Petroleum news

page 19 Herrera: Numbers will hurt Lieberman's bid to lock up ANWR

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Mardi Gras coming to Alaska

COURTESY PHOTO

Vince Vance & the Valiants will be in Alaska Feb. 5 and 6 to entertain attendees of the Pac Com Expo (see article below).

Bill Webb designs new, 'fun' Pac Com Expo; set Feb. 5-6

Oil Patch Insider

FOR PEOPLE WHO ARE "CON-FERENCED-OUT" there is a get-together in early 2008 that looks like fun. Serious fun. (And better, no political speeches.)

The event is Pac Com Expo on Feb. 5 and 6 in Anchorage. Before you yawn and turn the page, remember Bill Webb's company recently purchased the annual expo. And Webb, remembering the "good ole boys" of his oil patch days, has decided to make Pac Com worth attending.

BILL WEBB

First, he's setting the stage for an enjoyable atmosphere with a Mardi Gras theme, complete with colorful decorations, "great Southern food" such as catfish and barbecue ribs, and entertainment in the form of Dallas-based Vince Vance & the Valiants.

Second, instead of focusing on political topics, Pac Com's focus will be its exhibitors' products and services, and providing an atmosphere for building relationships.

"We have regularly attended the Pac Com Expo over the years and noticed less and less interest, less and less participation. … Alaska's heavy industries are for the most part booming and some, i.e. oil and mining, have huge projects

see **INSIDER** page 21

BREAKING NEWS

FINANCE & ECONOMY

EnCana to EnTexas?

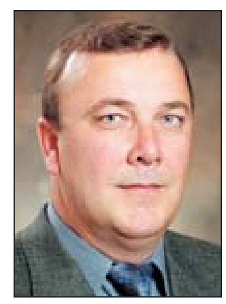
CEO insists there is no tie between Texas investment, Alberta royalty hikes, but…

By GARY PARK

For Petroleum News

On Sept. 28, EnCana Chief Executive Officer Randy Eresman dumped gasoline on the blazing Alberta royalty debate by warning that if the government review panel's recommendations were adopted in full many of the province's new and emerging resource plays would not be economically viable.

If that happened, Canada's leading gas producer, would "have no choice but to slow down our Alberta-based activity and move investments to other areas of Canada and the United States that are more economically attractive."



RANDY ERESMAN

That was accompanied by the threat of a US$1 billion cut in 2008 spending.

On Nov. 5, Eresman announced that EnCana was buying out its 50 percent partner in the Deep Bossier natural gas play in east Texas for US$2.55 billion.

But he was emphatic that there was no link between Alberta's proposed new royalty regime and the Texas move.

"It is a normal strategic event," he said. "This transaction has nothing to do with EnCana's future plans as they relate to the Alberta government's new royalty framework."

In fact, EnCana has repeatedly said it needs more time to figure out the impact of the 20 percent across-

see **ENCANA** page 21

EXPLORATION & PRODUCTION

Econ One: industry costs up

Consultant says Revenue used 2002-05 information; steep rises began in '05

By KRISTEN NELSON

Petroleum News

The Alaska Department of Revenue used publicly available cost data from 2002-05 when it assembled a fiscal note on expected North Slope production and operating and capital costs for the legislation that created the state's petroleum profits tax, or PPT, in 2006.

When tax returns came in earlier this year, however, costs — both operating and capital — were about twice those projected in the fiscal note.

The Legislature asked Econ One Research to review Revenue's modeling for the 2006 fiscal note — and the modeling used in the department's Aug. 3 status report on PPT, which addressed the increase in costs and the corresponding reduction in projected revenues from PPT.

As for future forecasts, Pulliam noted that while Revenue did not include cost-price sensitivity in its 2006 fiscal note or its PPT status report, the department's current forecast does adjust cost up or down when expected price levels rise above or fall below $60 per barrel.

In presentations to House and Senate Finance committees Nov. 7, Barry Pulliam, senior economist with Econ One, said the firm was asked to compare the estimates done for the PPT legislation with current estimates and to explain why costs came in so much higher than projected.

Revenue used 2002-05 information, Pulliam

see **COSTS** page 22

GOVERNMENT

This isn't Amerada Hess

Disputes under a net tax don't involve first impression issues; state the sovereign

By KRISTEN NELSON

Petroleum News

One of the issues that raises concern with a net production tax is litigation — the possibility that disputes between the State of Alaska and oil companies will generate lengthy legal disputes and end in settlements where the state takes cents on the dollar.

Both Alaska's existing petroleum profits tax, PPT, and Gov. Sarah Palin's proposed changes to it, Alaska's Clear and Equitable Share, ACES, are taxes based on the net. PPT, enacted in 2006, replaced a system that based production taxes on gross revenues.

DAN DICKINSON

STEVE PORTER

Litigation which began as oil first flowed down the trans-Alaska oil pipeline in 1977 took almost 20 years to settle.

Jon Iversen, director of the Tax Division in the Alaska Department of Revenue, told the Senate Judiciary Committee Nov. 1 that in the late 1970s and early 1980s the state was entering "an entirely new tax and royalty territory," without "a substantial body of case law and regulations."

There were issues that had never been dealt with before — and the state, in the royalty litigation,

see **DISPUTES** page 22

contents

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

● NATURAL GAS

TransCanada eyes larger role

CEO Hal Kvisle 'enthused' about Mackenzie Gas Project being based on 'flat-line' gas outlook in Alberta; offers TransCanada's expertise to build and operate the C$7B natural gas pipeline

By GARY PARK
For Petroleum News

Worried about declining natural gas production in Alberta, TransCanada Chief Executive Officer Hal Kvisle is making no secret of his company's eagerness to expand its role in the Mackenzie Gas Project and get gas out of the Arctic.

That could include relieving the anchor gas producers of the estimated C$7 billion cost of building a pipeline along the Mackenzie Valley, while they spend billions of dollars developing reserves and processing facilities on the Mackenzie Delta, he told a conference call Oct. 30.

TransCanada now sees "roughly flat line production in Alberta and significant growth in demand, which sets the stage for higher prices." — TransCanada CEO Hal Kvisle

Kvisle was asked to deal with rumors that TransCanada would be open to building and operating the main pipeline if the economics of construction and operation don't work for the four gas producers, whose rate-of-return expectations could surpass those of a pipeline company.

He said the MGP partners are "examining every alternative to come up with a toll that makes it attractive to the producers."

"We're discussing a whole range of different things and TransCanada has always been willing to contribute as best it can," Kvisle said.

"We have a lot of construction expertise in building pipelines; we have a lot of cold weather expertise and a very good working relationship with the producers and the Aboriginal Pipeline Group. We're working together to bring this project to fruition and that's all I can say."

Just three months after putting out word that TransCanada would sooner have a "larger interest than a smaller one" in the C$16.2 billion venture, he also gave an upbeat assessment of the project's viability.

> *If anything, other forecasters have pointed to an even bleaker outlook for Western Canada, including the National Energy Board's latest forecast that Canadian gas volumes could slump 7-15 percent over the next two years and Ziff Energy Group's prediction that exports to the United States will dive to 5.9 billion cubic feet per day by 2015 from 10.1 bcf per day in 2005.*

Kvisle told an Oct. 30 conference call TransCanada could single-handedly build and operate the proposed C$7 billion Mackenzie Valley pipeline like any other regulated Canadian pipeline.

He said Canada's largest pipeline company is able to look a "little more optimistically" at the MGP, typically portrayed as a beleaguered undertaking, because he doubted anyone "would be more aware than us of the challenges of sustaining gas production in Alberta."

For years, TransCanada has pointed to weakening performance in the Western Canada Sedimentary basin.

In early 2004, it said long-haul firm contracts dropped 78 percent in the previous six years, while short-haul contracts rose 1,421 percent, warning that near-term gas supplies from the basin could no longer meet intra-Alberta demand and fill all pipeline capacity out of Alberta."

Slump in output forecast

If anything, other forecasters have pointed to an even bleaker outlook for Western Canada, including the National Energy Board's latest forecast that Canadian gas volumes could slump 7-15 percent over the next two years and Ziff Energy Group's prediction that exports to the United States will dive to 5.9 billion cubic feet per day by 2015 from 10.1 bcf per day in 2005.

Kvisle said TransCanada now sees "roughly flat line production in Alberta and significant growth in demand, which sets the stage for higher prices."

He said that scenario is likely to unfold across North America, bolstering the demand for both liquefied natural and gas from the Arctic regions.

"That would be the fundamental reason we remain enthused about (the MGP)," Kvisle said.

Commenting on recent bullish forecasts of gas production growth in North America, he said they overlook the "inexorable decline from our base producing sources in all parts of Canada and the United States.

He has been one of the strongest voices warning that if social and regulatory issues become too complicated, the MGP could become more trouble than it is worth.

"But at this point we remain optimistic that we can pull all the details of this project together," despite efforts stretching over three decades.

"The challenges continue to be significant, but all parties are engaged and all parties are working on it," he said.

Whether the MGP is economic currently depends on the outlook for gas prices, production rates from the Mackenzie Delta and how much other gas is available from the region, he said.

"If you use today's gas prices and the very highest cost estimates that have been generated for it, I think you'd have to question the economic viability," Kvisle said.

TransCanada's role in the MGP includes covering the regulatory costs faced by the Aboriginal Pipeline Group, which is entitled to a 33.3 percent equity stake in the pipeline.

If a decision is made to proceed with the MGP, TransCanada has an option to acquire 5 percent of the anchor capacity (currently estimated at about 830 million cubic feet per day) and up to 50 percent of all or part of any interests sold by the anchor producers, Imperial Oil, Royal Dutch Shell, ConocoPhillips and ExxonMobil Canada. ●

Petroleum news

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● EXPLORATION & PRODUCTION

Winter 'toast,' drillers see crumbs for 2008

Canadian drilling contractors expect rig utilization to hit lowest ebb since 1986-92; braced for further revisions once oil and gas industry understands Alberta's royalty hike

By GARY PARK
For Petroleum News

Even without knowing the detailed impact of higher oil and gas royalties in Alberta, Western Canada is heading into its crucial winter drilling season in deep trouble and faces what the Canadian Association of Oilwell Drilling Contractors says will be a "sub-economic" year.

CAODC President Don Herring, who had previously said the winter was "toast," and PSAC President Roger Soucy both said producers and the industry were still calculating the impacts of Alberta's new royalties, which won't be implemented until Jan. 1, 2009, but are certain to affect 2008 drilling plans for wells that will be hit with the royalty hikes.

Taking its first stab at a 2008 forecast, CAODC predicts 13,735 wells in the region next year, down 38 percent from the 2006 peak of 22,298 and 26 percent from this year's expected 16,393 wells. It ties that forecast to price assumptions of US$80 per barrel for West Texas Intermediate crude and C$6.50 per thousand cubic feet for natural gas.

The Petroleum Services Association of Canada is dumping a similar bucket of cold water on its sector, predicting 14,500 wells in 2008, a 17 percent drop from the 17,550 wells anticipated this year, with Alberta facing a 25 percent decline, cushioned only partly by a 10 percent increase in British Columbia and a 3 percent rise in Saskatchewan.

Soucy said "all the indicators are for some negative impacts" from the Alberta changes.

Both trade associations expect to adjust their forecasts as companies develop a better understanding of the new Alberta regime and see what legislation is introduced.

Soucy said the latest numbers "indicate a rather dramatic downturn, which in due course will likely lead to more layoffs."

CAODC economic analyst Nancy Malone said the uncertainty generated by Alberta's royalty review process likely contributed to the bleak drilling outlook for 2008 because many companies set their budgets by late October for the upcoming winter season, which traditionally determines whether the calendar year is a success or failure.

Regardless of the Alberta royalties, the upstream sector was in trouble because of low natural gas prices, high operating costs in Western Canada and the high Canadian dollar.

Rig rate forecast at 34%

CAODC forecasts the rig fleet in Western Canada will have a 12-month utilization rate of 34 percent, the worst since 1986-92, compared with 69 percent in 2005, 63 percent in 2006 and an estimated 40 percent this year.

For successive quarters next year, the rate will be 50 percent, 15 percent, 30 percent and 40 percent, while the rig fleet will slide from 890 to 880, 870 and 860, consistent with industry warnings that a number of existing and newly finished land rigs will be shipped to the United States.

CAODC predicts the number of operating days in 2008 will be 101,640, a decline of 16 percent from this year's 121,309.

Its outlook for 2007 is consistent with the latest numbers, which show a rig utilization rate of 42 percent for the first nine months, the lowest since 1999. Well permits issued by regulators to the end of September halted four years of successive growth, with exploratory wells off 44 percent from a year ago at 2,902 and development approvals down 22 percent at 11,145.

Herring blamed the grim outlook for 2008 on the slump in gas drilling that started in late 2006 and CAODC now expects to stretch through to at least fall 2008.

CAODC said Western Canadian gas production may already have started to decline from a historic peak, with output down 1 billion cubic feet per day this year from 16 billion cubic feet per day a year ago.

The association said that each billion cubic feet of lost production costs the Canadian and provincial governments C$400 million in lost royalties at current gas prices and under existing royalties. ●

GOVERNMENT

Where from here on Arctic energy?

Arctic Energy Action Team will prepare roadmap of international issues relating to extractive, renewable, rural energy in the north

By ALAN BAILEY
Petroleum News

Whether it's offshore oil and gas development, skyrocketing fuel costs in rural communities or the development of renewable energy sources, it seems that there's no shortage of issues that relate to the production or use of energy in the Arctic.

What government policies are needed to address these issues? How do the issues relate to each other? What new energy-related technologies are needed in the Arctic? How can the needs of Arctic communities be met?

These are some of the questions that a new international group known as the Arctic Energy Action Team hopes to address, Jim Hemsath, senior fellow of the Energy Institute of the North, told the closing session of the Arctic Energy Summit Technical Conference in Anchorage, Alaska, Oct. 18. Initiated during the conference, the team plans to follow up on several of the issues raised during the conference.

"We've defined the Arctic Energy Team as an international group of policy makers and energy experts convened here at this technology conference to go forward with some of the discussions that we've had, with a specific goal of developing a roadmap for the enhancement of extractive and renewable energy recovery and the deployment of economical and environmentally sensitive energy sources for our rural Arctic communities," Hemsath said.

Challenges to address

The first step will be the formation of an executive team to help nail down the specific Arctic energy challenges that the team as a whole will address over a period of about 14 months, leading to the delivery in the first quarter of 2009 of recommendations to the International Polar Year Convening Committee and the Arctic Council, Hemsath said.

The International Polar Year, a major Arctic and Antarctic science research initiative, ends in March 2009 (the Arctic Energy Summit forms part of IPY). The Arctic Council is an intergovernmental forum for addressing common concerns and challenges faced by the Arctic countries, consisting of Canada, Denmark (including Greenland and the Faroe Islands), Finland, Iceland, Norway, the Russian Federation, Sweden and the United States.

The executive team will pick a specific major challenge from each of three areas: extractive energy, renewable energy and rural energy, Hemsath said. The team will then investigate each challenge within the context of eight issues that relate to Arctic energy. Those issues consist of government policies; human resource development; rural energy; shipping and transportation; environmental concerns; the energy infrastructure; the impact of climate change on people in the area; and energy security.

It's not possible to adequately address any Arctic energy challenge, without taking into account those eight issues, Hemsath said.

For example, the development of Arctic coal might make a good challenge to tackle in the area of energy extraction. That would raise questions such as what technologies to use for extracting energy from coal, what infrastructure would be needed on the ground, what transportation infrastructure would be required and what the environmental impacts might be.

"Environmental and cultural impacts, while they can't be assigned a monetary value, must be considered and must be articulated in any project that takes place," Hemsath said. "Energy development causes abrupt changes, not small, not incremental … to the surrounding communities."

And any technical development would require ground rules set by government policy.

Scenarios and roadmap

At the end of the 14-month project the team will present a series of scenarios for each of the energy challenges considered, Hemsath said. For those scenarios, the team will present a roadmap for research and technology development. And the team will present some government policy case studies, to illustrate the potential consequences of different policy decisions. The team will identify critical points in the roadmap where, for example, technologies need to change. The team will also identify critical interfaces, such as any interfaces needed between the administrations of different Arctic counties.

The emphasis will be on action rather than study, with a focus on things that can be achieved in 20 years or less, Hemsath said. In effect, the team will deliver to the Arctic Council a strategic Arctic business plan for the next 10, 15 or 20 years, he said.

Hemsath thinks that the Arctic Energy Action Team can make a difference to dealing with Arctic energy issues and in facilitating international trans-polar cooperation.

"This is our opportunity to do something bold and do something different. It's going to be hard and it's going to be tough," Hemsath said. "… We have the opportunity to make a step function change in how the Arctic is viewed and create a new energy vision of the north for the people of the north." ●

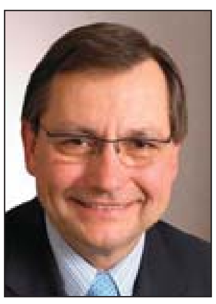
● GOVERNMENT

Message received, not understood

Alberta tries to spread glad tidings; investment bankers unsure about status of oil sands contracts; producers target heavy cuts

By GARY PARK
For Petroleum News

Alberta's Premier Ed Stelmach and Energy Minister Mel Knight are trying to spread a message across North America that their planned royalty hike has caused barely a ripple in stock markets and insisting they have no intention of voiding contracts.


ED STELMACH

A different, more telling verdict, is emerging from the full spectrum of oil and gas exploration and production companies, with Canadian Natural Resources shrinking its natural gas drilling by 30-50 percent in 2008 and Talisman Energy hinting it will trim drilling for deep, high-productivity wells.

Stelmach claimed the markets "recovered within a half-hour" of word that Alberta will raise royalties by 20 percent or C$1.4 billion by 2010, based on current prices and production, and were quickly followed by major announcements of "further investment in the oil sands."

Trying to head off negative perceptions outside Canada, Knight met with several Wall Street firms, such as Goldman Sachs and Lehman Brothers, and members of the U.S. Senate committee on Energy and Natural Resources.

He found some misunderstandings in the investment community about the structure of royalty hikes scheduled to take effect Jan. 1, 2009.

Knight said that "people seemed relatively pleased" when he explained that the new royalties for oil sands production would be about 5 percent during the start-up period and 33 percent once project costs had been recovered, capping at 40 percent if oil were to top C$120 per barrel.

Royalty agreements reopened

His major damage control mission involved the government decision to reopen royalty agreements with oil sands giants Syncrude Canada and Suncor Energy that were not due to expire until 2016.

Knight said U.S. bankers and fund managers wasted no time suggesting the province was "ripping up contracts."

"That is absolutely the farthest thing from the truth," he told reporters.

He said Syncrude and Suncor have told the government they want a level playing field for the industry and that is what the Stelmach administration wants, which means there should be no exemptions under the new regime.

But Knight would not discuss what options might be on the table when contract talks get under way, or what might happen if there is no agreement with the two companies.

Most E&P companies are still evaluating the potential impact of the new royalty framework on their 2008 capital spending programs and some say the final answers won't be known until the government tables legislation and regulations.

Even without factoring in higher royalties, the troubles confronting the gas sector were hammered home by Compton Petroleum, an intermediate-sized producer, which has responded to stagnant prices by dropping 75 wells, or 44 percent of its program, from fourth-quarter drilling.

Gas expected to be hit

But Canadian Natural and Talisman, two of the leading gas producers after EnCana, left no doubt that given the current pricing and cost environment the biggest reduction in activity will likely occur in the conventional gas business, which currently supplies about 15 percent of U.S. needs.

The challenge, according to newly installed Talisman Chief Executive Officer John Manzoni is to "run the numbers" based on a program that is so sensitive to prices, well depths and production volumes and therefore "well-specific."

Ron Eckhardt, vice president of North American operations, said Talisman's earlier forecast of a possible C$500 million cut in its Alberta spending next year remains "very accurate."

He said the Deep basin play straddling the northern Alberta-British Columbia border is "relatively unaffected," but the high-cost, high-productivity wells in the outer Foothills of the Canadian Rockies, which face very high initial royalties, will take the brunt of budget cuts.

Manzoni said market uncertainty in the light of royalty changes has forced Talisman to put on hold the disposition or spinoff of its midstream assets, valued at about C$1.7 billion.

Canadian Natural Chief Executive Officer Steve Laut said "it's pretty clear the conventional gas business has been hurt very badly" by the planned increases.

Although the company's 2008 capital budget won't be released until Nov. 27, its Alberta well count will probably drop to 450-600 of the 900 wells it could have drilled and planned conventional light oil wells in Alberta will be reduced by 50 percent to about 70.

That 30-50 percent cut in gas wells will be short of the 67 percent Canadian Natural warned it would make, but will probably see about C$500 million chopped from its Alberta spending.

Three Horizon phases a go

Canadian Natural also backed away from threats to scuttle billions of dollars in oil sands investment.

Laut said the first phase of the C$7.75 billion Horizon project, due to start production in the third quarter of 2008, is 76 percent completed and will be finished, while the second and third phases will proceed.

However, phases four and five will need rethinking, although Laut said they "do look okay," and C$7 billion worth of thermal projects at Kirby, Birch Mountain and Gregoire Lake have been hit by severe erosion of "tolerance for risk … and we'll be very cautious."

Even without factoring in higher royalties, the troubles confronting the gas sector were hammered home by Compton Petroleum, an intermediate-sized producer, which has responded to stagnant prices by dropping 75 wells, or 44 percent of its program, from fourth-quarter drilling.

That will trim C$75 million from its 2007 capital budget, or about 17 percent of its planned C$450 million, which was boosted in July when it held out hope for a rise in gas prices.

Gas prices down

Canada's benchmark AECO-C hub prices are currently below C$6 per gigajoule, better than August's C$4, but below the C$6.50-$7.50 range through most of the first half.

Farther down the food chain, Canext Energy, a junior operating on a C$12 million budget, said the new royalties forced it to bail out of a joint-venture drilling contract for an oil exploration well because of poor economics.

Chief Executive Officer Stephen Kapusta told the Calgary Herald the royalty structure has "changed the whole farm-in dynamics in the basin in Alberta."

If the government collects another 20 percent or more, contracts must be readjusted in a sector that is already struggling, he said

Kapusta said it took less than 24 hours after the royalty announcement when Canext's partner said it would not drill under the terms and conditions set out in the original agreement.

Gary Leach, executive director of the Small Explorers and Producers Association of Canada, said his whole sector is "collapsing" because of the impact increased royalties will have on already risky economics.

He said the new regime takes away the incentive for smaller companies to drill

see **MESSAGE** page 8

● EXPLORATION & PRODUCTION

Paspalof to head Pacific Energy in Alaska

By KAY CASHMAN

Petroleum News

Pacific Energy Resources Ltd. has named George Paspalof to head its Alaska operations, company president Darren Katic told Petroleum News Oct. 31.

The Long Beach, Calif. independent has played its cards close to the vest since it closed on Forest Oil's Southcentral Alaska assets in August.

According to www.zoominfo.com, from May 1988 through January of 1994, Paspalof was the L.A. basin field engineer for Texaco E&P, where he was in charge of ongoing operations in the Long Beach, Richfield, Aliso Canyon, Inglewood and Seal Beach oil fields that, combined, produced about 6,000 barrels of oil and 3 million cubic feet of gas per day from 200 wells. Paspalof's duties included management of field operations personnel, strategic budget planning, coordination with local and state entities, and long-term reservoir management.

Paspalof reportedly has extensive experience in implementing waterflood optimization programs.

Before going to work for Pacific Energy, from 1994 to April 2001, he was the president of Global Solutions Inc.

Creed said the company wanted to use a jack-up rig to explore its offshore prospects, which include Corsair — on the same geologic trend as the North Cook Inlet, Kenai and Cannery Loop gas fields. He said Pacific Energy was engaged in discussions with other companies interested in bringing a jack-up to the Inlet, and with drilling companies.

Buying a jack-up?

Pacific Energy Chief Financial Officer Jerett Creed told Petroleum News Aug. 30 that the company planned to move ahead with exploration of the Cook Inlet acreage it acquired from Forest.

Creed said the company wanted to use a jack-up rig to explore its offshore prospects, which include Corsair — on the same geologic trend as the North Cook Inlet, Kenai and Cannery Loop gas fields. He said Pacific Energy was engaged in discussions with other companies interested in bringing a jack-up to the Inlet, and with drilling companies.

In May, Katic said Corsair "alone has 200 million-barrel potential, provides large exploration upside … (and) was a high-priority" drilling prospect for his company. (In 2003 Forest said the prospect could also contain as much as 480 billion cubic feet of natural gas.)

Petroleum News sources say Pacific Energy is looking at buying a jack-up rig from Rowan, which has three jack-ups for sale that would work in Cook Inlet.

That information coincided with an Oct. 19 announcement by Pacific Energy that it had closed an equity private placement in the amount of US $65.5 million.

"The initial US$40 million of the private placement proceeds will be used to repay a portion of the debt associated with the acquisition of the offshore producing Alaskan assets of Forest Oil … with the balance of funds to be used for development of offshore Alaska and California properties and for general working capital and business purposes," the company said in a press release.

When the companies first announced the sale in May 2007, Pacific Energy said it was producing about 3,000 barrels of oil per day in California, two-thirds of which came from three offshore platforms in the federal waters of San Pedro Bay, and that Forest was producing about 5,900 barrels of oil equivalent per day in Alaska.

Pacific Energy reported total revenues of $8.9 million for 2006 and approximately $157 million in total assets. ●

continued from page 6

MESSAGE

because it doesn't understand the benefits of a junior drilling just one successful well in five.

Some indirect federal help

While it struggled to convey its own optimism, the Alberta government got some indirect help from the Canadian government.

Finance Minister Jim Flaherty, in showering Canadians with a wide range of tax cuts, said Oct. 30 the government would accelerate reductions in the corporate income tax rate from 22.1 percent in 2007 to 15 percent in 2012 at a cost of C$14 billion. The rate was previously set to drop to 18.5 percent by 2012.

Suncor, EnCana and Canadian Natural, all of them involved in the oil sands, reaped an immediate gain on the Toronto Stock Exchange.

Andrew Potter, an analyst with UBS Securities Canada, said the preliminary analysis of Flaherty's cuts "shows that if the changes go through the net present value per barrel of an onstream oil sands project would go up 1 percent-3 percent and the net present value of a greenfield project would increase in the 6 percent-12 percent range depending on price — a bigger potential impact than the royalty changes."

Pierre Alvarez, president of the Canadian Association of Petroleum Producers, agreed the tax reductions will change the net effect of the royalty changes and other measures.

Alberta also got a morale lift from federal Industry Minister Jim Prentice who said Stelmach and his government struck the "right balance" between the industry and Albertans, who own their natural resources.

"In the world in which we live, where there is a premium on a secure supply of oil and gas in a stable environment, Alberta will continue to prosper and I think do very well," he said in brushing aside warnings that Stelmach's move would derail the province's long-running economic boom. ●

● NATURAL GAS

ANS hydrate test results promising

Data from North Slope test well indicate hydrate saturation up to 75 percent but feasibility of gas production remains unknown

By ALAN BAILEY
Petroleum News

COURTESY BP EXPLORATION (ALASKA) INC.

Bob Hunter examining Mount Elbert core

In a paper presented on Oct. 16 to the Arctic Energy Summit Technical Conference Scott Digert, BP technical advisor, and Robert Hunter, ASRC Energy Services project manager, presented new results from the BP-operated Mount Elbert gas hydrate stratigraphic test well, drilled in mid-February on Alaska's North Slope (see "North Slope gas hydrate well hits target" in the Feb. 25 edition of Petroleum News).

Gas hydrate consists of a white crystalline substance that concentrates natural gas by trapping methane molecules inside a lattice of water molecules (methane is the primary component of natural gas). The hydrate crystals remain stable within a certain range of temperature and pressure. But when decomposed the crystals yield about 164 times their volume in methane, thus making gas hydrate deposits a potential major source of natural gas.

"We think that the ultimate recoverability (from the Eileen trend) could be up to 12 tcf, but we need to pin down that range." —Scott Digert, BP technical advisor

But the practicalities of producing gas from hydrate deposits are unknown, and the Mount Elbert well forms part of a multi-year project to determine whether or not gas hydrates can be developed on the North Slope.

BP, ASRC Energy Services, Ryder Scott Co., the U.S. Geological Survey, the U.S. Department of Energy, the University of Alaska Fairbanks and the University of Arizona have all collaborated in the North Slope project, with DOE footing the $4.6 million bill for drilling the Mount Elbert well.

Straddles the permafrost

In the Milne Point area, where the Mount Elbert prospect is located, the zone in which the underground pressures and temperatures support gas hydrate stability straddles the base of a permafrost zone that extends to about 2,000 feet below the ground surface. Because of the potential complications of trying to develop gas hydrates in the permafrost, the research team has focused its efforts on gas hydrate prospects below the permafrost.

However, with the gas hydrate deposits believed to be formed at relatively shallow depths from gas migrating upwards from oil fields deep underground, the necessary juxtaposition of appropriate reservoir and seal rocks represented a significant uncertainty at Mount Elbert.

"We weren't sure if these shallow formations would have sufficient charge of gas from the deeper oil fields, nor that they would have sufficient seal to retain this gas in the shallow sediments, because a lot of them are soft sediments," Hunter said.

But, drilled to a depth of 3,000 feet from an ice pad in the Milne Point unit using Doyon Rig 14, the Mount Elbert well encountered gas hydrate deposits that the scientists working on the project had predicted from the interpretation of seismic data. That result confirmed the effectiveness of some seismic techniques developed earlier in the gas hydrate project.

"We were pleased to see that the interpretation held through and we encountered two approximately 50-foot hydrate bearing zones," Hunter said. "… The hydrate was confirmed in both the primary sands."

Hydrate-bearing core

Successful core retrieval from the well resulted in the recovery of about 100 feet of hydrate-bearing core, the first significant hydrate core ever collected on the North Slope.

"We acquired about 430 feet of core, 100 feet of which was gas hydrate-bearing," Hunter said.

Although the drillers used oil-based drilling mud chilled to 30 degrees Fahrenheit to minimize damage to the hydrates while acquiring samples and data from the well, time was of the essence in recovering hydrate bearing core — releasing the underground pressure on the hydrate and bringing samples to the surface would cause the hydrate to start to disassociate.

"We used the first ever wireline coring system on the North Slope with a conventional drill rig, which enabled us to pull up the core quite quickly about 24 feet at a time," Hunter said.

The team cut the samples into 3-foot lengths and transferred them to a cold trailer for processing. Some hydrate samples were re-pressurized in methane or preserved in liquid nitrogen for later lab analysis, Hunter said.

Sample analysis is providing invaluable information about the precise nature of the hydrate deposits.

"This core clearly shows that hydrate is contained within the pore space of the sediment," Hunter said.

And that implies that the hydrate deposits at Mount Elbert originally formed as a conventional gas field. Then, when the permafrost formed about 2 million years ago, the lowering temperatures would have caused the hydrates to crystallize within the rocks, Hunter said.

Wireline logs

As well as taking core samples, the research team ran a suite of open-hole wireline logs in the well. One finding from the logging data was the extent to which the hydrates saturate the pore space in the reservoir rocks — the maximum saturation is about 75 percent, Hunter said.

The team also used a technique call modular dynamic testing, or MDT, to test the production characteristics of the hydrates in the well.

"This was the first in the world open-hole dual packer MDT program within hydrate-bearing sediments," Hunter said.

And, in a new method of data acquisition, a tiny instrument measured the temperatures and pressures at the inlet of the MDT tool.

The testing showed a sharp decline in temperatures when the hydrates disassociated down hole — the disassociation reaction is known to absorb heat. And the pressure response within the well following shutdown of production testing indicated some blocking or choking of the reservoir, possibly as a result of the reformation of hydrate crystals or perhaps from the formation of ice, Hunter said.

see HYDRATES page 10

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HYDRATES

That suggests that during a full production test at Mount Elbert it would be necessary to apply heat or use chemical methods to release gas, rather than just relying on reducing the pressure in the hydrate zone, Hunter said.

Next steps

So, where to from here for the gas hydrate research project?

The Mount Elbert prospect is part of the Eileen trend, one of two major gas hydrate trends in the central North Slope. And each of those trends contains many individual gas hydrate prospects, such as Mount Elbert. The total gas in place in just the Eileen trend has been estimated at a whopping 33 trillion cubic feet. But, in the absence of established methods of hydrate production, there are currently no technically recoverable resources.

The research project hopes to find some way of extracting at least some of the vast hydrate resource.

"We think that the ultimate recoverability (from the Eileen trend) could be up to 12 tcf, but we need to pin down that range," Digert said.

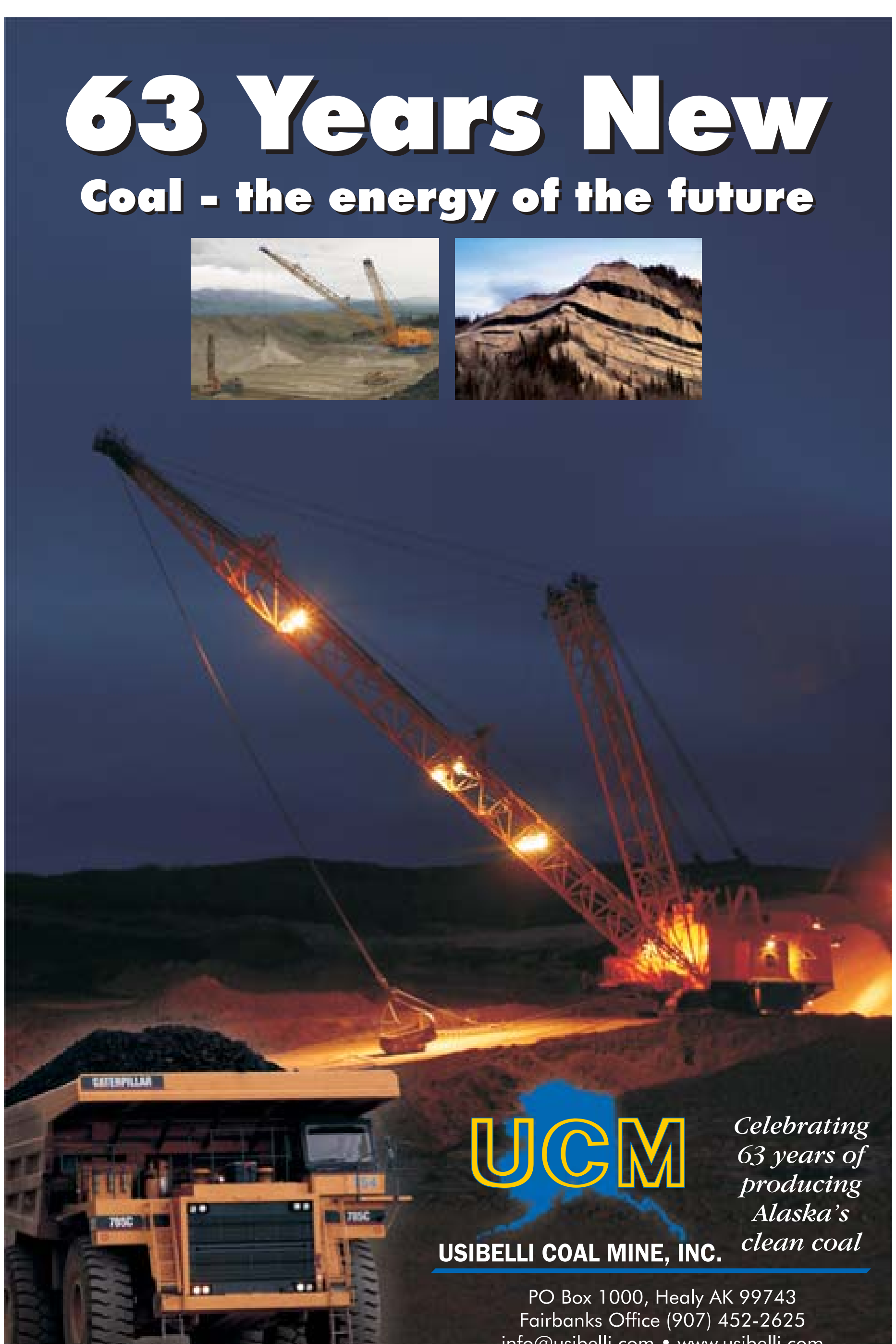
The next step will be the continued assessment of the Mount Elbert results, to evaluate whether there may be some viable method of gas production from the prospect. Armed now with the knowledge that the hydrates occupy pore spaces within the reservoir rocks and having data such as the hydrate production characteristics, the researchers will assess how the properties of the reservoir are likely to change during hydrate disassociation and, hence, evaluate strategies for production testing.

The various stakeholders in the project will then need to decide whether or not to proceed to the next project phase — that next phase would likely involve testing production methods at the prospect.

"Significant uncertainties remain and there are many things that we need to address before we fully understand hydrate productivity," Hunter said.

But the Arctic sands of the central North Slope form the tiny tip of what could become a large pyramid of gas hydrate production possibilities.

"What we're trying to do here … is use the Arctic as a natural laboratory to determine whether or not gas hydrate can become an unconventional resource, because that's something that we do not yet know," Hunter said. ●



● EXPLORATION & PRODUCTION


COURTESY PHOTO

The BP-operated Endicott field, including some 33,000 bpd of Prudhoe crude, averaged 46,853 bpd in October, up 24.9 percent from a September average of 37,506 bpd. Endicott includes production from Sag Delta and Eider.

North Slope output averages 721,000 bpd

By KRISTEN NELSON
Petroleum News

Alaska North Slope production averaged 721,000 barrels per day in October, up 11 percent from 649,117 bpd in September.

September production was pulled down by Prudhoe Bay, which dropped 16.7 percent from August to September. Prudhoe Bay operator BP Exploration (Alaska) told Petroleum News in October that the drop was due to seasonal variability and planned maintenance which included a scheduled turnaround at Gathering Center 2.

Prudhoe averaged 301,967 bpd in October, up 28.14 percent from a September average of 235,650.

Both the September drop and the October increase could be seen in daily production numbers for October. Prudhoe started the month at 230,088 bpd and ended the month at 328,477 bpd. Prudhoe Bay includes production from Midnight Sun, Aurora, Polaris, Borealis and Orion.

Greater Prudhoe Bay, which includes some 33,000 bpd of Prudhoe Bay Flow Station 2 oil moved through the Endicott line and production from Lisburne, averaged 364,111 bpd in October, up 21.2 percent from a September average of 300,364.

Endicott also increases

The BP-operated Endicott field, including some 33,000 bpd of Prudhoe crude, averaged 46,853 bpd in October, up 24.9 percent from a September average of 37,506 bpd. Endicott includes production from Sag Delta and Eider.

BP's Milne Point field, which includes Schrader Bluff production, averaged 36,827 bpd in October, up 7.7 percent from a September average of 34,198 bpd.

The BP-operated Northstar field averaged 34,644 bpd, up 0.5 percent from a September average of 34,472 bpd.

The ConocoPhillips Alaska-operated Kuparuk River field averaged 148,794 bpd in October, down 0.39 percent from a September average of 149,375 bpd. Kuparuk includes production from West Sak, Tabasco, Palm, Meltwater and Tarn.

The ConocoPhillips-operated Alpine field averaged 122,770 bpd in October, down 2.72 percent from a September average of 126,202 bpd. Alpine includes production from Fiord and Nanuq.

Lisburne production averaged 29,144 bpd in October, down 8.1 percent from a September average of 31,714 bpd. Lisburne includes production from Point McIntyre and Niakuk.

The temperature at Pump Station 1 on the North Slope averaged 22.4 degrees Fahrenheit in October, compared with a five-year average October temperature of 24 degrees F.

Cook Inlet production averaged 15,124 bpd in October, up 3 percent from a September average of 14,671 bpd. ●

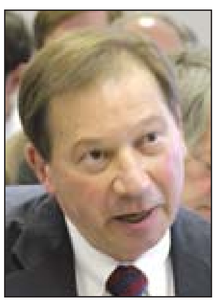
● NATURAL GAS

ANGDA promotes in-state gas options

By MARY ODDEN
Copper River Record

Far from special legislative session debates over the troubled PPT, the Alaska Natural Gas Development Authority is quietly focused on making North Slope natural gas available to Alaska residents, utilities and industrial customers.

At an Oct. 24 board meeting, ANGDA CEO Harold Heinze said the gas authority is putting the final touches on a plan which is "attachable" to the gas pipeline project of whichever entity earns the license to take Alaska gas to market. The licensee will be selected in the state's Alaska Gas Inducement Act process, which will take gas pipeline project applications through Nov. 30, then turn final approvals over to the state legislature in January.



FORREST CRANE

HAROLD HEINZE

ANGDA's AGIA application addendum is scheduled to be completed by the end of October and will be made available on its Web site: www.angda.state.ak.us.

Three major applications

Heinze says he expects at least three major gas line construction applications will be submitted to the state under the AGIA process. In addition, Heinze said he would not be surprised to see a "nonconforming application" submitted by one or more of the major gas lease-holders on the North Slope.

A gas lease-holder might submit a non-conforming application in objection to some of the AGIA provisions regarding the leases, Heinze said, but "it would be inconceivable to me if they don't turn in any plans at all."

After Nov. 30, "expect to see competition between prospective gas line builders turn into cooperation," he said, "because whoever is going to build the gas main line has to think about in-state gas. That's like an intelligence test."

The process of choosing a licensee will begin with the regular session of the Alaska Legislature in January, but may take weeks or months. After a license for a gas pipeline is issued, the license holder will initiate an "open season" of 60 or 90 days, during which prospective users of the gas will commit to buy the future volumes. Commitments made in the open season determine future pricing structures and the configuration of the main and distribution pipelines.

ANGDA offers in-state plan

Whether Alaska issues a license for gas to go down the Alaska Highway, to Valdez to be shipped as LNG or both, ANGDA will offer the licensee a detailed plan for in-state pipeline construction which will work with off-takes from their main line plans, Heinze says. For an Alaska Highway route pipeline, the ANGDA plan would attach the spur line at Delta. For a main line plan which brought gas to an LNG plant and export facility in Valdez, or a "Y-line" concept plan which sends gas both down the highway and to Valdez, the ANGDA spur line would attach at Glennallen.

Either form of the ANGDA application addendum is in compliance with AGIA, Regulatory Commission of Alaska and Federal Energy Regulatory Commission rules, and features conditional right-of-way permissions from the State of Alaska in place along its Glennallen to Palmer route.

The ANGDA addendum describes an Alaska gas spur line with three possible construction segments: from Delta Junction to Glennallen; from Glennallen to Palmer; and from Palmer to the Beluga electrical generation facility. Importantly, the Beluga gas field will serve as reservoir storage and provide consistency in line pressures for the gas, necessary because of seasonal and other fluctuations in residential heating and electrical power generation needs.

The spur pipeline (estimated cost \$1.25 billion for the Delta-Beluga line, or \$725 million for the Glennallen line, including off-takes and storage facilities) could be built without subsidies from the state, Heinze said, but the state would guarantee the gas supply.

Based on its analysis of gas market demand through 2025, ANGDA says the gas field reserve amounts (3 tcf) required

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ANGDA

for in-state use matches up with either the state's current royalty portion of Prudhoe Bay gas or projected new gas field developments. The spur line plans currently call for a 24-inch pipe, substantially smaller in diameter than the main gas pipeline because the required volumes are about 5 percent of the expected total gas volumes in the main line.

Earliest in-state gas 2014

ANGDA's role in the AGIA process, says Heinze, is "to make sure that Alaska's 5 percent is not the last 5 percent."

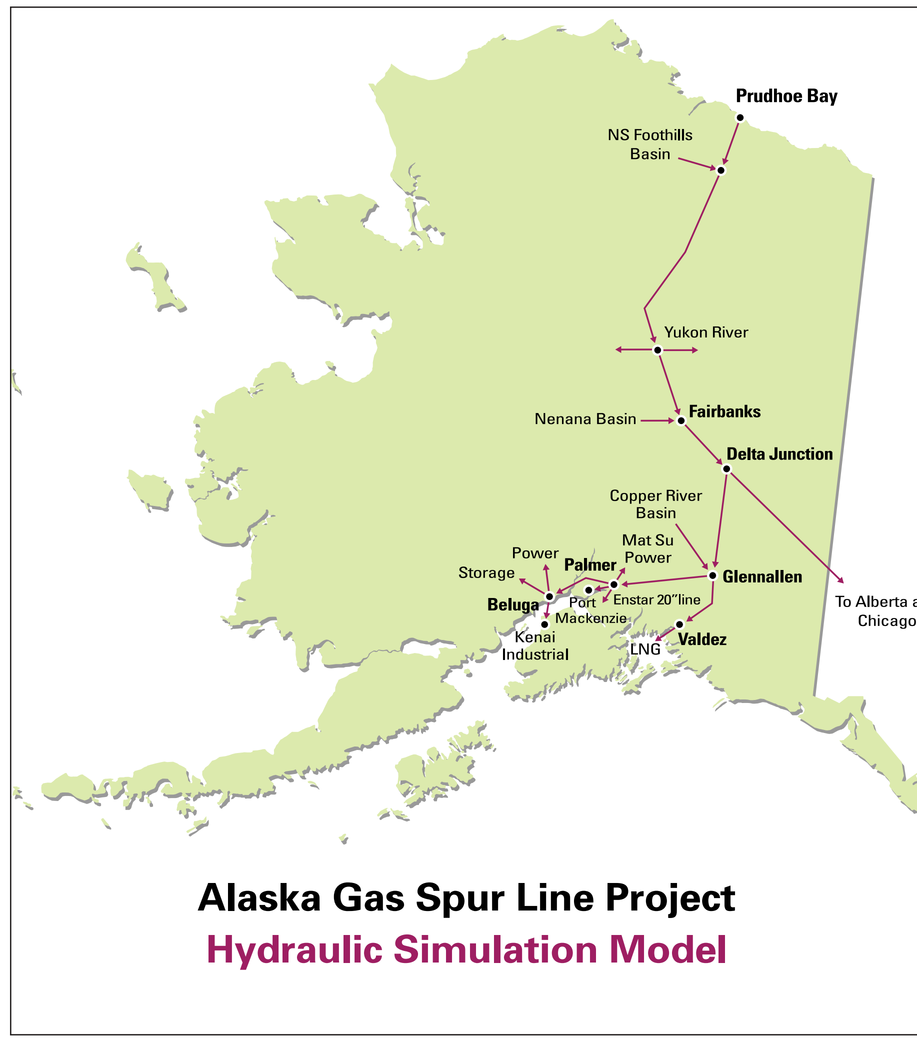
In-state gas market projections suggest that either the Delta-Beluga or Glennallen-Beluga alternatives are financially feasible, assuming only residential and utility consumers. The addition of Alaska industrial customers would further lower the cost per Btu to the consumer. With two field seasons and requisite permitting ahead of any configuration of spur project, Heinze said his nearest estimate for in-state gas flowing to consumers from the North Slope is the year 2014.

ANGDA, created in the election of 2002, is a public corporation of the state, with two employees and a seven member board of directors appointed by the governor.

Whether Alaska issues a license for gas to go down the Alaska Highway, to Valdez to be shipped as LNG or both, ANGDA will offer the licensee a detailed plan for in-state pipeline construction which will work with off-takes from their main line plans, Heinze says.

Among ANGDA's activities in the coming months will be open season training workshops for utilities and other prospective customers of the gas pipeline volumes. The workshops will be offered in conjunction with the Alaska Power Association, and will culminate in a "practice open season."

At the Oct. 24 meeting, ANGDA also introduced the project manager of its Yukon-Kuskokwim Propane Demonstration Project. Bartz Englishoe will work with the village of Tanana to convert private and public buildings to propane for electrical generation and heating. The demonstration project looks forward to the availability of propane fuels extracted from a natural gas pipeline at a Yukon River off-take, and made available to interior communities via river barge. ●



COURTESY ALASKA NATURAL GAS DEVELOPMENT AUTHORITY

ANGDA's gas spur line project hydraulic model, a page from the AGIA application addendum, depicts how gas flowing from the North Slope and other possible Alaskan sources would be distributed through an in-state system.

● NATURAL GAS

Team investigates Barrow gas hydrates

East Barrow and Walakpa fields may have gas hydrate resources that are maintaining reservoir pressures after years of production

By ALAN BAILEY

Petroleum News

For most Alaska rural communities escalating fuel costs have been triggering a crisis that threatens the continued economic viability of rural life. But not so Barrow, located at the northwest end of Alaska's North Slope.

For many years Barrow has enjoyed the benefit of plentiful natural gas from three gas fields just a few miles from the city perimeter: the East Barrow, South Barrow and Walakpa fields. And it is possible that methane hydrate deposits in those fields could extend gas supplies for Barrow for many more years than people have previously expected.

TOM WALSH

Methane hydrate (often referred to as "gas hydrate") is a crystalline substance that traps methane molecules inside a lattice of water molecules within a certain range of temperatures and pressures known as the methane hydrate stability zone. When decomposed the crystals yield about 164 times their volume of methane gas.

Because of the low temperatures in and below the deep permafrost of the North Slope, widespread areas within the methane hydrate stability zone are known to exist under the North Slope region. Gas hydrate deposits have formed under the central North Slope and scientists have speculated that more as yet undiscovered deposits exist elsewhere in the region.

Some of those deposits may exist in juxtaposition with free gas in the Barrow gas fields, Tom Walsh, principal partner and manager of Petrotechnical Resources of Alaska, told the Arctic Energy Summit Technical Conference on Oct. 16. The North Slope Borough and the U.S. Department of Energy National Energy Technology Laboratory are funding a research project investigating the possible existence of hydrates in the fields. PRA and the University of Alaska Fairbanks are doing the research, with assistance from an advisory committee of experts in gas hydrates and North Slope geology, Walsh said.

First discovery 1949

The U.S. Navy discovered the South Barrow field in 1949 during exploration of the Naval Petroleum Reserve No. 4, later to become the National Petroleum Reserve-Alaska. The East Barrow and Walakpa fields were discovered during U.S. Geological Survey exploration programs in the 1970s and 1980s.

The South and East Barrow fields, both east of the City of Barrow, are reservoired in the Barrow gas sands in a similar stratigraphic setting to the Alpine oil field, 135 miles to the east. The reservoir for the Walakpa field, southwest of Barrow, lies in the Pebble Shale unit, a major petroleum source rock for the North Slope.

All of the fields have been supplying gas to Barrow for heating and power generation.

By 2004 the South Barrow field had produced about 22 billion cubic feet of the originally estimated 32 bcf of gas in the field, Walsh said. The current estimate for original total gas in place at Walakpa is about 250 bcf, of which about 14 bcf have been produced, he said.

Puzzling

But the production history for the East Barrow field is puzzling.

Although the original estimate of gas in place for that field was just 6.2 bcf, 8 bcf have been produced from the field, Walsh said. And, perhaps more significantly, during the years of production the reservoir pressure has not declined — normally the gas pressure within a field reservoir should drop as the field depletes.

People had thought that subterranean water was maintaining the pressure in the field but no breakthrough of water

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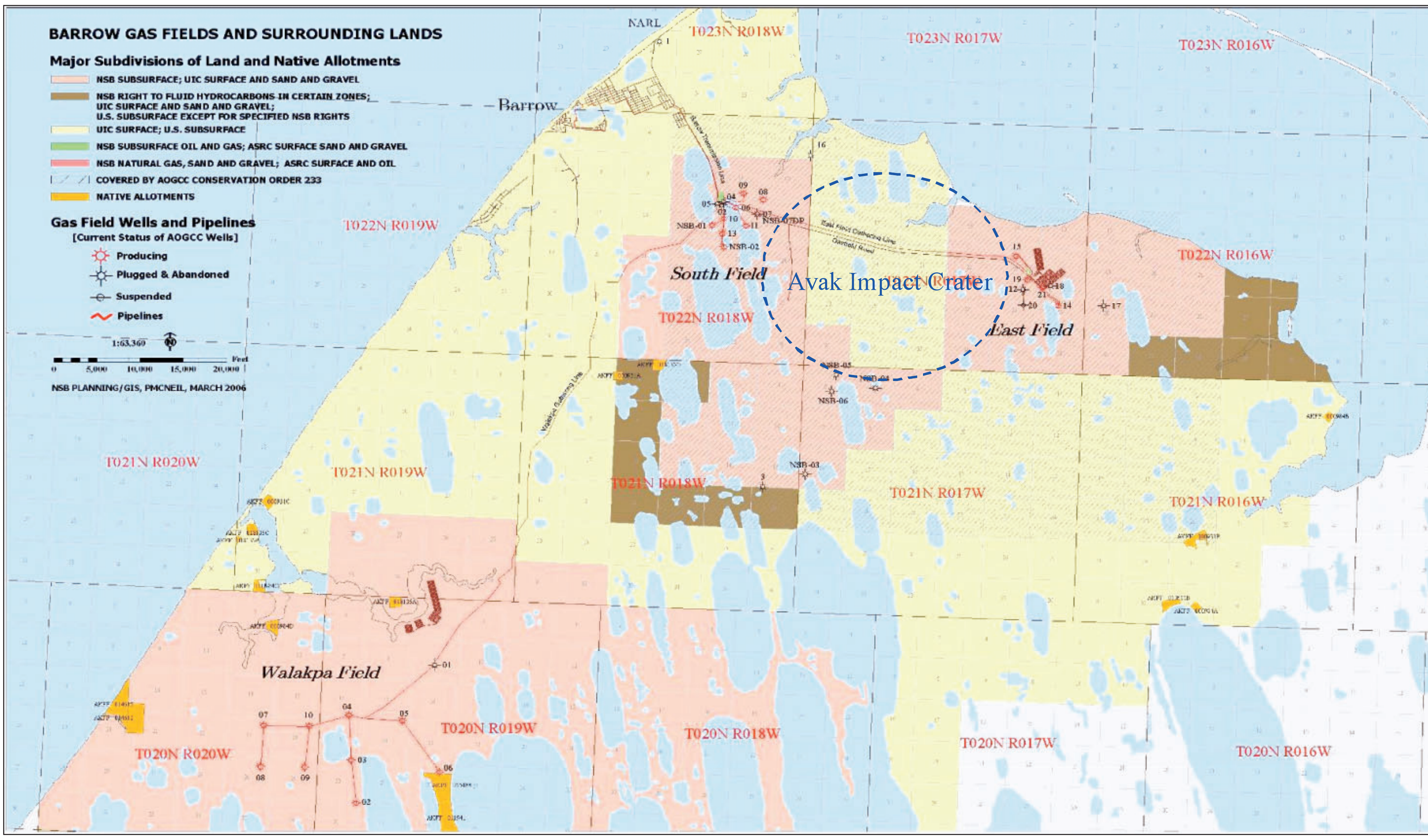


Map showing the locations of the Barrow gas fields. The Avak impact crater is the site of an ancient meteor impact.

continued from page 14

BARROW

into the reservoir has ever occurred. The lack of water subsequently led to speculation about the presence of methane hydrates in contact with gas in the reservoir — as gas is withdrawn from the reservoir, the reduction in pressure might cause some hydrate to disassociate, thus releasing more gas into the reservoir and maintaining reservoir pressure.

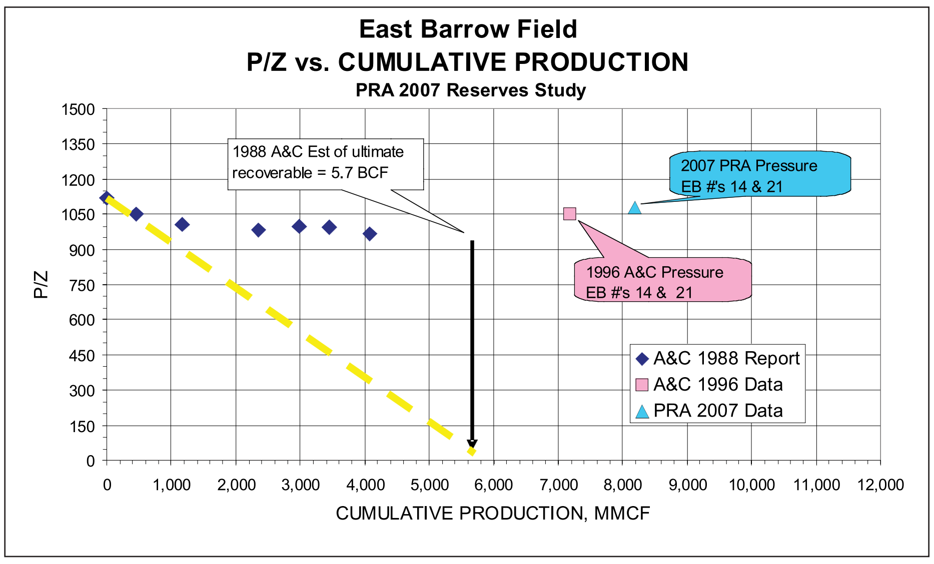
Hence the current research program.

"We haven't really seen that (water breakthrough) and that's one of the reasons that this hydrate study was commenced," Walsh said. "…The lack of a decline in the East (Barrow) field and some peculiar characteristics of the decline curve in the Walakpa field led us recently to want to reinvestigate this issue and see if hydrates are contributing now as an energy source to the free gas fields."

Do they exist?

The first step in the research, started in November 2006, has involved using existing information to determine whether it is feasible that gas hydrates exist in any of the three fields. In addition to assembling reservoir, fluid and gas data from previous studies and from

see **BARROW** *page 15*



PETROTECHNICAL RESOURCES OF ALASKA

A graph showing how reservoir pressures in the East Barrow gas field not declined as expected. Gas hydrate decomposition may have maintained the pressure.

continued from page 14

BARROW

well files, the team has been analyzing seismic data from the gas field area, Walsh said.

By piecing together knowledge about subsurface geologic structure and about the subsurface temperatures and pressures, it is possible to estimate the depth of the hydrate stability zone and evaluate how that zone might interact with field reservoirs — if the stability zone does not intercept any part of the gas reservoir, methane hydrate cannot exist in the field, Walsh explained.

It is also critical to assess the mechanics and timing of the petroleum system that gave rise to the Barrow gas accumulations and that may have resulted in the formation of methane hydrates, he said.

Promising

The research results look promising for the East Barrow field.

"Based on the salinities of the water and the gas composition that we're seeing we do have a hydrate stability zone that intercepts the top of the reservoir and penetrates into the reservoir in the middle Barrow sands at the East Barrow field," Walsh said.

In fact a structure map of the field indicates that there is about one square mile of the East Barrow reservoir inside the stability zone, he said.

Although the research team found several sets of temperature gradient data for the Walakpa field, the most recent data set leads to a conclusion that the base of the hydrate stability zone is at the crest of the currently mapped Walakpa structure. But there also appears to be plenty of potential reservoir acreage inside the stability zone, up dip from the producing reservoir — hydrates in that acreage could hugely increase the resource potential of the field.

"It would take about 4,000 acres of reservoir within the hydrate stability zone to double the reserves at Walakpa to say 500 bcf of gas," Walsh said. "So that could be a huge impact. Even if it was 10 percent of that it would be a huge impact."

On the other hand, the South Barrow field is unlikely to contain any methane hydrate.

"We didn't see these kinds of results on the South (Barrow) field," Walsh said. "The methane hydrate stability zone did not intercept the top of the reservoir in the south field."

Next phase

Having established the likelihood of methane hydrate associated with the East Barrow and Walakpa fields, the research team has now embarked on detailed reservoir characterizations of the two fields, using seismic data, well data and other information. For the Walakpa field the team is looking closely at the seismic data to determine whether there is enough reservoir sand updip of the producing field to reservoir significant volumes of hydrates.

The team will then need to use reservoir modeling to assess whether hydrate disassociation appears a feasible gas production mechanism in the fields.

Depending on the results of the reservoir characterization and modeling, the project may eventually drill a test well to core methane hydrates at one of the fields. But drilling is not currently funded and remains a long way off in the future, Walsh said.

However, establishment of a methane hydrate resource near Barrow could have a major economic impact in the region, as well as providing a significant contribution to scientific research, Walsh said.

"We're on the very practical end of hydrate research," Walsh said. ●

OIL COMPANY EARNINGS

Earnings from Petroleum News Top 25

Earnings third quarter 2007 • Change from third quarter 2006
Liquids production third quarter 2007 • Change from third quarter 2006
Natural gas production third quarter 2007 • Change from third quarter 2006

Company	symbol	earnings	%	liquids	%	gas	%
ExxonMobil	XOM	$9,410	-10	2,536,000	-4	8,302	+2
BP	BP	$4,406	-29	2,292,000	–5	7,879	-3
RD/Shell	RDS-A	$6,392	-8	1,874,000	–9	7,329	+6
Chevron	CVX	$3,718	-26	1,760,000	–4	4,983	0
ConocoPhillips	COP	$3,673	-5	940,000*	–17	4,916*	-9
Occidental	OXY	$1,324	+13	447,000	+5	747	+13
EnCana	ECA	$934	-31	136,000	+1	3,630	+8
Can. Natural	CNQ.TO	C$700	-37	333,062	+4	1,647	+15
Anadarko	APC	$504	-64	237,000	-4	1,637	-3
Devon	DVN	$735	+4	214,600	+25	2,418	+6
Marathon	MRO	$1,021	-37	199,000	-18	1,031	+43
Husky	HSE.TO	C$769	+13	266,500	-4	620	+7
Talisman	TLM	C$352	-33	230,616	-3	1,260	-6
Apache	APA	$612	-5	263,965	+16	1,785	+5
Imperial	IMO	C$816	-1	291,000	+4	430	-23
Suncor	SU.TO	C$588	-14	239,100	-1	211	+1
Petro-Canada	PCZ	C$776	+15	315,100	+49	723	0
Nexen	NXY.TO	C$403	+103	222,700	+34	227	+2
XTO	XTO	$412	+12	61,277	+8	1,561	+29
Chesapeake	CHK	$372	-33	29,778	+15	1,892	+9
Pioneer	PXD	$102	+26	45,694	+6	383	+6
EOG	EOG	$202	-32	43,700	+18	1,497	+11
Newfield	NFX	$83	-69	23,911	+13	536	-6
Pogo	PPP	-$46	——	17,165	-18	191	-3
Swift	SFY	$42	-17	22,900	-3	64	+14

** Does not include Lukoil investment*
***Millions of cubic feet equivalent*
Liquids production in barrels per day. Natural gas production in millions of cubic feet per day.

NOTE: Top 25 is based on Petroleum News research on exploration spending

● GOVERNMENT

DOI moving on OCS alternative energies

Final PEIS issued; Minerals Management Service publishing interim policy for offshore technology testing before regulations completed

By ALAN BAILEY
Petroleum News

On Nov. 5 the U.S. Department of the Interior issued the final programmatic environmental impact statement for the alternative energy and alternative use program for the U.S. outer continental shelf. The U.S. Minerals Management Service expects to issue a Record of Decision on the PEIS by the end of 2007.

Initiated as an outcome of the Energy Policy Act of 2005, the alternative energy and alternative use program will establish a regulatory framework for the development of offshore alternative energies such as wind power, wave power, solar energy, energy from underwater currents and the generation of hydrogen. The program only encompasses federal waters and does not apply to state waters around the coastline.

"Offshore Alternative Energy is a new and highly anticipated frontier for the nation, as well as a new regulatory program for the Department of the Interior and the Minerals Management Service," Secretary of the Interior Dirk Kempthorne said. "This is an important step in fostering a new industry offshore that will diversify our nation's power supplies and open up new avenues to supply renewable energy to areas that may otherwise have limited options onshore."

Kempthorne said that offshore wind turbine farms have the potential for the greatest immediate potential.

"Wind is the fastest growing source of electricity generation in the world," Kempthorne said. "Northern Europe has 27 offshore wind farms producing estimated 900 megawatts of electrical generation. At present there are no offshore wind farms in the United States."

Environmental impacts

The PEIS examines the potential environmental effects of alternative energy developments on the outer continental shelf over the next five to seven years and identifies policies and management practices for overseeing those developments. The document identifies issues and impact mitigation measures that need to be considered when reviewing specific offshore developments.

The environmental investigation has found that most of the environmental impacts would occur during the construction phase — significant air emissions or wastewater discharges are not anticipated during operation, Kempthorne said. But Kempthorne has established a wind turbines advisory committee to advise on measures to avoid or minimize impacts to wildlife from wind energy facilities.

And bearing in mind public concerns about the location of offshore facilities, offshore developments are excluded from areas such as marine national parks, wildlife refuges and national monuments.

MMS is in the process of preparing regulations for the alternative energy program. The service expects to publish a notice of proposed rulemaking in spring 2008, with a final rule probably coming out at the end of 2008. Issuing of a final rule will then enable alternative energy lease sales to be held. But given the harsh sea and weather conditions offshore Alaska, MMS anticipates that, within the timeframe of the PEIS, any offshore Alaska alternative energy developments will occur in state waters rather than on the outer continental shelf, said MMS Director Randall Luthi.

Policy for near-term testing

Meantime, MMS has established an interim policy for the testing of offshore alternative energy technologies, to enable companies to get a jumpstart on developing those technologies before the final rule is issued. After a 60-day public review period for the policy, the service will accept nominations for offshore research projects until the new alternative energy regulations come into effect.

"Through the scoping process for the EIS we found out there were many companies that really wanted to get out there now and find out what kind of information is there through the use of experimental (tests) and gathering data," Luthi said. "… Companies can submit to us where they would like to put some kind of a tower or some other equipment, in order to get technological or other data regarding those (alternative energy) resources."

Under the interim policy MMS may issue limited-term leases authorizing data collection and technology testing. And to assist in the nomination of projects, MMS is developing a web-based mapping viewer that will display features relevant to developments in specific areas of the continental shelf. The viewer will be operational in mid-November, MMS said.

Power for 50 million homes

Kempthorne said that mid-Atlantic region has 70 percent of U.S. wind potential in water depths less than 60 meters (180 feet).

"In the mid-Atlantic region this could be enough electricity to supply 50 million homes," he said.

And harnessing even a small part of the potential wave energy of the ocean could provide enormous benefits.

"At only 15 percent utilization, U.S. offshore waters are estimated to contain wave energy potential of 30,000 megawatts, enough electricity to supply more than 22 million homes," Kempthorne said.

Ocean currents can be harnessed using submerged turbines. Although the potential of this type of energy is not yet well understood, the greatest potential seems to lie off the east coast of Florida, Kempthorne said.

"It's estimated that utilizing just one thousandth of available energy from the Gulf Stream would supply Florida with 35 percent of its electrical needs," Kempthorne said.

"Our nation's consumption of renewable energy resources is about 9 percent of our total energy consumption today, but it's expected to grow more than 60 percent over the next 25 years," Kempthorne said. "We believe offshore alternative energy can contribute significantly to this growth, providing a secure, clean, renewable source of energy for our nation." ●

● FINANCE & ECONOMY

Trusts heed analyst's advice

Penn West, Canetic create North America's largest conventional trust, eye on global growth; CEOs spurn 'rocking chair'

By GARY PARK
For Petroleum News

The future of Canada's energy income trusts was given shape on Oct. 31, the exact anniversary of the federal government's Halloween bombshell that blew the sector apart.

It was resounding confirmation of a message from most analysts who say the sector has two choices: Go big, or go home.

Penn West Energy Trust pulled off a C$5.2 billion cash, shares and debt agreement to take over Canetic Resources Trust, creating a new trust with a market value of C$15.3 billion and the largest conventional oil and gas trust in North America, with production of about 210,000 barrels of oil equivalent per day.

Assuming unit holder and regulatory approval, the entity, which will keep the Penn West name, will be positioned to embark on even more aggressive expansion beyond North America and to enter the next generation of resource development in the oil sands, coalbed methane, shale gas and enhanced oil recovery.

Only oil sands trust larger

Only the Canadian Oil Sands Trust, a 36 percent owner of the giant Syncrude Canada oil sands consortium, exceeds the new Penn West in enterprise value at C$16.5 billion.

Cristina Lopez, an analyst at investment banker Tristone Capital, said the transaction will produce a royalty trust that is "competitive on the acquisition front," domestically and internationally.

The deal gives full weight to talk of a consolidation trend, which started in May with the merger of PrimeWest Energy Trust and Shiningbank Energy Income Fund to create a C$2.5 billion operation that lasted barely three months before the Abu Dhabi National Energy Co. (better known as TAQA) acquired PrimeWest for C$5 billion.

In the 12 months since the Canadian government reversed a promise and announced trusts would lose their tax-preferred status in 2011, saddling them with a 31.5 percent tax on their cash payouts, the sector has been in disarray.

Some have doggedly tried to force the government to change its mind — a campaign most now concede is wasted effort — while others have pondered their options.

Trusts building mass

The message from Penn West and Canetic chief executive officers, Bill Andrew and Paul Charron, is clear.

They have decided to take advantage of the remaining three years of their tax holiday to build a critical mass and prepare the way for conversion to a growth-oriented corporation in 2011 or later.

"As I have stated many times in the past, sitting still in today's dynamic market is not an option," Charron said.

Backed by tax pools worth C$5.5 billion, Penn West will be armed to "consolidate" even further in the Western Canada Sedimentary basin by issuing equity between now and 2011 without breaching the "safe harbor growth" rules Ottawa has established.

"The past year hasn't been a lot of fun in the sector," Andrew told reporters. "We've seen a loss in our ability to raise capital, a loss of some shareholder interest and we've looked for ways to work against that.

"One way is to head to the rocking chair and look for someone to buy you out."

But he and Charron assured analysts that neither of them has a rocking chair in his immediate future.

The best alternative, Andrew said, was to grow, rebuilding some of the strengths Penn West had as an E&P company before converting to the trust in 2005 by adding some muscle to the exploration team and asset base.

"We're making a very large step towards that," said Andrew, who will remain CEO, while Charron will be president.

Explaining the logic behind the strategy, Charron said size "enhances liquidity in (the Toronto and New York stock exchanges), increases weighting on the indices and attracts more attention from equity and income markets around the world."

Acquisitions will proceed

To underscore their growth ambitions, the two trusts will proceed with acquisitions already under way: Penn West's takeover of Vault Energy Trust for C$380 million and Canetic's purchase of Titan Exploration for C$98 million.

Although Andrew said the initial goal of the merger is to build the "dominant light oil producer" in the Western Canada Sedimentary basin, the larger purpose is to "create an aggressive Canadian player in the global markets."

Charron said Canetic tried unsuccessfully last year to make sizeable acquisitions outside Canada, including a bid for Houston-based Pogo Producing, which is now turning into a master limited partnership.

Undeterred by those setbacks, he said Canetic has assigned two employees to scout for opportunities in Western Europe, Australia, New Zealand and more stable South American countries.

UBS Securities Canada analyst Grant Hofer, in a prescient note to clients the day before the Penn West-Canetic announcement, said he believed "most trusts are evaluating merger opportunities with their peers, primarily … to better themselves to compete for future capital and acquisitions."

He said that although there is "no observable correlation between size and valuations (today), we agree that trusts will likely need greater size to attract investor interest beyond 2011."

Pointing to the weakness in the trust sector, Hofer said only five of the 28 trusts he follows have generated positive returns in the past year and neither Penn West nor Canetic was on the list.

UBS estimates unit prices for oil and gas trusts are down 27 percent from a year ago.

While the Standard & Poor's/Toronto Stock Exchange composite index has climbed 17 percent, the capped energy trust index has tumbled 16 percent.

Bulk prefer tax advantages

But Calgary attorney Ross Freeman told a recent Montreal conference that despite troubles stemming from low natural gas prices and problems trusts face in attracting funds, the bulk of trusts prefer to continue reaping the tax advantages available to them rather than jumping prematurely into the corporate world.

John Dielwart, chief executive officer of ARC Energy Trust and the most outspoken critic of the federal government's tax decision, said further clarity is being awaited from Ottawa.

"Whatever they hoped to achieve from this, it won't happen," he told the Globe and Mail. "You will either see our sector sold to other interests that can duplicate the exact model they were trying to get rid of, or it will fall into the hands of foreign investors," he warned.

In the meantime, "we believe we can continue to create value in our current trust structure," Dielwart said.

But he conceded that ARC must eventually choose between remaining a trust or switching to a more tax-efficient structure and paying less tax.

Gordon Kerr, vice-chairman of the Coalition of Canadian Energy Trusts — the lobby group formed to challenge the government — and chief executive officer of Enerplus Resources Fund, said the unintended fallouts from the tax move "continue to be felt throughout Canada, not to mention the devastation being felt by energy trusts and investors."

"The federal government's lack of consultation with energy trusts compounds the growing uncertainty investors face with doing business in Canada," he said.

Bill Holland, chief executive officer of CI Financial Income Fund, said the decision by Prime Minister Stephen Harper's government was "beyond absurd (and) reckless," setting the stage for foreigners to buy up cheap Canadian assets, resulting in the "hollowing out" of corporate Canada.

John Bitcover, chief executive officer of Priszm Canadian Income Fund, said it's not too late for the government to reconsider.

Unlike the United States, Canada has limited ways to finance a business and the trust sector is one way to let the average Canadian own different operating businesses and share the profit, he said. ●

A message from the publisher

Oct. 30, 2007

Dear readers,

We are required to publish the following information by the U.S. Post Office as part of our periodicals mailing permit. The numbers are for print copies only and represent only a fraction of Petroleum News readers because Petroleum News is largely distributed online.

The electronic version of Petroleum News has been very successful because it's easy-to-read and, most important, available on our Web site the same day it's printed, which is one to seven days ahead of the U.S. Mail.

The stories in the electronic version are clean and sharp, and if you click on an advertisement it will take you to that advertiser's Web site.

Another factor in attracting readers to the electronic version of Petroleum News is our online archives, which contain more than 11,000 articles from past issues of the newspaper and our special publications. Along with the latest issue of Petroleum News, the archives can be viewed at: http://www.PetroleumNews.com.

In addition to individual subscriptions, about two-thirds of the top oil and gas explorers and producers in Alaska and northwestern Canada have purchased bulk online subscriptions to Petroleum News, making it available at no extra cost to all their employees. Several pipeline and service and supply companies have followed suit, as have a number of government offices, including the State of Alaska, the U.S. departments of the Interior and Energy, the provincial governments of the Yukon, Alberta, British Columbia and Northwest Territories, and the federal government of Canada.

Almost all the subscribers to the print edition of Petroleum News also receive the online version, as it is included in the price of their subscription. Every Friday afternoon all online subscribers receive an email from Petroleum News, reminding them the newspaper (dated the following Sunday) is online and ready to read. The email gives them a direct link to that issue; plus access to our most special publications, such as the quarterly Petroleum Directory, the monthly Mining News, and the annual Explorers magazine.

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Sincerely,

Kay Cashman, publisher & executive editor
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● GOVERNMENT

Production tax hike moving

By KRISTEN NELSON
Petroleum News

An increase to a 25 percent tax base and aggressive progressivity are features of committee substitutes for Gov. Sarah Palin's revision of the petroleum profits tax. Committee substitutes reached the Senate and House Finance committees Nov. 5 and Nov. 6, respectively.

Legislators are trying to balance a desire for more state revenue at times of high crude oil prices with the need to get more investment from oil and gas companies.

The bill would amend the petroleum profits tax passed in 2006; that bill had a 22.5 percent tax rate and included progressivity — a tax increase based upon the price of crude oil.

Legislators are trying to balance a desire for more state revenue at times of high crude oil prices with the need to get more investment from oil and gas companies.

Both the Senate Judiciary and the House Resources committees relied on projections by consultants from Gaffney Cline that taxes based on the net can be aggressive and still allow companies positive investment returns from Alaska fields. Gaffney Cline told legislators that their model was based on in-field drilling at established fields, not more cost-challenged developments such as heavy oil.

The committee substitutes now being considered in the House and Senate Finance committees include the governor's request for a 25 percent tax rate, although the 10 percent gross tax floor on legacy fields has been dropped.

With the absence of the gross tax floor, the administration has said revenues to tide the state over in the event of low oil prices would come from strong progressivity features. The House Resources version currently in House Finance is particularly strong since there is no cap on progressivity, something House Finance Co-Chair Mike Chenault, R-Nikiski, said the committee would consider.

In stakeholder comments Nov. 8, the North Slope's largest producers — BP, ConocoPhillips and ExxonMobil — all told House Finance that the bill would have a negative impact on investment, and said the House Resources committee substitute would have a substantially more negative impact on investment than the governor's proposal.

Bills moving rapidly

The committees scheduled joint public testimony for the evening of Nov. 8.

Chenault said Nov. 7 that House Finance would probably be considering amendments on Saturday, Nov. 10, although both Chenault and Senate Finances Co-Chair Bert Stedman had earlier hoped to have the bills in committee discussion for amendments by Friday, Nov. 9.

The 30-day special session wraps up Nov. 16, and bill passage will require floor votes in both bodies and a conference committee to resolve any differences between House and Senate versions.

The bill which is passed first will become the vehicle for final passage. ●

● GOVERNMENT

Numbers will hurt proposal to lock up ANWR

By ROSE RAGSDALE

For Petroleum News

The latest bid by Congressional Democrats to permanently block energy development in the Arctic National Wildlife Refuge stands no better chance of success than earlier efforts to open the refuge's coastal plain to drilling by Congressional Republicans, according to drilling advocate Roger Herrera.

Twenty-six Democrats, led by Sen. Joe Lieberman, D-Conn., introduced a bill Nov. 7 that would place a wilderness designation on ANWR, ostensibly to protect its 1.2 million-acre coastal plain from the threat of oil and gas development.

JUDY PATRICK

"Certainly a majority of the Democrats would like to lock it up forever, but that is virtually impossible given the present makeup of Congress. This legislation has to be considered a threat, but it shouldn't keep us awake at night." —Roger Herrera

The legislation marks at least the second time this year that congressional Democrats have proposed legislation to block oil and gas drilling in ANWR. U.S. Rep. Edward Markey, D-Mass., introduced a bill in January aimed at converting the barren tundra of the coastal plain into permanent wilderness.

More than 25 years ago, Congress set aside this so-called 1002 Area for future energy development.

Development proponents quote U.S. Geologic Survey estimates that ANWR's coastal plain could produce a million barrels per day of oil for at least 30 years.

Drilling opponents say the region should exclusively preserve abundant populations of polar bears, caribou, musk oxen, and snow geese.

"America's strength is not in our oil reserves, but in our reserves of innovation," Lieberman said in announcing the legislation. "The answer is not to drill in our national treasures but to increase our energy efficiency and find alternative and renewable sources of energy."

Delegation promises fight

Alaska's congressional delegation, Sen. Ted Stevens, Sen. Lisa Murkowski, and U.S. Rep. Don Young, all Republicans, promptly vowed to fight the legislation.

"With the price of oil approaching $100 per barrel and with our energy dependence on hostile foreign nations at a record high, now is not the time to cut our country off from the resources held in Alaska's coastal plain," the delegation said in a statement Nov. 7.

The undecided in Congress will ultimately decide ANWR legislation, and those individuals "can surely recognize that $100 oil is more important to the country's future than $20 oil," Herrera said. "But then again, it's difficult to tell what they think, or if they think at all."

But the Democrats likely will encounter the same type of roadblocks in the Senate that pro-development Republicans ran into at least 10 times in the past decade trying to enact drilling legislation, said Herrera, a longtime Alaska ANWR drilling advocate.

"Certainly a majority of the Democrats would like to lock it up forever, but that is virtually impossible given the present makeup of Congress. This legislation has to be considered a threat, but it shouldn't keep us awake at night," Herrera told Petroleum News Nov. 8.

The undecided in Congress will ultimately decide ANWR legislation, and those individuals "can surely recognize that $100 oil is more important to the country's future than $20 oil," Herrera said. "But then again, it's difficult to tell what they think, or if they think at all."

Oil prices likely to go up

In the short term, prices are likely to continue to climb, Herrera said.

One theory is that speculators are bending oil prices to their will, and profit-taking is driving prices higher.

But Herrera said he strongly suspects the bigger force at work in world oil markets is ongoing global economic growth, which is spurring demand for crude.

"I can't see world economies putting their growth on hold because of higher prices, so I think demand will continue to be rather bullish for a while," he said.

But the direction of oil prices in the medium term is much more difficult to predict. Historically, long periods of economic growth have been balanced by reversals or recession. "If we see a downturn in oil prices, it will mean our economy will be in a downward spiral, and we will all suffer accordingly," Herrera said. "It's a very edgy time." ●

PIPELINES & DOWNSTREAM

Enstar: Gas prices will decrease slightly

After a 30 percent increase this year, Enstar Natural Gas Co. customers can expect a slight decrease in the price of gas next year, according to company officials.

Enstar, which provides gas to about 345,000 Alaskans, plans to reduce its rates by about 2 percent next year. That should equate to an average household savings of $2 or $3 each month, the company said.

When gas rates jumped this year, it prompted customers to cut back on the amount of gas they use, said Enstar spokesman Curtis Thayer, which in turn played a role in the proposed price reduction for 2008.

"We overestimated how much gas we were going to need, and what we already paid for, so now the customers get that back," he said.

Enstar's rates are based on two numbers, Thayer said. One is how much the company pays for gas, and the other is how much it is allowed to charge for administrative costs, profit and delivering the gas to homes.

Last year's large increase was entirely due to the rising cost of the natural gas it bought, he said. Another reason for the proposed savings next year is that oil and gas companies overestimated how much in taxes they would need to collect under a new state tax structure, so gas customers could see the resulting rebate shaved from next year's bills, Thayer said.

Enstar is asking the Regulatory Commission of Alaska, which decides whether utilities can change their rates, to approve the rate reduction. Thayer said he expects the commission will approve the request.

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Deborah Tompkins earned a degree in business administration from Fort Lewis College in Durango, Colo. She began TTT with her husband Tom (also a Fort Lewis graduate) in 2002. Before that she worked for VECO Operations for five years in administration and business development. Favorite activities include camping, fishing and snow-machining with the family; also participating in church activities. Deborah and her husband have two young daughters.

—PAULA EASLEY

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After several years in food industry management and eight years in the fasteners industry, Sandra Godbehere joined the U.S. Bearings team four years ago as warehouse manager. Now she's excited about moving into sales. Her passion is baking, a talent much appreciated by her three sons — Mark 22, Robert 17 and William 12. Her favorite quote is: "To the world you may be just one person, but to one person you may be the world."

—PAULA EASLEY

continued from page 1

ENCANA

the-board hike in Alberta royalties by 2010 and what affect that will have on its investment plans.

Eresman said the answer won't be made public until December when his company releases its capital spending for 2008.

However, he said "high risk exploration and development activity, particularly for projects that require higher commodity prices to be economic, will be challenged under the new regime."

Eresman said the decision to buy out its Deep Bossier partner, privately held Leor Energy, should not be seen as a signal that EnCana wants to raise investment outside Alberta.

But he also said the many opportunities generated by the Deep Bossier acreage and potentially other zones and play types could result in divestitures of lower-quality assets, without specifically placing Canadian properties on that list.

Deal one of EnCana's largest

Taken on face value, the deal is one of the largest in EnCana's history, giving it full control over the Amoruso field, which Eresman said has the "potential to be the leading resource play in our North American portfolio."

Jeff Wojahn, president of EnCana's U.S. operations, told a conference call Deep Bossier wells have already cost EnCana about $10 million each to penetrate depths of 15,000-20,000 feet and tap wells with reserves of 8 billion to 13 billion cubic feet.

The value of the field to EnCana is evident from its progressive acquisitions, starting at 30 percent in July 2005 and moving to 50 percent in June 2006, with the second chunk costing US$243 million.

But Moody's Investors Service said EnCana is "paying an aggressive price" of $18 per boe for finding and development costs — "substantially higher than the company's 2006 three-year all-sources F&D costs."

It noted there is "substantial execution risk, as these estimated incremental reserves (of 1.3 trillion to 1.8 trillion cubic feet of gas) will need to be proven over time and will require additional capital spending."

"Furthermore, the acquired field has a number of technical challenges, including reservoir characterization, high pressures and completion techniques," Moody's said.

Deep Bossier wells cost $10M

Jeff Wojahn, president of EnCana's U.S. operations, told a conference call Deep Bossier wells have already cost EnCana about $10 million each to penetrate depths of 15,000-20,000 feet and tap wells with reserves of 8 billion to 13 billion cubic feet.

He expects those costs will drop by about $1 million in 2008 with more efficient well designs and improved drilling and completion techniques.

Offsetting some of the technical challenges, EnCana qualifies for the 10-year production tax holiday available for deep wells in Texas, combined with operating and capital costs that are lower than in Western Canada, plus easier access to pipelines and markets.

Canaccord Adams analyst Richard Wyman said the cost structure in East Texas yields profits in the range of $6.30 per thousand cubic feet of gas (based on projected gas prices of $7.50). He said that translates into roughly double the net earnings available in Canada per barrel of oil equivalent sold.

EnCana said Amoruso holds some of the largest producing onshore U.S. gas wells of the past five years, with initial output from two wells exceeding 50 million cubic feet per day and the most recent well reaching 65 million cubic feet per day.

The Deep Bossier wells intersect shale and sandstone formations that are 2,000-3,000 feet thick, the company said.

Those are similar to the deeper, complex, high-cost wells whose economics EnCana suggests will be negatively impacted by Alberta's new royalties, even though the government is offering some breaks for deep and unconventional drilling.

EnCana expects production from Amoruso to top 220 million cubic feet per day by the end of 2007 and average 315-355 million cubic feet per day in 2008. ●

continued from page 1

INSIDER

waiting to go. Service and equipment providers need an annual forum to meet their old and potentially new customers, display their company's abilities and introduce new products and technologies," Webb said. "The exhibitors' booths and displays are the major component of Pac Com Expo along with their demonstrations and technical sessions."

"Way back in 1983 when I first joined the Alliance as a board member, we decided that we must focus on 1) meaningful actions, 2) providing information and 3) providing 'fun' networking for our organization to succeed. We did it. It worked." Webb is following the same mandate with Pac Com.

Key hours will be 4 p.m. to 7 p.m., when Vince Vance is performing and the Mardi Gras buffet is open — "fried catfish, BBQ ribs, giant Denali Cream Puffs and many other goodies."

Webb saw Vince Vance & the Valiants perform in Atlanta: "They were great. They are hilarious. … We booked them on the spot. They will play on stage (24 foot x 40 foot big). …Vince tends to take the show to the audience."

No host bars, espresso, coffee and sodas will be available throughout the expo, which starts at 11 a.m. and ends at 7 p.m.

Webb would also like to put a large, heated tent outside the George M. Sullivan Arena, where Pac Com will be held, for a heavy equipment display. He's looking for a tent and a heater company that wants to "show off their equipment."

Pac Com will not be open to the public or advertised in general media, but rather publicized through industry associations and publications. Registration at the door requires an invitation or proof the person works in an Alaska heavy industry, Webb said, noting his staff is in the process of setting up online registration.

For more information call (907) 272-5634 or e-mail info@anchoragemarkets.com.

—KAY CASHMAN

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DISPUTES

was not acting as sovereign, but as one of the parties to a contract.

Perhaps the most important thing that was lacking was "objective measure of value," Iversen said.

"… There wasn't a defined market or price set for … Alaska North Slope oil."

No established market

Iverson said there wasn't an established market price for ANS crude oil. Auditors had to use an established market price for some other oil as the basis for a price analysis, or work with a market basket of crudes.

Before the mid 1980s, when Platts came out with public data on oil prices, there wasn't an established pattern for ANS pricing.

And volumes were high: with some 2.2 million barrels, even a 5 cent difference in the value of oil made a tremendous difference. This was, Iversen said, a "huge risk area for the state and a huge risk area for the taxpayers and the royalty payers."

Dan Dickinson, a consultant to the Legislature on tax issues, and a former Tax Division director, told committee members he was a consultant in the Amerada Hess litigation, "royalty litigation under the net system."

"For the first 10 or 15 years the big issue was the value of the oil," Dickinson said. While publicly reported spot prices are the norm now, in the 1980s there were so-called official prices, but they were set in places like Saudi Arabia.

"We didn't know how much our oil was worth," Dickinson said.

Then there were price controls followed by phased decontrol, so for a period "every month … part of the barrel had a price control on it and part didn't; and every month it changed." It was "a nightmare" to figure out the value of the oil. The range was from $6-$7 for controlled price to de-controlled in the $30 range, he said.

That was followed by the windfall profits tax, with Prudhoe Bay under one regime and Kuparuk under another.

"I guess what I'm trying to say is there was a huge panoply of issues focused around the price," he said, and a small group of auditors in the Department of Revenue "grappled with that issue — and they grappled with that issue for 15 years."

And the issue was also being grappled with on the royalty side.

The issues never went to court, they were settled, "because typically both sides had … fairly decent arguments." Billions

see **DISPUTES** *page 23*

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COSTS

said, pulled together in 2005 and early 2006. This included cost information available from Securities and Exchange Commission filings for producers that break out costs in Alaska, confidential income tax filings and private consulting work on North Slope costs.

Pulliam said the fiscal note costs line up with information available for 2002-05 for Alaska, a total of $2.1 billion for operating and capital costs.

In August, Revenue forecast lease cost increases for the current fiscal year, FY 2008, of nearly $2 billion, almost doubling the 2006 fiscal note estimate. The August figures are from PPT tax filings that have come in to date, Pulliam said. Those returns have not yet been audited and Revenue is taking those costs as filed and using them as projections, he said.

Costs driven by prices

Pulliam said prices have been driving costs up.

The "dramatic long-run increase in oil prices" over the last few years is primarily to blame, he told legislators, and noted that just a couple of years ago when they ran price charts going out to $75 a barrel that per-barrel price seemed excessive to many.

As a cost driver, expectations are more important than the current price, he said. The futures market provides one measure of expectations. In 2005, futures topped out at around $60 a barrel; the current futures price is $80 for December 2011 delivery — $15 below the current price, he said, reflecting a general expectation that oil prices have shifted up.

The increased activity due to price expectation puts pressure on costs, Pulliam said.

The oil price is impacted by geopolitics — the current unrest in the world — and by uncertainty about the extent to which the Organization of Oil Producing Countries, the world's swing producer, will be resolute in keeping up the price, something Pulliam said OPEC has considerable ability to do.

The market also recognizes that the places where oil is found are increasingly expensive.

Pulliam said the low price case oil companies used in evaluating projects was generally assumed to be about $25 a few years ago; today it is understood to be $40-$50.

Info on cost increase

Revenue is unable to provide information on cost increases by field or by producer because of taxpayer confidentiality issues, so Pulliam said Econ One looked for publicly available information on oil and gas costs.

Data released by Cambridge Energy Research Associates in May provided an index for upstream capital costs with 2000 as a base year, he said. Oil and gas capital costs rose generally in line with inflation through 2004, and then in 2005 began to rise steeply. With 2000 pegged at 100, capital costs in 2005 rose from a level above 110 to above 140 by the end of the year, continued to climb in 2006 and reached an estimated level of 180 in the first quarter of 2007, almost doubling. Pulliam said there is some indication of flattening in this index, which is to be expected as suppliers of goods and services to the oil and gas industry gain confidence in a long-term demand increase and begin to make investments to meet that demand.

Spike in Alaska costs

As for the spike in Alaska costs, Pulliam said Econ One did not have access to taxpayer information from Revenue, but in 2006 there was some construction and volumes from Prudhoe Bay were down following the August leak, which would drive costs up for those barrels that were produced.

In addition, the costs associated in dealing with those disruptions and increased expenditures, Pulliam said, will put pressure on all other costs you have, such as cleanup, by diverting people to those activities.

SEC filings by ConocoPhillips and BP reflect operating costs for Alaska. Pulliam said figures reported by the companies reflect increasing production costs worldwide over the last four years with higher increases in the United States, and in particular in Alaska.

ConocoPhillips showed costs beginning to rise in 2005, with a 63 percent increase in 2006 to approximately $6.40 per barrel. He said BP's reported figures for Alaska are in the same general range as those reported by ConocoPhillips for 2003 and 2004, then rise by 38 percent in 2005 and increase sharply by 81 percent to more than $9 per barrel in 2006.

Revenue's 2006 fiscal note estimate was $7.27 per barrel (operating and capital costs combined); its spring forecast number in 2007 had risen to $14.56 per barrel.

Pulliam noted that Revenue does not have access to information on actual and anticipated costs which would be shared between working interest owners in the fields.

Costs related to corrosion issues can only be estimated from public data. BP has said it will spend $260 million to replace oil transit lines at Prudhoe Bay and said in a 2006 form 20-F filing that it planned to spend more than $550 million during 2007 and 2008 on integrity management in Alaska. Pulliam said the $550 million figure was not identified as BP's share or as what BP would spend as operator, although "net" was included in the description. If this is BP's share of integrity management, the total among all of the working interest owners would be far greater than $550 million.

As for future forecasts, Pulliam noted that while Revenue did not include cost-price sensitivity in its 2006 fiscal note or its PPT status report, the department's current forecast does adjust cost up or down when expected price levels rise above or fall below $60 per barrel. ●

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were paid to the state, including interest, by the time those cases settled, Dickinson said.

Changes produce legal uncertainty

"Every time you change the tax, you create a level of uncertainty," Steve Porter, told the committee. Porter, currently a legislative consultant and a former deputy commissioner of the Department of Revenue, said the uncertainty created isn't fiscal, it's legal.

"You create legal uncertainty and so you create new interpretations of the law. And … every time you change the tax you're going to go through that. It's to be expected because you're going to have a difference of opinion," Porter said.

Those differences could be over a small range of things or a large range of things but whether the tax is "gross or net doesn't matter — there's going to be uncertainty," he said.

Certainty will be created over the next four or five years, and five years from now there won't be so many disputes because "through regulation and through litigation" definitions will be determined.

Information also an issue

Iversen said that in the 1970s and early 1980s there were a lot of gray areas and the state's auditors pushed "to the edge of that gray area to benefit the state."

It was also a time when the state was digging into taxpayer records "when taxpayers weren't accustomed to that, so there would be some reticence there in terms of actually providing the information" and there were "aggressive cases of blue-sky audits," and from there, cases grew to have tremendous dollar amounts and lingered for a decade and a half.

Cases where there were strong issues for the state typically settled first, Iversen said. So when you hear rumors of cases with low settlement values, "for instance below 50 percent, that may be just on issues that were weak for the state to start with."

It's a different world today, he said, with oil prices publicly available and defined regulations.

"Also I would say we've gained some respect: We were pushing back all those years and being aggressive in our audits."

Iversen said the risk in terms of dollars is substantially less today than it was historically.

"The major issues are defined. We've got clarity now on major downstream cost issues; the downstream issues are not going to be as global … or as significant in terms of dollars as these enormous cases that started in the '70s and the '80s."

There will be "more discrete cost issues" now. "And so dollar for dollar on the issues it's going to be a smaller amount," Iversen said.

Fewer court cases

"Now most cases settle in the Department of Revenue unless we're just wrong — in which case we acknowledge a mistake…," Iversen said.

"Unless there's an actual mistake, most cases settle at 80 to 100 percent," he said, "…a much, much higher settlement number now, than what we had before."

On the issue of auditing costs for deductibility under the petroleum profits tax, Iversen said "there will be areas of dispute on the upstream cost side." But the state has a much more established realm of authority, he said, including the Internal Revenue Code standards.

And it's accounting, he said. "We're not hitting, necessarily, the vagaries of the market where there's just simply not an input that we need in order to make the tax calculation."

As for concerns about court cases, there is now a well established administrative process, Iversen said.

The division does the audit and if the taxpayer doesn't like it there is an informal conference at Revenue where the taxpayer can submit "all the evidence and information that they want to submit to us"; then the dispute moves out of Revenue to the Office of Administrative Hearings and presentation to an administrative law judge.

From there a dispute would go to court. While that will take time, it won't require "numerous motions of summary judgment, numerous huge, deep discovery requests in areas that are gray, muddy areas" as cases did after oil production started.

"We're not going to need to go there in a typical case," he said.

There will be issues in "areas of some fertile dispute" that will end up in superior court, but they won't require decades of litigation, Iversen said, because "the standards have changed; the world has changed." ●