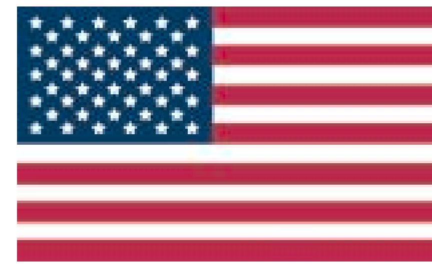
PETROLEUM NEWS ALASKA



"The power of America rests in a stirring but simple idea — that people will do great things if only you set them free."

—George Bush, 1992 State of the Union Address

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Partners wanted for Badami satellites

Judy Patrick

BP Exploration (Alaska) inc. says two of the three prospects advertised in a brochure touting farm-in opportunities on Alaska's North Slope are Badami satellites. Pictured here is a photo taken three years ago of the Badami facilities. See story on page 7.

Dave Donley defends bill to limit municipal debt

Senate Bill 186, which limits municipal debt, is designed to restore the intent of the Legislature when it adopted proposals in 1974 to prevent the monopolizing of oil and gas property wealth by any one community, Sen. Dave Donley told the Alaska Support Industry Alliance Dec. 13. The North Slope Borough, Donley said, has circumvented the Legislature's intent, using bits and pieces of two laws to monopolize taxes on oil and gas assets. Donley, Senate Finance Committee co-chairman, made the remarks as part of a state budget speech.

Sen. Dave Donley

North Slope Borough Mayor George Ahmaogak told the Alliance Oct. 25 that SB 186 would prevent any new construction projects and make it nearly impossible to repair and maintain existing infrastructure in the borough (see Nov. 4 issue of PNA).

Donley said the bill does not eliminate the borough's ability to sell bonds. Even if the borough exceeds the proposed municipal bonding cap of $15,000 per capita, it would be able to issue new bond debt of $1,000 per capita per year. The cap in SB 186 is reasonable and would not create a hardship for the borough, he said, because it is 20 times the statewide average, and it is phased in over 10 years.

Donley said the North Slope Borough has the highest debt load in the state yet it continues to issue new debt each year, although the 2000 Fitch bond rating report states that the borough's infrastructure is fully funded. The borough also has a

see DONLEY page 15

I N S I D E

■ ARCTIC GAS

Turning ice into fire could be key to long-term energy needs

International research team setting up operations on coast of Canada's Beaufort Sea to drill methane hydrate formation

By Gary Park
PNA Canadian Correspondent

With coalbed methane moving rapidly into the mainstream of North American energy supplies, attention is turning to a potentially greater, yet more mysterious source.

The first of 100 scientists and engineers from around the world is setting up operations in the Canadian Arctic in hopes of producing fire from ice this winter by tapping deposits of methane hydrates.

The C$14 million project on the coast of the Beaufort Sea as touted as one of the first serious attempts to exploit a future energy bonanza that some estimate could be 300 times greater than all conventional gas supplies in North America.

Huge volumes of the hydrates are locked in extremely hard, ice-like formations in deep-sea environments around the world, including beneath the permafrost of the Arctic tundra.

Scott Dallimore, a scientist with Natural Resources Canada, said the scientific community has long known about the formations, but has only recently started looking for feasible ways to produce the energy.

He cautioned that commercial development is

see HYDRATES page 2

U.S. Department of Energy

The drill ship M.G. Hulme is used to extract hydrates in the Nankai Trough off the coast of Japan.

■ GOVERNMENT

Department of Revenue suggests oil production tax might need to be changed

ELF designed to encourage small field development and ensure large fields aren't shut down early; Revenue recommends allowance for deduction of exploration and production costs to encourage re-investment in state

By Kristen Nelson
PNA Editor-in-Chief

The Alaska Department of Revenue is forecasting increased North Slope production — with new fields and satellite development bringing daily averages back over the 1 million barrel mark through fiscal year 2010.

But, Revenue said in its Fall 2001 Revenue Sources Book, issued in early December, Alaska's oil production is only about one-half of what it was when the massive Prudhoe Bay field peaked in 1988 and the new oil is taxed at a lower rate than oil than Prudhoe Bay oil, and will not bring the same tax benefit to the state.

The average rate of the production tax on Alaska North Slope crude oil has been falling

Judy Patrick

ELF was designed to prevent early shutdown of fields as production declines. Drilling pad at Prudhoe Bay pictured here.

as a result of the tax adjustment known as the economic limit factor — ELF.

ELF reduces the production tax rate on a reservoir based on the average rate of production and the average productivity of the wells. Production rates and well productivity decline as a field is produced, so the average production tax rate falls. ELF also reduces the tax rate on smaller oil field: most fields producing less than 20,000 barrels

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PETROLEUM NEWS
ALASKA

Story leads?

If you have a story lead or press release for Petroleum News • Alaska, please call Kay Cashman at 907 245-2297 or email her at publisher@gci.net.

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HYDRATES

far off. In fact, some U.S. scientists have put the horizon at 50 years.

U.S. reserve in thousands of trillion cubic feet

But the U.S. Geological Survey has estimated there could be 320,000 trillion cubic feet of hydrates in U.S. territory alone.

"If we're successful we'll be the first in the world to carry out modern production testing of a gas-hydrate deposit." —Scott Dallimore, Natural Resources Canada

USGS geologist Timothy Collett concedes a major technological effort will be needed just to reach the deposits, but tapping just 1 percent could more than double U.S. gas output in one fell swoop.

A USGS report projected world-wide hydrate supplies could be 400 million trillion cubic feet, compared with known gas reserves of 5,000 trillion cubic feet.

Over the next few weeks, the Canadian research project will see three wells drilled into a hydrate field discovered in 1971 by Imperial Oil Ltd., which is 69.6 percent owned by Exxon Mobil Corp. The program includes a main production well to a depth of about 4,000 feet and two observation wells.

"If we're successful we'll be the first in the world to carry out modern production testing of a gas-hydrate deposit," Dallimore said earlier this year.

Main purpose to advance the science

He said the main purpose of the current venture is to advance the science. Beyond there, real progress will need hundreds of millions of dollars of investment by producers exploring for gas in the Mackenzie Delta.

The team of scientists from Canada, the United States, Japan, Germany and India will conduct field experiments to assess how the hydrates respond to various extraction techniques.

Other researchers will be based in Inuvik, Northwest Territories, about 120 miles from the drill site, to analyze the hydrate core samples.

Dallimore said the study may also disclose whether the formations affect climate change, since methane is a greenhouse gas that has far greater potential to warm the planet than carbon dioxide.

Japan spearheading major research

The major research thrust is being spearheaded by Japan and its state-owned Japan National Oil Corp., which will oversee the Canadian drilling operation as part of spending about C$75 million a year on hydrate research over the past five years.

In the United States hydrates are plentiful on the North Slope, along the Carolina coast of the Atlantic Ocean, the Gulf of Mexico and off the Pacific …Large deposits have been found off British Columbia's Vancouver Island. A team of University of Toronto engineers estimates it has found enough hydrates in a mere four square mile area to meet the energy needs of all Canadian households for six years

This follows the drilling of a huge hydrate formation in the Nankai Trough,40 miles off Japan's Pacific Coast in the 1999-2000 winter, with the objective of possibly harnessing the energy potential in the next 15 years.

In the United States hydrates are plentiful on the North Slope, along the Carolina coast of the Atlantic Ocean, the Gulf of Mexico and off the Pacific Coast. Elsewhere, large deposits have been found around Russia's Lake Baikal and off British Columbia's Vancouver Island a team of University of Toronto engineers estimates it has found enough hydrates in a mere four square mile area to meet the energy needs of all Canadian households for six years.

But the hydrates barely register in the U.S. Department of Energy's radar screen. The U.S. Congress passed the methane Hydrate Research and Development Act of 2000, which authorized the DOE to spend $5 million on research this year, increasing to $12 million by 2005. That spending also includes the Canadian project.

But a spokesman for the DOE said a decision on the viability of commercial hydrate production is unlikely before 2015. ◆

PIPELINES & DOWNSTREAM

RCA approves Unocal-Enstar natural gas sales agreement

The Regulatory Commission of Alaska has approved, as amended, the natural gas sales agreement between Unocal and Alaska Pipeline Co. (a wholly owned subsidiary of Semco Energy Inc., of which Enstar Natural Gas Co. is a division).

In the Dec. 21 order accepting an addendum and approving the agreement, the RCA said Unocal and Enstar filed an addendum, as required by the commission, Nov. 14. The addendum limits the term of the gas sales agreement, limits Unocal's ability to sell third-party gas and provides Enstar with first-right of refusal to purchase non-economic gas.

The RCA said the Henry Hub futures price structure is higher than previously approved contracts and might encourage arbitrage. To protect ratepayers, the commission limited Unocal's ability to sell third-part gas under the contact to 15 percent of total annual volume.

The commission had conditionally approved the gas sales agreement Oct. 25, subject to the filing of an executed addendum limiting the agreement.

The RCA said the amendment limiting the agreement to 450 billion cubic feet "allows Unocal sufficient incentive to explore and recover its investment while providing a limit to the contract and giving us an opportunity to review whether continuation of the GSA remains in the public interest."

The price which Enstar will pay Unocal for gas will be determined annually based on a 36-month daily average of the Henry Hub natural gas futures and a floor price of $2.75 per thousand cubic feet adjusted for one-half the inflation rate after 2002.

The RCA said the Henry Hub futures price structure is higher than previously approved contracts and might encourage arbitrage. To protect ratepayers, the commission limited Unocal's ability to sell third-part gas under the contact to 15 percent of total annual volume.

The RCA also required revision of the original agreement's provision allowing Unocal to suspend its obligation to sell gas to Enstar during any period when gas production became uneconomic and to sell that non-economic gas to third parties. As amended, the agreement allows Enstar right of first-refusal to buy non-economic gas on the same terms and conditions as Unocal is willing to sell it to third parties and gives Enstar 30 days after receiving written notice from Unocal to determine whether or not to exercise that right.

—Kristen Nelson

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ARCTIC GAS

Royalty gas final finding issued

The Division of Oil and Gas will hold a competitive sale of the state's Alaska North Slope royalty gas.

The division said Dec. 26 that the commissioner of the Department of Natural Resources has determined that holding a competitive sale of the state's ANS royalty gas at this time is in the best interest of the state.

The state usually receives cash from oil and gas lessees for its royalty share but has the option of taking its royalty in kind and selling it itself. Depending on the outcome of the competitive sale process, the division said that the state may sell some of the royalty gas that will be produced if a North Slope gas pipeline is built.

Bids will be accepted through Jan. 31 and offers received by the deadline will be opened and announced at a public meeting Feb. 1 at 8:30 a.m. in room 240 of the Robert B. Atwood Building, 550 W. Seventh Ave., Anchorage.

PNA will have a story on the commissioner's final finding in its Jan. 6 issue.

■ FINANCE & ECONOMY

Oman to reduce oil output by more than expected

Reduction boosts chances of large cut by OPEC Jan. 1, even though goal of non-OPEC cuts of 500,000 barrels a day not achieved

By Bruce Stanley
Associated Press Business Writer

The likelihood that OPEC would curtail oil production by 6 percent and avert a global price war grew stronger Dec. 20 after Oman pledged to increase the size of a reciprocal cut in its own crude output.

"We believe it's already practically achieved. A barrel less or a barrel more, the fundamentals are there." —Venezuelan Oil Minister Alvaro Silva

Members of the Organization of Petroleum Exporting Countries agreed in November to trim their supplies by 1.5 million barrels a day in an effort to lift sagging oil prices. OPEC insists, however, that it will do so only if independent producers outside the cartel contribute by skimming 500,000 barrels from their daily output.

In a surprise move, the Persian Gulf state of Oman boosted the size of its promised cut to 40,000 barrels a day from 25,000 barrels, swelling the total commitment from non-OPEC producers to 462,500 barrels a day.

Oman's action eased concerns that OPEC might trigger a petroleum price war by refusing to put its own cuts into effect and swamping the world with oil.

"The decision to increase our contribution ... is to give support to the initiative of both OPEC and non-OPEC oil exporters in stabilizing the (oil) price in 2002," said Omani Oil Minister Mohammed Hamed Saif al-Rumhy.

The minister said Oman's cut would be effective for six months.

Goal "practically achieved"

Venezuelan Oil Minister Alvaro Silva said he thinks OPEC is likely to go ahead with its planned cut of 1.5 million barrels even if total contributions from non-OPEC producers don't quite add up to the magic number of 500,000.

"We believe it's already practically achieved," he said. "A barrel less or a barrel more, the fundamentals are there."

February contracts of North Sea Brent crude fell 27 cents to $19.20 a barrel in afternoon trading on the International Petroleum Exchange in London. Contracts of light, sweet crude fell 56 cents to $19.24 a barrel on the New York Mercantile Exchange.

U.S. prices have plunged 27 percent since Sept. 10, the day before the terror attacks on the United States. The attacks aggravated an economic slowdown, and slumping demand for oil, that was already under way at the time.

Desperate to reverse this slide, OPEC is coordinating a worldwide reduction in supply. It has persuaded Russia and Norway each to pledge cuts of 150,000 barrels a day. Mexico has promised to cut by 100,000 barrels and Angola by 22,500 barrels.

OPEC's official daily output target is 23.2 million barrels, and it pumps about a third of the world's oil. It has planned to make its cuts effective Jan. 1. ◆

ASSOCIATIONS

Prince William Sound RCAC seats new board members

The Prince William Sound Regional Citizens' Advisory Council seated three new board members at its quarterly December board meeting in Anchorage.

Louis Beaudry of Cordova replaced Bill Lindow as the representative of the Prince William Sound Aquaculture Corp.; Carol Giliam of Anchorage replaced Cheryll Heinze as the Alaska State Chamber of Commerce representative; and Mike Williams of Valdez replaced Bill Walker as representative of the city of Valdez.

Louis Beaudry of Cordova replaced Bill Lindow as the representative of the Prince William Sound Aquaculture Corp.; Carol Giliam of Anchorage replaced Cheryll Heinze as the Alaska State Chamber of Commerce representative; and Mike Williams of Valdez replaced Bill Walker as representative of the city of Valdez.

The board also elected Patience Andersen Faulkner as treasurer (Faulkner represents the Cordova District Fishermen United) and Blake Johnson as a member at large of the executive committee of Kenai (Johnson represents the Kenai Peninsula Borough).

WORLD OIL

BRITISH COLUMBIA

British Columbia replaces oil and gas output in 2000

British Columbia has the unique distinction among Canada's petroleum regions of replacing both oil and natural gas production in 2000, according to the annual reserves report of the province's Oil and Gas Commission.

Reflecting the surge of exploration in the northeastern sector, the report said established oil reserves as of Dec. 31, 2000, increased to 172.4 million barrels from 166.1 million barrels in 1999, while marketable natural gas reserves rose to 8.5 trillion cubic feet from 8.4 trillion cubic feet. Raw gas reserves were placed at 10.5 trillion cubic feet up from 10.3 trillion cubic feet in 1999.

The commission also reported marketable gas reserves not connected to delivery systems were 1.2 trillion cubic feet, while raw unconnected gas reserves were 1.6 trillion cubic feet.

Because so many gas wells came into production in 2000 — a record 449 were drilled and 120 cased — the report said some wells have not been properly analyzed to be included in the reserves.

To spread activity beyond the northeast — to include the Whitehorse Trough, Bowser Basin, Quesnel Trough and Nechako Basin in northern British Columbia — the commission is being urged to develop royalty regimes for these basins, along with coalbed methane and tight gas reserves.

The British Columbia Ministry of Energy and Mines estimates the Whitehorse Trough and Bowser Basin have combined potential resources of 8.3 trillion cubic feet of gas, 2.5 billion barrels of oil and 8 trillion cubic feet of coalbed methane. Estimated resources in the Quesnel Trough and Nechako Basin include 9.5 trillion cubic feet of gas, 5.1 billion barrels of oil and 1 trillion cubic feet of coalbed methane.

—Gary Park

Ladyfern pipeline approved by federal regulator

Canada Natural Resources Ltd. is set to quicken the pace of opening up British Columbia's Ladyfern natural gas field, now that it has National Energy Board approval to build a feeder line.

The C$8.6 million project , covering about 7 miles, is expected to start deliveries of 680 million cubic feet per day by mid-March 2002, both to meet Canada Natural Resources needs and anticipated third-party volumes for the foreseeable future.

The National Energy Board said in its Dec. 19 ruling a production-sharing agreement by Canada Natural Resources, Alberta Energy Co. Ltd. and Murphy Oil Co. Ltd. and the long-term prospects for North American gas consumption have satisfied the board that Canada Natural Resources can finance the project and that the pipeline will operate at a reasonable level for its economic life.

Murphy president Harvey Doerr said that his company has taken

see LADYFERN page 6

■ CANADA

Apache says Alberta's Zama field has a 'lot of running room'

U.S. independent excited by "opportunities" in Canada after spending almost C$2.5 billion on three acquisitions over two years

By Gary Park
PNA Canadian Correspondent

Ladyfern is hogging the spotlight, but Zama is competing for the attention of Apache Canada Ltd., which is unfurling plans for its stable of high-profile Canadian acquisitions.

The Calgary-based subsidiary of Apache Corp. views Zama in northwestern Alberta as a "very good area" for natural gas exploration after drilling 45 exploration wells this year, said Apache Canada president Floyd Price.

With its Canadian output more than doubling over the last year, the Houston-based independent now produces more oil and gas outside of the United States, with about 53 percent coming from Canada, Egypt, Poland and China.

Among its new gems is a 37 percent stake in northeastern British Columbia's Ladyfern field, which Apache said is now producing at about 320 million cubic feet per day and could ultimately peak at 1 billion cubic feet per day.

"We're going to drill more in Canada this year than we have in any other area in Apache's history." —G. Steven Farris, president and CFO, Apache Corp.

G. Steven Farris, Apache's president and chief financial officer, told a conference call during the summer that his company has a "tremendous inventory" of drilling opportunities in Canada, including at least two Ladyfern lookalikes west of the original discovery.

In fact, Apache expects to complete 550 wells in Canada this year compared to the 580 it drilled around the world in 2000.

"We're going to drill more in Canada this year than we have in any other area in Apache's history,"

see ZAMA page 6

■ WYOMING

Phillips pulls plan to send coalbed methane water to Cheyenne

Wyoming Department of Environmental Quality had told company it would not approve project because of concerns on downstream irrigation

By The Associated Press

Because of concerns raised by environmental regulators, Phillips Petroleum Co. has withdrawn an application to send discharged coalbed methane water from the Powder River Basin to the Cheyenne River system.

"We met with them last Thursday and explained to them, based on the public comments that we received on their application and our re-analysis of some of their assumptions, that we were not in the position to approve the project," said Gary Beach, administrator of the Department of Environmental Quality's Water Quality Division.

"The primary concerns were the (sodium adsorption ratio) in Antelope Creek and the effect on downstream irrigation," Beach said Dec. 17.

… Phillips plans to rework the application to demonstrate that the addition of coalbed methane water would not adversely affect irrigation because it would seep into shallow sand aquifers.

The sodium adsorption ratio is a measure of the degree to which sodium will accumulate in soil irrigated with the water. Water with high ratios can kill plants.

Because new discharges into the Powder River have been limited by a discharge water quality agreement between Wyoming and Montana, Phillips was seeking to gather water from between 2,000 and 2,500 methane wells in the Powder River Basin.

see PHILLIPS page 6

AUSTRALIA

Phillips Petroleum agrees with East Timor on gas pipeline

Phillips Petroleum Pty. Ltd. said Dec. 21 it has reached agreement with East Timor on a planned multibillion dollar gas pipeline from the Timor Sea to Australia.

The deal comes five months after Phillips shelved the pipeline when new financial issues were raised in the Timor Gap agreement between Australia and the United Nations Transitional Authority in East Timor.

Phillips and its co-venturers welcomed the East Timor Council of Ministers' decision to endorse a tax and fiscal package Dec. 21 that will see East Timor receive more than $3.6 billion in royalties over 20 years from the Timor Sea oil and gas fields.

The 310 mile pipeline — which will link Darwin with the Bayu-Undan gas field under the sea between Australia and East Timor — will also underpin 13 billion Australian dollars ($6.5 billion) in investment in Australia.

"This marks a historic day in the establishment of the Timor Sea as an important emerging gas development area," Phillips president Stephen Brand said in a statement.

"We now await ratification of the agreement by Australia so we can proceed with finalizing gas sales arrangements that will secure project development," he added.

The field contains an estimated 400 million barrels of condensate and liquefied petroleum gas and 3.4 trillion cubic feet of natural gas.

When the agreement fell through earlier this year, the new East Timor administration had intended to use its taxation powers to claw back generous investment incentives offered under the original treaty between Australia and Indonesia.

Phillips had insisted that business conditions under the new agreement with the newly independent East Timor be no more onerous. Before East Timor became independent, Australia shared Timor Gap revenues 50-50 with Indonesia.

—The Associated Press

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LADYFERN

an equity position and, although the line might be oversized for the "long run" it will serve an area much larger than Ladyfern.

Ladyfern production is currently around 450 million cubic feet per day, but Canada Natural Resources startled some industry observes in its pipeline application by projecting eventual output of 1.35 billion cubic feet per day. Canada Natural Resources alone estimates it will have more than 300 million cubic feet per day of production by March 2002.

In its latest quarterly report, Canada Natural Resources said it has two wells in production at Ladyfern — which has been rated as the largest single gas discovery in Canada since the late 1980s — although pipeline capacity has restricted output to 55 million cubic feet per day for each well. Drilling, completion and testing of three more wells has just been wrapped up.

—Gary Park

continued from page 5

ZAMA

Farris said.

Zama hottest prospect

Among its overlooked, but hottest prospects is Zama, where it holds 650,000 acres acquired a year ago for about C$760 million from Phillips Petroleum Co. in what Calgary-based Waterous & Co. rated the "largest single Canadian asset ever made available in a public offering."

At the time of the purchase, Zama was yielding 90 million cubic feet per day of gas and 7,500 barrels per day of oil from reserves of 71.6 million barrels of oil equivalent and was seen by Apache as a stepping stone into new exploration areas just across the borders into British Columbia and the Northwest Territories.

The Phillips deal came only three weeks after Apache spent about C$930 million to buy Fletcher Challenge Energy Canada Ltd., paying about US$5.66 per barrel for 338 million barrels of oil equivalent, and a year after it spent C$770 million acquiring Shell Canada Ltd.'s conventional oil and gas holdings in Western Canada.

Canadian production sizeable share of output

Out of those transactions, Apache established a powerful Canadian base, with about 500 employees, has raised its Canadian production to 328 million cubic feet per day of gas and 31,000 barrels per day of oil — a sizable share of its combined daily output of 1.17 billion cubic feet of gas and 155,000 barrels of oil.

While most of the Canadian attention has been concentrated on its partnership with Murphy Oil Company Ltd. in Ladyfern, the Zama play has operated in the shadows.

Price said Zama does not have "the big Ladyfern-type reserves, but it does have a lot of running room and lends itself to technology."

Last winter, Apache Canada shot 300 square kilometers of 3-D seismic in the area, identified 70 different opportunities, bought an additional 120,000 acres and has had an 88 percent success rate from 45 exploratory wells. It plans another 40 to 50 wells in 2002 and another 300 square kilometers of seismic.

Although Apache won't comment on the reserve potential, Farris said Ladyfern is "quite possibly, on a gross basis in North America, the largest thing we've ever found ... keep your eyes on B.C. and northern Alberta." ◆

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PHILLIPS

The water would be transported by pipeline to a reservoir system in northern Converse County, partially treated and then sent into Antelope Creek, a tributary of the Cheyenne River.

The proposal sought permission to discharge up to 32.3 million gallons a day. About 6,500 acres of irrigation water rights could have been affected downstream.

The Phillips plan would have called for a greater volume of water discharged at almost twice the normal sodium adsorption ratio the DEQ normally approves, Beach said.

The quantity of water was another consideration, he said.

"As you add more and more coal bed methane water to the Cheyenne River, it starts looking more and more like coal bed methane water," he said.

Phillips will rework application

Stephen de Albuquerque, a health, environment, safety and regulatory affairs supervisor with Phillips, said the company has not abandoned the plan. He said critics have not thoroughly examined the potential benefits to wildlife, especially on habitat for waterfowl and deer.

"The bottom line is that we spent a lot of time and effort designing a system that we felt would not have a lot of negative impact on landowners," he said.

He said Phillips plans to rework the application to demonstrate that the addition of coalbed methane water would not adversely affect irrigation because it would seep into shallow sand aquifers.

"Quite frankly, they are never going to see that water because we assumed zero infiltration," he said.

Conservation groups pleased

Conservation groups and landowners were pleased with Phillips' withdrawal of the application.

"This project was fraught with problems from the beginning and the people along the Cheyenne River were quite upset about it," said Cheryl Phinney of the Powder River Basin Resource Council.

"Phillips did try to fix the proposal, but I just don't think you can take coalbed methane water and put it in the river and expect it to work."

Donna Ruffing, a Niobrara County commissioner, said her constituents were "extremely pleased."

"But I don't think it's the end of it," she said. "We still have coalbed methane water being discharged into the Cheyenne River tributaries and no one has a clue as to what that quantity of water is." ◆

PETROLEUM NEWS
ALASKA

LAND & LEASING

EASTERN NORTH SLOPE

BP advertises for farm-in partners on slope prospects

BP Exploration (Alaska) Inc. is advertising for partners for its Badami satellites. The Badami unit, operated by BP, is the farthest east producing field on the North Slope.

The company published a brochure — "BP Exploration Alaska Farm-in Opportunities" — inviting companies to invest in three unnamed North Slope prospects for drilling in the winters of 2003 and 2004 and distributed it at a prospect fair in Houston this past fall. Farm-ins are generally handled by a unit's operator.

BP said farm-in deals have been cut for the largest of the three prospects — Slugger, an exploration unit which lies a few miles to the south of Badami — but the company would not talk about the status of the other two prospects, which it said are Badami satellites.

BP spokesman Ronnie Chappell did tell PNA that "companies interested in knowing more (subject to a standard confidentiality agreement) should contact Pete Zseleczky at 907 564-5083."

In the brochure the prospects' well depths (see sidebar) were listed as 11,500-13,000 true vertical depth, deeper than the Badami unit wells which range from 10,500 to 10,700 TVD. Well depth at Red Dog, a prospect just east of the Badami unit on the western edge of the Exxon-operated Point Thomson unit, is 12,379 feet. Point Thomson wells vary in depth from 13,200 to 14,100 TVD.

In its brochure BP said, "Two of the three prospects can be accessed from existing gravel pads in close proximity to processing facilities and pipeline to Trans Alaska Pipeline System."

It said the third prospect "is 12 miles from existing infrastructure," which is approximately the distance from the Badami facilities to the planned exploration well at Slugger.

Slugger interest farmed out

As reported by PNA in August, BP farmed out all — and Chevron and Phillips farmed out part — of its working interest in the Slugger unit to independents Forest Oil Corp. and Andex Resources LLC in exchange for a disproportionate share of the costs of the first Slugger well. Andex and Forest will each receive approximately a 20 percent working interest in the eastern North Slope unit.

The state's well requirement at Slugger calls for drilling through the Kemik interval by May 15, 2003, subject to termination of the unit and payment of a $430,000 penalty, which will be paid by BP and Chevron should the well not be drilled by the state's deadline.

On Aug. 21, a Chevron representative told PNA, "One of the reasons we like Slugger is it should ring the cash register faster than our other North Slope exploration prospects since, if successful, the production will likely be processed at the existing Badami facilities."

Good news for state

BP's search for farm-in partners for Badami satellites is good news for the state, Bill Van Dyke, resource manager for the state of

see PARTNERS page 8

■ ANCHORAGE

Arctic Power annual meeting billed as last by all speakers

Victory in sight for ANWR, but speakers say grassroots effort critical to success

By Steve Sutherlin
PNA Managing Editor

Speakers at the Arctic Power annual meeting Dec.18 at the Captain Cook Hotel in Anchorage had a common theme: this annual meeting would be the last.

Fenton Rexford, president of the Kaktovik Inupiat Corp. of the Village of Kaktovik, said his village, the only settlement within the Arctic National Wildlife Refuge, has worked with Arctic Power to bring oil development to the area for the benefits it will bring, such as adequate water and sewer in the village.

"We're trying to catch up with the modern world," he said. "We have lived in the area for thousands of years, and we have seen whalers, trappers, military and now oil and we are living quite well."


Jerry Hood, secretary-treasurer, Teamsters Local 959

Rexford compared the cooperative effort to land oil development to the landing of a whale, which can be opened up to get oil, but it takes teamwork to pull it up on the beach.

"There's just a little more to pull," he said: "We'll share the benefits of the whale, as is our tradition, not only among the villagers but with the people of the United States."

Labor report: Jerry Hood

Jerry Hood of the Teamsters said the ANWR effort is the broadest-based coalition he has ever worked on, encompassing labor and management, Native and non-Native, industry and government.

He said the support of individuals and organizations in Alaska is very important to the effort in Washington, D.C. The involvement of labor made a large difference in turning the issue around. In January, there was no labor coalition, Hood said, but in March, labor came forward, and there was an effect on the vote in the House.

"They said it would never pass the House, and it did," Hood said. "Labor helped re-frame the debate on ANWR. It's no longer caribou, it's jobs."

Hood said 2.2 million jobs have been lost in this country since the last election, but that an energy bill with ANWR included would put hundreds of thousands of people to work at decent jobs, at a decent income, and with health care and benefits.

Opponents of ANWR development are aware that broad-based support for development is threatening to derail their anti-development agenda, Hood said. Senate Majority Leader Tom Daschle underscored the support for ANWR development by his defensive tactics.

"(Daschle) jerked the energy bill from committee because he knew Frank Murkowski had the votes to take it to the floor," Hood said.

Democrats are risking the loss of the labor vote by courting radical environmentalists, Hood said, adding that the most recent presidential election might have

"Gore sided with the limousine liberals and society environmentalists and lost the blue collar vote in West Virginia, a loss of five electoral votes."
—Jerry Hood, Teamsters

been lost by a misplaced emphasis on the environmental vote.

"Gore sided with the limousine liberals and society environmentalists and lost the blue collar vote in West Virginia, a loss of five electoral votes."

The Teamsters Union is not in the pocket of any party, Hood said. He read a statement from James Hoffa, president of the Teamsters union: "The 1.4 million members of the Teamsters union refuse to be taken for granted. We have no permanent friends, only permanent interests."

"Sticking it to workers seems to be the most bipartisan pastime in Washington," Hood said. "We can be bipartisan too."

Legislative report: Sen. Frank Murkowski

"Frank Murkowski made ANWR a national issue when he persuaded George Bush to make ANWR a part of his platform," oil ands gas consultant Roger Herrera said in his introduction of Sen. Frank Murkowski. "Frank leads from the front, not the rear, and he is the prime architect of our success."

Murkowski said the delaying tactics employed by the opposition frustrated him, considering "the dimension of what ANWR will mean to the whole country."

Workers have rallied around the issue, and that most recently veterans have supported ANWR development because of its national security implications,

see MEETING page 8

continued from page 7

MEETING

he said.

It is important to continue pro-development efforts, because the opponents are well organized, Murkowski said. Many young attorneys come to Alaska on a mission. Environmental organizations with offices in Alaska have risen from 60 a few years ago to 92 today. Environmental groups see Alaska as a source of money and members, he said.

Murkowski said environmental claims that the oil supply in ANWR is insignificant don't hold water. A source of oil that would displace Iraqi oil is significant because oil income funds that country's development of missiles and biological weapons. In fact, Murkowski said, oil income keeps Saddam Hussein alive because it pays the Republican Guard that protects him.

Murkowski echoed statements that energy bill opposition in the Senate is tied to political aspirations of individual senators.

"I'm having a little problem with Tom Daschle. Something happens to people when they have illusions to run for president — he has that," Murkowski said, adding that Daschle also has a feeling that a candidate can have tremendous votes and power if he wins the support of the environmental lobby.

Murkowski said he was quoted by host Robert Novak on the CNN program, "Evans, Novak, Hunt & Shields," during an interview of Daschle Dec. 8. The subject was Daschle's maneuvering of energy legislation out of the Senate Energy Committee.

Murkowski had said the abuse of the legislative process was outrageous and reprehensible, and that partisan legislation was being advanced behind closed doors without a whimper from the press, Novak told Daschle.

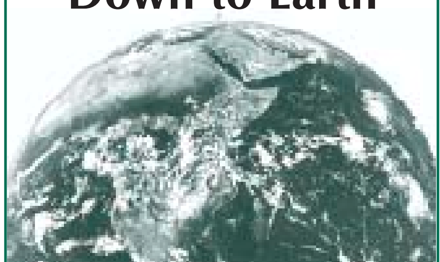
Daschle responded that the ploy was something Republicans have been doing for years.

That is false, Murkowski told Arctic Power. The ANWR issue is "big bucks, big pressure, and big power," he said, and as such, opponents feel the end justifies the means.

Murkowski said Sen. Ted Steven is also frustrated with opposition tactics, particularly with filibuster threats.

Stevens said: "Never has there been a filibuster on an issue of national security."

Murkowski said energy legislation will likely come up in the Senate in February, but there is no commitment from the Senate leadership to finish the issue. ◆



WASHINGTON, D.C.

Take action, fax Tom Daschle

Alaska Sen. Frank Murkowski says Senate Majority Leader Tom Daschle is stalling national energy legislation and avoiding Senate debate on the subject of opening the Arctic National Wildlife Refuge for oil and gas exploration.

Alaskans can send Daschle a fax about ANWR via a form on the Arctic Power Web site. Anchorage-based Arctic Power is in favor of opening ANWR to exploration.

Visit: http://www.anwr.org/features/send_fax.html

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PARTNERS

Alaska's Division of Oil and Gas, told PNA: "If one or more of these satellites is successful there's a good chance it will help Badami. …Even if the facilities are not used, it will for sure help reduce the cost of producing oil at the field. … At a minimum, it will put more oil in the Badami pipeline and lower the cost of shipping."

In its brochure, BP listed the pipeline tariff from Badami to Pump Station 1 of the trans-Alaska crude pipeline as $1 per barrel. According to Van Dyke, the tariff has been $8 a barrel because only about 2,000 barrels are being shipped currently from Badami.

"This (the $1 tariff in BP's brochure) assumes putting nine times more oil through the line. Operating costs don't change much," he said.

Farm-ins a normal practice

"It's pretty common for companies to want to share the risk on these exploration plays," Van Dyke said. "In a farm-in, the company farming in earns a working interest in the leases and, in most cases, they do that by paying a disproportionately higher share of the well cost. For example, you might earn a 50 percent interest in the lease but pay 75 percent of the well cost.

"I suspect BP has real good geological and geophysical data on these prospects and that — along with their record on the North Slope — is a plus," he said. "Different companies view them and risk a little differently but as far as data goes, BP will have a good data set."

In its annual progress report to the state on the Badami unit (see Dec. 16 issue of PNA for full story), BP said it has no plans for further development drilling at Badami but said satellite evaluation was continuing: "Further evaluation of satellite potential within the unit was undertaken and discussions with third parties interested in participating in exploration of this potential have taken place."

—Kay Cashman

Prospect highlights noted in brochure

- All prospects defined by 3-D seismic data
- Proven reservoirs on North Slope
- Structural and stratigraphic components
- Known hydrocarbon fairways
- Depth 11,500-13,000 TVD
- P50 (mid-case estimate) reserve estimates
  - Prospect 1: 45 million barrels of oil
  - Prospect 2: 34 million barrels of oil + 51 million barrels of oil (stacked reservoirs)
  - Prospect 3: 280 million barrels (Slugger)
- Well costs
  - $16 million to $19 million per initial exploration well — completion $500,000 to $1 million
  - $5 million to $11 million per development well
- First production: 2003
- Exploration entry linked to facilities ownership
- Total project cost estimates, including everything from finding and development to transport to the West Coast is $12-13.50 per barrel.

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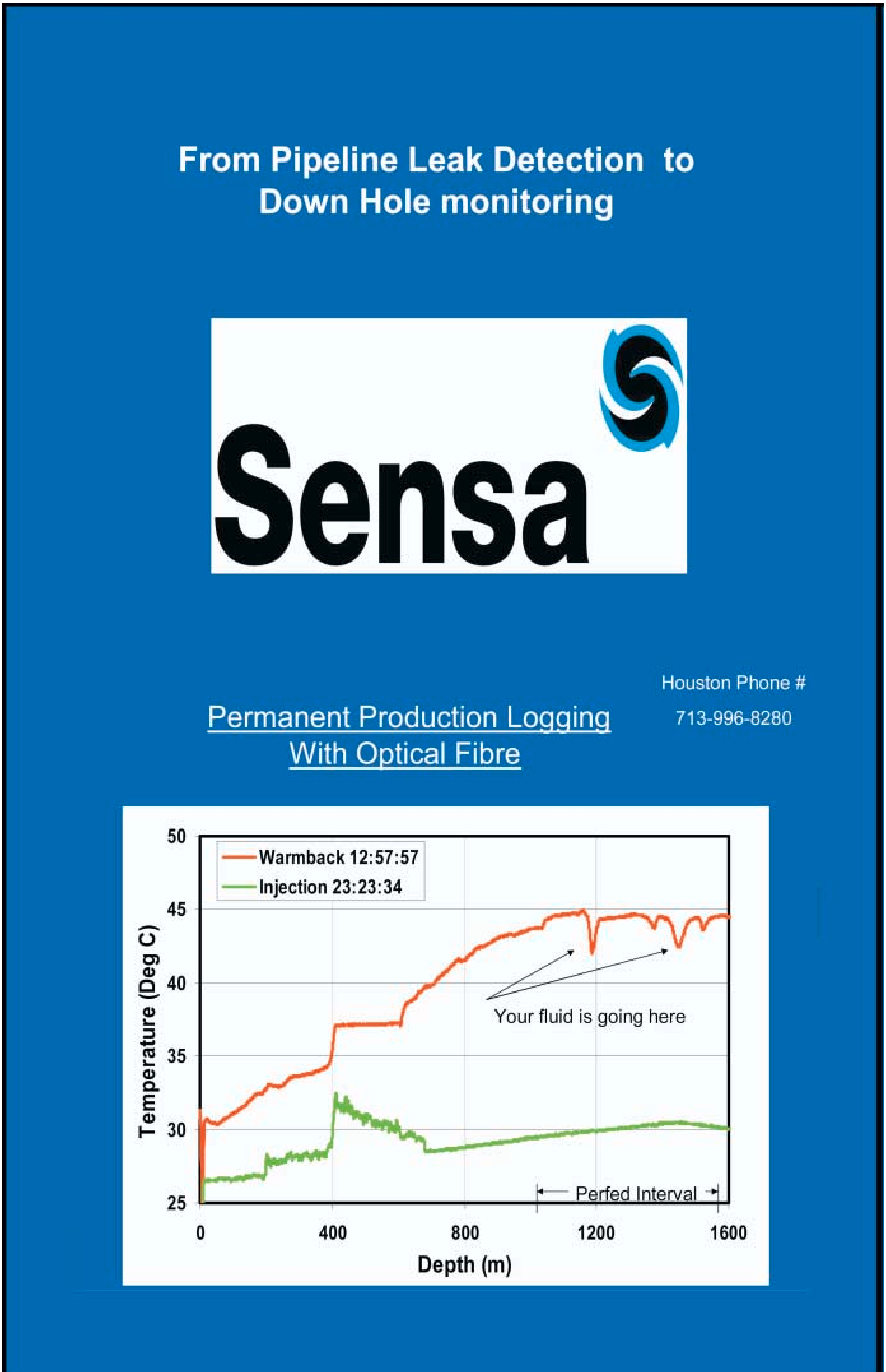

WASHINGTON, D.C.

Murkowski calls for gas line meeting

Sen. Frank Murkowski is calling for those interested in developing Alaska's North Slope gas reserves to a meet in Washington, D.C., early next year.

Murkowski said he wants to get the gas producers and pipeline companies together sometime in late January or early February.

"If they don't want to meet together then we'll extend the invitation individually," Murkowski said.


Sen. Frank Murkowski

A study group organized by Alaska's three major gas owners — BP, ExxonMobil and Phillips Petroleum — has concluded that a pipeline is not economically feasible at this time. Their final report hasn't been issued, however.

Murkowski said he wants to get the gas producers and pipeline companies together sometime in late January or early February.

But pipeline companies have been more optimistic about the project than the producers. A consortium of American and Canadian companies that had first proposed the gasline in the 1970s has agreed to resolve financial issues associated with the project and will present a gasline proposal to producers early next year. Murkowski said he hopes to include representatives from the state of Alaska in the meetings, the Fairbanks Daily News-Miner reported.

He also suggested increased state involvement in any pipeline construction.

"There are some distinct advantages to the state, the state's regulatory and revenue capability, that favor a relationship with the pipeline companies," Murkowski said. "If that doesn't happen, we can legislate it."

Asked to clarify whether he was advocating that the state be a part owner of the pipeline, Murkowski said he thought it should be kept open as an option.

"I wouldn't rule it out," he said.

The meetings Murkowski seeks probably would be private get-togethers followed by news conferences rather than public hearings, he said.

—The Associated Press

ARCTIC GAS

CANADA

Canadian aboriginals try to hurdle land claims settlement

Aboriginal lands covering a huge swatch of the Northwest Territories, Yukon and British Columbia could be opened up for oil and natural gas exploration before a comprehensive land claims settlement is negotiated.

The Acho Dene Koe First Nation, seen as one of the most proactive native communities in the field of resource development, has proposed a memorandum of understanding with industry and governments that would see lands posted and activity continue.

Chief Pat Kotchea said Dec. 20 that a memorandum of understanding would allow exploration and development on an interim basis without undermining whatever treaty rights might be included in a final agreement.

> ***…his community has already benefited from development in the Fort Liard area … and is ready to expand its horizons provided it is "involved very step of the way ... and has a final say in what happens."***
> ***—Acho Dene Koe Chief Pat Kotchea***

He said his community has already benefited from development in the Fort Liard area of the lower Northwest Territories and is ready to expand its horizons provided it is "involved very step of the way ... and has a final say in what happens."

Acho Dene Koe leaders and representatives of ADK Holdings Ltd. have held meetings with company and government officials in Calgary, including BP Canada Energy Co.

Gas in production

Two years ago, Chevron Canada Resources announced a major gas find with its K-29 well in the Fort Liard area, which was rated as one of the largest onshore wells drilled in North America. The three Liard wells are now producing close to 100 million cubic feet per day.

> ***The Acho Dene Koe First Nation has proposed a memorandum of understanding with industry and governments that would see lands posted and activity continue.***

A spokesman for ADK Holdings said a busy winter is anticipated for the Liard including at least three seismic programs, drilling by Paramount Resources Ltd. and well servicing by Canadian Forest Oil Ltd.

One of the trickiest aspects of reaching an MOU is that the Northwest Territories government does not yet have jurisdiction over its oil and gas resources. The administration remains under the control of the federal Department of Indian Affairs and Northern Development.

But the Acho Dene Koe emphasized that although trying something unprecedented it is not attempting to alter administrative or regulatory practices in its desire to "move forward and allow business to happen."

—Gary Park

■ NORTH SLOPE

Cambridge Energy Research pessimistic about Alaska gas

CERA updates state on prospects for Alaska North Slope gas, says Lower 48 gas prices have pushed pipeline out to 2015, Alaska LNG too costly in an over-supplied Pacific market and Alaska costs make gas-to-liquids uncompetitive

By Kristen Nelson
PNA Editor-in-Chief

There was no good news when Cambridge Energy Research Associates updated the state on prospects for Alaska natural gas Dec. 19. When the Alaska Department of Revenue contracted with CERA for 2001, said Ed Kelly, in Anchorage from CERA's Houston office, it asked for a global perspective on the market and on how Alaska gas would fit into that market.

The December update was focused on global liquefied natural gas and gas-to-liquids, but in response to a question about the prospects for a natural gas pipeline from Alaska to the Lower 48, Kelly said CERA now believes the window for Alaska gas to the Lower 48 has moved out some five years — to about 2015 — because of sluggish economic growth (see Dec. 23 issue of PNA).

> ***Over the past 12 months, the demand side for LNG has moderated, but "on the supply side we're seen more and more projects being touted and being put forward… and so we have quite a bullish view on supply, slightly bearish on demand."***
> ***—Michael Stoppard, CERA***

Michael Stoppard, by phone from CERA'a Paris office, said CERA sees the Pacific basin as pretty well supplied with liquefied natural gas for the next 10 years, and does not see an Alaska LNG project — which would require an expensive pipeline to get the gas to a liquefaction plant — as part of that supply.

And Martin Meyers, in a phone presentation from Boston cut short by a power failure in Anchorage, said CERA expects to see a pretty substantial gas-to-liquids business emerge over the next 20 years, but it will be a competitive commodity business and CERA doesn't see Alaska as being among the low-cost places to develop GTLs.

Changes in LNG over 12 months

Stoppard, who coordinates CERA's global LNG studies, said there have been some major changes in LNG in the last 12 months.

The demand story for LNG is very bright, he said.

"But the word of caution is that the supply side of the story looks increasingly competitive and tough. And that therefore we can expect to see some changes in the traditional way that the business is done and possibly in the way that LNG prices are set and indexed."

Worldwide, he said, gas associated with oil was often flared, but there is "strong government pressure around the world to reduce gas flaring" and "more importantly, the major international oil companies are very sensitive about gas flaring."

Coupled with the desire to monetize gas, there is what Stoppard called "a very significant improvement in cost recently in the liquefaction process." This is not a technological change, but is due to competition in building liquefaction facilities. There are two processes available, and new facilities are now asking for bids for both processes.

Economies of scale are also reducing costs as liquefaction plants get larger. A couple of years ago, Stoppard said, 3 million tons was a normal LNG train — but most new projects are going to be 4.5 to 5 million tons.

LNG shipping fleet set to grow dramatically

One of the biggest LNG stories, Stoppard said, is in shipping. "There are 128 ships in the LNG fleet," he said. "By 2004, it's highly likely that there will be over 160. That's a massive increase in the LNG shipping fleet." It took 30 years to get to 128, he said, and over the next three years the count will rise to more than 160, most probably more than 170. And those new ships will be large.

"But the basic message is that we are probably moving from a world of constraint on shipping in LNG to a world in 2003 to 2006 when we will have a surplus of LNG shipping, which would be our baseline expectation," Stoppard said.

The cost of LNG ships has also come down. They cost as much as $320 million in the past, he said, and the cost has been coming down through the 1990s "from just over $200 million a ship to as low as $150 million a ship." Shipyard constraints are now edging costs back up as LNG tankers compete for slots with double-hulled very large crude carriers.

But the main cost difference in shipping LNG

see PIPELINE page 12

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PIPELINE

remains the distance, Kelly said:

"The number of days the ship must be on the ocean to get from a supply point to a particular market point is the lion's share of the difference in the shipping cost from one supply terminal to a market terminal."

Re-gasification proposals

There are also dramatic developments in re-gasification, Stoppard said, with proposals to site receiving terminals into the United States on the both the East and West Coasts. Twelve months ago, he said, it was not evident there would be any additional LNG shipping terminals in the United States beyond the four which are operating or being re-opened. Most of the proposals will never get built, but the cost of re-gasification is now less than $200 million a plant, putting it within the reach of a wide variety of companies.

Kelly said CERA believes maybe one or two new re-gasification facilities could be built, "one on the West Coast of Mexico — which would actually feed into the U.S…. but could feed into the Mexican grid as well, and one on the East Coast of Mexico feeding into the Mexican grid."

Rigid contracts being undermined

CERA is also seeing changes in how LNG is sold. Stoppard said "almost all the LNG trade that is going on today is in fairly rigid bilateral contracts... Anything that's going into Japan or into Europe, you've got a rigid bilateral contract."

But when U.S. prices were very high in early 2001, European cargoes under long-term bilateral contract were diverted to the United States.

"So clearly it is possible to come to a mutually beneficial commercial agreement that takes precedence over what's written in the contract," Stoppard said.

Contracting is also changing. Taiwan recently used "a competitive tender for supply. "

"Which is a radical departure from the typical system of developing a long-term bilateral business relationship with companies and with individuals… over many years," Stoppard said.

"They're basically taking bids" in Taiwan, said Kelly.

There "is a lot of talk and discussion about whether LNG will become a normal commodity business by which basically means will people build a liquefaction plant without take or pay contracts? Or without long-term contracts. And just hope to sell the LNG as a commodity," Stoppard said.

CERA thinks that unlikely, he said, because the $1 billion cost of an LNG plant.

But the expectation is that facilities will go ahead without 100 percent of output contracted. A 5 million ton train, for instance, might be built with 4.5 million tons contracted, Stoppard said, "and then you've got a little bit on the margin to play with the trading market."

"It's not the message I would like to be delivering to this audience, but I think it needs to be said loud and clear. I think pretty much the conventional wisdom …the Pacific basin is seen as pretty well supplied for the next 10 years." —Michael Stoppard, CERA

Asia will continue to be focus of LNG trade

The global LNG market, about 100 million tons today, could double by 2010 with economic growth, but will move from 100 million to 150 million tons even under CERA's more conservative scenario, Stoppard said.

Oil companies, he said, are under very strong pressure from the financial community to show growth and are looking for organic growth.

"And there isn't much organic growth in the oil business. If you're looking at 1-2 percent oil demand growth it's difficult," he said. LNG presents a way to grow organically, at rates of 5-10 percent and LNG is environmentally sound, an "essentially attractive growth" opportunity, Stoppard said.

LNG remains an Asian business, with 71 percent of LNG in Asia, 24 percent in Europe and 5 percent in America in 2000.

More than 50 percent of LNG in 2020 will still be in the Asian market but the Americas will grow to 18-19 percent. Still small volumes compared to the overall natural gas market in America, Stoppard said, but enough to make it a significant potential demand target.

Supply exceeds demand

CERA has put together a worldwide supply-demand balance. "And not surprisingly, we found out that expected LNG supply was in excess of LNG demand," Stoppard said. Over the past 12 months, the demand side for LNG has moderated, but "on the supply side we're seen more and more projects being touted and being put forward… and so we have quite a bullish view on supply, slightly bearish on demand."

The "inability to involve all the potential supply" has put "downward pressure on price," he said.

In the Atlantic basin demand is expected to be 80 million tons — Europe and America together — which will be supplied out of the Atlantic basin or Mediterranean, Stoppard said.

Demand in the Pacific by 2010 will be "somewhere between 100 and 130 million tons. About three-quarters of that can easily be met in the Pacific basin, Stoppard said. The Middle East probably won't capture more than about 35 million tons by 2010.

Conservative scenario already under construction

"Under our conservative scenario," Stoppard said, "the whole of the world's LNG requirements for 2010 are already under construction with very little room for new contracts.

"Under our more positive… scenarios, there's space for another approximately 50 or 60 million tons to be developed."

And there are known competitors for that 50 to 60 million tons, Kelly said.

By 2006, the Pacific basin will have something like 70 million tons of liquefaction capacity." Asian demand by 2010 will be between 100 and 120 million tons. Liquefaction in the Pacific basin by about 2004, will be about 70 million tons and with approximately another 30-32 million tons in the Middle East. So that gets you up to about 100. So you're up to about, you're probably up to about 100 million tons by about 2004. And then there's a 20 million ton upside going out over the next five, six, seven years."

"It's not the message I would like to be delivering to this audience, but I think it needs to be said loud and clear. I think pretty much the conventional wisdom …the Pacific basin is seen as pretty well supplied for the next 10 years," Stoppard said.

Alaska GTL not economic

Meyers, who follows the refinery products business for CERA, only got in a brief introduction before he was cut off by a power outage in Anchorage, but did say there will be a pretty substantial global gas-to-liquids business emerging over the next 20 years, with as much as 2 million barrels a day of GTL productive capacity.

The technology message is encouraging, he said.

"But the other part of the message that I put to you is that in our view Alaska is probably not among the most likely sites for a gas-to-liquids development given cost."

The problem, he said, is that GTL "plays in this energy game which is a pretty brutal competitive commodity business and those with low costs are those that survive and prosper."

For this particular technology, Meyers said, "we don't see Alaska as being among the low-cost places to develop this technology." ◆

PIPELINE OPEN SEASON NOTICE

Kenai Kachemak Pipeline, LLC (KKPL) announces that it is holding an open season to solicit good faith expressions of interest from persons interested in shipping gas on a firm basis on the proposed KKPL system. The pipeline system will extend between a point of interconnection with the Kenai Nikiski Pipeline (KNPL) and Alaska Pipeline Company (APL) pipelines in or near the Kenai Gas Field, Alaska, and a point near the town of Anchor Point, Alaska.

The pipeline is intended primarily to transport gas from new fields developed on the southern part of the Kenai Peninsula to the existing pipeline system serving the northern part of the Kenai Peninsula and Anchorage. The pipeline also may be used to deliver gas to utilities providing service to customers located on the southern part of the Kenai Peninsula. The pipeline will consist of approximately 58 miles of pipeline. Much of its route will follow the Sterling Highway.

Expressions of interest are being solicited by no later than January 25, 2002, from those persons potentially interested in shipping gas on a firm basis on the pipeline system. Such submissions will be used by KKPL to determine the level of interest for various portions of the system, to calculate preliminary rates for the planned pipeline system and to ensure the appropriate sizing of the system. KKPL will hold an informational meeting for potential shippers in Anchorage, Alaska on January 15, 2002, to further discuss the proposed pipeline system, the transportation services to be provided through the pipeline and the open season process.

KKPL anticipates that it will file an application with the Regulatory Commission of Alaska (RCA) in the first quarter of 2002 for a certificate of public convenience and necessity for authorization to construct and operate the proposed facilities. KKPL reserves the right not to file an application or to file an application for less than all of the described facilities if it determines, that the demand for such services do not justify all of the anticipated facilities. The final rates and tariff for the pipeline system are subject to review and approval by the RCA.

Additional project and open season information is included in the KKPL Open Season Terms Sheet. For a copy of the KKPL Open Season Terms Sheet or for additional information, including information about the January 15, 2002, informational meeting, interested persons should contact John P. Zager, Kenai Kachemak Pipeline, LLC, 909 West 9th Avenue, P.O. Box 196247 (99519-6247), Anchorage, Alaska 99501, phone: (907) 263-7662, fax: (907) 263-7874, email: jzager@unocal.com.

To express an interest for firm capacity in the KKPL pipeline system, interested parties must complete and execute the non-binding, preliminary Expression of Interest attached to the KKPL Open Season Terms Sheet and return it to John Zager at the above address by either facsimile or electronic mail no later than 5:00 p.m., January 25, 2002.

Published 12/30/01

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TAX

per day will pay little or no production tax, Revenue said.

The result is dramatic.

The base production tax rate is 15 percent. In fiscal year 1994, Revenue said, the average oil production tax rate for North Slope fields was 13.5 percent; the rate is projected to be 8.75 percent for fiscal 2002.

"Having the tax rate vary with price is another way to better balance the tax system under a wide range of economic conditions, while maintaining international competitiveness for attracting investment." —Alaska Department of Revenue

ELF a major part of state's oil and gas taxes

ELF is a major part of the state's oil and gas tax structure. Other taxes include: property taxes; royalty on oil and gas; bonus bids for leases; and corporate income tax.

Estimated unrestricted oil revenues for fiscal 2002 (which ends June 30) include: oil and gas property tax of $43.2 million; oil and gas corporate income tax of $150 million; production tax of $450 million; and royalties including bonuses of $506.1 million.

Estimated restricted oil revenues for fiscal 2002 include: royalties to permanent fund and school fund of $226.7 million; settlements to constitutional budget reserve fund of $100 million; and National Petroleum Reserve-Alaska royalties, rents and bonuses of $1.3 million.

Of an estimated $1.48 billion, the production tax is 30 percent.

Is ELF working as intended?

Revenue said that as Alaskans look at the state's fiscal situation, "it's also worthwhile to look at existing revenue sources and ask if they are working as intended. "

One of the purposes of ELF was to ensure that the production tax does not discourage development of smaller oil and gas fields. Revenue said the ELF formula is complicated, but the result is that the smaller the field or less productive the wells, the lower the tax rate. The current ELF formula took effect in 1989.

Another idea behind the ELF was that the actual tax rate should decline over time so that the production tax does not cause fields to prematurely shut down as they become less economic due to falling production, Revenue said.

What is ELF?

ELF is a multiplier between zero and one that reduces the actual tax rate for a field, "based on average well productivity and the field's total daily production."

The oil production tax rate is 15 percent, with a 12.25 percent rate for the first five years of a field's production. An ELF of 0.5 would yield an effective tax rate of 7.5 percent. There is a minimum tax of 80 cents per taxable barrel. To calculate the effective tax rate, multiply the statutory tax rate, even if it is the minimum 80 cents, times the ELF.

In the ELF formula, Revenue said, "the two factors of well and field productivity are related exponentially" so "the drop in the ELF will be much steeper than if either of the two factors were applied alone."

Older, larger fields have rapidly declining production and there have been no discoveries of large fields to offset those declines, the department said. Most new standalone fields have production of 50,000 to 100,000 bpd.

How could ELF be changed?

The current ELF formula, Revenue said, was established in 1989 and "was predicated on conditions that were in place then. Those conditions have changed. Would it be appropriate to change the ELF as a consequence? While frequent changes in resources taxes creates instability — particularly where the economics are marginal — tax changes made in response to new conditions or structural deficiencies may be in the public interest."

Revenue said production fell 34 percent from 1990 to 2000. Over the same period, at a hypothetical oil price of $15 a barrel, ELF dropped tax revenues by 53 percent.

"And while we forecast North Slope production remaining relatively flat between 2002 and 2010, because of ELF the average tax rate will fall 52 percent," Revenue said.

It is reasonable, the department said, for ELF to push the tax rate lower as production and declines because fixed operating costs will increase on a per barrel basis and gas and water handling costs may rise. "In addition, it is reasonable for the ELF to decline to zero by the end of a field's life."

But, Revenue asks, does the existing ELF reduce tax rates too quickly?

At Kuparuk the 2002 ELF was 0.6 and production was 212,000 barrels per day. ELF will be zero at Kuparuk in 2010 — but production is expected to be above 100,000 bpd and another 10 years of production is projected for the field.

Because Alaska does not allow deduction of exploration and development costs from taxes, its tax system "may induce companies to take their Alaska profits and invest them elsewhere." —Alaska Department of Revenue

"Is the ELF going to zero sooner than it needs to ensure maximum production?"

Disparity between large and small fields, satellites

Revenue also said that ELF may make too much of the operation cost disparity between large and small fields.

Under the existing ELF, a 50,000 bpd field with average well production of 450 bpd would have an ELF of 0.003. A 200,000 bpd field with the same average well production would have and ELF of 0.493. The smaller field would pay production tax at a rate of 0.045 percent while the larger field would pay at a rate of 7.395 percent.

"It is doubtful," Revenue said, "that the per barrel operating costs of the two fields would be so different as to justify the larger field paying a tax rate 164 times higher than the other field.

"It is worth asking: Is the ELF formula doing its job the way it should, or does it need changing?" Revenue said.

The effect of ELF on taxes from satellite fields is also an issue, as satellites have been developed in the last 10 years — since the existing ELF formula was set in 1989.

Satellites have lower production, with maximum levels in the 5,000 bpd to 50,000 bpd range, but Revenue said the ELF rates for these fields are "very low, and zero in many cases.

"However, given the degree to which these fields share costs with large, profitable fields, and the degree to which many of these costs have already been recovered, the economics of such fields are not the same as those of similarly sized fields that stand alone."

ELF components could be separated

Revenue said a possible modification

see TAX page 15

Companies involved in Alaska's oil and gas industry

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

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DONLEY

savings account of $470 million as a cushion, he said.

Bill not source of rural-urban divide

Donley said his bill does not create a rural-urban divide in the state.

"With less than 2 percent of the state's population, the North Slope Borough hardly constitutes rural Alaska," Donley said.

The North Slope Borough contains 79 percent of the state's taxable oil and gas property. he said, and the monopolization of the revenue from those assets by the borough is unfair to the rest of the state, rural and urban.

"It's disappointing to hear people make allegations of a rural-urban divide, rather than making a proposal for reasonable compromise," Donley said, adding that the borough's allegations were based on "sensationalism and name calling, rather than talking about the facts. … It behooves us as Alaskans to reach a reasonable compromise."

Donley said the modifications contained in the bill were based on testimony provided to the Senate, and that the borough had notice of hearings on the bill.

"It behooves us as Alaskans to reach a reasonable compromise." —Sen. Dave Donley, regarding SB 186

Bill rose from lawsuit

The Borough of Ketchikan sued in 1999 because the North Slope Borough was monopolizing oil asset taxes, Donley said. After more than four years of litigation, the court directed the Legislature to address the issue.

SB 186 is designed to address the unfair distribution of oil and gas property taxes, he said. In addition to limiting bond exposure, the bill also gradually reduces the mill rate on oil and gas property for municipalities with a per capita assessed value of all taxable property over $500,000, Donley said in the sponsor statement for SB 186. In 2000, the North Slope Borough had $1,160,818 per capita assessed property. The next highest community is Valdez, with $236,000. The statewide average is $81,548.

A 1973 law that allows the state to tax oil and gas property also grants a state tax credit to the property owner for taxes paid to a municipality. SB 186 would allow more tax money to flow to state coffers for the benefit of the entire state, Donley said.

SB 186 is unlikely to result in withdrawal of support for oil development on the part of the borough, Donley said, because the borough would continue to receive hundreds of millions of dollars in local taxes and because of that the residents in the borough would continue to have an incentive to take a "leading role in the energy future of Alaska."

Concern about default

Donley said he was also concerned about liability for the state if the North Slope Borough was to default on its debt.

"If NSB was left alone and unchecked in the area of debt issuance — and not if but when the oil fields dry up — the bond market believes the state would certainly have a moral, if not legal obligation to bail out the NSB from under its bond debt," Donley said in a statement. Donley said the Fitch bond rating agency gave the borough an A minus on a scale that begins at AAA, not an A as Ahmaogak claimed in his remarks to the Alliance.

According to the state Department of Revenue, in June 2000 the North Slope Borough had the highest per capita general obligation debt in the state at $62,600. Donley said this amount is 65 times the statewide average. He said senators are concerned about the borough's long-term ability to support high debt levels because repayment of the debt is based on a nonrenewable resource.

Vote a directive for fairness, balanced fiscal policy

Donley said a September 1999 vote against new taxes indicates Alaskans don't want to be asked to pay taxes until the Legislature succeeds in achieving efficient state government.

"SB 186 is one essential first step to show people you have a fair and efficient state government," Donley said.

He said 20 percent of Alaska pays nothing locally for education, and that he won't ask Anchorage to pay more taxes until fairness is restored.

"We must get back to fairness if we're going to ask Alaska to pay taxes, " Donley said.

"After over 20 years, it's time to take a step back and say, 'what's the right way to do this?'"

—Steve Sutherlin

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TAX

to the existing ELF formula "would be to have separate components in the ELF formula for total field production and well productivity." Both are key indicators of field profitability, the department said, but "they are largely independent. Thus, rather than treat them exponentially, where their effects over exaggerate economic tendencies when mixed, the ELF formula could be modified so that these distinct features could be summed.

"It is worth asking: Is the ELF formula doing its job the way it should, or does it need changing?" —Alaska Department of Revenue

"For example, the ELF could consist of a total field productivity component and a separate well productivity component. Each of these components could be weighted 50 percent in the final ELF factor for each field."

Revenue said this "would result in less drastic swings in tax rates as field or well productivity changes.

"In general," the department said, "where rates are now high they would be lower, and where they are now low they would be higher."

And as a side benefit to having an ELF which would decline less drastically over time, Revenue said, the proposed change "would also make the ELF easier to understand."

Price could be tied in

In addition to the exponential problem in the current ELF formula, Revenue said there are two other major problems with the production tax.

The production tax rate is fixed, which means "the government's share of profits is high when profits are low, and low when profits are high." This regressive feature of the production tax "creates an unbalanced situation," Revenue said.

"At low prices or high costs, the burden of the tax creates additional investment risk. At high prices the state's share of the profits is much less than in internationally comparable conditions and the state leaves money on the table."

If oil price were incorporated into the ELF formula, the production tax system would be progressive: the tax rate would vary with oil price and the government's share of profits would be lower when profits were low and higher when profits were high.

"Having the tax rate vary with price is another way to better balance the tax system under a wide range of economic conditions, while maintaining international competitiveness for attracting investment," Revenue said.

Investment could be encouraged

The other major problem with Alaska's production tax, Revenue said, is that it does not encourage re-investment in the state. The tax system is based on gross revenue at the wellhead.

"Is the ELF going to zero sooner than it needs to ensure maximum production?" —Alaska Department of Revenue

"Unlike other jurisdictions," Revenue said, "the regressive system in Alaska does not allow deduction of exploration and development costs. In those other jurisdictions, taxes are reduced by investing there, and companies that invest pay less taxes than those that do not."

Because Alaska does not allow deduction of exploration and development costs from taxes, its tax system "may induce companies to take their Alaska profits and invest them elsewhere," Revenue said.

"A tax credit for exploration and development would enhance interest in investing here. The credit could be capped so as not to drop the actual production tax rate too much, but enough to be attractive to exploration and development." ◆