Petroleum news

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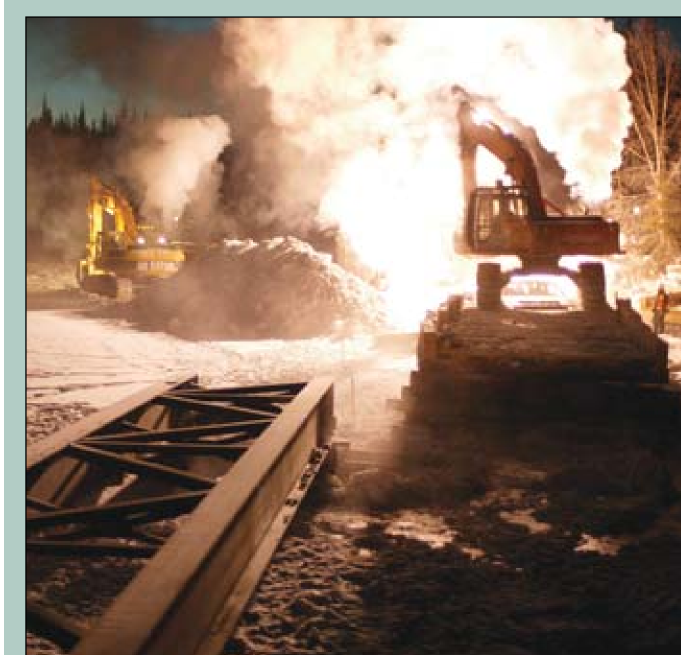
North America's source for oil and gas news

Week of February 8, 2004 • $1

page 15 Alaska partners intend to exercise option for share of gas pipeline

Watch for it next week



JUDY PATRICK

A monthly mining publication for Alaska and northern Canada debuts in the Feb. 15 issue of Petroleum News. Above is a photo of a temporary bridge being installed this month as part of the ice access road to Teck-Cominco's Pogo gold mine in Interior Alaska. The 50 mile long, single lane ice road, built by Cruz Construction of Palmer, Alaska, will be used to transport camp modules and other equipment and supplies to the site for the summer construction season. Alaska Interstate Construction will construct the permanent year-round gravel access road to the mine.

Exxon unwilling to line up

Although the major North Slope producers got together to submit a joint application under Alaska's Stranded Gas Development Act, they are not of one mind whether to spend any more time discussing a possible northern route for a natural gas line from the slope.

The application for a state fiscal contract covers the proposed pipeline route that would follow the Alaska Highway into Canada and also the so-called over-the-top route that would run from the North Slope offshore to Canada's Mackenzie River

"It's just Exxon being Exxon."
—John Manly, Alaska Gov. Frank Murkowski's press secretary

see **EXXON** *page 19*

Income trusts fuel Canadian financings, up 14% from 2002

A powerful combination of rising market demand for income trusts, high oil and natural gas prices, low interest rates and a fresh wave of junior companies boosted the total value of Canadian petroleum industry financings by 14 percent last year to C$11.4 billion, according to Sayer Securities.

The Calgary-based firm, which raises money for small and medium-sized firms, reported a staggering 190 percent hike in trust unit issues to C$4.1 billion from C$1.4 billion in both 2002

see **TRUSTS** *page 18*

BREAKING NEWS

HOUSTON, TEXAS

Evidence mounts

Indicators favor drillers, service firms: U.S rig count expected to jump 12%

PETROLEUM NEWS

Drillers and others in the oilfield services business are looking even more confident than a few weeks ago about their future, as are industry analysts who cover the sector.

"Given our constructive view of the macro energy outlook, we believe there is a growing likelihood of a sustainable increase in drilling activity over the next several years," concluded investment bank Simmons & Co.

Gene Isenberg, chairman and chief executive officer of Nabors Industries, also was upbeat coming off a successful 2003 drilling season. "Looking forward, we expect every one of our businesses to achieve higher results in the first quarter of 2004," he said.

Doug Rock, chairman and chief executive officer of oilfield service company Smith International, said

see **EVIDENCE** *page 18*

JUDY PATRICK

Nabors Rig 33-E, BP's Northstar field, Beaufort Sea, Alaska

NOVA SCOTIA

Sable gas field hard hit by reserve downgrades

Projections wipe 10 years off field life, hope rests in discoveries, Deep Panuke JV

By GARY PARK
Petroleum News Calgary Correspondent

Nova Scotia's lone producing gas field has been rocked by a third downsizing of reserves that has slashed the operating life of the C$3 billion project in half to just 10 years and added to the dismal recent record of Canada's East Coast.

With estimated sales gas reserves now at 1.35 trillion cubic feet, compared with an original 3.5 tcf, the field could run out of gas about 2014, instead of the hoped-for 2024 when it came on stream four years ago.

James Kinnear, president of Pengrowth Energy Trust, which owns 8.4 percent of Sable, told a conference call Feb. 3 that at current rates of production the Sable reserve life index is 7.2 years, while the "economic" operating life is 10 years.

He was confident that the field could maintain production at about 400 million to 500 million cubic feet per day for the "foreseeable future," but declined to estimate when output would peak.

see **SABLE** *page 18*

EL SEGUNDO, CALIF.

Unocal cuts Gulf shelf exploration

Alaska has lowest replacement cost, company replaces 149% of production

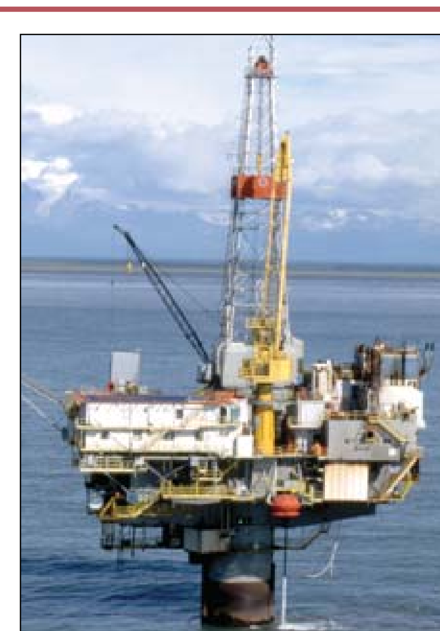
By ALLEN BAKER
Petroleum News Contributing Writer

Unocal Corp. has cut its exploration program for the Gulf of Mexico shelf by about 50 percent for the current year after disappointing results from that area in 2003.

Overall, Unocal replaced 149 percent of its 2003 production with new reserves, though asset sales led to a decline in the overall reserve base.

The move in the Gulf came after drilling cost overruns and

see **UNOCAL** *page 18*



JUDY PATRICK

Unocal's monopod platform, Cook Inlet, Alaska

● ALBERTA

Report counts on oil sands bonanza

Alberta Chamber of Resources says five-fold increase to 5 million barrels per day is possible from oil sands by 2030; but group acknowledges wide range of technological challenges

By GARY PARK

Petroleum News Calgary Correspondent

Technology has been the key to achieving production of almost 1 million barrels per day from Alberta's oil sands and will underpin expansion to 2 million bpd in 2012 and possibly 5 million bpd in 2030, said the Alberta Chamber of Resources.

In an 82-page study released Jan. 30, the chamber predicted that the oil sands will meet 16 percent of North America's oil demand by 2030 provided innovation remains in the forefront.

After nearly 40 years of commercial production, encompassing two phases of growth, the oil sands sector is "now poised for a third wave of development" that could generate C$40 billion of economic growth in Canada, create tens of thousands of new jobs and produce up to C$90 billion in new investment over 30 years, the report says.

Within less than 10 years, oil sands are expected to account for 2 percent of Canada's Gross Domestic Product.

Challenges ahead

But those lofty goals will not be reached without meeting a series of challenges.

Chamber Executive Director Brad Anderson said the Athabasca, Cold Lake and Peace River regions form a basin "with a lot of oil in it, but it's also the most expensive hydrocarbon in the world to produce."

The chamber's roadmap is designed to set a course for growth by identifying issues and technology options to overcome hurdles.

"As producers work toward this new vision, they will rely heavily on technology to grow a truly sustainable industry," the report said.

Building and maintaining momentum requires change on many fronts:

• Product diversity must be expanded.

• Markets in North America and the Pacific Rim must be developed.

• Sustainable development must be apparent in all aspects of operations.

• Economic wealth must be shared broadly across Canada and more narrowly among the communities — aboriginal in particular — likely to be most affected by continued development.

Oil sands could bridge energy gap to future

The chamber said that as conventional crude and natural gas decline, the oil sands could bridge the gap between nonrenewable fossil fuels and cleaner energy options of the future.

Surface mining currently recovers about 90 percent of bitumen and that recovery rate could be improved by 6 percent to 8 percent with new technology.

For in-situ recovery, using techniques such as steam-assisted gravity drainage to extract bitumen too deep to mine, the report estimates ultimate recovery rates of 40 percent to 70 percent.

But if as steam-assisted gravity drainage production is to expand greatly "much of the new production will need to be upgraded to higher value product," the chamber said.

The industry is put on notice that challenges in managing air emissions will become greater with time and will require attention to community relations.

Although 70 percent to 80 percent of life cycle greenhouse gas emissions come from burning the final fuel products, the 15 percent or so released at the production stage are largely the result of high energy use for bitumen recovery and reducing that use is a major target for overall cost reduction.

The full report is available online at www.acr-alberta.com.

Advances on several oil sands projects

The findings were released during a week when advances were made on several oil sands projects.

• Having received regulatory approval, Canadian Natural Resources may start work this fall on Alberta's fourth large-scale oil sands project. Backed by a work force that will peak at about 3,500, the C$8.5 billion Horizon project could come on stream in 2008 and grow to 232,000 bpd by 2012, producing about 5.6 billion barrels over 50 years.

• Nexen and OPTI Canada are scheduled to decide this month whether to proceed with their C$3.2 billion joint venture. The Long Lake project is designed to use steam-assisted gravity drainage to produce 60,000 bpd of refinery-ready light oil. Privately held OPTI is currently working on raising C$300 million-$500 million in private equity and plans an initial public offering in the second quarter for another C$500 million.

• Alberta's Energy and Utilities Board is on the verge of ruling on an application to expand the Shell Canada-operated Athabasca complex, with Western Oil Sands and Chevron Canada Resources each holding 20 percent. Athabasca is working towards its first stage capacity of 155,000 bpd, but has an ultimate target of 500,000 bpd by 2014 to be achieved in phases.

• A raft of emerging oil sands players are raising funds for start-up projects: Deer Creek Energy has raised C$100 million for a steam-assisted gravity drainage venture and is now drilling on leases south of the Horizon lease; Petrobank Energy and Resources is raising C$30 million to advance work on its Whitesands project; Meg Energy wants to develop a steam-assisted gravity drainage project in the Athabasca region; and privately owned Synenco Energy is targeting C$100 million in private equity along with a public offering to backs its plans for a C$4.5 billion Northern Lights project. ●

In an 82-page study released Jan. 30, the chamber predicted that the oil sands will meet 16 percent of North America's oil demand by 2030 provided innovation remains in the forefront.

Want to know more?

If you'd like to read more about the oil sands, go to Petroleum News' web site and search for these articles, which were a few of the articles published on this subject in the last couple of months.

Web site: www.PetroleumNews.com

2004

● **Jan. 18** Gas-bitumen showdown enters a critical phase
● **Jan. 11** No end to oil sands vs. bitumen fight
● **Jan. 11** Canada ships 60% of crude to U.S.
● **Jan. 4** Oil sands poised for gusher
● **Jan. 4** Canadian pipelines chase U.S. markets

2003

● **Dec. 28** Two oil sands ventures make progress
● **Dec. 21** Oil sands best hope for cap-ex hike
● **Dec. 14** Carriers go from pipedreams to pipelines to ship oil sands

CANADA

Canadian oil patch rolls out welcome mat for old foe, Jean Chretien

Jean Chrétien has gone from pain to gain in the oil patch in less than the two months since he stepped down as Canada's prime minister.

With dazzling speed, the man who spent 40 years in politics has landed four private sector consulting jobs, the latest as special advisor for international relations with PetroKazakhstan, the Canadian independent which operates solely in the former Soviet republic.

JEAN CHRÉTIEN

Chrétien, himself a lawyer, had previously accepted jobs with three legal firms, including Calgary-based Bennett Jones, which is heavily involved in the oil industry and includes Peter Lougheed, a former Alberta premier and one-time Chrétien adversary, among its partners.

The transformation of Chrétien has bemused many in the industry, who remember him as a cabinet minister when the Canadian government imposed the National Energy Program in the early 1980s to cap domestic oil prices, costing companies and governments billions of dollars in lost revenues, then as prime minister when he rammed through the Kyoto Protocol on climate change with consequences to the industry that remain unknown.

PetroKaz Chairman Bernard Isautier is counting on Chrétien to help overcome the often troublesome relations between the company and the Kazakhstan government and

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Petroleum news

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NORTH SLOPE, ALASKA

Orion Schrader Bluff satellite at Prudhoe to be developed in three phases

The state of Alaska has approved formation of the Schrader Bluff formation Orion participating area in the northwest corner of the Prudhoe Bay unit and approved an initial plan of development through May 31, 2005. In a Feb. 2 decision, the Alaska Division of Oil and Gas approved inclusion of portions of 14 leases and approximately 18,842 acres of the viscous Schrader Bluff formation in the participating area.

The Schrader Bluff accumulation was discovered in the Orion area in 1968, and since then more than 90 wells have penetrated the formation; most were completed in deeper formations. In November two wells, V-201 and V-202, were producing at a combined rate of 2,500 barrels per day.

Prudhoe Bay field operator BP Exploration (Alaska), the Orion operator, used data from the two producing wells, as well as a 3-D seismic survey, to delineate the extent of the Schrader Bluff within the Orion area. BP applied to form the participating area in October on behalf of itself and Chevron USA, ConocoPhillips Alaska, ExxonMobil Alaska Production and Forest Oil.

The state said the Schrader Bluff hydrocarbon accumulation in the Orion participating area is believed to extend to the boundary of the Milne Point unit Schrader Bluff participating area.

The Orion accumulation includes Schrader Bluff N and O sands at depths of 4,000 to 5,000 feet, and will be developed from existing Prudhoe Bay drill sites L, V, Z and W, and a possible new pad, I.

BP told the Alaska Oil and Gas Conservation Commission in its pool rules application that it estimates 1.07 billion to 1.785 billion barrels of oil in place, with waterflood recovery expected to be 20-25 percent of the oil in place, and peak production 30,000-50,000 barrels per day.

Development in three phases

Development at Orion will begin near the crest of the structure and move toward the outer margins.

"Phase I development targets the areas with good seismic quality and well control," the state said, with drilling a combination of development and appraisal wells, "designed to provide early production and injection well performance information, while evaluating the fluid and rock quality in previously untested areas of the reservoir." At V Pad, the V-201 and V-202 wells are on production and V-105 is on water injection for pressure support.

Phase I will include more V Pad wells and at least one L Pad well, a tri-lateral producer. A well may also be drilled in the W-Pad area in 2004 to test the southern area of

see **SATELLITE** *page 4*

● NORTH AMERICA

TransCanada wants piece of pipe

Company says it holds rights to Alaska gas line under 1970s' certificates

By LARRY PERSILY
Petroleum News Government Affairs Editor

Efforts to build a North Slope natural gas pipeline sometime during the next decade will depend in part on whether the parties can work through or work around a 1976-1978 series of U.S. and Canadian laws and a treaty between the two nations governing an Alaska gas line project.

Calgary-based TransCanada, with operates more than 24,000 miles of gas pipe in Canada and holds an interest in 4,500 pipeline miles in the United States, believes it holds the still-valid 1977 U.S. regulatory certificate and 1978 Canadian certificate to build an Alaska natural gas line.

The approvals apply to the Alaska Natural Gas Transportation System, a specific project designed almost 30 years ago to carry an average 2.4 billion cubic feet per day from the North Slope into Alberta for distribution through the North America pipeline grid. The certificates and 1977 U.S.-Canada treaty detail an exact route, the sites for compressor stations and other specifics for the line that was never built.


JUDY PATRICK

ConocoPhillips Alaska President Kevin Meyers declined to answer whether his company believes TransCanada holds exclusive rights to any Alaska gas line project. "We're interested in talking to people who bring value to the table," he said. "Clearly, they have skills and value."

TransCanada has held recent talks with MidAmerican Energy Holdings Co., which is looking at building a North Slope pipeline, and ongoing discussions with the three major North Slope producers, which also want to build a line to move their gas to market, said Hejdi Feick, spokesman for the Canadian company.

TransCanada ready to talk

TransCanada is ready to work with either developer, so long as they acknowledge the company's claim to exclusive rights to build and operate the portion of the line in Canada, Feick said. The company also believes it holds similar legal rights to the Alaska portion of the line, though Feick said the company would consider transferring its rights to the Alaska mileage in exchange for either developer signing up TransCanada to build the Canadian line.

MidAmerican and the North Slope producers don't necessarily agree the only way to move Alaska gas to Lower 48 markets is through TransCanada's claim to permits almost three decades old.

"We're not saying we're building the ANGTA project," said MidAmerican project leader Kirk Morgan, referring to the 1976 Alaska Natural Gas Transportation Act in Congress that led to the 1977 U.S. law and cross-border treaty granting the project rights to Northwest Pipeline Co., which through a series of mergers and acquisitions came under TransCanada's control.

MidAmerican's proposed gas line may follow much the same route and use data made available by TransCanada, but it could be considered a different project, Morgan said. As such, he said, it would not be limited to the existing permits and the company could apply to the U.S. Federal Energy Regulatory Commission for its own certificate under the Natural Gas Act that regulates pipeline construction.

The pipeline company says it is talking with MidAmerican Energy Holdings Co. and the major North Slope producers about possible involvement in the proposed natural gas line.

No decision from MidAmerican

At this point, Morgan said, the company isn't ready to say which procedural process it might follow.

MidAmerican is proposing to build only the 745 miles of the line in Alaska, stopping its pipe at the Yukon Territory border. TransCanada is MidAmerican's most likely partner for the Canadian portion of the line, Morgan said. "We think it makes sense because of the licenses they hold," he said, and because of TransCanada's extensive Western Canada pipeline network.

BP Exploration (Alaska) believes the producers' pipeline proposal is different enough from the dormant Northwest Pipeline venture that the companies are not necessarily restricted to relying on TransCanada's claim to exclusive rights to the project. The producers are proposing a line at 4.5 billion cubic feet, almost twice as large as the old project, with more compressor stations and route changes from the 1970s' proposal, said BP gas project spokesman Dave MacDowell.

see **TRANS-CANADA** *page 19*

continued from page 3

WELCOME

also help open up new markets, notably in China.

"Once Mr. Chrétien resigned as prime minister, Mr. Isautier felt that by contacting him there might be an opportunity here for both of us," PetroKaz spokesman Ihor Wasylkiw told reporters.

The two men have known each other for many years, including a period when Isautier was advisor to the French government's energy and industry minister.

The market gave an instant endorsement to the Chrétien hiring, boosting the PetroKaz share price by 5 percent on Feb. 3, adding C$118 million to the market capitalization.

—**GARY PARK,** Petroleum News Calgary correspondent

continued from page 3

SATELLITE

the field.

Phase II will include completion of drilling from existing gravel pads, with 10 to 20 producers and 20 to 40 injectors on L, V and Z pads. There may be two additional producers and four to eight injectors on W Pad.

Phase III development will target the northwest portion of the field, an area that cannot be reached from L Pad, and would require construction of I Pad, which would have 10-20 producers and 20-40 injectors in the most northerly area of the reservoir.

—**KRISTEN NELSON,** Petroleum News editor-in-chief

● SOUTHWEST ALASKA

Shallow gas leasing uncertainty delays Holitna project

Upstart Alaska independent loses funding for winter exploration drilling; state leases still not finalized

By PATRICIA JONES
Petroleum News Contributing Writer

Holitna Energy's plan to drill two exploratory wells this winter for shallow gas and coalbed methane occurrences on prospective state land in southwest Alaska have been cancelled.

According to a Jan. 31 interview with Holitna Energy's President and founder Phil St. George, $2 million in funding for the planned remote exploration program fell through at the last minute.

Placer Dome, a mining company earning an interest in a neighboring gold deposit, "continually told us they wanted to fund the core drilling but backed out at the last second, a really big disappointment," he said.

"We are currently pursuing other sources of funding for a possible summer core drilling program, and possibly some spring geophysics," St. George added.

Unresolved land access

One of the major reasons for the funding fiasco is unresolved land access.

Spending $20,000 for lease application fees, Holitna Energy filed in May 2003 with the Alaska Division of Oil and Gas for four shallow gas leases, covering 19,840 acres of state land. Those non-competitive leases, along with two other applications submitted under Alaska's relatively new shallow gas leasing program, still have yet to be issued by state regulators.

Public controversy that arose from one of Alaska's first coalbed methane development programs in the Matanuska-Susitna area, north of Anchorage, caused the delay. Recently, Alaska state officials put a moratorium on the shallow gas leasing program until additional regulations can be filtered through the public debate and Legislative approval process.

Alaska's existing shallow gas leasing plan is "a great program. They need to stay the course," St. George said.

Talk of possible buy-backs would be "a big mistake for the state … a setback for the shallow gas program," St. George said. "The state knew what it was doing when it put the land out there for leasing, which is good for the state."

Leases hold up other financing

Holitna's leases being in limbo has hurt the company and its partner, local Native corporation TKC, in securing other types of financing for the project, St. George said.

"We have the (exploration) permits almost in place, even though the leases weren't issued yet," he said. "Even so, it's tough to do financing with the land tenure not completed."

Although it's legally allowable to permit and conduct some initial exploratory work on the state ground without approval of the leases, St. George said it's difficult to secure private financing for exploration without the land tenure issue resolved.

"We're trying to get the leases finalized as quickly as possible," he said.

State regulators told him to expect finalized leases in late February or early March, he said.

Leases likely to be issued this summer

Pat Galvin, coalbed methane coordinator for the Alaska Division of Oil and Gas, said it's likely to take several months before shallow gas leases are issued.

"In the summer is our best guess," he told Petroleum News Feb. 4.

Galvin is involved in a series of public workshops in the Mat-Su area, which are continuing throughout February. Comments from those five meetings will be incorporated in the revised state shallow gas leasing program that state Legislators will consider, he said.

A draft document will be produced and then be released for further public comment, Galvin said.

Terms in the state's existing shallow gas program, developed by legislation passed in 1996, include a $5,000 per lease application fee, and one dollar per year rental for the three-year term. Leases can be maintained beyond the three-year term if the company can show cause to extend the term, or if production starts on the land.

Alaska's non-competitive shallow gas leases are for fields in which part of the production gas extends in a formation above 3,000 feet true vertical depth, although drilling work can follow the formation further down.

Gas for gold mine power

St. George, a long-time mineral geologist and a former project manager at the 28 million ounce Donlin Creek gold deposit in southwest Alaska, left the mining industry last spring to work on the Holitna gas project.

Based on geological and geochemical information gathered by state geologists in recent years, St. George and his partners believe there is a gas resource in the remote area that would be sufficient to power a large industrial user, such as a proposed gold mine at Donlin Creek.

"Technically, the basin is looking better with every bit of new data we get," St. George said. "So we are more encouraged then ever that there is something there."

His fast-track development plan was designed to identify the presence of gas this spring, in order that it be considered by Placer Dome during the company's ongoing feasibility study for the Donlin Creek project, located about 50 miles northwest.

Now, St. George believes the mining company will need to use another source of power for consideration in the feasibility plan, while Holitna Energy continues to pursue its exploration.

"If gas is there, it will be a benefit … it's cleaner and a less expensive fuel, so whatever (other energy source) is permitted, it will be over-permitted," St. George said. "If we find gas out there, it will be the energy source for Donlin Creek." ●

FAIRBANKS, ALASKA

Royalty board to meet Feb. 17

The Alaska Royalty Oil and Gas Development Board will hold a public hearing Feb. 17 at 10 a.m. in the auditorium of the Noel Wien Library in Fairbanks, Alaska.

The commissioner of the Department of Natural Resources is proposing to sell state North Slope royalty oil to Flint Hill Resources Alaska LLC under a 10-year contract, and the board will determine whether this proposal meets criteria set out in state law. The board will also prepare its recommendation to the Legislature on the proposed sale.

Public comment will be taken at the hearing.

JUNEAU, ALASKA

Bill proposes CBM tax for Alaska

The sponsor of last year's coalbed methane development bill has proposed legislation intended to help ease Southcentral Alaska residents' concerns over shallow gas drilling's potential impact on water quality.

Wasilla Rep. Vic Kohring's bill would set up a new state fund so that if any water wells were damaged by shallow gas drilling – an unlikely event according to experienced coalbed methane developer Evergreen Resources Corp. — the owners of those wells could apply for money to drill new wells. The Water Well Restoration Fund would get its money from a new tax on coalbed methane production.

The production tax would shut off when the Water Well Restoration Fund reaches $250,000, and then turn on again when the fund falls below the cap.

Kohring, Republican chairman of the House Special Committee on Oil and Gas, proposed a "shallow natural gas exaction" tax of one cent per 20 thousand cubic feet of production from each lease.

Evergreen Resources (Alaska) Corp., a subsidiary of Denver coalbed methane producer Evergreen Resources Corp., has started exploration work in Southcentral's Matanuska-Susitna Borough, but no commercial coalbed methane production is under way in the state.

Limit on tax collections

The production tax, as proposed in House Bill 420, would shut off when the proposed Water Well Restoration Fund reaches $250,000, and then turn on again when the fund falls below the cap.

The bill was scheduled for its first hearing in Kohring's committee Feb. 5.

"HB 420 encourages responsible development by ensuring private water wells are protected. In the unlikely event a well goes dry, this fund would pay for a quick replacement, without the property owner having to hassle with a long legal or governmental process," Kohring said in a prepared statement.

The representative's staff said Kohring worked with industry and the state Department of Natural Resources on the legislation.

Thirty day public notice required

Kohring's bill also addresses complaints that state law does not provide adequate notice of exploration activity by the subsurface owners. HB 420 would require exploration companies to provide written notice to surface owners of any activity on their land at least 30 days before starting work.

Other bills introduced this session go further than Kohring's measure to protect the rights of the surface owner. The proposed Water Well Restoration Fund could be used — subject to legislative appropriation each year — to pay a surface owner's costs of cleaning up water well contamination within 1,500 feet of a shallow gas drill site or, if needed, drilling a new well. Surface owners would have to test their well for purity and flow after receiving notice of coalbed methane exploration in the area, show DNR that any damage occurred after work started, and show that the contamination was the "probable hydrologic consequence" of the drilling.

—PETROLEUM NEWS

HOUSTON, TEXAS

El Paso to reduce reserve estimates

Regulatory filings by El Paso Corp. show an expected reduction in proved natural gas and oil reserve estimates by the nation's largest natural gas pipeline company.

Officials of the Houston-based company said Feb. 2 the planned drop is "a material negative revision." Such reserves are a key number used in the industry for predicting the potential of oil and gas production.

In January, The Royal Dutch/Shell Group of Cos. said it was reducing its estimate of its proved hydrocarbon reserves by about 20 percent.

El Paso's stock has come under pressure partly because of reserve worries.

Company officials said in their third-quarter financial report filed with regulators in November that they had hired a new outside firm as its primary reserve engineer. That firm prepares its estimates, which are reviewed by a third party.

—THE ASSOCIATED PRESS

FORT WORTH, TEXAS

XTO Energy picks up more production

Exploration and production independent XTO Energy closed deals adding 30 trillion cubic feet of gas equivalent per day to its growing production base and established year-end 2003 proved reserves at around 4.1 tcf of gas equivalent.

XTO also expects daily natural gas production to increase from 750 to 755 million cubic feet in the 2004 first quarter to 780 to 790 mmcf during the final three quarters of the year. Oil production is expected to remain flat at 13,000 to 13,500 barrels per day, as well as natural gas liquids at 6,000 to 6,500 bpd.

With the close of previously announced acquisitions amounting to $243 million in East Texas and Louisiana, the company added about 182 bcf of gas equivalent, roughly half of which falls into the category of proved developed, XTO said Jan. 30. Development activities by year-end 2004 are expected to increase daily production to 40 mmcf of gas equivalent from a current 30 mmcf of equivalent, the company said. About 90 percent of the production is said to be natural gas.

XTO estimated cost of the reserve additions to be about 80 cents per thousand cubic feet. The company will operate more than 80 percent of the asset value which covers 55,000 net acres in the development corridor.

In East Texas, XTO purchased proved reserves amounting to 77 bcf of gas equivalent, 37 percent of which are developed. Current production from the properties is about 14 mmcf of equivalent per day. "Significant volume growth is anticipated during 2004," the company said.

XTO also expanded its position in northern Louisiana with the purchase of proved reserves totaling 105 bcf of equivalent (60 percent developed) in various fields, including Haynesville and Middlefork. The properties currently produce some 12.5 million cubic feet of natural gas and 500 barrels of oil per day.

● HOUSTON, TEXAS

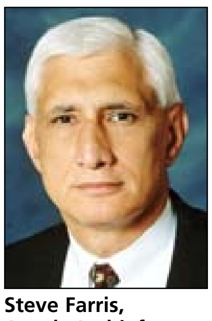
High-flying Apache to launch drilling at North Sea Forties

Houston independent generates $1 billion-plus in 2003 profits, intends to launch 20-well drilling program

PETROLEUM NEWS

Apache, which for the first time in its nearly 50-year history collected over $1 billion in profit for a single year, is poised to launch an aggressive drilling program at the North Sea Forties field it acquired from BP last year in a $1.3 billion deal that also included properties on the Gulf of Mexico's continental shelf.

Once the weather clears, Apache intends to launch a 20-well drilling program that could add up to 13,000 barrels per day of oil to current production of roughly 54,000 barrels per day, Steve Farris, Apache's chief executive officer, said in a Jan. 29 conference call.



Steve Farris, Apache's chief executive officer

"This will drive capital spending much higher," Farris said, adding that the effort would require between $250 million and $275 million in investment. The company spent about $60 million on the field last year, largely on platform upgrades.

Still, Farris was reluctant to speculate on just how much this year's investment might increase production at the aged Forties field. Initial investment helped raise output to around 45,000 barrels per day on proved reserves of 147.6 million barrels.

"If anywhere it's going to be hard to project, it's in the North Sea," he said. "Right now we are waiting on the weather. But each well will have the potential of increasing production and reserves."

Company had solid fourth quarter

Meanwhile, Apache weighed in with another solid financial performance in the 2003 fourth-quarter and also managed to generate over $1 billion in profit in 2003, a first for the big Houston independent.

Lifted by a combination of strong commodity prices, acquisitions and success with the drill bit, Apache's 2003 fourth-quarter profit rose 45 percent to $260 million or 80 cents per share, following a 2-1 stock split, compared to $179 million or 59 cents per share during the same period a year earlier. Adjusted for special items, Apache earned $284 million or 87 cents per share, beating analysts' consensus by 3 cents.

Apache's fourth-quarter results included an after-tax write down of $10.2 million or 3 cents per share, reflecting remaining costs associated with termination of operations in Poland. Results also included the effect of currency exchange rates on deferred tax balances, partially offset by restatement of Canadian deferred liabilities to reflect the country's tax reduction.

"Strong commodity prices are only part of the story," Farris said. He said Apache's 2003 production compared to the previous year increased 22 percent and worldwide reserves rose 26 percent, while the company replaced 330 percent of its production at an enviable $6.07 per barrel of oil equivalent. Moreover, Apache reduced its year-end 2003 debt-to-capitalization ratio to 26 percent compared to 35 percent at year-end 2002.

Overall daily production averaged 441,000 barrels of oil equivalent in the 2003 fourth quarter, compared to 338,300 barrels for the same period a year earlier. Liquids alone averaged 231,400 barrels per day, while natural gas averaged 1.26 billion cubic feet per day, up 17 percent. However, overall production declined slightly from the 2003 third to the fourth quarters.

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The largest jump in natural gas production during the fourth quarter versus the period a year earlier came in the United States, up 47 percent to 685.7 million cubic feet per day. Australian gas volumes rose 20.5 percent to 121.9 million cubic feet per day.

Canadian gas production down, oil flat

Canadian volumes decreased nearly 10 percent to 328.1 million cubic feet per day, while Egyptian production fell nearly 15 percent to 116.6 million cubic feet per day.

On the oil side, Apache's fourth quarter production increased nearly 46 percent from the year earlier period to 71,982 bpd. Egyptian output was up about 8 percent to 47,000 bpd.

Canadian oil production during the final quarter of 2003 was fairly flat at 25,450 bpd, while output from Australia fell 13 percent to 26,553 bpd. In its first year on Apache's books, the Forties field in the North Sea averaged 40,950 bpd. Production from Apache's startup field in Bohai Bay averaged 7,943 bpd. Argentine production was flat at 557 bpd.

Apache said it also added 234 million barrels of proved reserves last year through exploration and production activities, representing "one of the company's best drilling performances ever." For one, production was finally launched from Apache's Zhao Dong block in China. Another 267 million barrels of equivalent were added through acquisitions, most notably Apache's acquisition of North Sea and Gulf of Mexico properties. At year-end 2003, Apache reported proved reserves of 1.7 billion barrels of oil equivalent. ●

CANADA

Ensign mounts challenge to Precision's market dominance

Precision Drilling remains Canada's largest oilfield services company, but there is an emerging battle for the top spot, with Ensign Resource Service Group on an expansion path.

Of the more than 21,000 wells rig released in Canada last year, Precision drilled 8,083 for 27.45 million feet of hole, while Ensign and its affiliates racked up 5,020 wells and 17.8 million feet.

Combined, the two companies accounted for 13,013 wells or about 61 percent of the total.

Members of the Canadian Association of Oilwell Drilling Contractors completed 74.8 million feet, up 38 percent from 2002's 54.1 million feet.

Those companies booked 110,999 operating days for 678 rigs, taking an average five days to drill a well to an average depth of 3,449 feet.

Ensign ended the year by acquiring Big Sky Drilling, whose nine rigs had an average 2003 utilization rate of 67.4 percent, the best in Canada.

In its pursuit of growth, Ensign, through its wholly owned subsidiary Rockwell Servicing, acquired 11 well servicing rigs and related assets Dec. 23 from privately held Crown Well Servicing. The purchase price was not disclosed.

Then on Jan. 31, it bought three specialty drilling rigs from Layne Christensen Canada, again for an undisclosed amount.

Ensign's Chief Operating Officer Bob Geddes said the acquisition will allow the company to expand into the oil sands and growing coalbed methane markets.

—**GARY PARK,** Petroleum News Calgary correspondent

MEXICO

Pemex chief: Monopoly must look to deep water deposits

The head of Mexican state oil monopoly Petroleos Mexicanos said Feb. 2 the company needs to look to deepwater deposits as it pursues long-term goals of raising oil production, but lacks the technology to do so.

At a news conference, Raul Munoz said the oil concern known as Pemex is currently allying itself with international oil companies to explore ways it can acquire the necessary technology.

Pemex has explored only 18 percent of its territory likely to contain oil and gas, and of the remaining four-fifths, much is in deepwater, Munoz said, adding that Pemex's future is "virtually tied to this subject."

Last year, Pemex produced a record 3.37 million barrels a day of crude oil, and plans to add an additional 80,000 daily barrels this year on its way to meeting a 2006 goal of 4 million barrels a day.

Munoz said Chinese firms were among about 10 companies with which Pemex is exploring possibilities for acquiring deep-

see **MONOPOLY** *page 8*

● HOUSTON, TEXAS

Anadarko lowers 2004 production target

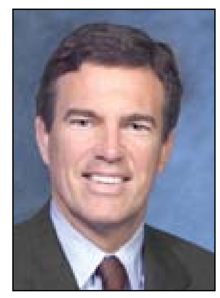
Numbers fall in wake of weather-related delays at Marco Polo development

PETROLEUM NEWS

Anadarko Petroleum, which reported both reduced earnings and production in the 2003 fourth quarter vs. a year earlier, also has lowered its growth target for this year, largely because of weather-related delays at its Marco Polo development in the Gulf of Mexico.

Despite the setbacks, Anadarko scored record earnings in 2003 and increased year-end proved reserves 8 percent to 2.5 billion barrels of oil equivalent, the company told analysts in a Jan. 30 conference call.

But the big independent also spent a lot of time justifying its reserves, noting that engineering consultant Netherland, Sewell okayed its report after reviewing 70 percent of its 2003 reserve additions and about half of its existing proved reserves.



James Hackett, Anadarko's new chief executive officer

Mark Pease, Anadarko's vice president of onshore and offshore operation

"We know the quality of reserves is a critical issue, particularly in the light of recent industry events," said Mark Pease, vice president of onshore and offshore operations for Anadarko.

How industry accounts for its reserves has come under scrutiny by the U.S. Security and Exchange Commission. Shell recently reduced its proved reserves by a shocking 20 percent, followed by a 17 percent write down by Denver-based independent Forest Oil.

"We have received their (Netherland, Sewell's) letter of confidence in both our process and the reason-

see **ANADARKO** *page 8*

● CANADA

Expectations of share sale for Petro-Canada take hit

Integrated oil company takes drubbing over 5% cut in reserves and lowered production outlook; but sets long-term goal to 'significantly' replace reserves

By GARY PARK

Petroleum News Calgary Correspondent

Speculation that the Canadian government might finally unload its last 18.6 percent stake in Petro-Canada was even more firmly pushed to the side Jan. 29 when the company absorbed one of the largest single-day declines in its share value.

More than 11 hours after posting a 44 percent drop in its fourth-quarter profits, a 5 percent drop in its proved reserves in 2003 and a projected 3 percent drop in production this year, the Calgary-based integrated held a conference call to explain the bad news.

But by then the damage had been done. In a staggering sell-off, 7.3 million shares changed hands —

In a staggering sell-off, 7.3 million shares changed hands — 12 times the average daily volume — with the stock plunging 12.35 percent and wiping as much as C$2.18 billion from the market capitalization.

12 times the average daily volume — with the stock plunging 12.35 percent and wiping as much as C$2.18 billion from the market capitalization.

Most analysts agreed the response was an overreaction, given that Petro-Canada had boosted its 2003 profits to C$1.67 billion from C$974 million in

see **PETRO-CANADA** *page 8*

OIL COMPANY EARNINGS

Top 35 North American E&P Spenders

Earnings fourth quarter 2003 • Change from fourth quarter 2002
Daily liquids production fourth quarter 2003 • Change from fourth quarter 2002
Daily natural gas production fourth quarter 2003 • Change from fourth quarter 2002

Company	symbol	earnings	%	liquids	%	gas	%
BP	BP						
RD/Shell	RD						
EnCana	ECA						
ExxonMobil	XOM	$6,650	+63	2,595,000	+4	4,405	-1
Can. Natural	CNQ.TO						
ConocoPhillips	COP	$1,021	(-)	1,012,000	–2	3,592	+1
El Paso	EP						
ChevronTexaco	CVX	$1,735	+92	1,803,000	–2	4,182	-4
Anadarko	APC	$295	-5	721,000	-4	1,762	+5
Devon	DVN						
Dominion	D	-$130	(-)	22,687	-6	1,095	-14
Burlington	BR	$404	+157	127,700	+31	1,957	+4
Occidental	OXY	$382	+18	440,000	+13	597	-3
Husky	HSE.TO	C$245	+1	217,700	-2	656	+14
Newfield	NFX						
Petro-Canada	PCZ	C$200	-44	324,100	-1	886	+1
Unocal	UCL	$167	+36	157,000	-2	1,577	-9
Kerr-McGee	KMG	$51	(-)	139,900	-22	742	-6
EOG	EOG						
Nexen	NXY.TO						
Imperial	IMO	C$255	-44	253,000	-1	557	+10
Talisman	TLM						
Pioneer	PXD	$57	+217	66,463	+23	607	+60
Apache	APA	$260	+45	231,436	+45	1,260	+17
Marathon	MRO	$485	+150	187,300	-11	1,121	-9
Suncor	SU.TO	C$300	+16	235,200	+3	194	+7
Merit							
Williams	WMB						
Chesapeake	CHK						
Pogo	PPP	$55	+45	62,955	+18	297	+7
Penn West	PWT.TO						
XTO	XTO						
Spinnaker	SKE						
Forest	FST						
BHP Billiton	BHP						

Top 35 is based on Petroleum News research
Liquids production is barrels per day
Gas production is millions of cubic feet daily

continued from page 7

MONOPOLY

water technology, but gave no further details.

Under the constitution, Pemex has a monopoly on all upstream oil and gas activities. While it has a refining joint venture with Royal Dutch/Shell in Texas, Mexico does not allow production joint-ventures.

In June 2000, Mexico and the United States reached an accord to divide up a 6,565 square mile area in the Gulf of Mexico that could contain significant hydrocarbon reserves. Mexico was apportioned 62 percent of the area.

—THE ASSOCIATED PRESS

continued from page 7

ANADARKO

ableness of our numbers," Anadarko's new chief executive officer, James Hackett, said in his first earnings call with analysts. "I am confident about Anadarko's proved reserve numbers."

Anadarko said it "cost-effectively converted a significant number" of proved undeveloped reserves or PUDs into the proved developed category, which increased its proved developed inventory to 69 percent from 67 percent of its worldwide reserves. The company said it replaced nearly 200 percent of production last year, with most of it coming via the drill bit.

U.S. reserves up 12 percent

In the United States alone, Anadarko's reserves increased 12 percent to 1.7 billion barrels of oil equivalent, representing 68 percent of the overall increase, with primary growth areas identified by the company as the Gulf Mexico, North Louisiana, Texas and Wyoming. Canadian proved reserves increased 9 percent to 314 million barrels of equivalent, representing 12 percent of the total, the company said.

"We know the length of time each PUD remains on the books as undeveloped and have an action plan for developing them," Hackett pledged.

With regard to earnings, Anadarko reported a 2003 fourth-quarter profit of $294 million or $1.17 per share on revenues of $1.28 billion, down from $309 million or $1.21 per share on revenues of $1.12 billion earned in the quarter a year earlier.

Anadarko also reduced its 2004 production growth forecast to 1 to 4 percent from 4 to 10 percent with later-than-expected start-up of its deepwater Marco Polo field. However, the company said it expects an annual growth rate of 3 to 7 percent over the following two years.

Anadarko also said it planned to invest $2.6 billion to $2.9 billion on capital projects this year, slightly more than the nearly $2.4 billion it spent last year. The company said it reduced its total debt by $400 million to just over $5 billion in 2003, and saw its debt decline to 37 percent of capitalization from 44 percent. Finding and development costs fell to $6.95 per barrel of oil equivalent, a considerable improvement over the previous year's double-digit performance.

Anadarko also managed to generate record earnings of $1.3 billion last year, helped by a strong commodity price environment. ●

continued from page 7

PETRO-CANADA

2002, but the immediate result was to lower the value of the government's stake to C$2.88 billion from a record high of C$3.44 billion.

Analysts agreed that the new Canadian government, which had already cooled talk that it might divest its Petro-Canada shares, would have even less reason to announce a sale with a spring election in the offing.

One-time problems cited

Chief Executive Officer Ron Brenneman, discussing why the company fell short of analysts' predictions for the first time in several quarters, said the drop in final quarter profit to C$200 million from C$356 million a year earlier stemmed from a number of one-time problems.

He blamed the write-down of an Edmonton refinery that had been targeted for conversion, C$51 million in higher Ontario taxes and "quite extreme" margins as companies jockeyed for market share at the gasoline pumps.

Predicting that "those events are behind us," Brenneman said Petro-Canada will be looking for ways operationally this year to beat its production outlook of 450,000 barrels of oil equivalent per day, down from 471,500 barrels in the final quarter of 2003 and 465,000 barrels through last year.

He also cautioned that 2004 would be a transitional year, with Petro-Canada increasing its capital budget by only 3 percent to C$2.6 billion and no "large projects coming on this year to offset natural decline in our mature areas."

One of the few hopes for 2004 is the possibility of deferring maintenance shutdowns at Newfoundland's Terra Nova and Hibernia offshore oil fields, which delivered a net 87,500 bpd in the fourth quarter and were projected to drop to 80,000 bpd this year assuming the maintenance proceeded.

Beyond 2004, there are a number of additions on tap — Petro-Canada's 27.5 percent share of the White Rose oil field offshore Newfoundland that is due to start pumping in 2006 and peak at 92,000 bpd; a 12 percent interest in the Syncrude Canada oil sands consortium that is expected to grow by more than 50 percent to 350,000 bpd in 2005; and its portfolio of wholly owned Alberta oil sands assets.

Long-term goal to improve reserve replacement

Brenneman emphasized that Petro-Canada's "long-term goal is to significantly replace reserves," indicating he was encouraged by the 80 percent reserve replacement rate for natural gas in the maturing Western Canada sedimentary basin, although there was "still a lot of work to be done" to better the 50 percent replacement rate in the company's international operations, which grew dramatically in 2002 with the C$3.2 billion acquisition of Germany's Veba Oil & Gas.

"Over time we expect to do a lot better than the 50 percent reserve replacement that we achieved last year in international," he said. "We're fully intending to get that up to 100 percent or better over time."

Exploration programs are planned for this year in blocks recently acquired in Algeria, Tunisia and Syria. In addition, Petro-Canada is part of a Marathon Oil-led group that is studying a gas-to-liquids, LPG and condensate project in Qatar and has a 10 percent interest in a consortium bidding on development of the Kuwait North oil fields.

Further growth is possible in Newfoundland offshore fields, as Petro-Canada and its partners delineate the Far East block at Terra Nova and evaluate the Avalon sands at Hibernia.

Brenneman said the company expects to unveil a development plan later this year for both opportunities, while weighing some small satellite fields that are within reach of both production systems.

He also said there could be "room to start talking about reviving" Newfoundland's stalled Hebron-Ben Nevis project — operated by Chevron Canada Resources with a 28 percent stake and including ExxonMobil Canada at 38 percent, Petro-Canada at 24 percent and Norsk Hydro Canada at 10 percent.

Progress on the C$3 billion scheme was stopped two years ago when the partners decided that the field, comprising three adjacent fault blocks and holding about 414 million barrels of oil and 313 billion cubic feet of gas, was too technically difficult and expensive to develop.

But hopes have been revived again in recent months, with talk of a possible breakthrough on a separate royalty regime for Hebron-Ben Nevis. ●

CANADA

Canada heads for second-best drilling year with 20,005 wells

The bar has been raised yet again for Canada's drilling sector, with the Petroleum Services Association of Canada hiking its 2004 forecast by 5 percent to 20,005 wells — the second best year on record next to last year's 21,802.

Natural gas targets, led by shallow prospects in southeastern Alberta, southwestern Saskatchewan and northeastern British Columbia, will dominate activity even more.

The association predicted 18,965 wells in its original forecast in October. From 10,771 gas wells last year, the industry is anticipating 12,596 wells this year, or 63 percent of all wells drilled and 71 percent of the net producing wells.

Petroleum Services Association President Roger Soucy, speaking for 250 member companies, said there is no sign of activity abating in the popular gas regions.

"We fully expect natural gas to maintain the industry's attention throughout 2004 and into 2005," he said.

Soucy said the reduced forecast for 2004 stems from an anticipated 5 percent reduction in oil and gas capital spending.

The forecast is based on projected average commodity prices of C$5.25 per thousand cubic feet for gas and US$27.50 a barrel for oil.

Alberta will easily dominate the drilling, accounting for 14,790 wells, followed by Saskatchewan at 3,900 and British Columbia at 1,100, with the Northwest Territories, offshore East Coast and Manitoba making up the balance.

—GARY PARK, Petroleum News Calgary correspondent

NORTH AMERICA

North American rig count up by six to 1,669 by Jan. 30

The North American rotary rig count increased by six to 1,669 during the week ending Jan. 30, according to rig monitor Baker Hughes. The Canadian rig count continued to ramp up for the winter drilling season, increasing by nine from the previous week to 585 rigs. The count also was 33 ahead of the same period last year.

In the United States, the number of operating rigs fell by a net three to 1,084 but was still ahead by 211 rigs compared to the same weekly period last year. The number of land rigs actually increased by two to end the recent week at 973. But offshore rigs decreased by three to 96, while inland water rigs declined by two to 15.

Of the total number of rigs operating in the United States, 938 were drilling for natural gas and 142 for oil, while four were being used for miscellaneous purposes. Of the total, 722 were vertical wells, 268 directional wells and 94 horizontal wells.

Among the leading U.S. producing states, Texas' rig count increased five to 462. Alaska's increased by two to 10. Oklahoma was up by one rig to 147. Wyoming's count fell by five rigs to 66. Louisiana's was down by five rigs to 150. And California's count dropped by one to 17. New Mexico was unchanged at 61 rigs.

—PETROLEUM NEWS

● ALASKA

Technology key to ANS production increases

Alaska's North Slope has been proving ground for coiled tubing drilling, other technology; new information technology next

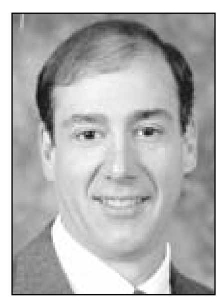
By KRISTEN NELSON

Petroleum News Editor-in-Chief

How many barrels was the Kuparuk River field on Alaska's North Slope projected to produce when it started up in the early 1980s? And how many barrels had it produced as of Jan. 17?

The answer, says Joe Leone, president of upstream technologies at ConocoPhillips, is the same: 2 billion barrels.

But obviously ConocoPhillips Alaska is continuing to produce from the Kuparuk River field—in fact it is Alaska's second largest producing field, second only to Prudhoe Bay. And the latest report from the Alaska Division of Oil and Gas lists more than 1 billion barrels remaining to be produced from the Kuparuk main reservoir — 1.5 billion barrels when satellite fields are included.



You could argue the specifics, but whatever the actual number is, "technology is actually the biggest driver of performance improvement in our industry." —Joe Leone, ConocoPhillips

At Prudhoe Bay, where field development in the 1970s originally called for 500 wells: "We've already drilled 1,300 penetrations, and plan another 200," said Tony Meggs, BP group vice president for technology.

"Ten years from now I predict we'll have another 200 to drill, regardless of all the drilling we'll do in the meantime," he said.

Did industry misjudge the fields' reservoirs when development first got under way?

No, the technology available to develop the reservoirs has changed — and continues to change, both Leone and Meggs said in Anchorage Jan. 23 at the Alaska Support Industry Alliance's "Meet Alaska" conference, the theme of which was technology.

Leone said a study by Shell found that 80 percent of improvements in upstream production are due to development and application of technology, compared to 20 percent for all other factors. You could argue the specifics, he said, but whatever the actual number is, "technology is actually the biggest driver of performance improvement in our industry."

Prize is billions of barrels of oil

What does the future hold? And why should the companies keep investing in technology development for the North Slope.

"For BP," Meggs said, "the potential prize is 5 billion barrels of oil equivalent." About 2 billion of that is proven, he said, and about half of it is light oil.

"To transform the potential into production," he said, BP must continue "to research ways to produce

see TECHNOLOGY page 10

BP has resource in Alaska, wants continued good business climate

Because BP has "5 billion barrels of known oil and gas in our Alaskan portfolio," the company's North Slope assets will continue to attract capital for investment "for many years to come," BP Exploration (Alaska) President Steve Marshall said Jan. 23.

STEVE MARSHALL

But there is something BP can't provide, he told the Alaska Support Industry Alliance's Meet Alaska conference in Anchorage, and that is a good business climate.

BP's investment in its Alaska business will be more than $650 million in 2004, including more than $200 million in double-hulled tankers.

"And that means we continue to be the state's number one investor."

BP's investment in the four tankers is about a billion dollars, Marshall said, with the first of the new tankers scheduled to enter service this year.

see BP page 10

Alpine capacity could be expanded to 135,000 barrels of oil per day, says Meyers

The first capacity expansion at Alpine will start this year, adding some 5,000 barrels of oil per day to the facility's capacity, ConocoPhillips Alaska President Kevin Meyers said Jan. 23.

He told the Alaska Support Industry Alliance "Meet Alaska" conference that Alpine facilities, originally planned for 70,000 bpd, were upped in the planning stage to 80,000 bpd, and now the facility handles an average 100,000 bpd, and"hit 118,000 barrels per day" in early January. (See production story page 12 this issue.)

Alpine capacity expansion No. 1, ACX1, begins later this year, adding 5,000 bpd of oil capacity and increasing the facility's produced water handling.


The Alpine field on Alaska's North Slope.

"In the next few months we expect to sanction our second Alpine facility expansion, that's called ACX2, and that should start in the 2005 time frame and it will increase the oil production at Alpine to over 135,000 barrels a day," he said.

That capacity will handle satellite discoveries. "They're relatively small fields," he said, but together they add up.

This expansion is the subject of the Bureau of Land Management's current draft environmental impact statement, and Myers said that it is "not 100 percent guaranteed, but if the economics hold together" it will be the first oil production out of the National Petroleum Reserve-Alaska.

Also investing in heavy oil

ConocoPhillips is also investing in heavy oil, he said. There are now some 35,000 bpd of heavy oil coming off the slope, about 3.5 percent of production.

"If you look at what technology has the potential to do, we at ConocoPhillips believe by the end of the decade we could increase that heavy oil production … could shift the number up to closer to 100,000 barrels per day, which would be about 10 percent of our North Slope production, so this is an important part of our future on the North Slope."

The West Sak 1-J drill site, on the west side of the Kuparuk River field, by itself would produce more than 30,000 bpd, Meyers said.

"ConocoPhillips sanctioned 1-J this last December and we're hoping to see our partners approve it later this year so we can move this project along to development in 2004 and 2005," he said.

continued from page 9

TECHNOLOGY

viscous (heavy) oil competitively. And we must move North Slope natural gas to market."

Promising technology in the viscous area is the "introduction of long, horizontal completions, multilateral wells" and developments which are reducing operating costs and increasing production rates, Meggs said. Viscous production on the North Slope has "nearly doubled" in recent years, he said, and with continued investment, "we believe we can more than triple viscous production by 2010."

Meggs said areas where technology is improving include: subsurface visualization, drilling efficiency, low-salinity oil recovery and use of polymers in enhanced oil recovery.

Billions to develop new technology

That technology doesn't come cheap.

BP will spend "close to a billion dollars a year" over the next five years to develop and test new technology worldwide, Meggs said.

Those technology dollars translate into dollars spent on the ground in Alaska. Meggs said BP completed a $180 million viscous oil project at Milne Point, and the Prudhoe owners will spend $500 million on the Orion project over the next four to five years.

And out in the future? BP is looking at biotechnology, nanotechnology and information technology. On the biotech side, BP is taking a "fresh look" at producing "the elusive bug that gobbles up all residual oil and returns it to the surface." Nanotechnology could lead to new materials.

The information technology area is more immediate: "advances in computing power, automation, remote sensing and miniaturization are leading to a potential transformation in the way we run oil and gas fields."

In the future, Meggs said, digital technology could "collect reservoir, drilling, well and facility performance data on a continuous basis." The result: increased production and reduced costs.

What would it look like? Permanent seismic arrays and other sensors would "provide real-time measurements from the subsurface and surface."

What is needed? Control over flow down in the well and "the ability to adjust flow to optimize oil production and minimize production of associated water and gas," and "real-time data on the performance and operational integrity of surface equipment."

With increased automation, companies would be able to operate facilities remotely.

Meggs said "bits and pieces" of this technology are already in use.

"But we'll be incorporating the entire package in new developments next year in Trinidad, the deepwater Gulf of Mexico and the North Sea." He said BP will use the North Slope as a testing ground for components of the new technology.

Faster seismic

ConocoPhillips is working with technology which will dramatically reduce the processing time for changes in the models geophysicists make as they interpret results of seismic programs.

Even with clusters of processors, Leone said, it takes five weeks to run a single cycle of processing because the data sets are so large. Technology which should be online the first quarter of this year will cut cycle time to a few hours.

On the North Slope, ConocoPhillips set an extended reach drilling record at West Sak this fall: 11,812 feet drilled in the reservoir.

This translates directly to production he said, with an initial production of more than 5,000 barrels a day, compared to 150 barrels a day for a West Sak well drilled in the 1980s.

"What's the difference between those two wells? Technology," Leone said.

More long lateral wells are planned on the North Slope, he said, as well as tri-lateral wells.

And coiled tubing drilling, which was pioneered on the North Slope, now accounts for 60 percent of Prudhoe Bay drilling.

Then there is gas handling.

Natural gas is produced with crude oil and needs to be separated and re-injected.

But there is only so much gas-handling capacity on the North Slope, and gas-handling is a limiting factor in the amount of crude oil that can be produced. The gas-handling facilities are so huge that economics don't justify additional expansion, he said.

A technology now under development could change all that, by separating gas from crude oil at the bottom of wells.

What is being developed, Leone said is "gas separation and re-injection technology so small it would go down 3 1/2-inch tubing." There is no guarantee the technology will become commercial, he said, but if development success continues for this subsurface processing and re-injection, the technology could be employed by 2006. ●

continued from page 9

BP

The company will "drill more than 100 new penetrations in fields we operate" on the North Slope, he said, including 19 viscous wells. And while the company hasn't had any high-profile projects since Northstar, "our focus on drilling generates new production and new state revenues today — not five, 10 or 15 years from today," he said.

Ongoing investments have resulted in a 13 percent increase in BP's production over the last two years, a production level the company expects to sustain for several years to come. Over that same two-year period, the company has reduced its "total cash cost by more than 10 percent," Marshall said.

But while BP sees a "tremendous potential for an extended and stable business in Alaska," that will require "the right business environment," Marshall said.

There is "relentless" competition for investment within BP, he said. "Alaska's remoteness, high cost and complex regulatory environment has very real competitive challenges."

What does BP see as the right business environment?

Marshall listed having "confidence in the long-term stability and fairness of the fiscal and regulatory climate in Alaska," changes in the Alaska Pipeline Act "to eliminate ambiguity over the jurisdictional issue and ensure that rules regarding tariffs and other pipeline matters are clear, precise and consistent over time."

He also said that, before BP can move forward with commercializing North Slope natural gas, "we must have confidence in a strong, sustainable oil business throughout the life of the project. The two are inseparable."

The reform legislation passed by last year's Legislature must be transformed "into real streamlined regulations."

And the company must have confidence in the tax structure that has already "helped to enable the oil industry to invest hundreds of millions of dollars, billions of dollars, in new viscous oil projects with very marginal economics."

● NORTH SLOPE, ALASKA

Foothills open for tundra travel

Ongoing modeling by Alaska agency results in earliest access to North Slope's eastern coast in eight years

By PATRICIA JONES

Petroleum News Contributing Writer

The Alaska Department of Natural Resources opened the lower and upper Foothills areas of the North Slope for tundra travel on Jan. 29.

It was the final state-regulated area to be opened for exploration access, Harry Bader, the department's northern region land manager, told Petroleum News on Jan. 30.

The department opened the eastern coastal area — from Prudhoe Bay east — on Dec. 23, the earliest heavy equipment access to the frozen tundra in eight years.

The earlier opening this winter came in part due to ongoing research being gathered to develop a computer model that will help state regulators scientifically determine winter tundra travel periods on the North Slope.

"That's in spite of a warmer winter than normal," Bader said. "We had two weather events — an ice storm event on Oct. 30, which is very rare; and a significant snowfall that insulated the ground."

The state's western coastal tundra opening was Jan. 9, he added.

The earlier opening this winter came in part due to ongoing research being gathered to develop a computer model that will help state regulators scientifically determine winter tundra travel periods on the North Slope.

The Alaska Department of Natural Resources, in collaboration with Yale University and with $270,000 in funding from the U.S. Department of Energy and in-kind contributions from industry, is leading the research effort.

Since Oct. 4, 2002, researchers have spent one week on and one week off the slope, gathering data for the modeling project, Bader said. At 30 monitoring stations, crews used slide hammers to determine the hardness of the ground. Snow depth was measured and the researchers also looked for the existence of and measured the depth of snow slabs.

Weeks of on-site ground sampling helped move up the first opening date by 10 days to two weeks, Bader said, "… without sacrificing the standards of tundra resistance."

The earlier access was based not on statistical or quantitative data, he said, but on using the ground research information more as a case study.

"I felt comfortable opening the tundra at the time I believe was closer to the point in time that the tundra was ready to be on," he said. "The intensive sampling provided a context that did have an effect."

Final ground data from test areas will be collected next summer, and the computer modeling effort will continue, Bader said. "Parts of the model definitely will be used in the coming season," he said.

Phased opening allows earlier access

Last winter was the first time state regulators divided the North Slope into four areas based on weather and ground conditions, allowing winter access in stages.

"For 30 years, the North Slope was treated as a single unit," Bader said. "It will be hard to compare future openings with past data, because we now have these progressive openings."

The modeling research project is designed to offer a scientifically based alternative to standards currently used by the department to determine exploration and development access on North Slope tundra. Since the 1960s, state regulators have required that tundra be frozen at least 12 inches deep and have six inches of snow cover before winter travel is allowed.

Using those criteria has resulted in a decrease in tundra travel days available to exploration crews, due to increasingly warmer winters, Bader said.

In 1970, regulators allowed tundra travel for 210 days, compared to 103 days in 2002. The study's objective is to increase the exploration access window on the North Slope to at least 130 days per season.

Industry participation continues

Initial research work began in 2002 when department workers gathered data in the Brooks Range foothills, working with Anadarko Petroleum seismic crews.

Such logistical collaboration with industry continued through this fall's data gathering work, Bader said.

"A conservative estimate of the goods and services provided by the oil service industry and the oil companies themselves certainly exceeded $80,000," he said. "More important than the value was that their contributions were critical. We could not have done it without their logistics." ●

COOK INLET, ALASKA

Aurora Gas and Forest Oil identify two gas prospects, plan two exploration wells, seismic at Three Mile Creek unit

The Alaska Division of Oil and Gas has conditionally approved formation of the Three Mile Creek unit so that state leases set to expire at the end of January can be included in the unit.

Aurora Gas LLC and Forest Oil Corp. are partners in the proposed 8,156 acre unit, on the west side of Cook Inlet, with Aurora holding approximately 79 percent of the acreage and Forest approximately 21 percent.

The unit includes two state oil and gas leases, 5,596 acres, and two Cook Inlet Region Inc. leases, 2,560 acres.

The division said that both the state and Cook Inlet Region proposed modifications to the application as submitted. An acceptable plan of exploration, the appropriate unit area, and amendments to the proposed unit agreement have been negotiated with the applicants.

The applicants agreed to the revised terms Jan. 29, and the state issued a conditional unit approval Jan. 30 because the state leases would have expired Jan. 31.

The applicants have until March 1 to execute and deliver to the state the revised agreement and revised exhibits or the state will deny the application and re-offer the acreage in its 2004 Cook Inlet areawide oil and gas lease sale.

The division said it will issue a complete evaluation of the application by March 26.

Two natural gas prospects

The state said the applicants identified two natural gas prospects within the unit area, the Three Mile Creek and the Olson Creek prospects, and committed to acquire new seismic data over the unit area, drill an exploration well in each prospect, and obtain approval of a participating area during the three-year term of the agreement.

Within the first two years — before Jan. 31, 2006 — an exploration well will be drilled and new seismic acquired over the unit area.

The first exploration will be drilled to the base of the Tsuga 2-4 interval or the stratigraphic equivalent of the 4,300-foot true vertical depth marker as seen in the Three Mile Creek State-1 well, whichever is deeper, with the bottom hole in ADL 338233. Not less than 27 line miles of new seismic data will be acquired over the entire unit area.

Failure to either drill the first exploration well or acquire new seismic by Jan. 31, 2005, would result in termination of the unit, and payment to the state of $8 an acre for the expired state acreage. Failure to both drill the first exploration well and acquire new seismic by Jan. 31, 2006, would result in termination of the unit and payment to the state of $16 an acre for the expired state acreage.

If, after drilling the first exploration well and acquiring seismic the companies decide not to drill the second exploration well in the third year, a portion of the acreage would contract out of the unit and the owners would pay the state $16 an acre for the contracted acreage.

Requirements for the third year are drilling a second exploration well and obtaining approval for an initial participating area within the Three Mile Creek unit by Jan. 31, 2007. If the second well is not drilled, a portion of the acreage would contract out of the unit and the companies would pay the state $24 an acre for the contracted acreage. If an initial participating area is not approved by Jan. 31, 2007, the unit will automatically terminate.

—KRISTEN NELSON, Petroleum News editor-in-chief

● NORTH SLOPE, ALASKA

Alpine, Northstar fields hit new production highs

By KRISTEN NELSON

Petroleum News Editor-in-Chief

Alaska North Slope crude oil production averaged 999,048 barrels per day in January, up 1.76 percent from a December average of 981,738 bpd. Northstar and Alpine, both of which had mechanical problems late last year, set daily production records in January.

On Jan. 1, Alpine produced 118,613 bpd, and on Jan. 26 Northstar produced 84,954 bpd. Northstar, operated by BP Exploration (Alaska), averaged 78,667 bpd in January, up 33.39 percent from a December average of 58,973 bpd. In December the field was down early in the month awaiting delivery of a replacement after a transformer failed Nov. 27 and BP had to bring in a helicopter from out of state to lift a replacement in from Prudhoe Bay. Production ramped up at the field beginning Dec. 7, accounting for the low average production in December.

ConocoPhillips Alaska-operated Alpine had a problem with an inlet separator in December, resulting in lower-than-normal average production. The field averaged 104,893 bpd in January, up 19 percent from a December average of 88,133 bpd.

Production down at most North Slope fields

All other North Slope fields had lower daily average production in January than in December. The BP-operated Lisburne facility (which processes production from Lisburne, Point McIntyre and Niakuk) averaged 58,561 bpd in January, down 5.8 percent from a December average of 62,168 bpd. The Alaska Department of Revenue reports that Lisburne production decreased for the tie-in of a new well at month end.

BP-operated Endicott averaged 27,745 bpd in January, down 2.47 percent from a December average of 28,447 bpd.

BP-operated Milne Point averaged 49,443 bpd in January, down 2.1 percent from a December average of 50,489 bpd. The state reports a turbine replacement at Milne Point this month, with production averaging just 37,000 bpd Jan. 19-25.

The ConocoPhillips-operated Kuparuk River field, which processes Kuparuk and West Sak production, as well as satellites Tabasco, Tarn, Meltwater and Palm, averaged 197,566 bpd in January, down 2.15 percent from a January average of 201,908 bpd.

BP-operated Prudhoe Bay, including satellite production from Midnight Sun, Aurora, Polaris, Borealis and Orion, averaged 482,173 bpd in January, down 1.92 percent from a December average of 491,620 bpd.

The North Slope temperature at Pump Station No. 1 averaged -8.1 degrees Fahrenheit in January, compared to -3.2 degrees F in December.

Cook Inlet production averaged 25,717 bpd in January, down 4.82 percent from a December average of 27,024 bpd. ●

CANADA

Purcell launches winter drilling

The lower Northwest Territories along with northern British Columbia and Alberta will again figure prominently in this winter's drilling by Calgary-based Purcell Energy, which has set a capital budget for the year of C$36 million.

It has a 24 percent interest in two wells at Fort Liard in the Northwest Territories — 3K-29 which is currently being drilled directionally from the K-29 facilities site and 2M-25 — that are expected to produce a combined 50 million cubic feet a day of raw gas once they are on stream by the third quarter.

After almost four years of production, aggregate gross production from Fort Liard's initial four wells is about 114 billion cubic feet, or 80 billion cubic feet of sales gas. At Tenaka in northeastern British Columbia, where Purcell holds interests varying from 28 percent to 90 percent in 52,000 gross acres of gas-prone lands, the first exploratory well was recently spudded. It should reach total depth of about 7,800 feet in early March. A second exploratory well is now under way.

The wells are testing two Slave Point gas prospects of those identified by a three-dimensional seismic program last year. A second 3-D survey will be completed this winter. The company said a successful drilling program could result in a multi-year exploration and development effort.

—GARY PARK, Petroleum News Calgary correspondent

ALASKA

BLM sets public hearings

The Bureau of Land Management has set dates for public meetings in Alaska on the draft environmental impact statement for ConocoPhillips Alaska's Alpine satellite development plan.

All meetings will be from 7 to 9 p.m., preceded by open houses beginning at 5:30:
Barrow, Feb. 9, North Slope Borough Assembly Chambers;
Nuiqsut, Feb. 10, Kisik Community Center;
Atqasuk, Feb. 12, Village Community Center;
Anaktuvuk Pass, Feb. 17, Village Community Center;
Fairbanks, Feb. 18, Noel Wien Public Library;
Anchorage, Feb. 23, Wilda Marston Theater, Z.J. Loussac Library.
Written comments on the draft EIS are due March 1.

● NORTH SLOPE, ALASKA

Nikaitchuq unit wells to explore 3 objectives

Update on Kerr-McGee, Armstrong winter exploration plans at Northwest Milne prospect: first drilling permit issued

By KRISTEN NELSON
Petroleum News Editor-in-Chief

Kerr-McGee Oil & Gas and Armstrong Alaska have three targets in mind for wells from their proposed North Slope Nikaitchuq unit.

The companies have applied to the Alaska Division of Oil and Gas for formation of an exploration unit (see story in Feb. 1 issue of Petroleum News) and Kerr-McGee has received a drilling permit from the Alaska Oil and Gas Conservation Commission for an exploration well on one of the leases in the unit application.

Armstrong brought in Kerr-McGee, a large Oklahoma City-based independent, as majority partner and operator at the Northwest Milne prospect — the proposed Nikaitchuq unit — in early January.

Jan. 29, the companies filed an application for the Nikaitchuq unit in the Spy Island area immediately north of both the Kuparuk River and Milne Point units off Alaska's North Slope.

There are some 12,978 acres in the proposed unit. Five of the eight leases expire Dec. 31 unless included in a unit; two expire May 31, 2008; one was just acquired by Armstrong and would expire in 2010.

Armstrong has been planning wells on this acreage. It told the state this fall that it would drill up to three Nikaitchuq wells at two locations offshore the Milne Point unit in the Spy Island area some three miles north of Oliktok Point.

The companies said in their unit application that three wells are planned for the Nikaitchuq exploration unit: one to be drilled this winter, one to be drilled in 2006 or earlier, and the third well to be drilled in 2008 or earlier.

Both Armstrong and Kerr-McGee have said they would like to drill more than one well this winter, depending on the test results from the first well and the drilling window on the North Slope.

The drilling permit Kerr-McGee received from the Alaska Oil and Gas Conservation Commission is for the Nikaitchuq No. 1, to be drilled from a surface site in section 16, township 14 north, range 9 east, Umiat Meridian, to a bottom hole in section 9-T14N-R9E, UM, on state leases ADL 388580 and ADL 388582. The companies said in their unit application that the No. 1 well has a proposed true vertical depth of 9,150 feet.

The unit application lists the other two proposed wells as the Nikaitchuq No. 3 and No. 4. These are also deviated holes, both from the same proposed surface as the No. 1 well.

The No. 3 has a bottom hole in section 4-T14N-R9E, UM, and a proposed true vertical depth of 9,600 feet.

The No. 4 has a bottom hole in section 20-T14N-R9E, UM, and a proposed true vertical depth of 7,500 feet.

In drilling plans which Armstrong filed with the state this fall it said drilling would be with a land-based drilling rig from an ice pad and approximately four miles of ice road, access to which would be from the existing North Slope road system at Oliktok Point.

The companies said in their unit application that they plan to test prospective intervals in the Cretaceous Brookian sandstone, the Jurassic Nuiqsut sandstone and the Triassic Sag River sandstone.

They said exploration and development drilling in the area of the Nikaitchuq unit "establishes an overall prospective trend for improved Sag River sand quality and thickness to the north/northwest over the northwest Milne structure and within our proposed Nikaitchuq exploration unit."

The Jurassic interval, the secondary interval of prospective interest, has been tied to three-dimensional seismic and to the Thetis Island No. 1, Ivik No. 1, Oooguruk No. 1 and Kalubik No. 1 wells, the companies said.

And the third objective, the Brookian interval, was found "with good reservoir quality and hydrocarbon shows" in wells directly to the southwest of Nikaitchuq. ●

GULF OF MEXICO

Anadarko hits pay in Eastern Gulf

Anadarko Petroleum has made a fourth gas discovery in the Eastern Gulf of Mexico at its Atlas NW prospect, Jim Emme, Anadarko's vice president of exploration and business development, said Jan. 30.

Emme said the exploration well was drilled to a total depth of 16,800 feet on Lloyd Ridge Block 5 and encountered 50 feet of net pay in two middle Miocene intervals. While reserve estimates were not disclosed, Atlas NW is expected to be developed as a satellite, the company said.

Anadarko and other producers in the Eastern Gulf are considering a hub or central processing facility to handle a number of gas discoveries in the area. In addition to Atlas NW, other Anadarko discoveries that could be included in a hub are Atlas, Jubilee and Spiderman.

Anadarko and other producers in the Eastern Gulf are considering a hub or central processing facility to handle a number of gas discoveries in the area. In addition to Atlas NW, other Anadarko discoveries that could be included in a hub are Atlas, Jubilee and Spiderman.

Emme said Anadarko plans to start booking reserves in the Eastern Gulf and appears confident a development plan for the region would be in place by year-end. Anadarko also may drill another well at Jubilee and possibly another at the Atlas-Mondo complex. The 100 percent Anadarko owned Atlas NW discovery was drilled from Transocean's Deepwater Millennium drillship.

—PETROLEUM NEWS

WASHINGTON, D.C.

President's FY 2005 budget proposal assumes ANWR lease sale revenues

Few seemed very surprised that President George W. Bush included projected revenue from potential Arctic National Wildlife Refuge oil and gas lease sales in his proposed budget to Congress, though even supporters acknowledged approval to drill in ANWR is not likely this year.

"It's almost a sort of pro forma action these days," said Roger Herrera, coordinator in Washington, D.C., for Alaska-based Arctic Power, the mostly state-funded group pushing to win congressional approval to open ANWR to exploration and production.

"It's better than not being there," he said of the president's Fiscal 2005 budget, submitted Feb. 2. This is the fourth year of Bush's presidency and the fourth time he has included ANWR lease sale revenues in his proposed budget. Senate opponents have managed to block repeated legislative attempts over the years to lift the federal ban on drilling in the refuge's coastal plain east of Prudhoe Bay.

And this being a presidential election year, Herrera sees the same political problems in winning an ANWR vote in the Senate, especially since it would take 60 votes in the 100-member chamber to block a filibuster — unless supporters can stick ANWR in a budget bill that is exempt from the filibuster maneuver.

Budget does not open area to drilling

The president's budget merely counts ANWR income in federal revenue totals. It does nothing to actually open the area to drilling.

Bush's budget assumes the Department of Interior would collect $2.4 billion from its first ANWR lease sales, which under federal law would be shared 50 percent with the state of Alaska and 50 percent for the federal government.

The ANWR revenue, which first appears in the president's budget for Fiscal 2006, represents about one-twentieth of 1 percent of Bush's proposed $2.4 trillion spending plan for Fiscal 2005, which the administration estimates will run at a $363 billion deficit. Bush proposed that the $1.2 billion federal half of ANWR leasing fees should go toward increased funding for the Energy Department's renewable technology research programs, with the money to be spread over seven years.

The Bush administration wants to lease between 400,000 acres and 600,000 acres in the refuge's coastal plain in 2005. The Interior Department estimates ANWR could hold several billion barrels of recoverable oil, with an estimated production of 5 billion barrels if prices hold around $22 per barrel. The Alaska Department of Revenue estimates it would take seven years after congressional approval for production to start.

The Alaska Legislature has appropriated $12.6 million over the past decade for the state's lobbying efforts to push Congress to open the wildlife refuge to oil companies.

—LARRY PERSILY, Petroleum News Government Affairs Editor

● W A S H I N G T O N , D . C .

Federal energy bill will be cut back

Senate leadership looks to trim costs in effort to win passage

By LARRY PERSILY

Petroleum News Government Affairs Editor

Senate leadership has decided a smaller, less expensive federal energy bill stands a better chance of winning passage this year, and Alaska natural gas line proponents will be looking to make sure the project's incentives don't get trimmed away in the process.

The energy bill that stalled out in the Senate in November includes tax and loan provisions to encourage construction of the $20 billion pipeline from Alaska's North Slope to mid-America.

The 1,100-page bill also includes provisions to spur oil and gas exploration and production in the National Petroleum Reserve-Alaska, and up to $1 billion over 20 years for rural energy projects in the state.

The Congressional Budget Office estimated the bill's price tag in appropriations and tax credits totals at least $26 billion — three times more than the president had said he wanted at the start of the legislation. Opponents say the eventual total could reach $80 billion, after discretionary spending and other future provisions are included.

Sen. Pete Domenici, chairman of the Senate Energy and Natural Resources Committee, said Feb. 2 he plans to significantly reduce the cost of the energy bill to the federal treasury and will bring the lower-cost legislation to the full Senate for a vote, perhaps as soon as the end of this month.

The House passed the bill in November, and its approval would be required again if the Senate passes a different version.

Federal deficit prompts cuts to bill

"It is necessary, in light of current deficit numbers, to trim spending every way that we can," Domenici, R-N.M., said in a prepared statement.

In addition to senators who are griping about many of the home-state projects that House and Senate leaders added to the bill during closed-door meetings last fall to win votes, several fiscally conservative Republicans object to the bill's overall high costs and are unwilling to support the measure unless it is scaled back.

"(Domenici) is saying basically, I get the message, this bill is too rich," said John Katz, director of the state of Alaska's office in Washington, D.C.

It is possible, Katz said, that the cutting will not nick the Alaska gas line provisions or the NPR-A royalty reduction provision.

"All you can say with certainty is that such things as the gas line provisions and the NPR-A leasing provisions have not been controversial to this point," Katz said. "Our goal remains the same, which is to get as many of the Alaska provisions as we can."

In addition to gas line tax and loan incentives, the bill includes up to $1 billion over 20 years for the Denali Commission to spend on rural energy projects in Alaska and a $125 million federal loan to possibly rebuild the dormant Healy coal power plant 110 road miles south of Fairbanks.

Filibuster threat still a problem

Because of threats to filibuster the energy bill, supporters need 60 votes in the 100-member Senate to cut off debate. They fell short by three votes in November. But even if they defeat the filibuster, backers could face another supermajority procedural vote because of the bill's high price tag.

There are objections that the bill's total cost doesn't comply with the federal Budget Act, and overcoming those objections could require another 60-vote majority.

In addition to the cost of the legislation, a controversial provision to exempt gasoline additive manufacturers from product liability claims also is holding up passage of the measure.

The additive, MTBE, or methyl tertiary butyl ether, was used to clean up gasoline emissions but faces its own cleanup problems where it has leaked and threatens underground water supplies.

Several senators have said they would vote for the bill if the MTBE liability waiver is dumped from the measure. But House Energy and Commerce Committee Chairman Billy Tauzin, R-La., whose state is home to MTBE producers, is not willing to concede to their demands.

While not giving in to the opposition, however, Tauzin is resigning his committee chairmanship and said he will not seek re-election to the House in November. Tauzin is considering a high-paying job offer to lead the Pharmaceutical Research and Manufacturers of America, the drug makers' major trade association.

His decision to give up the committee chairmanship effective Feb. 16 is seen as a move to calm accusations that the job offer looks like a payoff for his committee's negotiations with the trade group for prescription drug benefits in the Medicare bill. ●

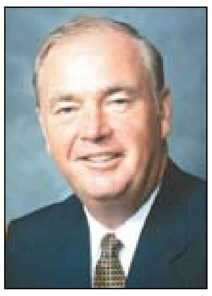
JUNEAU, ALASKA

Murkowski eyes state share of gas line, briefs lawmakers

Alaska Gov. Frank Murkowski told a joint session of the Legislature that perhaps Alaskans should own a stake in any pipeline that moves North Slope gas to market.

The governor, however, did not provide an investment plan.

"Alaskans, in my opinion, should now consider the opportunity to invest in the gas pipeline," he told the Feb. 4 assembly of House and Senate members.



Alaska Gov. Frank Murkowski

Murkowski briefed lawmakers on the status, process and potential outcome of Stranded Gas Act negotiations with the major North Slope producers and MidAmerican Energy Holdings Co., both of which have submitted fiscal contract applications to the state. The Stranded Gas Act allows potential gas line project sponsors to negotiate a long-term fiscal contract with the state in lieu of risking frequent changes in state and municipal taxes.

Either of the applicants is capable of taking on the project, the governor said. "The receipt of these applications represents a first step in the right direction."

Governor lists state benefits

That direction, he said, could lead to increased oil and gas exploration in Alaska, $600 million a year in state production tax and gas royalty payments starting sometime after 2010, construction jobs for Alaskans, job orders for Alaska contractors, a new gas supply to cover Cook Inlet's dwindling flow for Anchorage and the Kenai Peninsula, and economic development opportunities for gas-less communities such as Fairbanks including petrochemical industries.

He also cautioned lawmakers, however, there is more work to do before construction begins. "Keep in mind the Stranded Gas Act does not compel the applicant to build the pipeline, it only assures fiscal terms should the decision to build be made."

In addition to negotiating a fiscal contract with the state, both project developers need the federal incentives in the stalled energy bill and confidence in their construction cost estimates and market demand and price projections before committing to spending money and burying pipe.

But if either the producers or Lower 48 pipeline operator MidAmerican decides to build the multibillion-dollar Alaska gas line, the state and individual Alaskans might want to buy a share of the venture, Murkowski said.

No specific plan for state ownership

The governor does not have a financial plan ready for how the state or individuals could buy a share of the project, but he

see SHARE page 16

Senate committee recommends state gas authority funding

The Alaska Senate Resources Committee has recommended $2.15 million in additional funding for the state gas development authority, which says it needs the money soon to complete its planning work for a state-owned liquefied natural gas project.

The committee moved the funding measure, Senate Bill 241, to the Finance Committee for its consideration. No hearings in Finance were scheduled as of Feb. 5.

Board members of the Alaska Natural Gas Development Authority have been pushing hard since last fall for the additional money to add to the $350,000 they have already spent this fiscal year. The authority, created by a voters' initiative in November 2002, has a mid-June deadline to submit its project development plan to the Legislature.

The authority is looking at building a natural gas pipeline from Alaska's North Slope to Valdez, where it would build an LNG terminal to ship the chilled gas to possible buyers around the Pacific Rim. The project is estimated to cost at least $12 billion.

Resources Committee members Sens. Ralph Seekins, R-Fairbanks, and Kim Elton, D-Juneau, recommended passage of the bill Jan. 28. Sens. Scott Ogan, R-Palmer; Ben Stevens, R-Anchorage; and Fred Dyson, R-Eagle River, signed the bill sheet "no recommendation."

● NORTHWEST TERRITORIES

Mackenzie gas project faces full review

Canadian government orders exhaustive environmental assessment; decision welcomed by Imperial Oil, which sees no reason why project should be delayed

By GARY PARK

Petroleum News Calgary Correspondent

The Mackenzie Gas Project will get a thorough environmental probe to ensure there is no negative impact within the Inuvialuit area of the Mackenzie Delta region.

The Canadian Environmental Assessment Agency announced Jan. 30 that a special federal review panel will be appointed to conduct the "most rigorous level of environmental assessment."

Environment Minister David Anderson said the referral is an important step in "establishing a rigorous, coordinated environmental assessment process for the entire project."

He said the process will "allow for significant cooperation between the Inuvialuit and the federal government while ensuring a level of scrutiny that a project of this magnitude deserves."

Two Inuvialuit-nominated members on panel

Frank Pokiak, chair of the Inuvialuit Game Council, said he was satisfied that the inclusion of two Inuvialuit-nominated members on the panel would ensure that aboriginal interests could be accommodated.

"This is especially important since such an extensive and significant part of this gas project — the gas fields and the gas gathering system — are located within our settlement region," he said.

> *Frank Pokiak, chair of the Inuvialuit Game Council, said he was satisfied that the inclusion of two Inuvialuit-nominated members on the panel would ensure that aboriginal interests could be accommodated.*

Anderson set the wheels in motion last August to establish a single joint review panel process by referring the project to a screening committee, which determined the project could have a significant negative impact on the environment or Inuvialuit wildlife harvesting in the Inuvialuit Settlement Region and decided to refer the project to the federal review panel process.

Review will help determine pipeline location

Hart Searle, a spokesman for Imperial, the lead partner in the Mackenzie Delta Producers Group, told the Calgary Herald the decision to conduct a detailed review was not unexpected and was a step the project sponsors had recommended.

He said there was nothing to indicate a delay in having the project completed. If construction work starts on the gathering system and main pipeline in 2006, the first deliveries are still possible in 2008 or 2009.

see MACKENZIE page 16

● ALASKA

Alaska partners ready for North Slope natural gas line

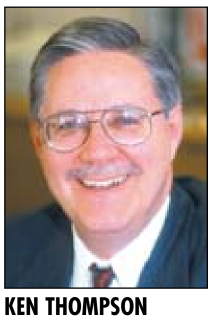
Native corporations, Pacific Star Energy in line for 19.9 percent share

By LARRY PERSILY

Petroleum News Government Affairs Editor

The Alaska partners in MidAmerican Energy Holdings Co.'s bid to build and operate a North Slope natural gas pipeline say they intend to exercise their options to take a combined 19.9 percent ownership if the project moves forward.

"We will execute that option," said Ken Thompson, president of Pacific Star Energy LLC, one of MidAmerican's two partners in the project. Pacific Star is an Anchorage-based consortium of 12 of the state's regional Native corporations.



KEN THOMPSON

The agreement gives Pacific Star Energy and Cook Inlet Region Inc., the Native regional corporation for Cook Inlet, the option to each take 9.95 percent ownership in the project. Des Moines, Iowa-based MidAmerican, controlled by Warren Buffet's Berkshire Hathaway Inc., would hold 80.1 percent of the pipeline venture.

Until MidAmerican issues its first capital call, the Alaska partners' investment is small. But if the Lower 48 pipeline operator proceeds with the project, estimated at $6.3 billion, the Alaska partners could be called on to contribute about $380 million to maintain their 19.9 percent share if the project goes ahead at 30 percent equity and 70 percent debt.

As part of the deal, MidAmerican is holding out the option for other investors to buy in at up to 5 percent, in which case CIRI and Pacific Star Energy would see their shares reduced to 7.45 percent each to make room.

TransCanada could join partnership

Thompson said one possibility is that TransCanada could take the full 5 percent option. The Calgary-based pipeline company is the likely candidate to build and operate the pipeline from the Alaska border, where MidAmerican's ownership would end, to central Alberta, where the pipe would connect to the North America distribution grid. (See related story on page 4.)

In addition to its individual 9.95 percent option in the pipeline venture, CIRI is among the 12 corporations with a stake in Pacific Star Energy. The only one of Alaska's 13 regional for-profit corporations not in the deal is Ahtna Inc., the Glennallen-based corporation for the Copper River basin, Thompson said.

The 12 corporations needed to sign on for $83,400 each, or $1 million total, to start up Pacific Star Energy last year and carry the business through the

see PARTNERS page 16

● JUNEAU, ALASKA

Lease buyback bill gets Senate hearing

Alaska senators told cost of shallow gas buyback could be in the millions

By LARRY PERSILY

Petroleum News Government Affairs Editor

State senators took no action at the first committee hearing on legislation to buy back up to 23,000 acres of shallow gas state leases north of Homer on Alaska's Kenai Peninsula.

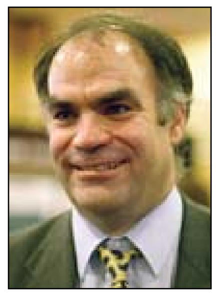
Buying back the leases could cost the state much more than the $500 each the company paid for the right to lease the acreage, said Mark Myers, director of the Oil and Gas Division at the state Department of Natural Resources.

Myers told the Senate Community and Regional Affairs Committee the price tag could include any costs incurred by the developer and, possibly, compensation for the value of any gas that might exist underground.

The committee, which took no public testimony on the bill at its Feb. 4 hearing, could bring up and move the bill in the 13 weeks before the Legislature's scheduled May 12 adjournment or kill the measure by not sending it to its next committee.

The sponsor, Sen. Gary Stevens, told committee members the coalbed methane leases were an "unintended consequence" of a 1999 decision to exclude the area from a larger lease sale program. By excluding the uplands near Kachemak Bay from the state's areawide lease program, he explained, the subsurface rights to the land became available for the less regulated over-the-counter leasing program.

JUDY PATRICK



"The applicants could claim significant resource value." —Mark Myers, director of Alaska's Oil and Gas Division

Fish and wildlife, tourism the issues

Stevens, a Kodiak Republican whose district includes the lower Kenai Peninsula, wants his colleagues to support his bill to buy back the leases and impose a moratorium on any new leases in the area. Many residents fear the drilling could hurt water quality, fishing and tourism, the senator said. The state in 1976 banned oil and gas leasing in Kachemak Bay to protect the rich marine life of the area, and Stevens believes the ban should be extended to the uplands to safeguard fish and wildlife habitat and the area's profitable and growing tourism industry.

If the state and leaseholder cannot reach a negotiated buyback price, Myers told committee members, the state could use its eminent domain authority to take the leases but would have to pay "just compensation," which could cover undiscovered gas reserves.

For example, he speculated, if one-fifth of the acreage holds gas in a 50-foot-thick sands play, it could total 20 billion cubic feet of natural gas, or perhaps $20 million in value at $1 per thousand cubic feet.

"The applicants could claim significant resource value," he told the committee.

The estimate applies to conventional gas in sandstone formations, which Myers said is probably the leaseholders' target rather than methane trapped in coalbed seams. There is likely more coalbed gas in the area, he said, but it is more costly and difficult to extract, and would present its own problems for calculating its value in an eminent domain case.

No exploration under way

No exploration work is under way on any of the leases, Myers said, adding, "no one has proposed a well." He also told the senators, "In all likelihood, many of these leases will not be explored."

The eight shallow gas leases are south and east of Anchor Point, just north of Homer and toward the head of Kachemak Bay. ●

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continued from page 15

PARTNERS

end of this year, Thompson said. "There may be additional investment in 2005."

Until more money is needed, "we're assisting MidAmerican with our knowledge," said Thompson, a former president of ARCO Alaska Inc. In addition to the Native corporations, Thompson and his wife are shareholders in Pacific Star, through their company Pacific Rim Leadership Development LLC.

No schedule announced for capital

MidAmerican project leader Kirk Morgan declined to say when the company would issue its first capital call if it goes ahead with the Alaska gas project. Its application to the state for a fiscal contract for the project shows permit work starting the second half of 2004, detailed engineering starting the second quarter of 2005, construction in 2007 and full gas flow in 2010 at 4.5 billion cubic feet per day.

MidAmerican's application under Alaska's Stranded Gas Development Act allows the company to negotiate a fiscal contract with the state for a schedule of payments in lieu of perhaps uncertain state and municipal taxes over the life of the project. The application is not a commitment to build the line, but would set up the state and municipal payment plan if the company goes ahead with the investment.

The three major North Slope producers submitted their own Stranded Gas Act application to the state a couple of days before MidAmerican turned in its proposal last month, and state officials plan to start separate fiscal contract negotiations with both applicants this month. It likely will be up to MidAmerican and the producers, not the state, to decide which one goes ahead with the pipeline, or perhaps the companies might join forces for the project.

Thompson said Pacific Star Energy expects it could use its cash flow from the pipeline to build natural gas and gas liquids distribution centers in Alaska and perhaps spur pipelines to carry gas to Fairbanks and Anchorage. He said Pacific Star would look at such ventures on its own, separate from the MidAmerican partnership.

Native corporation has cash to invest

Cook Inlet Region Inc. said it decided to invest for the expected profits and to give Alaskans an ownership stake in the gas line — something they don't have in the trans-Alaska oil pipeline. CIRI already holds natural resource investments through its partnership with Nabors Industries in Peak Oilfield Service Co. and Alaska Interstate Construction LLC, which provide oil field, mining and construction services.

The Anchorage-based Native corporation has rung up impressive profits in recent years, totaling $723 million in net income between 1997 and 2002. In addition to its oil field and construction businesses, it also holds investments in Alaska tourism ventures, resort hotels in Arizona and Nevada, and wireless communications systems nationwide.

"CIRI's recent financial performance has allowed it to accrue the funds needed to participate in the project independently," said a prepared statement issued by the company. ●

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continued from page 15

MACKENZIE

Environmental groups, including the Sierra Club of Canada, the Canadian Nature Federation and the Canadian Arctic Resources Committee, have signaled their intention to challenge the Mackenzie project and demand an examination of alternative energy projects.

In the meantime, progress on soil analysis and geotechnical surveys is moving ahead along the 800-mile pipeline route.

Searle told Petroleum News the work will help determine the optimal location of the pipeline.

He said the program has been completed in the Inuvialuit area and is now under way in the Gwich'in and Sahtu regions, while negotiations are taking place with the Deh Cho to extend the studies to the lower Northwest Territories. ●

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continued from page 15

SHARE

believes it might make sense for the state to buy in equal to the one-eighth royalty share it holds on North Slope gas production, said John Manly, Murkowski's press secretary.

The governor also did not say if he wanted state ownership options discussed as part of the Stranded Gas Act negotiations, which will start soon and, hopefully, he said, produce a contract he can bring to the Legislature in time for adoption before its May 12 adjournment deadline.

In addition to negotiating fiscal terms for project owner payments to the state, the Stranded Gas Act negotiations could condition any development incentives on work requirements for the project, according to a fact sheet distributed by the governor's office during the speech.

— BY LARRY PERSILY, Petroleum News government affairs editor

Companies involved in North America's oil and gas industry

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

Petroleum news

Business Spotlight

By PAULA EASLEY

FORREST CRANE

Greg Thies, director of marketing

Evergreen Helicopters of Alaska

Evergreen Helicopters of Alaska Inc. operates in Alaska and Panama and has added to its services on-call, medical and hot freight aircraft charter support using a 7-8 passenger Lear 35A, 14-19 passenger Gulfstream VI and a Beech King Air B200C. It will soon test-fly the world's largest aerial tanker for laying down fire retardant and oil spill surfactants.

Greg Thies has a broad background in transportation services. For the last 13 years he has worked to develop cost-effective aviation solutions for Alaska and the Russian Far East, and "growing" Evergreen. When not doing that, he and wife Carol Gray enjoy growing show-stopping vegetables and flowers. Greg also supports organizations that work to grow Alaska's economy. His favorite quote: "A cord of three strands is not quickly broken."

FORREST CRANE

Lisa Marquiss, regulatory compliance director

Carlile Transportation Systems

Carlile Transportation Systems is headquartered in Anchorage with terminals in Deadhorse, Fairbanks, Kenai, Seward, Houston, Federal Way, Washington, and Edmonton, Alberta. This Alaska-owned and operated full-service transportation and logistics company incorporated in 1980. Accommodating increased security initiatives for freight transportation, Carlile's security plan will be the first federally reviewed plan in Alaska.

Designing and managing unique, security-sensitive shipping and handling projects greatly appeals to regulatory compliance director Lisa Marquiss, who joined Carlile in 1986. She's an expert at managing hazardous materials and hazardous waste shipments, and is intrigued by recent advancements in transportation technology. Lisa enjoys shotgun sports and bowling with daughter Christynne (20), a student at UAA, and sons Greg (14) and Christopher (11).

continued from page 1

EVIDENCE

2003 provided a foundation for a new up cycle for Smith. "We're optimistic about our prospects for 2004 with the global economic recovery providing a backdrop for longer-term sustainable growth in the oil service market," he added. Rowan Companies and BJ Services, the first major contract driller and oilfield services company to report 2003 fourth-quarter earnings two weeks ago, dropped a strong hint then business was going to improve following a couple of challenging years for industry.

E&P companies need to be willing to spend

Drillers and service companies depend almost entirely on the financial health of exploration and production companies and their willingness to spend. However, despite last year's high commodity price environment, so-called E&P companies were cautious on the drilling front, opting to exercise capital discipline by using excess cash for such things as paying down debt, buying back shares of their own company and making property acquisitions that generally bring proved reserves.

But E&Ps have entered the new year with cleansed balance sheets and should "witness commendable" increases in drilling activity over the next two or three years, Simmons said in a report to investors. Simmons is forecasting a U.S. drilling rig count of 1,151 in 2004, 12 percent higher than the 2003 average of 1,031. Internationally, the rig count is projected to expand 6 percent to 821, while the offshore rig count alone could increase by 12 percent, led by a recovery in activity in West Africa.

Nevertheless, because E&Ps apparently "have awakened to the virtues of capital discipline, we expect excessive conservatism and adherence to capital discipline to continue," Simmons said, adding that it does not believe industry "will revisit the halcyon days" of 1995 to 1997, and "especially" 2000 when U.S. drilling activity swelled by 48 percent.

Over the next two years, Simmons said it expects compound annual earnings growth of about 20 percent to 30 percent for service companies and 30 percent to 40 percent for contract drillers — "not bad, but not explosive relative to oil service standards of recent past cycles."

Nabors, Smith both report growth

Nabors, which owns and operates about 600 land rigs and 950 land workover and well-servicing rigs worldwide, reported 2003 fourth-quarter net income of $64.9 million or 42 cents per share, compared to net income of $50.3 million or 33 cents per share in the 2003 third quarter and $27.2 million or 18 cents per share for the same period a year earlier.

"All of this continues to reinforce our conviction that we can sustain robust growth in our results for the next several years," Isenberg said of the company's financial performance. "In 2004, we expect to see a continuation of the magnitude of growth in earnings per share that we saw in 2003, even in the face of a much higher tax rate."

Smith, a leading worldwide supplier of products and services to industry, posted net income for the 2003 fourth quarter of $38 million or 41 cents per share. Because of significant growth in Western Hemisphere drilling activity, results were more than double the $17.7 million or 18 cents per share reported for the same period a year earlier. Compared to the 2003 third quarter, revenues grew 6 percent while earnings improved 6 cents, or 17 percent, after excluding the impact of charges.

"Although we are pleased with the strong earnings performance, we're equally impressed with the level of cash flow we've been able to generate so far this cycle," said Loren Carroll, Nabors' executive vice president. ●

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TRUSTS

and 2001 and C$800 million in 2000.

Sayer said the trusts snapped up C$4.5 billion worth of assets last year, mostly to replace production and build reserves.

The trust ranks have mushroomed from 15 in 2000 to 18 at the end of 2002 and 28 at the end of 2003.

Sayer said debt financing for 2003 was valued at C$5 billion, as prime interest rates started and ended the year at 4.5 percent.

The primary issuers were Nexen with C$1.18 billion in two transactions, Petro-Canada with C$814 million in two deals, EnCana C$671 million, Suncor Energy C$657 million, Canadian Oil Sands Trust C$570 million and Pengrowth Energy Trust C$291.5 million.

Equity issues attracted C$2.3 billion, up 46 percent from 2002's C$1.57 billion, with junior producers dominating the markets.

There is no sign of a slackening this year, with an initial public offering of C$52.5 million by Duvernay Oil drawing a flood of interest. Duvernay's chief executive officer, Mike Rose, held the same post at Berkley Petroleum when it was acquired by Anadarko Petroleum for C$1.4 billion in 2001 — making him one of several experienced oil patch leaders who have taken the helm at start-up companies.

—GARY PARK, Petroleum News Calgary correspondent

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UNOCAL

lower than expected discovery volumes pushed well beyond the company's goal of spending $8 or less per barrel of oil equivalent reserves in finding, development and acquisition costs. FD & A costs for the Gulf shelf were just under $42 per barrel.

In North America, the Alaska, Pure Resources and Northrock programs met or exceeded the $8 goal, the company said Feb. 2, but Gulf costs drove the overall cost of a barrel of new reserves in North America to $9.88 per barrel. That figure doesn't include the company's deep water drilling program, where costs were running $32.43 a barrel.

International FD & A costs at less than $5 per barrel

For Unocal's international operations, finding, development and acquisition costs came in at less than $5 per barrel. Unocal, based in El Segundo, Calif., booked new reserves in Bangladesh and offshore Indonesia as reserves outside North America grew by a hundred million BOE to 1,182 million BOE, two thirds of the company's total.

In Alaska, the company added 9 million equivalent barrels to its reserves, at an FD&A cost of $4.71 a barrel, best of any company segment. Six million BOE came from discoveries and extensions, while about 3 million came from revisions and purchases. Alaska reserves still declined from 104 million BOE to 101 million as the company produced 13 million BOE in the state during 2003.

The company booked 7 million barrels of oil equivalent for the Mad Dog and K2 projects in the deepwater Gulf. Mad Dog startup is expected next year.

Unocal added 203 million barrels of oil equivalent to its reserves through discoveries and extensions out of total additions of 258 million BOE, while producing 169 million BOE. Worldwide reserves at the end of 2003 were estimated at 1,765 million BOE, down from 1,774 million a year earlier due to sales of 98 million barrels of oil equivalent reserves.

Unocal says it's cautious in evaluating projects to avoid overstating prospects. Last year, more than 75 percent of Unocal's reserves were evaluated by auditing teams that include an independent engineering firm. ●

continued from page 1

SABLE

Keeping production within that range means the South Venture field — one of Sable's six fields — must come on-stream as scheduled later this year and additional compression facilities must be introduced in 2006, Kinnear said.

New discoveries, JV deal could extend operating life

Beyond that, he said the best hope for extending the operating life hinges on new discoveries and possibly reaching a joint venture deal with EnCana, which owns the nearby Deep Panuke field.

Pengrowth's decision to chop its share of reserves to 126 billion cubic feet from 176 bcf was based on a preliminary analysis by independent appraiser Gilbert Laustsen Jung Associates. It came only four days after Shell Canada, which has a 31.3 percent stake in the consortium, downgraded its reserves by 40 percent to 430 bcf from an original 1.1 tcf.

ExxonMobil Canada, the 50.8 percent operator, said its own analysis of Sable production data confirms the Shell Canada numbers.

In a report to clients Jan. 30, FirstEnergy Capital estimated that Sable comprised 16.1 percent of Pengrowth's reserves at the end of 2002 and thus the trust would be the "most adversely affect" of the consortium partners.

Pengrowth, one of the largest energy trusts in North America, said the Sable revisions have lowered its overall proved reserves by 9.3 percent or 17.1 million barrels of oil equivalent, but Kinnear said they had already been factored in when the trust paid C$122 million last year for a stake in Sable pipeline and processing facilities, on top of its 8.4 percent working interest in the field.

The trust said Feb. 2 that it expects to maintain its monthly distributions of 21 cents per unit through 2004.

Investors spooked

But unit holders were temporarily spooked by the reserves cut, sending units on a wild ride Feb. 2, shaving as much as 16.2 percent in early trading before ending the day down 4.6 percent.

Since starting production, Sable has peaked at 550 million cubic feet per day in exports to the U.S. Northeast, with expectations that it would sustain exports of 500 million cubic feet.

But the flow has gone into decline, averaging only 430 million cubic feet per day last year, against a background of mounting analysts' predictions that Sable was unlikely to meet its forecast 25-year operating life.

The bleak outlook was reinforced by Shell Canada's announcement that a development well last year showed the Glenelg field — the last field that was targeted for inclusion — was not economically viable as a standalone development. There had been hopes that Glenelg would start pumping sometime between 2004 and 2007.

In addition to removing Glenelg from current development plans, Pengrowth said the Sable consortium has excluded an undrilled fault block at the North Triumph field and experienced poorer-than-anticipated performance from the producing Venture field.

Government calls for stepped up drilling

Nova Scotia Energy Minister Cecil Clarke said the reserve downgrade and the Glenelg write-off is a "disappointment," but should also be a "rallying call" for the industry to step up drilling off Nova Scotia.

A Shell Canada spokeswoman told reporters the South Venture field should come on stream later this year to sustain production, while the company is ready to move on its own or with partners to explore both the shallow and deep waters of the region "because we still think it has potential."

The reserve setback also shifts the spotlight to discussions taking place between the Sable owners and EnCana about the possibility of connecting EnCana's 930 bcf Deep Panuke field to the Sable infrastructure.

Once targeted for a 2006 start-up and peak output of 400 million cubic feet per day, Deep Panuke was scrapped in its present form two months ago, while EnCana weighs several options including a smaller facility.

Faced with shaky economics for a standalone project, EnCana is now exploring a possible joint effort or cooperation to use Sable's established infrastructure.

In addition, the MarCoh D-41 well, which was drilled last year in the Deep Panuke reservoir by ExxonMobil, EnCana and Shell Canada and encountered 100 meters of gas bearing reservoir, could be a candidate for tying in.●

continued from page 1

EXXON

delta, where the pipe would pick up Canadian gas and head south to Alberta.

ConocoPhillips and BP Exploration (Alaska) said they are not interested in the over-the-top route, but ExxonMobil wants to keep the option open.

"It's just Exxon being Exxon," said John Manly, the governor's press secretary.

State law prohibits permitting the over-the-top route, which Alaskans generally oppose because of the perceived environmental risks from a buried pipeline running offshore in the Beaufort Sea; the loss of short-term construction jobs from building less pipe in Alaska; and the loss of potential gas delivery to Fairbanks and other Interior communities unless the highway line passes through the area.

Conoco firm on highway route

"ConocoPhillips has been steadfast over the past three or four years that the best way to do this project is the southern (highway) route," said Kevin Meyers, president of ConocoPhillips Alaska Inc. "Not all of our partners have converged on that conclusion yet."

The company also put it in writing to the state. "ConocoPhillips is only interested in a southern route project," said a Jan. 13 letter accompanying the stranded gas application and signed by ConocoPhillips and BP.

BP has reached the same conclusion. "BP is entirely focused on a southern highway route," said Dave MacDowell, gas project spokesman in Anchorage.

The application acknowledges that the producers' 2001-2002 multimillion-dollar engineering study looked at both routes, but also says: "It is recognized that current state law prohibits the issuance of right-of-way permits for a northern route pipeline until a southern route pipeline is built."

The producers have applied to negotiate a long-term fiscal contract with the state, setting up a schedule of payments in lieu of state and municipal taxes should the companies decide to build the gas pipeline. Negotiations are expected to start this month, and the contract is subject to legislative approval.

Exxon wants all options open

ExxonMobil, however, is not ready to limit the discussions to just the highway route.

"A commercially viable project has not been identified," said company spokesman Bob Davis of Houston. "For this reason all options need to remain open. This approach provides the greatest opportunity to identify a commercial project."

ExxonMobil was not part of the original application submitted Jan. 13 by ConocoPhillips and BP, but a few days later approached the two companies and asked to join the application. The producers submitted their amended application Jan. 20.

Asked why the company was not part of the original application but later joined up, ExxonMobil's Davis answered, "I can't respond to this question, but ExxonMobil is delighted to be working with the state on fiscal terms."

The other application to the state to negotiate a gas line fiscal contract, from MidAmerican Energy Holdings Co., applies only to the highway route. MidAmerican submitted its application Jan. 22, two days after the three producers turned in their amended application.

—LARRY PERSILY, Petroleum News government affairs editor

continued from page 4

TRANS-CANADA

"We believe a greenfield process is certainly one of the possibilities," MacDowell said of the producers' options for permitting the project.

FERC report looks at issues

"There are no simple answers to the legal questions posed," said a 2001 FERC staff report on whether the treaty, laws and certificates of 25 years ago are the only way to get the line built.

The report does note, however, that the Alaska Natural Gas Transportation Act of 1976 "does not bar proposals that might compete" with the Northwest Pipeline certificate.

ConocoPhillips Alaska President Kevin Meyers declined to answer whether his company believes TransCanada holds exclusive rights to any Alaska gas line project. "We're interested in talking to people who bring value to the table," he said. "Clearly, they have skills and value."

Standard & Poor's Ratings Services also sees value in TransCanada's potential to take part in an Alaska gas line project. The agency Jan. 23 boosted its commercial paper rating for Foothills Pipe Lines Ltd., which is 100 percent owned by TransCanada. In raising Foothills to an A-1 rating, S&P noted: "Foothills' ownership of the construction and operating rights to the Alaska Highway Pipeline Project is important to TransCanada's interest in transporting Alaska gas."

For its part, TransCanada is encouraged to see two potential developers step forward and apply to the state of Alaska to start negotiations for a fiscal contract for the project, Feick said. ●

● ALASKA

MMS seeking interest in Chukchi Sea

Agency considering incentives, offered for the first time in Alaska in September's Beaufort Sea OCS sale

By KRISTEN NELSON

Petroleum News Editor-in-Chief

If we held a lease sale, would anyone come?

That's the question the Minerals Management Service is posing to oil and gas companies about the Chukchi Sea northwest of Alaska and the Hope and Norton basins west of Alaska's Seward Peninsula.

"The Chukchi Sea and Norton Basin have great potential as sources of oil or gas but the accompanying high economic cost due to the distance from any infrastructure make them challenging areas to lease," said MMS Alaska Regional Director John Goll.

"Our objective through this 'special interest' process is to see whether any companies are interested at this time to explore these frontier areas. If they are, we can design a sale. If no one expresses interest, we save a lot of work and money," he said Jan. 30.

The agency published a call for information and nominations in the Federal Register, seeking comments on proposals from industry and the public. MMS requests that industry nominate small, very specific areas where they are willing to commit to exploration.

This would be the first step in the special 18-month leasing process for federal outer continental shelf tracts in frontier agencies.

MMS said it "is considering offering economic incentives similar to those offered recently in the Beaufort Sea Sale 186 held in September 2003."

The agency said it will used information received to make a decision on whether or not to proceed with leasing, and if there is no interest this year, it will postpone the sales and ask for leasing interest in the areas again next year. If a company is interested in one of the areas, MMS would then ask them to identify the area of interest. The areas open for nominations are relatively large, MMS said, and "the purpose of this 'special interest' process is to identify and offer only small focused areas in these federal waters where industry has a significant interest in exploration."

Nominations and comments are due by April 29.

First Alaska incentives in September's Beaufort Sea OCS sale

MMS offered incentives for the first time in an Alaska outer continental shelf lease sale in its Beaufort Sea sale last September. In addition to reduced minimum bid amounts and sliding scale rentals, the agency offered royalty suspension for first oil production, with suspension volumes varying by sale zone.

Economic incentives are also being offered for the first time in Cook Inlet OCS lease sale 191, tentatively scheduled for May 19: a longer primary lease term of eight years; lower minimum bid ($25 per hectare) and annual rental rates ($5 per hectare); and royalty suspension volumes, which would relieve royalty payments on a producing lease for the first 30 million barrels of oil equivalent, applied to both oil and natural gas, with price floor and ceiling thresholds. ●

Want to know more?

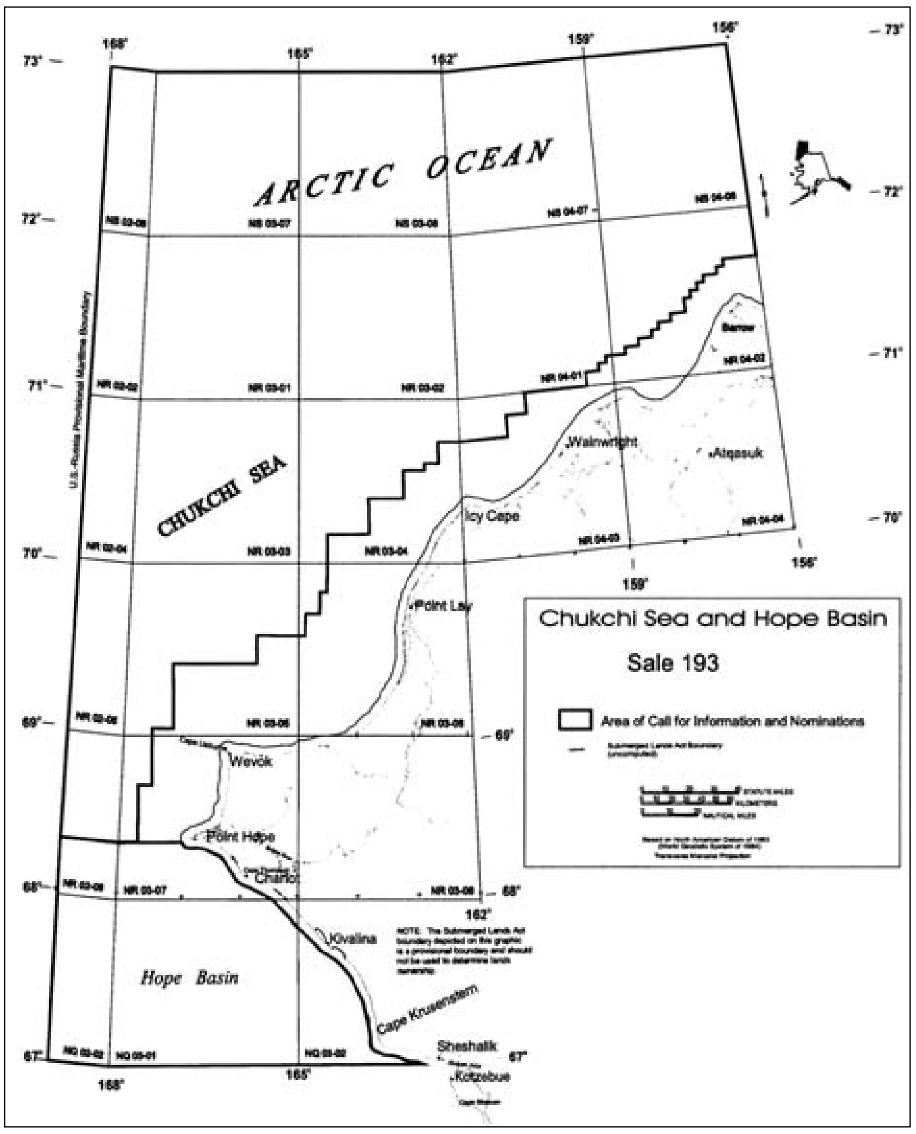
If you'd like to read more about the Chukchi Sea, go to Petroleum News' web site and search for these articles, which were some of the articles about the Chukchi published in the last few years.

Web site: www.PetroleumNews.com

2003
- **June 29** EIA says U.S. crude imports up from last year
- **March 30** MMS asks for nominations for Norton Sound, Chukchi Sea-Hope Basin
- **March 2** Selling the Beaufort
- **Feb. 23** MMS issues final EIS for Beaufort Sea planning area
- **Feb. 16** Arctic commission says if U.S. ratifies U.N. treaty it can lay claim to oil rich Chukchi Cap

2002
- **Dec. 29** She(ll) loves me, She(ll) loves me not, She(ll) loves me?
- **Dec. 29** Tantalizing possibilities (major Chukchi article about geologic potential)
- **Feb. 10** February 1989: Officials approve Shell's Chukchi oil search

2001
- **Nov. 4** A wait and see game: Shell returns
- **March 28** Climbing temperatures will affect oil patch
- **March 28** Rotational model spins out clues to next big Arctic oil find



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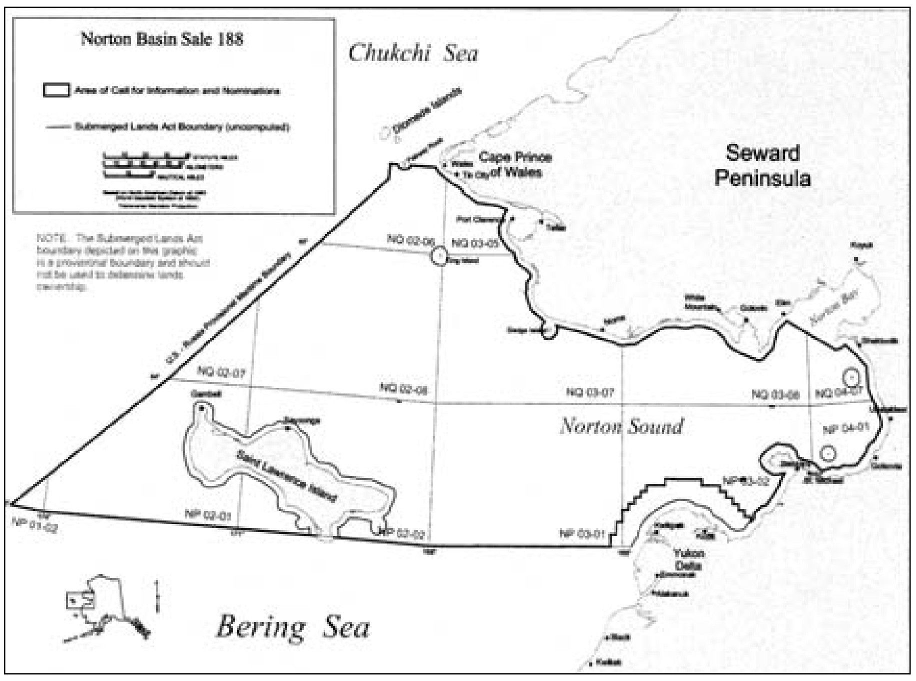
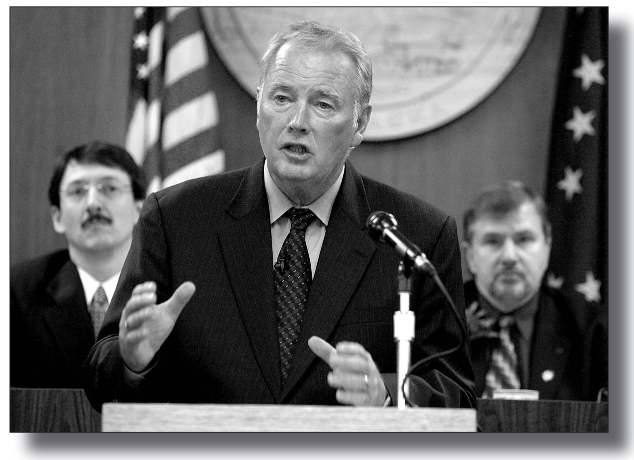


COURTESY MMS

Securing Alaska's Future
A Report to Alaskans

On January 13, I delivered the State of the State address to the 23rd Alaska Legislature in Juneau. The following excerpts from that speech are provided as a public service to Alaskans. The issues we face as a State are important to every Alaskan, and it is my hope that you will take the time to read this publication and become familiar with the issues addressed. Throughout my long public service career I have been consistent in my trust in the people. It is time to engage all Alaskans again in the process of securing Alaska's future. By working together to face the challenges before us, we can secure a brighter future for generations to come.



My theme tonight is securing Alaska's future.

What we have accomplished this past year is a result of teamwork, and I know the spirit of cooperation and the spirit of service will continue to reap benefits for Alaska's future.

Alaska's greatest resource is our people. The energy, the enthusiasm, the spirit of Alaskans is what makes us strong.

With one year in office now passed, my enthusiasm and optimism for Alaska is brighter than ever.

The state of our state is strong!

The opportunity and the responsibility lie before all of us to make an even better future for Alaskans.

Before becoming your governor, I promised I would:
- launch an aggressive resource development program,
- impose no income tax, and
- rein in state spending,

I take my promises seriously.

And I am proud to report that we are implementing our fiscal program to keep our promises. In just one year we have accomplished a great deal for which all Alaskans can be proud.

We instituted a meaningful program to stimulate natural resource development in a responsible way. It includes: a streamlined permitting process, new incentives to encourage private investment, and a business-friendly regulatory climate -- without relaxing our strict environmental safeguards.

We held firm on the imposition of no new income tax.

And we reduced General Fund spending by $245 million dollars.

I recognize that a government's budget is about more than just how much money is spent. It's also about our responsibility to see that those dollars produce results. And, it's about getting a return on the dollars invested in services. But most important it's about people, their lives and their children. What we approve during this legislative session will have a great impact on the future of our children, who make up nearly one third of the population. We still have much to do. Indeed, we are going to be held accountable by future generations for how well we conduct our stewardship responsibilities today.

In an address I intend to make on March 9th I will detail the many initiatives and developments of my administration. They include oil, gas and mineral development, new roads, revitalized timber and fisheries, and new services - especially for senior citizens.

In fact, each of you has on your desk a special report describing what we are doing in these areas. Others can find the report on the state's web site.

Our initiatives promise great results for Alaskans.

But to achieve these results, we must create an investment climate based on financial stability and certainty. Everything else depends on it.

When I delivered my proposed budget on December 15th I promised to discuss my long-term fiscal program with you tonight.

This subject is so important that it's the primary topic of my remarks.

It will chart our shared future.

And the key to that future is financial stability. Throughout our short history, Alaskans have demonstrated the ability and resolve to balance individual and shared needs.

I am calling Alaskans to the task again.

The Alaska Constitution bestows extraordinary authority and responsibility on the Governor and along with that authority goes the responsibility to lead. I eagerly shoulder this responsibility, and I am proposing a fiscal program that sets a path to financial stability for us to follow together.

This path is consistent with my promise to develop jobs, a strong economy and to control state spending without undue burden on our citizens.

My fiscal program is based on sound economic principles.

It recognizes that development of our resources, both human and natural, is the only long-term foundation for fiscal stability for Alaska.

This program recognizes that building a vibrant and sustainable economy will not be served by simply taxing the income of hard working Alaskans.

People don't tax themselves to prosperity. They invest to prosperity.

Let me discuss the five elements of my fiscal program.

Thirty years ago, the Trans-Alaska Pipeline was designed and built to carry two million barrels of oil a day. It only reached that capacity briefly in the late 1980s when the nation was gearing up for the Persian Gulf War. Today, the pipeline moves less than 1 million barrels and in the years to come we can continue to expect less unless we act now to explore and develop new oil fields.

New oil in the pipeline, coupled with new developments in natural gas, form the first element of my program.

The state will help build the infrastructure and create the economic atmosphere to increase oil flow and move gas to market.

The top priority of this administration is the construction of a gas pipeline - to move to market the 35 trillion cubic feet of gas stranded in Prudhoe Bay. Remember though - Prudhoe Bay took 8 years to develop after it was discovered. It will likewise take time for new developments like the natural gas pipeline, the National Petroleum Reserve, and oil and gas from the Alaska Peninsula. The state will gain the jobs and economic lift from these activities by the end of the decade.

The second element of my program is fiscal discipline. My commitment to this element of my fiscal program is unwavering. This means:

• Control state spending and be accountable for delivering results for every dollar spent; and

• Emphasize the essential responsibilities of government such as education, public health and safety, transportation and environmental protection, all of which are hallmarks of a strong and caring society.

Spending by state government cannot serve as the underpinning of our state economy. Government spending cannot be our economy. The role for state government is to enable Alaska's economy to grow by encouraging the development of our land and its resources.

My Administration has taken the first step with our state's budgets for fiscal years 2004 and 2005. These budgets do control state spending and are needed to preserve our Constitutional Budget Reserve until we realize the financial benefits from our resource investments.

Over the last 13 years, $5 billion dollars of the $7 billion in the Constitutional Budget Reserve has been used to prop up every day spending.

We are committed to end this drain on the Constitutional Budget Reserve.

We will spend less than the preceding year and narrow the gap between spending and current revenue. By spending less we extend the life of our Constitutional Budget Reserve.

Let me thank the Legislature for its leadership in the "Missions and Measures" process by which state departments define their purpose and measure the effectiveness of their results.

In fact, this is the first time in 27 years that this kind of comprehensive review of departments has been undertaken.

I thank also the state employees who are essential in making this initiative successful and delivering results.

I am proud that we are fulfilling this element of my program and have been able to maintain funding for essential state services while keeping our roads open in winter and parks open in the summer.

The third element of my program is that the costs of government should be borne as much as possible by the direct users of services.

My fiscal program expects that those who directly benefit from state services pay a fair share through modest fees and taxes that do not interfere with personal savings and investment.

The fourth cornerstone of my program is local responsibility for local needs. Local governments should look first to local revenue sources to help fund schools, public facilities, fire and safety services.

The regional and local development of timber, fisheries, minerals and tourism provides jobs. It also provides a tax base that strengthens local economies, which then will need less financial support from the state. It also means greater local control. We encourage even our smallest communities to support economic development that will create local jobs.

After all, one of the best social programs is a good job.

Finally, the fifth element is whether to use a portion of the Permanent Fund income to maintain public services. While one can argue whether this should happen in an election year or some other time, I think the time has come to begin this process.

Over the last quarter century Alaskans have shown foresight and ability to make tough choices. Guided first by Governor Hammond, and later by Governor Hickel, citizens prudently developed both the Permanent Fund and the Constitutional Budget Reserve from the wealth produced by oil.

The Constitutional Budget Reserve was intended to be a savings account to serve as a shock absorber against a drop in oil prices -- not as a source of funds for everyday spending.

We must maintain a cushion to protect funding for essential public services when oil prices go down, and keep sufficient cash in the bank to maintain our cash flow.

In spite of our reduced spending and high oil prices, the Constitutional Budget Reserve is projected to dip below one billion dollars in July 2006.

Allowing the Constitutional Budget Reserve to drop below a billion dollars in order to continue to underwrite the budget deficit will not happen on my watch!

Both the Permanent Fund and the Constitutional Budget Reserve were voted in by the people. I am trusting the people to again consider the interests of all Alaskans and I am calling on the Legislature to join me in allowing Alaskans to decide.

We all acknowledge the Permanent Fund was established for the future. The opening contribution to the fund was 54 million dollars. Today the Fund is 27 billion dollars.

The income has flowed in two ways: into dividends and back into the principal. The principal has grown so large that the income created by the Fund often has exceeded the revenue the state received from oil.

Let me repeat that. The principal has grown so large that the income created by the Fund exceeds the revenue the state receives from oil.

At the same time we are threatened with an erosion of essential public services. Alaskans need to consider the health of our society in terms of both the dividends they receive and shared services.

How much and for how long do we allow the Fund to grow -- and public services to decline -- before we Alaskans address using a portion of the Permanent Fund's annual income to support our most important public services?

Tonight I am announcing a process to do just that.

Let's start the discussion now.

There are two paths before us. One is the easy road -- avoid the issue, do nothing and wait. The other is the course I propose. It will require that we move beyond the rhetoric and the politics of the past to protect our future.

I am calling for a non-partisan Conference of Alaskans to determine whether the time has come to use a portion of the Permanent Fund income to maintain essential public services. Such a proposal would be in the form of a Conference Resolution that will be developed into a bill for submission to the Legislature.

As the Conference deliberates, let it be clear to Alaskans that there are two important principles on which I will insist for use of any portion of the Permanent Fund income:

• First, the people of Alaska must agree. We must have a vote on the proposal in November.

• Second, I will work with the Legislature for an effective Constitutional Spending Limit in order to assure Alaskans that government will be frugal and efficient.

This spending limit must also be on the November ballot.

I have worked hard to find a diverse group of knowledgeable and fair-minded Alaskans to convene this Conference.

Sitting in the gallery are: Mike Burns who will serve as Chair, and Steve Frank, Clark Gruening, Marc Langland, Helvi Sandvik, Arliss Sturgulewski, and Eric Wohlforth who will serve as convenors.

I want the Conference to get straight to work: Former Representative Brian Rogers -- who is also with us in the gallery tonight -- will facilitate the Conference.

Any ballot question addressing the Permanent Fund, must reflect the best thinking of the people of this state. It must represent broad-based, non-partisan consensus and focus only on the best interest of Alaskans.

There will be 55 participants in the Conference. This is the same number that sat in the United States Constitutional Convention in 1787, and the same number who traveled to Fairbanks for our own Constitutional Convention in 1955.

The Legislature's Majority and Minority leaders are included as members of the Conference. The seven convenors will select the remaining participants by a majority vote of the convenors who must reflect the many faces of Alaska and a wide range of thinking.

Those selected will be knowledgeable about the issues and willing to work cooperatively with other Alaskans to come up with the best recommendation. As with our Constitutional Convention in 1955, those chosen must be prepared to put politics aside and focus solely on what is best for Alaska. Like Judge Tom Stewart, who was the Secretary to Alaska's Constitutional Convention almost a half century ago.

Judge Stewart has agreed to be Honorary Chair of the Conference.

I am pleased to announce the Conference will take place at the University of Alaska Fairbanks on February 10-12, 2004.

It's not going to be just another government task force or a collection of words. It will be a fast-moving, results-oriented group that will debate one issue -- whether and how to use the Permanent Fund income to protect our future.

Please note, I am not asking the Conference to address a broad-based tax plan for Alaska.

I charge the members to reach a consensus in the form of a Resolution which addresses the following four questions:

First: Should the use of income from the Permanent Fund be limited by the Constitution to 5% of the Funds' value, as the Permanent Fund Trustees have proposed?

Second: Should a portion of the income of the Permanent Fund be used for essential state services, such as education?

Third: Should the use of the income of the Permanent Fund for dividends and possibly for other purposes be determined annually by the Legislature, as is currently the case? Or should it be dedicated in the Constitution?

Fourth: Should the state maintain a minimum balance in the Constitutional Budget Reserve to stabilize state finances against fluctuation in oil production or prices?

I am asking the Conference to address specifically these four issues so that Alaskans can assess what will happen to the dividend if we also use some of the Permanent Fund income to pay for essential public services? Also, what will happen to our economy, jobs and public services if we do not?

The Resolution received from the Conference will be the basis for legislation that I will present to the Legislature.

I am calling the Legislature into special Session on March 1st to consider legislation that I will propose. I believe this issue warrants the focused attention and limited agenda of a special session.

I will work closely with the Legislative Leadership to make sure the Legislature approves a ballot proposal.

I then will ask Conference members to join with my administration, the Legislature and other Alaskans in discussing the proposal in preparation for the November election.

This education process must be comprehensive and explain the proposal's impact on dividends, future state spending, jobs, Alaska's economy, and the value and management of the Permanent Fund itself.

Throughout my long public service career I have been consistent in my trust in the people. It is time to engage them again. They will make the choice.

I thank in advance those who will participate in the Conference.

I also thank those Alaskans who will wait, listen and carefully consider the proposal and give the process a chance.

In conclusion, my program is consistent with my promises:

• To generate new income from oil and gas.
• To control government spending.
• To avoid an income tax.
• To grow strong local economies and provide job opportunities which support strong local governments.
• To give Alaskans the opportunity to implement two of the purposes of our healthy and growing Permanent Fund:
• To meet shared public needs, and
• To provide fiscal stability.

Finally a little reflection on the state of our state. Consider what we have:

• 20% of the nation's known oil reserves
• 15% of the nation's natural gas
• 50% of the commercial harvest from the sea
• spectacular open land with limitless tourism potential
• pristine environment
• engaged citizens and
• 27 billion dollars in the bank
• Most states can only dream of our wealth.

The Permanent Fund plays a unique role in defining our past. Wealth from oil was a springboard to growth throughout the state and remains an annual stimulus to our economy.

But remember, the Fund was and is dedicated to Alaska's future.

The Permanent Fund program converts our non-renewable resources to the sustainable and renewable resource of annual income for those of us here now and for future generations.

That wealth is part of our present currency and will be our children's inheritance. But an inheritance without the benefit of a great education, a sound economy, and job opportunities would be a cruel hoax on our children and grandchildren.

One third of Alaskans are under the age of 20. We are told that nearly 40% of our young people leave Alaska after graduation. We must turn this around.

Our wealth arose from our collective efforts and a portion of its renewable income should accrue to the shared burdens and benefits of citizenship in our Great Land.

Bold moves are not without controversy.

I was elected to make decisions that affect people's daily lives.

I pledge to do what is right for Alaska, and I will -- controversy or not.

Our generation of Alaskans has something to learn from our pioneers, who left a legacy of commitment to future generations.

Our legacy can be a vibrant economy and jobs for our children to allow them to stay here in the state and raise their own families.

Our legacy can be the highest quality of life in the United States.

Our legacy will rest on whether we place a higher priority on investment than consumption.

I welcome all Alaskans to join me along the way.

Our shared future is bright. Our Northern frontiers are open.

I look forward to our journey.

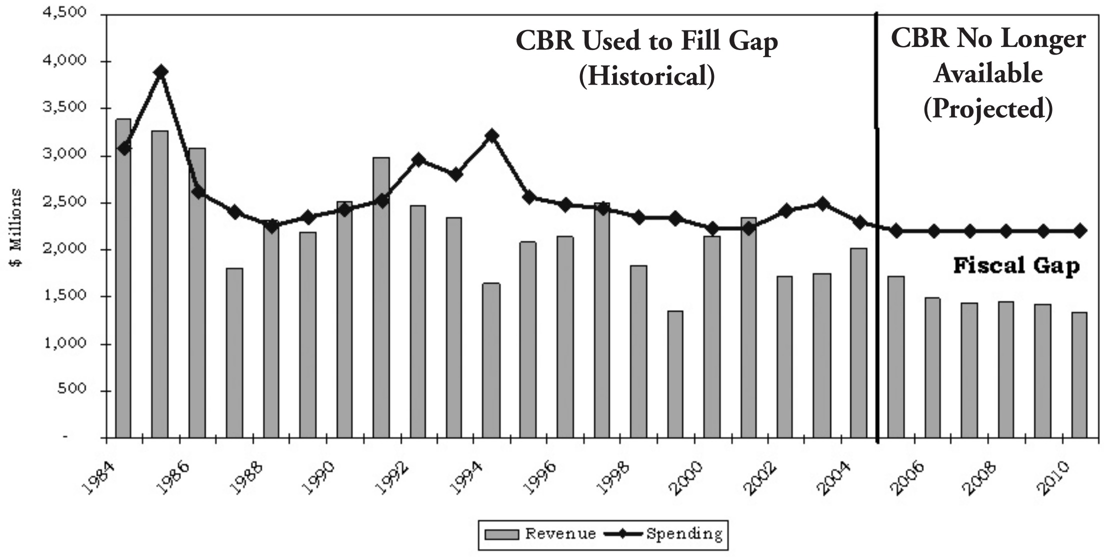
God Bless the United States of America and God Bless Alaska.

Understanding the Budget Gap, Income Tax, and Use of Permanent Fund Income

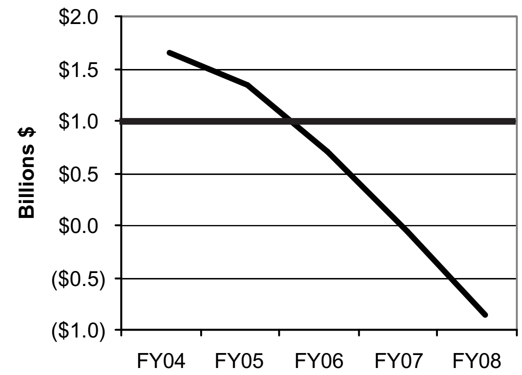
The following charts show that the state has historically spent $5.4 billion in excess of its revenues. The difference has been made up by one-time withdrawals from the Constitutional Budget Reserve. The Governor is emphatic that the state retain a budget reserve of at least $1 billion to protect against fluctuating oil prices and to cover the cash flow needs of the state. It is anticipated that the budget reserve will be down to $1 billion in July 2006. At that point, it will take a 25% budget cut or a 25% increase in revenue to balance the state's budget.

The Budget Gap: Looking Forward

Historical & Projected General Fund Revenues vs Expenditures FY 1984 - FY 2010



Constitutional Budget Reserve Balances FY04 - FY 08



The current formula for calculating dividends each year is based on a five-year average of Permanent Fund earnings. The Permanent Fund Trustees have recommend that the calculation be 5% of the Fund's annual market value. The advantage is clear - the money taken from the Fund each year would be based on the $27 billion dollar value of the Permanent Fund and not as subject to the fluctuations of the stock market. Last year a drop in the stock market put payment of a dividend to Alaskans in question.

The Trustees' proposal assumes the $27 billion Permanent Fund would earn on average 8%, which it has historically earned. Five percent per year would be removed as income. The 3% difference (or $810 million) would remain as inflation-proofing.

Some have proposed that of this 5% annual amount, 2.5% be used to fund public services such as education, public safety and health care (about $670 million) and 2.5% be used for dividends (another $670 million). That would make your dividend for the next two years about $1,080 and $1,130 respectively. Each Alaskan can weigh the income tax cost compared to a small reduction in the dividend.

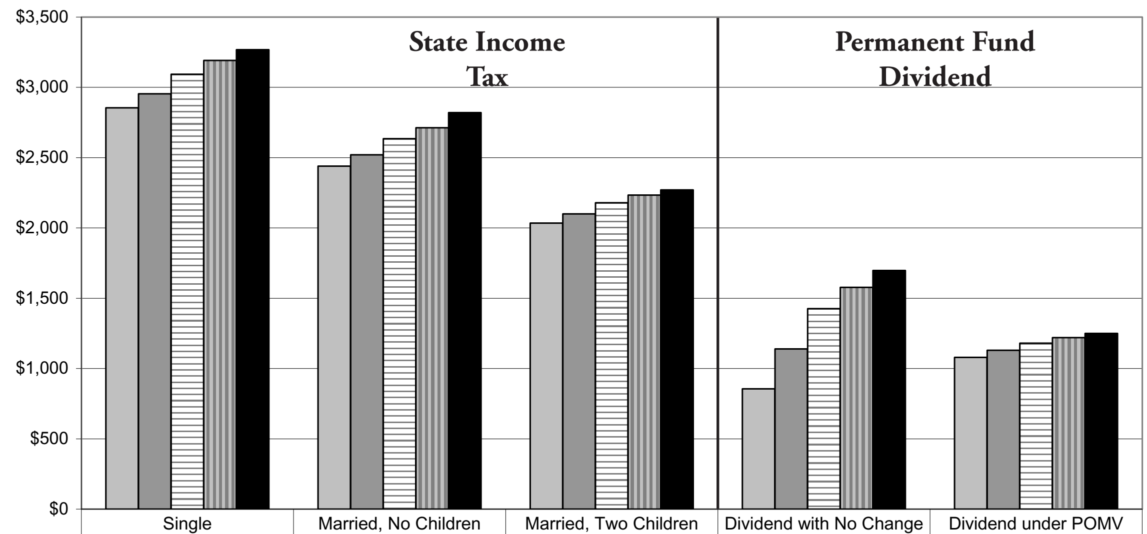
The charts to the right show how much a single person or family would pay if there was a State income tax. They also show the amount of a Permanent Fund Dividend, both under the current formula and if only 50% of Permanent Fund income was used for dividends. Some people have suggested that an income tax is the best solution for the state's budget problems. The following charts show what an income tax would cost in comparison to projected dividends both using the current model and under the proposed Percent of Market Value endowment model.

For example, a single person who earns an annual income of $50,000 would pay $3,094 in state income taxes. His or her dividend would be $1,426 under the current model and $1,180 under a 50/50 split POMV endowment model. A married couple with two children with an annual income of $100,000 would pay $5,395 in state income taxes. Their dividends would total $5,704 under the current model or $4,720 under the POMV endowment model.

The Governor has made it very clear that Alaska must have a solution during this Legislative session. Anything less would be an abrogation of the Governor's and legislators' sworn oaths.

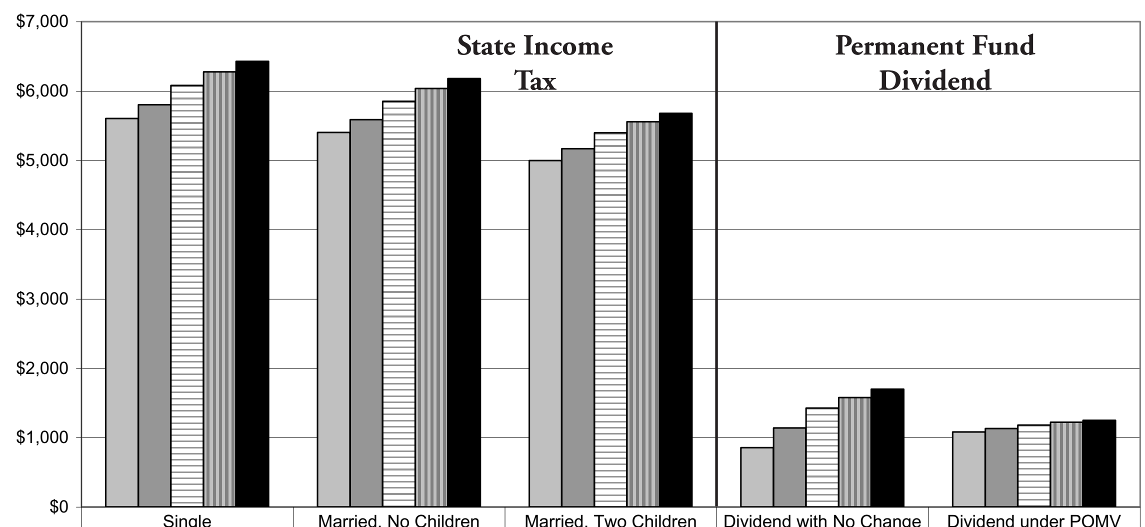
The State of the State address and information about the Conference of Alaskans is available on the Governor's web site at http://gov.state.ak.us/

Income Tax Burden - $50,000 Adjusted Gross Income*
(Median Alaska Income - $57,000)
Total Amount of Taxes Collected Each Year Based on Permanent Fund Earnings that Could be Available under a 50/50 Percent of Market Value (POMV) Split**



	Single	Married, No Children	Married, Two Children	Dividend with No Change	Dividend under POMV
FY 06	$2,855	$2,440	$2,035	$856	$1,080
FY 07	$2,954	$2,520	$2,100	$1,139	$1,130
FY 08	$3,094	$2,635	$2,179	$1,426	$1,180
FY 09	$3,192	$2,713	$2,234	$1,577	$1,220
FY 10	$3,268	$2,820	$2,270	$1,698	$1,250

Income Tax Burden - $100,000 Adjusted Gross Income*
Total Amount of Taxes Collected Each Year Based on PF Earnings that Could be Available under a 50/50 POMV Split**



	Single	Married, No Children	Married, Two Children	Dividend with No Change	Dividend under POMV
FY 06	$5,603	$5,400	$4,995	$856	$1,080
FY 07	$5,800	$5,586	$5,166	$1,139	$1,130
FY 08	$6,078	$5,851	$5,395	$1,426	$1,180
FY 09	$6,274	$6,034	$5,556	$1,577	$1,220
FY 10	$6,427	$6,178	$5,678	$1,698	$1,250

*Adjusted Gross Income is after deductions such as for an IRA, student loan interest, moving expenses, medical savings accounts and self-employed medical insurance.
**Revenues to be collected: FY06 $684 million; FY07 $721 million; FY08 $762 million; FY09 $795 million; FY10 $825 million

This publication's purpose is to inform the public about important issues facing the State of Alaska. It is released by the Office of the Governor at a cost of 10 cents per copy and was printed in Anchorage, Alaska.