical surveys to prove up acreage for oil and gas drilling. The company currently has two crews working on the North Slope for Anadarko Petroleum Corp. One crew is shooting 3-D seismic; the other 2-D seismic.

Watt and his wife, Marion, have three grown daughters living in Denver, Colo. Watt is the proud grandfather of six-year-old Montana (Tanner) Lawrence Richardson and five-month-old Spencer Logan Hill. Watts enjoys golfing and fishing. His favorite fishing hole is at Lake Creek off the Big-Su River.

continued from page 13

AEC

year."

At the Foothills areawide sale in May, AEC and Anadarko "picked up five blocks, two of which we're currently shooting a large 3D over."

The last transaction was in December, James said, when AEC took a 12 percent interest from Phillips in Heavenly project — the third well in which AEC will participate this year.

AEC came to Alaska, James said, because fields like Prudhoe Bay and Kuparuk make the North Slope a giant petroleum province and the company "felt that the opportunity existed for us to get involved in some significant world-class opportunities."

McCovey is the prospect AEC finds most intriguing, James said. Phillips was the operator and drilling was planned from an ice island in early 2001, but Phillips "was unable to obtain all of their permits in the required timeframe" and the decision was made to delay the project "and look at alternatives for drilling it in 2002."

AEC took over as operator of McCovey at the end of October and expects to receive permits in April to drill the prospect from the SDC, a bottom-founded Arctic drilling platform. The SDC would be towed to the McCovey drilling location in August, James said, and the well would be spud by mid-November, "three and a half months prior to when it would have spud on the ice island." Drilling and testing the initial well, and any delineation drilling and testing, would be done by the end of February and the operation would be suspended or abandoned in early March, "a full two and a half months before we would have done so under the ice island" plan, James said.

James said AEC has been working on the permitting process with state agencies, the U.S. Minerals Management Service, the North Slope Borough and Natives in the villages that may be affected by drilling of an offshore well.

He said AEC believes all parties are in agreement on the plan the company has proposed, "and we're hopeful that we will receive our permits in April."

Alaska's gas potential is the other reason AEC came to the state, James said.

"We are at the beginning of the gas exploration cycle for Alaska," he said.

AEC has had field parties over the last two summers in the Foothills and has looked at the few well penetrations in the area and believes that in the Foothills "there is significant opportunity to find large gas accumulations," James said, and land available for lease.

The Alaska gas industry is "where Alberta was in the 1950s," James said.

"We've had 50 years of sustainable gas growth in Alberta," he said.

Alaska should have 50 years of gas, too: "In fact, when you factor in such things as possibly hydrates it could be much more than 50 years," James said.

AEC would need, he said, "access to pipelines and facilities at fair prices" so that the company could "monetize our assets in reasonable time lines…"

Asked by Rep. Reggie Joule, D-Kotzebue, if there were access issues in Alberta, James said Alberta "tended to develop its gas reserves based around the pipeline access. The various pipeline companies would follow what's going on and pipelines would be built into areas."

But, he said, the cost of developing new pipelines to reserves in Alberta is nowhere near the cost of building a gas pipeline from the North Slope to the Lower 48. ◆

Editor's note: Alberta Energy Co. Ltd. and PanCanadian Energy Corp. are merging to create a new company, EnCana Corp.

continued from page 11

BILL

addressing permitting issues in this state so that over the next two years as the new administration comes on, when the Legislature says what can we do to help, we will have some clear ideas about how that could work."

Brady said Alaska is the only state with both elevation and a petition process. Andm appeals of each agency decision. And the petition process is not part of the state's administrative procedures act: "In other words, you do not have to petition to go to court — you can go directly to court." That, Brady said, is what the Coastal Policy Council intended when they tried to eliminate the petition process in the 1980s.

DGC does not oppose the bill

Patrick Galvin, director of the Division of Governmental Coordination, told the committee "there are members of the public who would like to have the ability to appeal through administrative agencies… rather than having to go directly to court." But, he said, the current petition process does not provide a real appeal because it looks at only whether comments were fairly considered, not at the consistency determination itself.

Galvin said the division does not oppose the bill, although it would like to see a discussion "with the folks that are involved in our program — including industry, the conservation groups, individuals who participate in our processes and local governments — to see if there's another vehicle, but we don't have time at this point in the session to do that."

Other project delayed

Ken Donajkowski, Phillips Alaska Inc. health, environment, safety and training manager, told the committee "the petition process addressed in this bill significantly delayed a total of five consistency determinations for Phillips Alaska during the months of December and January just past. This petition process enables an individual to easily hamper responsible oil and gas development. House Bill 439 appropriately removes this needless component from the overall ACMP process."

In addition to the five petitioned projects, Donajkowski said, "an entirely unrelated project package was impacted for 15 days because DGC staff needed to prepare for the Coastal Policy Council hearing." ◆

continued from page 1

RESPONSE

Revisions will be required to the contingency plan to better describe existing systems such as leak detection and source control. The contingency plan could also be enhanced to include containment tactics as well as more information on permits needed for portions of the response.

The joint work group included Alyeska Pipeline Service Co.; the Alaska departments of Environmental Conservation, Fish and Game, Labor and Workforce Development, Natural Resources and Public Safety; the U.S. Environmental Protection Agency; the Joint Pipeline Office; the U.S. Department of Transportation-Office of Pipeline Safety; and U.S. Department of the Interior-Bureau of Land Management.