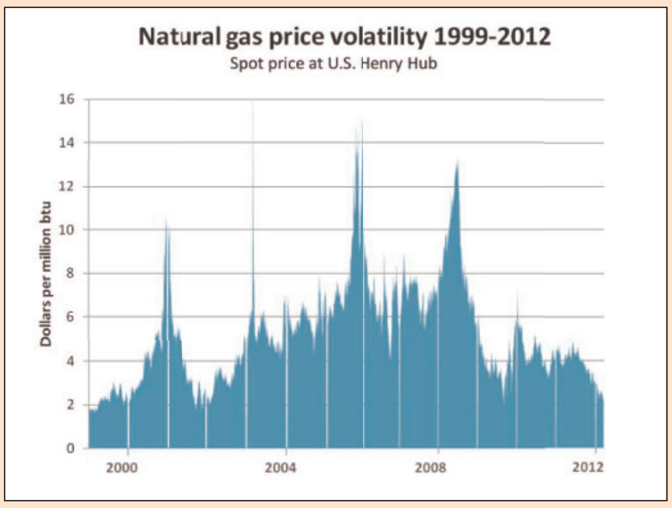
Petroleum news

Vol. 17, No. 17 • www.PetroleumNews.com | *A weekly oil & gas newspaper based in Anchorage, Alaska* | Week of April 22, 2012 • $2

page 8 'Middle earth,' frontier basins credits, tax cuts pass Legislature



OFFICE OF THE FEDERAL COORDINATOR

The volatility of U.S. natural gas prices is a major part of the story of Alaska's attempts to commercialize North Slope natural gas. See story on page 10.

'Arctic Opening' report predicts huge but risky investment ahead

A new report out of London takes a sweeping look at the Arctic and reckons it could attract investment topping $100 billion over the next decade.

Most of the investment will be in the oil and gas and mining sectors, says the study, which also looks at shipping, fisheries and tourism.

"The epicenter of that investment is likely to be in the Barents Sea area, north of Norway and Russia, and in northern Alaska," it says. "Smaller investments, but with major local and international consequences, could occur in Greenland, Canada and elsewhere in the Arctic."

The study comes from Lloyd's, the global insurance concern, and Chatham House, also known as the Royal Institute of International Affairs.

The report is titled "Arctic Opening: Opportunity and Risk in the High North."

Lloyd's is an outfit that certainly knows something about risk. It describes itself not as a company, but "a market where

see **ARCTIC REPORT** *page 19*

2012 North Slope exploration well count likely 13-14, not 34

Of the eight operators who hoped to drill as many as 34 exploration wells on Alaska's North Slope in 2012, two could not get rigs so postponed drilling, one will be drilling starting mid-May since it can drill year round, four have completed their wells, and one is just about to finish drilling as the winter exploration season in northern Alaska winds down to a close.

Of the 34 wells the eight oil companies had hoped to drill, six to eight wells might still be drilled this year by Great Bear Petroleum; Repsol drilled two out of the 15 wells it had planned; Brooks Range Petroleum drilled one out of two planned wells; Savant Alaska is close to finishing its one out of one; ConocoPhillips drilled one out of one; Pioneer Natural Resources Alaska drilled two out of two; and UltraStar Exploration and Linc Energy's wells were cancelled until next winter.

If Savant is able to finish its well, a total of seven wells will have been drilled, with another six to eight in the works for Great Bear.

If all the wells planned would have been drilled, 2012 would have been the busiest exploration season since 1969, when 33 exploration wells were drilled following the Prudhoe Bay discovery.

Still, 13 to 15 wells for 2012 compares favorably to the single well drilled in the winter of 2011 by Brooks Range.

see **EXPLORATION UPDATE** *page 23*

FINANCE & ECONOMY

A tight situation

Buccaneer announces financing & rig purchase after contractor complaints

By ALAN BAILEY
Petroleum News

Following complaints about unpaid bills due to contractors for work done at the company's Kenai Loop gas field on Alaska's Kenai Peninsula, on April 18 Buccaneer Energy announced that it had secured $20 million in project financing and that it had also agreed to the purchase of Marathon's Glacier No. 1 drilling rig for $7.5 million.

$20 million facility

The new $20 million finance facility will enable Buccaneer to pay its vendors and purchase the Glacier rig, in addition to paying some other company expenses, Buccaneer said. The prospective lender is currently conducting due diligence prior to finalizing the deal, the company said, adding that it expects the deal to close in the next 14 to 28 days.

However, concerned about the potential ramifications of a "mechanic's lien" against property on city land, the council voted to only issue a new special use permit for Buccaneer's operations up to May 4, rather than for the term of one year that Buccaneer had requested.

see **TIGHT SITUATION** *page 23*

FINANCE & ECONOMY

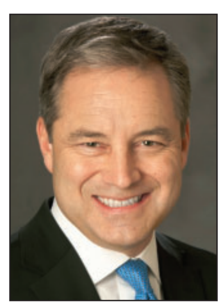
Legislators back at work

Special session called on oil taxes, in-state line; bill based on Senate's new field tax

By KRISTEN NELSON
Petroleum News

It looked like Senate Finance had an oil tax compromise senators could live with when, after weeks of work on the measure, it moved Senate Bill 192 out of committee April 11.

But SB 192 never reached the Senate floor.



GOV. SEAN PARNELL

The bill, a fundamental change of Alaska's oil and gas production tax system with different tax rates for existing production from legacy fields, incremental production from legacy fields and new oil, couldn't garner enough support from members of the Senate Bipartisan Working Group.

On April 14 another plan surfaced, a tax change affecting only production from new fields. Senate Finance added that measure to House Bill 276, credits for exploration and seismic work in frontier basins (see story in this issue).

The Senate passed HB 276 by a vote of 17 to 3, but it got no traction in the House, with portions of HB 276 moved to other legislation and HB 276 withdrawn by its sponsor.

The tax change proposed by Gov. Sean Parnell last year, an across-the-board production tax cut, passed the House last year but stalled out in the

see **SPECIAL SESSION** *page 22*

PIPELINES & DOWNSTREAM

Pipe dreams showdown

Kinder Morgan proposes larger-than-expected line to Vancouver for Alberta crude

By GARY PARK
For Petroleum News

The all-out contest to open new markets for Alberta crude oil producers, who are losing an estimated C$18 billion a year because of current export bottlenecks, and the battle against the rising tide of pipeline projects has reached a crescendo.

Kinder Morgan has emerged from virtual obscurity with plans to almost triple capacity on its Trans Mountain system from Alberta to the Pacific Coast, joining rivals TransCanada and Enbridge in the conflict over the shipment of oil sands crude to the Texas Gulf Coast and Asia.

After two years of low-key negotiations with potential shippers, Kinder Morgan has disclosed its plans to seek regulatory approval to enlarge Trans Mountain to 850,000 barrels per day from its current 300,000 bpd, setting the stage for what will be the ultimate showdown over pipelines and tankers in the British Columbia region.

"I am fiercely opposed to (an increased number of tankers) in Vancouver's harbor." **—Vancouver Mayor Gregor Robertson**

The little-known Trans Mountain system has been operating for decades, carrying crude to a Washington state refinery and Port Metro Vancouver for shipment to California and Asia.

see **PIPE DREAMS** *page 21*

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● EXPLORATION & PRODUCTION

Repsol completes two North Slope wells

Gas blowout at Qugruk No. 2 disrupts drilling program; Kachemach No. 1, Qugruk No. 4 completed by end of winter exploration season

By ALAN BAILEY
Petroleum News

After a North Slope exploration season that might be characterized as a "full Alaska experience" Spanish oil major Repsol, a newcomer to the Alaska oil scene, has been reviewing the lessons learned following a gas blowout on one of its exploration wells, Bill Hardham, Repsol's Alaska operations manager, told Petroleum News March 13.

Although the blowout on the company's Qugruk No. 2 well caused delay and disruption to Repsol's drilling program, the company did eventually complete two wells: the Kachemach No. 1, to a depth of about 10,100 feet, and the Qugruk No. 4, to a depth of about 7,700 feet, Hardham said.


BILL HARDHAM

The Qugruk well is located near the Beaufort Sea coast on the Colville River Delta, with the Kachemach well some distance to the south, just east of the Meltwater participating area of the Kuparuk River unit.

Repsol is partnering in its drilling program with 70 & 148 LLC, a subsidiary of Denver-based Armstrong Oil & Gas, and with GMT Exploration Co. LLC.

Ambitious plan

Having acquired interests in about 500,000 acres in North Slope leases that were already part way through their lease terms, with some due to expire within the next year or two, Repsol has been anxious to forge ahead with drilling in its acreage, Hardham said. So the company initially planned to concurrently use five drilling rigs to drill multiple well penetrations at five locations. However, after listening to concerns expressed by residents of Nuiqsut, a community near the planned drilling locations, the company decided to scale back its plan, opting instead to use four rigs at four locations while only drilling concurrently with up to three rigs.

"That was something that the community thought was more reasonable than what we initially proposed," Hardham said.

The revised plan would have resulted in four wells: the Kachemach 1, the Qugruk 1, the Qugruk 2 and the Qugruk 4 (abbreviated as K-1, Q-1, Q-2 and Q-4), with the three Qugruk wells being drilled at different locations in the same general area.

Successful start

As the winter approached, Repsol started the construction of the ice roads that it would need for access to the drilling sites, collaborating with Pioneer Natural Resources to share part of the annual ice road that Pioneer constructs to its offshore Oooguruk oil field. To support its operations, Repsol had to install several temporary camps, including a camp on an ice pad next to a ConocoPhillips well pad on the western side of the Kuparuk River unit. And the company chartered an aircraft for flying personnel to and from Anchorage.

Repsol started drilling the K-1 well in early-February and shortly afterwards starting drilling Q-2.

At that point the company's challenging logistical exercise in support of the drilling was progressing pretty much to plan.

"Up to that point we had, I think, done pretty well pulling it off," Hardham said.

Shallow gas

But a few days after the start of drilling of Q-2, about half an hour before a group of Repsol managers was due to visit the drill site, the drill bit penetrated an unanticipated shallow gas pocket, causing the well to kick and shoot drilling mud onto the snow and ice adjacent the drill pad. The incident occurred while the crew was drilling the surface section of the well, before setting the surface casing and installing the blowout preventers, Hardham explained.

The drilling crew responded well, ensuring that gas flowing from the well passed through a diverter pipe, away from the rig, and shutting down the power on the rig to prevent a gas explosion. The rig crew did nothing wrong, Hardham said.

No oil was spilled. And there were no injuries or major damage. Gas flowed from the well for about eight hours, with water from the underground rock formation then flowing for another day or so.

Incident response

Invoking its pre-prepared incident response plan, Repsol activated its contracts with incident response companies and established an incident command center managed by a unified command. The company also stopped drilling its K-1 well — the company wanted to focus on dealing with the Qugruk incident and did not wish to risk the possibility of a second incident while it was still bringing the Q-2 well under control, Hardham said.

Once the Q-2 blowout happened, the response to the incident proceeded very successfully, he said.

And drilling at K-1 stopped for about three weeks, restarting around March 8, Hardham said.

To enable the plugging of the unsecured well it was first necessary to thaw out and clean up the drilling rig which had been shut down in severely cold conditions. Eventually, about a month after the incident, it became possible to plug the well with cement.

Drilling mud that had spilled from the well, being water based, had formed a solid, frozen slab on top of a sheet of ice in an area of less than an acre adjacent the ice drilling pad. The water-based mud was environmentally benign, Hardham said. It took about three weeks to break up and remove the frozen mud, with the cleanup finishing around April 8. Repsol plans to inspect the site in the summer to evaluate any need for follow up work, Hardham said.

Permits withdrawn

Following the Q- 2 incident the Alaska Oil and Gas Conservation Commission withdrew the drilling permits for Repsol's remaining Qugruk wells. The commission wanted new permit applications, demonstrating Repsol's understanding of what had caused the Qugruk incident and explaining how the company would address the blowout risk when drilling those other wells, Hardham said.

The gas pocket that caused the blowout was in a shallow rock formation that cannot necessarily be seen in seismic section — Repsol submitted revised drilling plans involving the setting of surface casing and installing the blowout preventer before drilling to the depth of this formation, Hardham said. The company also specified the use of a heavier drilling mud, he said.

The commission re-issued the permits. But at this point Repsol decided that there was insufficient time left in the season to drill the planned Q-1 well.

"In the end we did not pursue that well this year — we just didn't have enough time left," Hardham said.

Two wells completed

However the company did proceed with the drilling of the Q-4 well, a well designed to be drilled from an ice island.

"We reached TD (total depth) on that well a few days ago and we are doing the logging right now," Hardham said.

And meantime the drilling and logging of the K-1 well had been completed, with Repsol planning to finish all of its drilling operations by April 15.

Repsol is still assessing the data from the two wells that it finally completed and is not yet in a position to announce the results of the drilling, Hardham said.

Extremes

Looking back on its experiences from the winter, Repsol has found Alaska to be a land of extremes, both in terms of the climate and the remoteness of the land.

"The logistics is every bit as challenging as we were led to believe, but that

see REPSOL WELLS page 17

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● LAND & LEASING

On to the 9th

Groups opposed to exploration in Chukchi Sea take '08 lease sale appeal to higher court following District Court February decision

By ALAN BAILEY
Petroleum News

In the latest move by those opposed to oil and gas development in the Arctic offshore, the Native Village of Point Hope, the Inupiat Community of the Arctic Slope and 12 environmental organizations have taken an appeal against the Department of the Interior's 2008 Chukchi Sea lease sale to the U.S. Court of Appeals for the 9th Circuit.

The groups had appealed the lease sale in the federal District Court in Alaska. However, following a court case that lasted several years and that involved a rewrite by Interior of the environmental impact statement, or EIS, for the lease sale, in February District Court Judge Ralph Beistline dismissed the case. Beistline said that, following the EIS rewrite, Interior had complied with all applicable laws in approving the sale.

And so the groups challenging the lease sale have now appealed the District Court's decision to the 9th Circuit.

Shell, ConocoPhillips, Statoil and other companies bought leases in the sale — Interior received $2.6 billion in bonus bids. A ruling by the court that the lease sale was invalid would presumably invalidate the leases that the companies purchased.

Plans and schedules

Shell plans to drill in its Chukchi Sea leases this year, while ConocoPhillips and Statoil plan to start drilling in 2014.

The 9th Circuit court has set a schedule for the lease sale appeal, with opening briefs by the appellants due on July 23 and Interior's reply brief due by Aug. 22.

The court is already processing three other appeals against Shell's planned Arctic drilling. One of those appeals, against the Environmental Protection Agency air quality permits for the Noble Discover, the drilling vessel that Shell plans to use in the Chukchi, has a briefing schedule due for completion at the end of May. The other two appeals are against the Bureau of Ocean Energy Management's approval of Shell's Chukchi Sea and Beaufort Sea exploration plans: these two cases have been consolidated, with oral arguments scheduled for May 15.

Shell plans to start drilling in the Chukchi Sea in July.

Drilling controversy

People opposed to Arctic offshore drilling say that too little is known about the delicate Arctic marine environment to risk the potential negative impacts of industrial activities. These people also question the feasibility of responding to an oil spill in Arctic waters, especially given the severe Arctic climate, the prevalence of sea ice and the paucity of an infrastructure for logistical support. Native groups are concerned about the potential impacts of industrial pollution and disturbance on the marine wildlife that form a core component of subsistence food supplies.

Shell says that enough is now known about the Arctic offshore environment to conduct a limited program of exploration drilling; that there are proven techniques for dealing with an Arctic marine oil spill; and that its planned wells present little oil spill risk. The company is assembling a major oil spill response fleet, with the intention of having a self-sufficient, onsite spill response capability should an emergency arise. Shell and the other companies planning offshore drilling have been conducting environmental research in the Chukchi and Beaufort seas, with Interior having also sponsored environmental research programs in the region for a number of years.

Government regulatory agencies have now endorsed Shell's plans, although the company still needs approved drilling permits and approvals for the accidental minor disturbance of marine mammals. The U.S. Coast Guard, while acknowledging the logistical challenges of mounting an oil spill response in offshore northern Alaska, has said that it thinks that Shell is adequately prepared for its planned drilling.

EIS questioned

The District Court Chukchi Sea lease sale appeal that has now moved to the 9th Circuit focused on what the petitioners claimed were deficiencies in the lease sale EIS. And the court upheld claims that, in preparing the EIS, Interior had failed to adequately consider the environmental impacts of potential natural gas development in the Chukchi and had not adequately considered the significance of missing Chukchi Sea environmental information.

In a subsequent rewrite of the EIS, Interior added an analysis of the potential impacts of natural gas development; identified and commented on every instance of documented missing information; and voluntarily added a new section analyzing the potential impacts of a hypothetical very large oil spill in the Chukchi Sea. Judge Beistline accepted the adequacy of the EIS changes. ●

Contact Alan Bailey at abailey@petroleumnews.com

● FINANCE & ECONOMY

Asian money eyes Canada

PetroChina, Petronas intensify pressure for action on LNG, crude export projects; Canada works regulatory and workforce constraints

By GARY PARK
For Petroleum News

Billions of dollars are flowing across the Pacific into development and distribution of Canada's oil and natural gas resources and billions more are set follow.

In the latest moves to accelerate the opening of Asian markets, PetroChina is bidding to help build and own part of Enbridge's C$5.5 billion Northern Gateway project, Malaysia's Petronas said it wants to spend C$5 billion more securing Canadian natural gas supplies, while Japan's Mitsubishi and South Korea's state-owned Korea Gas are hoping for an initial agreement in April on a Shell-operated LNG project that could cost US$12 billion.

As industry plans unfold at a rapid rate, the Canadian government is answering the call for help to accelerate regulatory approvals and to head off a looming shortage of skilled tradespeople.

Immigration Minister Jason Kenney said in a Calgary speech that his government will create a separate entry arrangement by the end of 2012 to allow "tens of thousands" of foreign workers to find jobs at resource-based projects, notably in the LNG and oil sands sectors.

That coincided with confirmation from Natural Resources Minister Joe Oliver of a 20-year export permit for 230,000 million cubic feet per day of liquefied gas by the BC LNG Export Co-operative, adding to an earlier license for Apache-operated KM LNG Operating General Partnership, to convert 1.4 billion cubic feet per day into LNG.

Oliver, who is spearheading his government's promise in March to streamline environmental reviews of major energy projects, said the LNG permits "show the world we are serious about getting our energy resources to market" as Canada pursues its goal of becoming a "global energy super-power."

He said that the government "does not want any project to proceed unless it's safe for the environment and safe for Canadians."

Pressure grows for outlets

The pressure to find new outlets for Canadian gas is building as North American prices shrink, threatening the ability of producers to remain in business long enough to capture a chunk of the Asian markets.

Eric Nuttall, portfolio manager at Sprott Asset Management, said the three announced LNG export projects for British Columbia will need liquefaction capacity of 4.2 billion cubic feet per day, or 35.2 tcf of dedicated reserves.

That prospect was reinforced by Spectra Energy Chief Executive Officer Greg Ebel, who said Eastern Canada could soon dramatically curtail its shipments of gas from Western Canada in favor of buying gas from the Marcellus shale in Pennsylvania and New York.

He said Union Gas, Spectra's Ontario-based subsidiary, is seeking expressions of interest from producers and customers to expand a pipeline that was previously used to export Western Canadian gas into New York state and is now being reversed to tap into production from the prolific Marcellus shale.

In a speech in Ottawa and an interview with the Globe and Mail, Ebel said he expects the development of U.S. shale gas to cut deeply into Canadian exports into the U.S. Northeast and even erode traditional markets in Ontario and Quebec.

"With the price of natural gas in New York and Pennsylvania versus the delivered cost of gas, it's just very difficult for the Western Canadian gas to compete in some markets in the United States," he said.

EIA forecasts exports to US to drop

The U.S. Energy Information Administration buttressed that view forecasting that Canada's gas exports to the U.S. will decline by 62 percent over the next 25 years, having already fallen to 6 billion cubic feet per day from 9 billion cubic feet per day in the last five years.

Ebel said the loss of sales in eastern North America make it even more urgent for Western Canadian producers to advance plans for LNG exports to the Asia-Pacific region.

Spectra itself is investing C$1.5 billion on its British Columbia gas transportation and processing system and is looking for firm shipping commitments that would support an expansion of its pipeline to the Pacific coast.

Against that backdrop, PetroChina and Petronas have positioned themselves to play key roles in developing Alberta's oil sands and Western Canada's shale gas.

PetroChina in 'open bid process'

PetroChina has entered an "open bid process" by expressing interest in building the 525,000 barrels per day Northern Gateway pipeline and is pondering an equity stake in the project, Enbridge Chief Executive Officer Pat Daniel told the Financial Post.

He said PetroChina has "made the point to us that they are very qualified in building pipelines and we will take that into consideration when we are looking for contractors."

However, if PetroChina were to acquire an ownership stake it would have to purchase an equity interest from one of Northern Gateway's 10 existing owners because there is no opportunity to expand that group, Daniel said.

What PetroChina could bring to the table is access to a workforce of about 2 million and cheaper labor costs, which would ease growing concerns over Canada's ability to proceed with its slate of potential LNG and crude oil export pipelines and terminals and expansion of the oil sands, although there could be anxiety over the transfer of Canada's resource assets to Chinese owners.

British Columbia's powerful labor unions might also raise objections to the use of non-unionized foreign workers and environmentalists and First Nations would likely intensify their opposition to shipping Canada's oil and natural gas across the Pacific.

PetroChina was involved as a prospective 49 percent equity partner in Northern Gateway until 2007 when it withdraw, accusing Canadian governments and producers of hindering its attempts to aggregate 200,000 bpd of production for the pipeline.

Petronas seeks to invest C$5 billion

Petronas pulled a surprise when its Chief Executive Officer Shamsul Abhar Abbas told news agency Bloomberg that has company was seeking an investment of C$5 billion in Canadian gas plays as part of its strategy to "grow big in Australia and Canada."

Petronas paid C$1.07 billion last year to acquire a 50 percent stake in 150,000 acres of Progress Energy gas properties in British Columbia's North Montney play and was ready to take 80 percent ownership of a related LNG export terminal on the British Columbia coast.

At the request of the Toronto Stock Exchange, Progress issued a statement saying it was not involved in any negotiations with Petronas to enter into business transactions beyond its existing joint-venture deal.

But it said results of an LNG feasibility study with Petronas should be released no later than September.

see **ASIAN MONEY** *page 7*

NATURAL GAS

Walakpa gas field expansion requested

The Alaska Oil and Gas Conservation Commission has tentatively scheduled a public hearing for May 29 at 9 a.m. at its Anchorage offices on a request for expansion of the area covered by the Walakpa gas pool rules.

Walakpa, along with the East Barrow and South Barrow gas fields, supplies natural gas to the City of Barrow, with the majority of gas coming from Walakpa, according to AOGCC production data.

The North Slope Borough, operator of the Walakpa gas field, is drilling additional development wells in the field. Petrotechnical Resources Alaska is providing technical and management services for the project.

PRA told AOGCC in an April 4 letter that Walakpa wells 11 and 12 have been completed in the eastern portion of the field and drilling of the Walakpa 13 is under way, targeting the Walakpa gas pool in the western portion of the field.

Walakpa 13 extends into section 22 of township 20 north, range 20 west, Umiat Meridian. That section is not included in current pool rules for the Walakpa gas pool, PRA told the commission. The North Slope Borough is requesting that all of section 22 and the north half of section 27 of township 20 north, range 20 west, UM, be included in the pool rules area for the Walakpa gas pool.

These wells are part of a drilling program which includes two wells in the East Barrow field and four wells in the Walakpa field.

Drilling started last fall.

—KRISTEN NELSON

● LAND & LEASING

Another stab at Telemark

BRPC and its partners are proposing a smaller unit on the eastern North Slope after withdrawing initial plans last September

By ERIC LIDJI
For Petroleum News

A joint venture operated by Brooks Range Petroleum Corp. is proposing to form the Telemark unit over nine leases covering 16,235 acres on the eastern North Slope.

The proposed unit would sit between the Badami unit and the western edge of the Arctic National Wildlife Refuge. The group proposed a four-year term running through Dec. 31, 2015, with a possible five-year extension if the companies meet their work requirements.

The companies are proposing to conduct a 3-D seismic survey at the unit by the end of the year, chose a drilling location by Dec. 1, 2013, and drill the well by March 31, 2014, or risk losing the unit. The companies would apply for a second unit plan by Dec. 31, 2015.

The Alaska Department of Natural Resources is taking comments through May 21.

The working interest owners in the proposed unit are Brooks Range Petroleum parent company Alaska Venture Capital Group LLC and affiliate Brooks Range Development Corp. and Nabors affiliate Ramshorn Investments Inc. The companies have spent "well over" $4 million exploring the region since acquiring their first leases in October 2003, primarily through field work in 2007 and 2009 and a 3-D seismic program sanctioned in 2008 but delayed by tundra closings.

The proposed Telemark Development Project would produce oil from the Flaxman Sands, a Brookian age reservoir discovered with the East Mikkelsen well in 1971.

Standalone processing

Brooks Range Petroleum would build a standalone processing facility at the unit, which would be close to the existing Badami pipeline and the future Point Thomson pipeline.

"The proposed Telemark Development Project will create a vital processing facility for (the Telemark unit), providing synergies which will lower the economic hurdle allowing other potential hydrocarbon accumulation within and around the (Telemark unit) to be developed," the company wrote in its application. "The other potential hydrocarbon accumulations are currently believed to be higher risk, which characterizes them as marginally economic and they would not likely be developed without existing infrastructure and processing facilities with the (unit). Likewise, future development of the other potential hydrocarbon accumulations within (the unit) using the Telemark processing infrastructure will extend the economic life of Telemark production."

The proposed Telemark Development Project would produce oil from the Flaxman Sands, a Brookian age reservoir discovered with the East Mikkelsen well.

A second attempt at unit

Telemark is the second attempt at a unit in the region.

Brooks Range Petroleum applied last summer to form the 200,058-acre Greater Bullen unit over 68 State of Alaska leases in a similar area of the eastern North Slope, but withdrew the application and relinquished some 100,000 acres a few months later.

The acreage the companies kept included nine leases in the "N" block, also known as the Telemark prospect, located between the existing Badami and Point Thomson units.

With Telemark, Brooks Range Petroleum would operate six units across the North Slope: the Putu, Tofkat, Southern Miluveach and Kachemach units nestled in the fairway between the Kuparuk River unit and the Colville River unit; the Beechey Point unit north of the Prudhoe Bay unit and the proposed Telemark unit on the eastern North Slope. ●

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● EXPLORATION & PRODUCTION

Marathon serious about sands

By GARY PARK
For Petroleum News

Marathon Oil Canada is stepping up its presence in the Alberta oil sands by filing an application with the Energy Resources Conservation Board and Alberta Environment for an in-situ operation due on stream in 2016 at 12,000 barrels per day and aiming for an eventual 40,000 bpd.

Approval from the government and the Alberta Energy Resources Conservation Board is expected to take about 18 months, allowing construction to start in the fourth quarter of 2013.

The Birchwood property, acquired from Western Oil Sands in October 2007, has independently evaluated recoverable resources of 100 million to 615 million barrels, based on 100 exploration wells, the filing said.

Marathon said computer simulations and results from other steam-assisted gravity drainage or SAGD projects indicate 60 percent of the bitumen originally in place is recoverable using SAGD technology.

First oil is planned between the first and third quarters of 2016 and the operating life s projected at 20 years.

First oil is planned between the first and third quarters of 2016 and the operating life s projected at 20 years.

Marathon said capital costs for the initial phase are estimated at C$510 million, or C$42,500 bpd of production, while annual operating costs are expected to average C$65 million to C$85 million.

Funding from Marathon

The Birchwood project will be financed through internal funding provided by parent company Marathon Oil.

Marathon said it is targeting a steam-oil ratio of 3.5 for the first project, within the range of other SAGD projects, and aims to recycle more than 95 percent of the produced water for steam.

The company said the plant will be designed to maximize heat recovery and economize on the use of natural gas.

Vapor emissions will be captured and used as fuel, or reclaimed into the diluted bitumen product.

Marathon owns a 20 percent working interest in the Athabasca Oil Sands Project, operated by Shell Canada with a 60 percent stake, with Chevron Canada holding 20 percent.

Marathon also has ownership interests in 143,000 acres of in-situ leases, including its 60 percent operated Namur project, 33 percent of the Shell-operated Saleski project and 20 percent of the Chevron-operated Ells River project. Recoverable resources are estimated at 1 billion barrels of net bitumen from these projects.

Cenovus seekingpartners

Another oil sands project has also entered the regulatory stream, with Cenovus Energy seeking approval for its 90,000 bpd Telephone Lake project to be built in two equal phases, with first bitumen production targeted for 2018.

Since late 2011, the Calgary-based company has been seeking partners, probably from Asia, for Telephone Lake and another project at its Borealis lease.

Meanwhile, the Alberta Energy Resources Conservation Board, citing a complaint from an intervening party, has delayed by seven weeks to July 17 the start of hearings into an application by Osum Oil Sands to own and operate the 35,000 bpd Taiga project in the Cold Lake area of Alberta. ●

Contact Gary Park through publisher@petroleumnews.com

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ASIAN MONEY

Michael Culbert, chief executive officer of Progress, said the LNG study is focused on a two-train facility with a total capacity of 7.4 million metric tons a year, requiring 560,000 million cubic feet per day of gas feedstock.

He said an LNG scheme of the size envisioned by Progress and Petronas would need proven reserves of 9 trillion cubic feet to supply a liquefaction plant for 20 years.

Progress currently has 1.9 tcf equivalent of proved plus probable reserves, 58 percent assigned to the North Montney play, and a market capitalization of C$2.5 billion. It also holds 450,000 acres of liquids-rich properties in northwestern Alberta's Deep Basin.

35.2 tcf of dedicated reserves

Eric Nuttall, portfolio manager at Sprott Asset Management, said the three announced LNG export projects for British Columbia will need liquefaction capacity of 4.2 billion cubic feet per day, or 35.2 tcf of dedicated reserves.

To book those reserves companies will have to "drill aggressively or buy aggressively," he said, estimating that would require a combined 626 wells a year over three years in British Columbia's Montney and Horn River plays.

A source in the British Columbia government said it was unlikely Petronas would signal a possible acquisition within the next three months unless negotiations were well advanced, otherwise it would only be driving up share values of prospective candidates.

He said Petronas may have issuing an early signal to Canadian lawmakers and regulators of its interest in making an outright takeover bid.

Under Canadian legislation a foreign investment review is required for any purchase valued at more than C$312 million.

David Collyer, president of the Canadian Association of Petroleum Producers, said that "diversifying markets for Canadian oil and natural gas products is vital to ensuring Canada continues to grow its production and receive full value for its natural resources." ●

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FINANCE & ECONOMY

Frontier basins credits, tax cut approved

'Middle earth' bill started out as exploration credits for Nenana basin; expanded to include five other areas close to communities

By KRISTEN NELSON

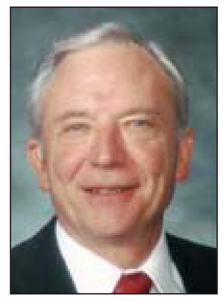
Petroleum News

Rep. Steve Thompson, R-Fairbanks, designed House Bill 276 to help solve high energy prices in Fairbanks by providing exploration credits for the Nenana basin, which could supply energy for Fairbanks.

Another of Thompson's bills, HB 289, provided credits for construction of liquefied natural gas storage tanks.

Both measures passed the Legislature April 15, not as separate bills, but rolled into Senate Bill 23, a bill on firm tax credits which passed the Senate last year.

When the House Majority held a press availability after the Legislature gaveled out April 16, Thompson described getting the bills passed as a rollercoaster ride. He said while the bills didn't provide a near-term fix to high energy costs, he said the bills put some things in place that would bring energy relief to Fairbanks and rural areas in the mid-term.



STEVE THOMPSON

The House Resources Committee spent considerable time on HB 276 and a committee substitute applied the exploration credits to five other unexplored or underexplored basins close enough to communities that hydrocarbons found would help reduce energy costs.

The House passed HB 276 by a vote of 35 to 2.

North Slope vehicle in Senate

In the Senate Finance Committee, however, HB 276 became the vehicle for a North Slope tax reduction for new oil. This was after the Senate's more comprehensive oil tax change, SB 192, couldn't garner enough support in the Senate Bipartisan Working Group to be advanced to the floor.

The Senate passed the amended HB 276 by a 17 to 3 vote April 14.

Had the House concurred in the Senate amendment to HB 276 that would have meant House acceptance of the Senate's North Slope new-oil tax reduction without a hearing.

Had the House voted not to concur, the "frontier basins stampede" credits could well have died because the Legislature was so close to gaveling out.

House Rules, meeting April 15, the last day of session, came up with another solution and Thompson withdrew HB 276 on the House floor.

The Rules Committee added the so-called "middle earth" or "frontier basins stampede" provisions of HB 276, along with HB 289, to Senate Bill 23, which started life in January of 2011 as an extension of the state's film tax credit and had passed the Senate 18 to 1 in April 2011. The new oil tax provisions added to HB 276 in Senate Finance were not included.

The House Rules version of SB 23 — now containing frontier basin tax credits and tax credits for LNG tank storage in addition to film credits — passed the House by a vote of 37 to 2; the Senate concurred by a vote of 19 to 1.

Frontier basins

The "frontier basins stampede" portion of SB 23 provides exploration credits for drilling and seismic, and a reduced production tax for the first seven years of production.

Thompson told House Rules that incentives combined in SB 23 "have been thoroughly briefed in both bodies by many committees." He said the incentives in the bill "will encourage commerce with credits for the film industry, new oil and gas in under, unexplored regions and the commercialization of natural gas to Alaskans, quite possibly by Alaskans."

The production tax will be reduced to 4 percent for the first seven years of commercialization or production for oil or gas produced outside the Cook Inlet sedimentary basin and not including land north of 68 degrees latitude (i.e. the North Slope) for production beginning after Dec. 31, 2012, and before Jan. 1, 2022.

The exploration drilling credit is for the lesser of $25 million or 80 percent of total exploration drilling expenditures; the seismic credit is the lesser of $7.5 million or 75 percent of total seismic exploration expenditures.

According to cost estimates for a North Nenana well prepared for Doyon Ltd. and included with House Resources Committee documents, costs for wells between 8,000 and 12,000 feet measured depth would range between $22.8 million and $27.6 million; these wells assume a summer barging operation and include the cost of barging, mobilizing and demobilizing a rig from Nenana. Petrotechnical Resources of Alaska, which prepared the estimate, said time for the drilling was based on the 2009 Nunivak No. 1 well; drilling rig costs were assumed to be $51,000 per day reflecting the current tight rig market; equipment, materials and other costs were based on the Nunivak No. 1 escalated by 12.5 percent for inflation; completion costs were based on a current Kenai drilling program with 25 percent increase for the remote operation; and a contingency was added for delays from drilling problems, fire delays or weather conditions.

Pre-approval required

Before work is done the explorer must submit to the commissioner of the Department of Natural Resources "the information necessary to determine whether the geologic objective of the well is a potential oil or gas trap that is distinctly separate from any trap that has been tested by a preexisting well," SB 23 says.

The credits are available for the first four exploration wells within the areas specified and are limited to the first two

see FRONTIER BASINS page 9

● ALTERNATIVE ENERGY

TDX continues to pitch Chakachamna

Sponsor discusses competing public and private interest in hydropower project, but State of Alaska denies involvement

By ERIC LIDJI
For Petroleum News

Although pushed to the back burner by the State of Alaska, a hydropower project at Lake Chakachamna continues to be on the mind of the company sponsoring the project.

In an update submitted to the Federal Energy Regulatory Commission in early February, TDX Power Inc. said two competing coalitions continued to study the project.

"The State of Alaska, though its development agency (AIDEA), has been seeking funding partners with friendly governments and private equity funds," TDX Director of Business Systems Jolene Lekanof wrote in the six-month status update to FERC on Feb. 9. "The State hopes to form a coalition that will lead to a successful public/private partnership."

The State, however, denies involvement in the project.

"We are not involved in any discussions with TDX," Alaska Industrial Development Authority spokesman Karsten Rodvik told Petroleum News by email on April 4.

The office of Gov. Sean Parnell said no other state agencies are involved in the project.

The update also mentioned that a "competing coalition is forming that would be 100 percent private sector based," noting the current attractiveness of energy investments. "Also both sets of investors appreciate the fact that this project is environmentally friendly. The Chakachamna project, since it generates power underground, has no need for a dam or reservoir, a common impediment to other potential hydroelectric projects."

That statement most likely refers to the proposed Susitna hydroelectric project.

No clarification response

TDX did not return several requests for clarification.

FERC issued a preliminary permit in February 2010 for TDX to study the hydroelectric project, requiring the company to provide updates on its progress every six months.

As considered, the project would involve diverting water from Chakachamna Lake about 85 miles west of Anchorage through an 11-mile tunnel to an underground power plant.

The 300-megawatt project is estimated to cost $2.9 billion in 2008 dollars.

For the coming six months through August, TDX told FERC that it "intends to continue exploring development options including evaluating the financial feasibility of the hydroelectric project and options for reducing costs and/or securing continued funding from the State of Alaska, friendly foreign governments and the private sector to contribute to the project. A positive funding coalition looks very promising at the point."

Although both projects have long histories and both have been recently reconsidered as the scarcity of natural gas and the price of diesel fuel have forced policymakers to consider alternative energy sources, the Alaska Energy Authority issued a report in November 2010 recommending the Susitna project over the Chakachamna project.

Calling Chakachamna a worthy alternative, AEA chose Susitna because it would produce cheaper power and pose fewer potential cost overruns. While the Susitna project would cost roughly 50 percent more than Chakachamna, it would produce more than twice as much power, according to AEA. The report also raised concerns about the underground engineering at Chakachamna and the geologic risk from nearby volcanoes and faults. ●

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FRONTIER BASINS

exploration wells within a single area. Work must be done between June 1, 2012, and July 1, 2016.

Seismic credits are available for the first four seismic exploration projects and are limited to one seismic exploration program per area.

In exchange for the tax credits, the recipient must agree to provide to the state specific data acquired through the project.

The frontier basin areas covered in the bill include: within 100 miles of Kotzebue; within 150 miles of Fairbanks (Nenana and Yukon Flats basins); within 50 miles of Emmonak; within 50 miles of Glennallen; within 100 miles of Egegik; and within 100 miles of Port Moller.

LNG storage credits

The other oil and gas bill consolidated under SB 23, HB 289, provides a tax credit for investment in a liquefied natural gas storage facility that begins operation before Jan. 1, 2020.

The facility must be regulated as a utility and available to furnish LNG storage to customers, utilities or industrial facilities.

A sponsor statement by Thompson said HB 289 provides an incentive for the private sector delivery of lower cost natural gas to Interior Alaska by extending tax credits to an LNG trucking project for the Interior.

The bill provides tax credits to tanked storage with a minimum volume of 25,000 gallons with the credit limited to 50 percent of construction costs up to $15 million, allowing areas of Alaska which lack the depleted gas reservoirs available in Cook Inlet a monetary incentive for costs associated with constructing aboveground tanks for storing LNG. The credit also applies to expansions of existing facilities as long as the expansion is a minimum of 25,000 gallons.

The bill also provides for an exemption from land lease payments for up to 10 calendar years for lands leased from the state for LNG storage facilities.

The bill passed the House 36 to 1 April 4. ●

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● NATURAL GAS

2000 to today: Alaska gas interest revives

Changing gas supply situation in Lower 48 sparks pipeline interest; Far East prices put liquefied natural gas back on the boards

By BILL WHITE

Researcher/writer for the Office of the Federal Coordinator

Editor's note: This is the first part of the concluding section of a three-part story.

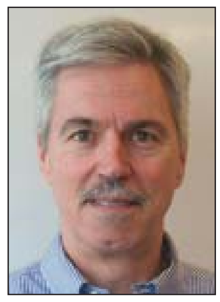
1 2 3 SERIES

The Alaska gas pipeline project got another life in the late 1990s as North Slope producers showed renewed interest in tackling the job.

Oil production from the flagship Prudhoe Bay field had plunged about 50 percent since its peak a decade earlier. With Prudhoe fading, perhaps the time was near for marketing the megafield's natural gas, which largely had been reinjected for 20 years to push more oil from the reservoir. But there was still that pesky problem: Could a gas line make money?

The market targeted in the 1970s — the Lower 48 — remained unattractive. Natural gas prices were too low.

But Japan showed promise. The Japanese gas market was just one-ninth the size of the Lower 48 market in 1999 — too small to absorb the massive volume of liquefied natural gas an Alaska project would produce. But the appetite of utilities there and in South Korea had been growing, and with continued growth might reach the critical mass an Alaska project needed. They also paid more for LNG than U.S. buyers paid for pipeline gas.

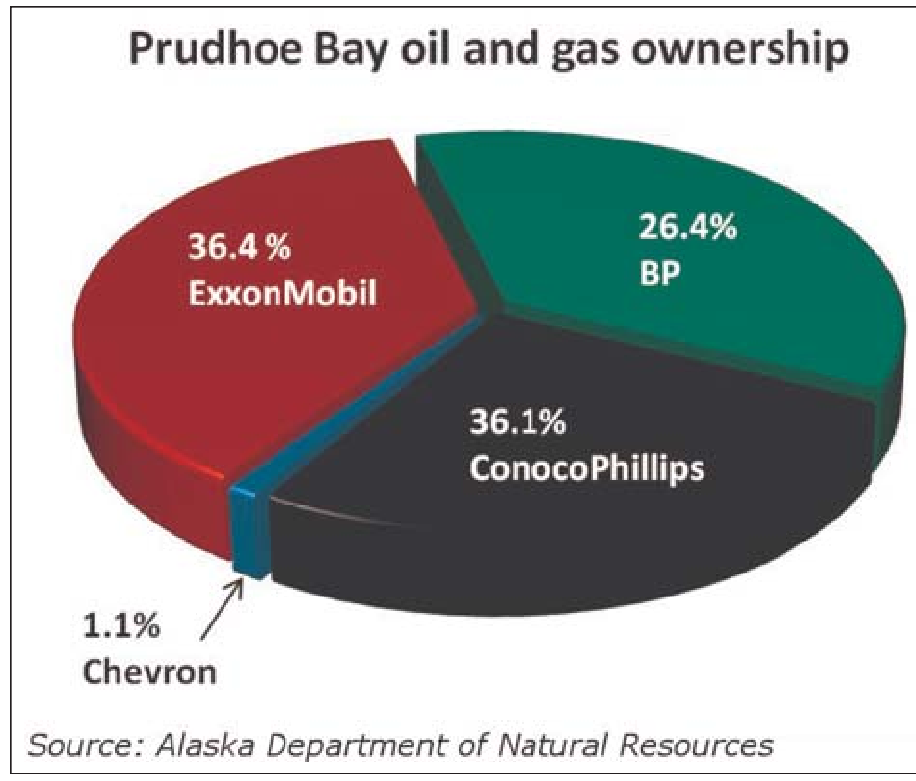


BILL WHITE

The lack of a gas project gnawed at some Alaska leaders. One in particular, state Rep. Ramona Barnes of Anchorage, chairwoman of a House-Senate gas task force, made an LNG project her crusade.

In early 1997, Barnes lectured a roomful of oil lobbyists and executives: "We're going to build this project in my lifetime." (She died in 2003.)

The main producers — BP, Exxon and ARCO — had been talking for a year or two about how Asia might want Alaska LNG, perhaps as early as 2005, more likely closer to 2010. But the project's $15 billion estimated cost was a barrier, making Alaska LNG too expensive to compete for the growing demand, the president of ARCO Alaska said after visiting Asia buyers in fall 1995.



OFFICE OF THE FEDERAL COORDINATOR

In March 1997, the producers said they would study how to shave costs from an LNG project. But they wanted the state to change taxes and/or royalties to improve the economics, too.

In 1998 Alaska enacted the Stranded Gas Development Act. "Stranded" due to no pipeline to carry the North Slope's estimated 35 trillion cubic feet of gas reserves to market. The new law didn't change taxes, but it allowed the producers and state to negotiate a fiscal contract to replace the normal set of taxes. It was unclear whether this was constitutional. At Rep. Barnes' insistence, the contract could apply only to an LNG project.

That law lapsed a few years later with no takers. Asia prices and demand were up, but not nearly enough.

Then the LNG project all but faded from view, eclipsed again when a freak of nature put new energy behind the old plan: Pipe Alaska gas to the Lower 48.

This time, the Lower 48 route had real traction.

First, government — initially the state but Congress as well by the early 2000s — was actively looking for ways to help.

Second, North Slope producers now were publicly engaged in trying to solve how to move Prudhoe Bay gas to market profitably.

Government and producer enthusiasm wasn't enough, however. Something needed to shore up Lower 48 natural gas prices. Without higher prices, the cost of piping Alaska gas 3,000 miles to Chicago would make the gas too expensive to attract buyers.

On that front, good fortune for the project was coming.

As 2000 began, anxiety resurfaced that the United States was running short of natural gas — the same anxiety that birthed Alaska gas pipeline plans 30 years earlier. The nation's old reliable gas fields were petering out.

Soon, enflaming that anxiety, the Lower 48 was whacked with a nasty winter — the coldest in years.

Natural gas prices spiked during the winter of 2000-2001.

And a race was on to pipe Alaska gas south to the rescue.

New energy for a gas pipeline

For utilities and other buyers, their affection for natural gas flip, flopped, then flipped again during the span of years starting in about 1999. It became the fuel of choice, then the fuel of risk, then back to the fuel of choice again.

The buyers' manic responses were swayed by the breathtaking volatility of natural gas prices during this period.

As gas-shortage anxiety bloomed in the early 2000s, several Alaska gas pipeline ideas came forward. These proposals exposed schisms among Alaskans and among the oil producers over which idea was wisest, complicating efforts to unify behind a single project.

Most of the ideas responded to the same cue: Natural gas prices that blasted off like a rocket.

In 1999, Lower 48 gas prices averaged a ho-hum $2.20 per thousand cubic feet at the wellhead, roughly the average of the

see GAS WARS page 11

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GAS WARS

previous few years.

But as the anxiety sank in during the next year, prices began to creep up.

The benchmark Henry Hub spot price topped $3 in April 2000 and $4 in June before leveling off. Then it got very cold in November. The price spiked to $6 around Thanksgiving, and by Christmas it topped $10, more than four times higher than at the start of the year.

The catalyst was an unusually cold weather — the 26th coolest winter in the previous 106 years, the National Oceanic & Atmospheric Administration Reported at the time.

"The winter began with record or near-record cold across much of the nation in December as arctic air spread from the Rocky Mountains to the East Coast behind a series of strong cold fronts," NOAA said. "Severe winter storms and record snowfall fell in many cities from Amarillo, Texas, to Buffalo, New York." (Meanwhile, Alaskans were enjoying their mildest winter since statewide records began in 1918.)

In California, power companies imposed rolling blackouts on customers.

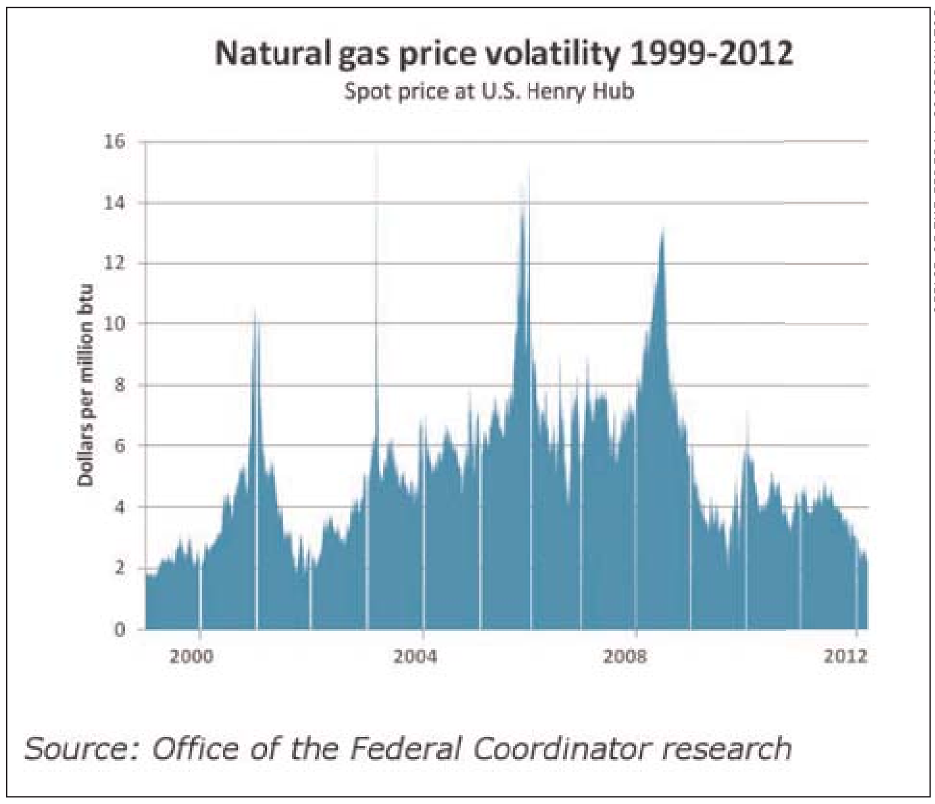
The cold weather broke later that winter. Gas prices deflated like a botched soufflé. The Henry Hub price plunged under $6 in February and pierced $5 in May. By Thanksgiving 2001, the spot price had even penetrated below $2 briefly.

But the shortage fears lingered and a new paradigm of high prices took root in the U.S. gas industry. The Lower 48 wellhead price averaged $4.92 per thousand cubic feet from 2001 through 2006, double the price of the late 1990s.

The answer to high prices seemed obvious: Get more supply. Besides renewed interest in the Alaska gas pipeline project, billions of dollars were invested in Lower 48 LNG import terminals.

In 2000, the three major North Slope producers formally teamed up on a fresh look at piping Alaska's gas to market.

Easing their effort was a recent détente that took hold among them. On the surface, the oil industry can appear monolithic, hand-in-hand sharing risks and rewards while jointly developing fields. To some extent that does describe the industry's dynamic.



OFFICE OF THE FEDERAL COORDINATOR

But a closer look often reveals divisions not readily apparent from afar. And this was true for Prudhoe Bay's big three.

A gnarly schism involved their unbalanced ownership of the oil and gas rights. BP owned 51 percent of Prudhoe's oil production but only 14 percent of the gas. ExxonMobil and ARCO (soon to be bought by Phillips) each owned 23 percent of the oil and 43 percent of the gas. BP wanted the gas retained to help produce more oil. ExxonMobil and ARCO had a stronger urge to move some gas to market.

This schism flared among the companies from time to time, but for the most part it was invisible to the public. The détente occurred in April 2000. The three companies announced a major shuffling

see **GAS WARS** *page 12*

Alaska gas pipeline 1998-2012

1998 – Alaska enacts Stranded Gas Development Act to let an LNG project sponsor negotiate state fiscal terms on natural gas development. Law lapses in 2001 after no one applies.

April 2000 – ExxonMobil, BP and Phillips – the major North Slope producers – announce they will rejigger their interests in Prudhoe Bay so that each company's share of oil production matches its share of gas production. This alignment eases cooperation on a gas project.

2000 – As U.S. natural gas prices rise over gas-shortage worries, ExxonMobil, BP and Phillips announce in December a joint effort to evaluate gas development, from cost to potential pipeline routes. They spend $125 million over the next two years.

2000-2001 – Severe winter causes Lower 48 natural gas prices to briefly spike above $10 per million Btu.

2002 – Alaska voters approve creating Alaska Natural Gas Development Authority, a state agency charged with obtaining North Slope gas for an LNG project. Agency languishes, however.

2003 – Alaska enacts Stranded Gas Development Act to let any gas pipeline sponsor negotiate state fiscal terms, not just an LNG sponsor as in the 1998 law.

2004 – State receives separate applications under the SGDA from pipeline companies, natural gas producers and others.

October 2004 – Congress enacts the Alaska Natural Gas Pipeline Act, which streamlines federal permitting for a project, limits lawsuits and authorizes $18 billion in loan guarantees, adjusted for inflation, for gas delivery to Lower 48.

2004-2006 – Gov. Frank Murkowski negotiates contract with ExxonMobil, BP and ConocoPhillips under the SGDA. Terms include state ownership share of project, gas taxes locked in for 35 years, and significantly higher oil taxes but no more changes for 30 years.

2006 – Public pans proposed Murkowski contract. Legislature never votes on it but does raise oil taxes. Murkowski loses re-election bid.

2007 – Alaska enacts Gov. Sarah Palin's Alaska Gasline Inducement Act over protests of the big three North Slope producers. Law authorizes up to $500 million in pre-construction subsidies to a proposed project that meets certain state conditions.

2008 – State awards AGIA license to TransCanada. BP and ConocoPhillips say they will look at building a non-AGIA sanctioned pipeline to Canada.

2009 – TransCanada gets a partner: ExxonMobil, the largest holder of North Slope gas reserves.

2010 – TransCanada/ExxonMobil and BP/ConocoPhillips separately hold open seasons soliciting customers for their proposed pipelines.

2011 – The BP/ConocoPhillips project disbands, citing "lack of customer support." The companies spent $165 million.

Early 2012 – Lower 48 natural gas prices sink to 1990s levels amid shale-gas boom. TransCanada/ExxonMobil has signed no customers from its open season but, as required by AGIA, continues to work toward applying to Federal Energy Regulatory Commission for a construction and operation certificate on a line to Canada. FERC in early stages of environmental impact statement.

● NATURAL GAS

New study favors Valdez as LNG port

Cook Inlet's ice, big tides make it less desirable as a place to load huge tankers for exporting North Slope gas, report says

By WESLEY LOY
For Petroleum News

Port Valdez would be a better choice than Cook Inlet for loading giant tankers to export liquefied natural gas from Alaska, a new study concludes.

Valdez, in Prince William Sound, already serves as the pickup point for tankers hauling North Slope crude that comes down the trans-Alaska oil pipeline.

Port Valdez has distinct advantages over Anchorage or other potential LNG ports in Cook Inlet, says the comparative risk analysis prepared for the Alaska Gasline Port Authority.

"The Port of Valdez has already proven that it is a world-class oil export facility, with the infrastructure in place to export large volumes of North Slope gas in the form of LNG from Alaska," the study says.

Jeff and Jonathan Pierce conducted the study for the port authority. The authority is a partnership of the Fairbanks North Star Borough and the city of Valdez seeking to commercialize Alaska's stranded North Slope gas reserves.

Jeff Pierce is a licensed oil tanker pilot with extensive experience in Alaska waters.

Recently, interest has flared anew in the idea of piping North Slope gas to a tidewater port somewhere along the state's southern coast. There, it would be converted to liquid form and loaded onto special LNG tankers for shipment to Asia, where the price of gas currently is high compared to gas prices in North America.

Something of a regional rivalry exists as to where a gas pipeline would terminate — the Cook Inlet area or Valdez. For local economic development boosters, an LNG terminal would be a real prize.

When it comes to the practical and safety considerations of shipping, Valdez is the "port of preference," the study concludes.

And Bill Walker, spokesman for the port authority, noted that Yukon Pacific Corp. once held government approvals to export LNG from Port Valdez.

Valdez is a deepwater port and the northernmost North American port free of ice year-round, the study says. It has hosted oil tankers since 1977, when crude began flowing down the pipeline.

Port Valdez waters are relatively docile compared to Cook Inlet, the study says. A fleet of powerful escort tugs are stationed there, as well as a U.S. Coast Guard system to monitor vessel traffic.

In contrast to Port Valdez, Cook Inlet is characterized by extreme tides, shoals, strong currents, less tug and Coast Guard support, and the need for dredging to maintain adequate depth for ships arriving at Anchorage, the state's largest city and main seaport.

The Matanuska-Susitna Borough is developing a new port at Point MacKenzie, just across Knik Arm from Anchorage.

The study also describes ice floes that can choke Cook Inlet during winter months. The current-driven floes are dangerous, capable of exerting enough force to tear a ship from its moorings. This happened in 2006 with the oil tanker Seabulk Pride, which broke away from a dock at Nikiski.

Prince William Sound does have the threat of icebergs from Columbia Glacier drifting into the shipping lanes. This threat was a factor in the Exxon Valdez tanker disaster in 1989. But the port authority study says the amount of ice coming from the receding glacier has diminished over the last 20 years.

Very large LNG ships — larger than the oil tankers calling at Valdez, with three times the capacity of ships loading at the ConocoPhillips LNG facility at Nikiski — likely would be needed to carry the huge volumes of North Slope gas.

The study concludes Cook Inlet isn't well-suited presently to accommodate large LNG ships in winter. ●

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GAS WARS

of their ownership interests so that each company's share of oil was the same as its share of gas.

That ownership shuffle more closely aligned their interests in developing Prudhoe Bay gas.

Within a few months, they were zeroing in on a project. In September 2000, BP and Phillips told the U.S. Senate Energy and Natural Resources Committee they hoped to "achieve consensus on route and timing" within a year.

Internally, the three companies were not fully aligned on the project. ExxonMobil was pushing a route that was about to ring alarm bells within Alaska, the national environmental community and even Congress.

Over the top

Besides ExxonMobil's Alaska North Slope holdings, its Imperial Oil subsidiary had smaller gas discoveries in the Mackenzie Delta across the Canadian border.

In the 1970s, Exxon (and the other two producers) backed the unsuccessful Arctic Gas project that would have strung a pipeline eastward from Prudhoe Bay to the Mackenzie Delta then south through Canada and into the U.S. Midwest and West.

That project died in 1977 when President Jimmy Carter and the Canadian government backed a competing proposal that would pipe North Slope gas south into Interior Alaska then southeast along the Alaska Highway to the Lower 48.

In 2000, ExxonMobil saw an opportunity to resurrect the Prudhoe-to-Mackenzie project, dubbed the "over-the-top" route. This time it would pick up gas from the company's big Point Thomson discovery east of Prudhoe then wade offshore coastal Alaska to avoid trenching the Arctic National Wildlife Refuge as the 1970s project proposed. Conservationists had spent decades lobbying to keep oil and gas development out of ANWR.

BP and Phillips were more attuned to the mood of Alaskans about wanting a south-bound pipeline that would bring some North Slope gas to the state's population center.

In late September 2000, Dick Olver, BP's global production chief, said in an Anchorage speech that speculation about a route or even a project was premature. BP was considering all options, including LNG and converting gas to a liquid that could flow down the underused trans-Alaska oil pipeline.

But mostly he discussed a pipeline into Canada. In a nod to the controversy stirring on the over-the-top route, Olver said the project ultimately must be "in the best interests of U.S. consumers, the people of Alaska and our Canadian stakeholders."

"The stars appear to be aligning for Alaska," he said.

The CEO of Phillips had a similar message in an Ohio presentation. "The time is right, the technology is here and the market is here," said Jim Mulva. "We are completely committed to making this a reality."

In December 2000, the big three producers announced they had formed the North American Natural Gas Pipeline Group to assess costs and technology, pick a route and apply for construction permits. They budgeted $75 million and ultimately spent $125 million.

The prospect of an over-the-top line alarmed Alaska political leaders. Gov. Tony Knowles in November 2000 declared that route off-limits, dropping a slogan that caught on: "My way is the highway."

The Alaska Legislature followed in 2001 with a law that prohibited granting state rights of way for an over-the-top route. Some in Congress also began discussing a ban on the route. ●

See the concluding part of this story in the April 29 issue of Petroleum News.

Editor's note: This is a reprint from the Office of the Federal Coordinator, Alaska Natural Gas Transportation Projects, online at www.arcticgas.gov/print/Interest-in-Alaska-gas-revives-2000-to-today.

● EXPLORATION & PRODUCTION

Pioneer files ops plan for Nuna project

Module fabrication would get under way this year, first pad 2013, development drilling through 2018, first oil production 2014

PETROLEUM NEWS

Although Pioneer Natural Resources Alaska has not yet announced the results of its Nuna 1 appraisal well from this past winter, it has filed a lease plan of operations with Alaska's Division of Oil and Gas, indicating it hopes to move forward with its two-pad Nuna development, which would involve between 35 and 65 horizontal wells, targeting primarily the Torok reservoir, although other zones might include the Kuparuk, Nuiqsut and Ivishak.

The plan of operations was similar to the original plan filed with the division about a year ago.

Per its agreement with the state for expanding its nearshore Oooguruk unit to include the Nuna project leases, Pioneer has to decide by June 30, 2014, whether it plans to sanction development.

Pioneer spokesman Casey Sullivan told Petroleum News April 19 that the project has not been sanctioned.

Both pads on shore

In Pioneer's plan both pads are onshore, targeting offshore targets, with production expected to begin in 2014.

In a smaller Torok participating area in the main part of the Oooguruk unit, Pioneer estimated in 2011 that the Torok PA contained as much as 690 million barrels of original oil in place and believed it could recover as much as 25 percent of that using primary and enhanced recovery techniques. But in 2011 the company has also mentioned 50-100 million barrels of recoverable oil in connection with the Nuna development.

In the division's April 16 public notice, asking for comments on the development, the state said Pioneer planned to build "two onshore production drillsites, roads, flowlines and power lines elevated on vertical support members, and a pig launching and receiving tie-in pad on state of Alaska oil and gas leases," including two Pioneer leases (390505, 390697) and six ConocoPhillips leases (390506, 025528, 025844, 380107, 025532, 025531).

Nuna project's plan of operations

Activity	Schedule
Conceptual Engineering and Design	Initiated 4th Qtr. 2010
Permit Review and Approvals	2011
Long Lead Procurement	2012
Commence Module Fabrication	2012
Appraisal Drilling	Winter 2012
Mine Site Construction	2013
Ice Road Construction	2013
Gravel Construction, NDS1	2013
Flowline Construction	2014
Module Installation	2014
Development Drilling	2014 to 2018
First Production	2014
Development of NDS2	2015 or later
Site Decommissioning and Closure	End of Field Life

April 16, 2012, lease/unit plan of operations filed by Pioneer Natural Resources with Alaska's Division of Oil and Gas.

Hydrocarbon resources, the target mainly being oil, would be accessed using horizontal drilling into the following state leases: 355038, 355039, 391459, 390504, 380505, 390434 and 390505, all held by Pioneer and Eni, with one lease owned 100 percent by Pioneer. (PN was unable to locate information about the status of leases 390504 and 380505 prior to going to press.)

NDS1 at site of Nuna 1

One of the proposed gravel drillsites, NDS1, which is at the site of the Nuna 1 well Pioneer drilled this winter, would be two and a half miles northwest of Drillsite S-3S, commonly known as DS-3S, in the Conoco-operated Kuparuk River unit. It is approximately 1,000 feet from the Colville River.

The other proposed gravel drillsite, NDS2, would be about 4 miles upriver from NDS1, approximately 600 feet from the Colville.

Flowlines would transport production, gas and water between the drillsites and the Oooguruk tie-in pad, OTP.

North of DS-3S a junction tie-in pad would be built to launch and receive NDS2 flowline cleaning and inspection pigs.

Pioneer wants to build gravel roads from DS-3S for year-round access and support activities.

The flowlines would be separated from the gravel roads by at least 500 feet.

Power would be generated using existing and expanded power generation equipment at the OTP and transmitted to the drillsites on lines suspended on the flowline vertical support members.

Pioneer's plan includes 25-50 wells at NDS1 and 10-15 at NDS2.

About half would be producers and half injector wells, and one at each drillsite would be a Class I/II Underground Injection Control disposal well.

Multiphase flowlines for oil, gas and water would transport the produced fluids from the drillsites to the Oooguruk tie-in pad and "eventual transmission through the Trans Alaska Pipeline System."

Economic benefits to borough

In the economic benefits portion of its proposed plan for Nuna, among other things Pioneer said about the North Slope Borough that, "The tax valuation for capital in place will likely be $165 million over the first 10 years," and that the borough "would likely receive $33 million" in property taxes from Nuna.

see **NUNA PROJECT** *page 19*

ENVIRONMENT & SAFETY

ALASKA DEC

Some Prudhoe wells idled after pipe bursts

A pipeline leak on the afternoon of April 10 prompted BP to shut-in some wells at drill site 1 in the eastern operating area of the Prudhoe Bay oil field.

The production impact was limited, within the range of daily fluctuations normally seen in overall North Slope output, BP Alaska spokesman Steve Rinehart told Petroleum News.

The failed pipe was an above-ground, 8-inch seawater injection line running between a manifold building and well 11 at drill site 1. The drill site was among the earliest installed at Prudhoe Bay, the nation's largest oil field.

The failed pipe was an above-ground, 8-inch seawater injection line running between a manifold building and well 11 at drill site 1. The drill site was among the earliest installed at Prudhoe Bay, the nation's largest oil field.

Because the well had been shut-in for servicing, the pipeline was filled with freeze protection fluids, Rinehart said. The fluids consisted of about 60 percent methanol and 40 percent seawater.

The pipeline failure occurred "during a well warm up procedure conducted in preparation for a mechanical integrity test on Well 11," said a situation report from the Alaska Department of Environmental Conservation.

3,675-gallon spill

Field workers were moving seawater into the line and noticed pressure at the manifold but not at the wellhouse, Rinehart said. Then they saw fluids spraying from the pipeline.

The burst pipe, as well as an adjacent line, dislodged off the rack elevating them above the ground, the DEC's John Ebel said.

No one was injured in the incident.

Several wells were shut-in as a precaution, Rinehart said.

Well 11, formerly an oil producer, now serves as an injection well to send seawater into the Prudhoe Bay reservoir to help enhance oil recovery.

BP estimated the spill at 3,675 gallons, based on the engineered volume of the 8-inch line between the manifold building and well 11, the DEC said. Aside from methanol and seawater, a small amount of crude oil also spilled, the agency said.

The fluids were released onto the snow-covered gravel drill pad and flowed into a reserve pit, the DEC said. Responders surveyed a contamination area of about 3.85 acres.

BP worked to remove contaminated snow, ice and gravel. The pipeline was blocked and blinded at the manifold building and at the well.

The company was looking into what caused the leak, such as ice perhaps plugging the line despite freeze protection.

—WESLEY LOY

FINANCE & ECONOMY

Royale hires K&L Gates for shale project

Royale Energy Inc. recently hired law firm K&L Gates LLP to advise the company through its attempt to explore the source rock potential of its North Slope acreage.

K&L Gates attorney and former Alaska Department of Revenue Commissioner Patrick Galvin will lead the effort, according to the San Diego based independent.

K&L Gates attorney and former Alaska Department of Revenue Commissioner Patrick Galvin will lead the effort, according to the San Diego based independent.

"Patrick shares our desire to approach the appropriate regulatory and community entities with deference and respect," Co-CEO Stephen Hosmer said in a statement. "We are guests on this land and we want to develop this resource in a responsible manner."

Royale plans to announce details in the coming months of its program to drill between three and six wells to assess the potential of the Shublik and Kingak shale on its acreage.

The company picked up more than 100,000 acres in three blocks in December 2011.

—ERIC LIDJI

● FINANCE & ECONOMY

Senators weigh in on commodity lawsuit

They say Congress meant for regulators to impose trading limits to curb 'excessive speculation' on oil; Obama offers get-tough plan

By WESLEY LOY
For Petroleum News

Alaska's Mark Begich is among 19 U.S. senators, all Democrats, jumping into a federal lawsuit concerning regulation of possible "excessive speculation" in commodity markets.

The action comes amid a rising election year backlash over high gasoline prices across the nation. On April 17, President Barack Obama announced a five-part plan to strengthen oversight of energy markets and safeguard against what the White House called "illegal manipulation, fraud and market rigging."

The president's plan centers on providing more manpower and technology to the Commodity Futures Trading Commission.

"I'm pleased the Obama administration is finally proposing tough new actions to rein in oil speculators, whose actions have slowed our economic recovery," Begich said in an April 17 press release. "It's easy to blame 'big oil' for high oil prices, but in fact it's the largely unregulated speculators who drive up prices, forcing many drivers in Alaska and across the country to pay more than $4 a gallon for gas. The cost of speculation is estimated at 56 cents for every gallon of gas."

Court brief filed

On April 13, Begich and 18 of his Senate colleagues filed an amici curiae or "friends of the court" brief in a lawsuit now pending in U.S. District Court in Washington, D.C.

Two trading industry groups, the International Swaps and Derivatives Association and the Securities Industry and Financial Markets Association, sued the CFTC in an effort to block a new regulation to impose position limits on the trading of commodities on U.S. markets, a Begich press release said.

A key issue in the suit is whether Congress, in passing the Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010, mandated that the CFTC establish position limits or merely gave the agency the option to do so if needed.

The intent of position limits is to restrict the ability of any single trader to manipulate oil markets.

"High gasoline prices are choking our economic recovery," said Michigan Sen. Carl Levin, who led the effort to file the amici brief. "Oil supplies are plentiful and demand is down, so high gas prices can't be explained by ordinary market forces of supply and demand. An ongoing contributing factor is excessive speculation in U.S. commodity markets. Two years ago, the Dodd-Frank Act directed the CFTC to clamp down on excessive speculation by imposing trading limits on speculators, and the CFTC issued a new regulation to do just that. The financial industry slapped the CFTC with a lawsuit claiming Congress never meant for the trading limits to prevent excessive speculation to be mandatory, but our amicus brief shows that is exactly what we meant and what the law requires."

Aside from Levin and Begich, other senators signing onto the amici curiae brief included Richard Blumenthal of Connecticut, Barbara Boxer of California, Sherrod Brown of Ohio, Maria Cantwell of Washington, Ben Cardin of Maryland, Dianne Feinstein of California, Tom Harkin of Iowa, Patrick Leahy of Vermont, Joe Manchin of West Virginia, Claire McCaskill of Missouri, Robert Menendez of New Jersey, Barbara Mikulski of Maryland, Bill Nelson of Florida, Bernie Sanders of Vermont, Jeanne Shaheen of New Hampshire, Sheldon Whitehouse of Rhode Island and Ron Wyden of Oregon.

SEN. MARK BEGICH

Obama's plan, and reaction

Obama's five-part plan includes a request that Congress fund more "cops on the beat" to oversee oil markets. He wants "at least a six-fold increase in the surveillance and enforcement staff for oil futures market trading at the CFTC," a White House fact sheet said.

The president also wants funding for information technology upgrades at the CFTC to "strengthen monitoring of energy market activity."

And Obama proposed "a ten-fold increase in maximum civil and criminal penalties for manipulative activity in oil futures markets."

House Speaker John Boehner, R-Ohio, panned the Obama plan as a "gimmick."

"The White House can't produce one shred of evidence that this manipulation is taking place. And if they thought it was taking place they have the tools and the laws already in place to go after it," Boehner said.

American Fuel & Petrochemical Manufacturers, a trade association, said this:

"To the extent that there is any manipulation in the marketplace, the government should investigate and take corrective actions. Historical data shows speculators are not the primary force impacting prices at the pump. In fact, U.S. refiners count on financial markets to hedge against potentially higher crude oil costs, which work to prevent consumer costs from increasing further.

"We have vast untapped resources under our feet and off our shores and available from our good friend and neighbor Canada via the Keystone XL pipeline. If the president is serious about meeting our energy and national security needs, it's time we take the appropriate steps to increase our North American oil and natural gas production and bring our nation back to economic prosperity." ●

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EXPLORATION & PRODUCTION

BOEM requests comments on Ion survey

The Bureau of Ocean Energy Management has asked for public comments for an environmental assessment for a seismic survey that Ion Geophysical plans to carry out in Alaska's Beaufort Sea during the early winter of 2012. Ion has applied for a BOEM geological and geophysical permit for its planned survey: Under the terms of the National Environmental Policy Act BOEM has to conduct an assessment of the potential environmental impacts of the project. Public comments are required by April 30.

Ion has developed a technique for gathering seismic in sea ice, using a geophysical vessel working in tandem with an icebreaker. The geophysical vessel tows a streamer of seismic recorders deeper in the water than usual, allowing the recorders to operate below the ice. By thus operating after the end of the Arctic open water season Ion says that it can avoid conflicts with subsistence whale hunting.

Ion wants to carry out a deep, basin-wide 2-D survey along the entire length of the U.S. Beaufort Sea and into the northeastern Chukchi Sea, connecting surveys that the company has previously conducted in the Canadian Beaufort Sea with a similar survey conducted in 2006 in the Chukchi Sea. The survey would provide insights into large-scale geologic features in the Beaufort Sea continental shelf.

In March Ion told the National Marine Fisheries Service's Arctic Open Water Meeting that the company anticipates recording 7,177 kilometers of seismic lines in the Beaufort, operating in nine-tenths to ten-tenths cover of ice less than two feet thick.

—ALAN BAILEY

● GOVERNMENT

Alaska congressional delegation questions Arctic offshore DEIS

Says document addressing future Arctic offshore permitting is flawed and threatens excessive restrictions on offshore exploration

By ALAN BAILEY

Petroleum News

Alaska's congressional delegation has raised concerns about a draft environmental impact statement, or DEIS, that the National Marine Fisheries Service, a division of the National Oceanic and Atmospheric Administration, has prepared for Arctic offshore oil and gas exploration.

The Fisheries Service published the DEIS in December for public comments with, as reported by Petroleum News shortly afterwards, the intention of having an EIS that would establish future policies for the issue of marine mammal harassment authorizations for exploration drilling in state and federal waters offshore northern Alaska, and for the issue of geophysical permits for seismic surveys on the federal Arctic outer continental shelf. The EIS would apply to the years 2012-17.

The delegation noted that the more aggressive alternatives in the EIS would prevent Shell, Statoil and ConocoPhillips from conducting simultaneous drilling in the Chukchi Sea.

The Fisheries Service has not yet decided on its preferred option from a range of alternative policies presented in the DEIS, but all of the alternatives would place restrictions on exploration activities, with those restrictions ranging from a possible ban on all exploration to limits on the amount of drilling or seismic surveying that could be carried out in a single year.

Lubchenco meeting

In a statement issued on April 18 the three members of Alaska's congressional delegation said that they had met with NOAA Administrator Jane Lubchenco to emphasize the importance of oil and gas exploration and development in the Arctic offshore and to raise concerns about the effects that the EIS might have on oil and gas activities. The delegation noted that the more aggressive alternatives in the EIS would prevent Shell, Statoil and ConocoPhillips from conducting simultaneous drilling in the Chukchi Sea.

"I understand the importance of NOAA's role in ensuring explorers in the Arctic avoid conflicts with marine mammals but, as it stands, the DEIS is flawed and goes beyond the agency's mission and expertise," said Sen. Lisa Murkowski.

"I appreciate Administrator Lubchenco taking the time to hear from a united delegation on this pressing issue," said Sen. Mark Begich. "We all understand that marine mammals are important, but the document, as it stands, is flawed. I believe she understands that and am encouraged about our prospects to improve it moving forward."

"As I made clear to Administrator Lubchenco today, this document — as written — is not only troubling to me, but to the entire Alaska delegation," said Rep. Don Young. "Moving forward, it's important that this document advances not hinders responsible development in the Arctic, and after today's meeting, Administrator Lubchenco understands our concerns." ●

Contact Alan Bailey at abailey@petroleumnews.com

FINANCE & ECONOMY

MGM writes down Arctic assets

Northern Canadian explorer MGM Energy has joined the write-down of resources related to the troubled Mackenzie Gas Project by reducing the value of its Arctic assets by 70 percent while shifting its attention to the Central Mackenzie Valley.

The one active driller in the Mackenzie Delta region in recent years, MGM posted a net loss of C$153.3 million for the fourth quarter of 2011, due mainly to writing down its northern holdings to C$60 million from C$214 million.

It said the move reflects the significant decrease in forecasted long-term natural gas prices and the continued delay in restarting the Mackenzie Valley pipeline.

Company President Henry Sykes said MGM holds to its belief that its substantial natural gas assets in Canada's North hold tremendous potential which will eventually be realized.

But, without offering any specifics, he said that given the current uncertain timing of the Mackenzie pipeline MGM is considering alternative means of commercializing the Mackenzie Delta assets.

Concentrating on Canol shale

Sykes said in a statement that MGM is concentrating on advancing the regulatory process for the Canol shale rights it obtained last year.

MGM had working capital of C$10.7 million at the end of 2011, enough to fund current expenditure levels into 2013, but not sufficient to fund the cost of a Central Mackenzie Valley well next winter.

As a result, MGM said it is looking at various forms of financing, including farmouts, joint ventures, asset sales and/or equity issues, adding it anticipates considerable interest in its land position.

The company believes it will attract the necessary financing because of the current and pending activity in the Canol play, notably the large successful bids on adjacent parcels by Husky Energy, ConocoPhillips Canada, Shell Canada, Imperial Oil and ExxonMobil Canada, along with MGM and its partner 6362 NWT Ltd.

—GARY PARK

GOVERNMENT

F&W issues new polar bear ESA rule

On April 19 the U.S. Fish and Wildlife Service published for public review a new rule for the protection of polar bears under the Endangered Species Act, or ESA. The new rule replaces a similar rule issued in December 2008.

In May 2008 Fish and Wildlife listed the polar bear as threatened under the ESA on the grounds that the bear's sea ice habitat is being eroded by global warming. But, recognizing the difficulty of using the ESA to regulate the greenhouse gas emissions that many blame for rising world temperatures, the agency subsequently issued a special rule for the polar bear listing. That rule said that activities outside Alaska cannot be considered as harassment of the bears; the rule also allowed the bears to be conserved under the terms of the Marine Mammals Protection Act.

Environmental groups, who argued that the polar bear listing required Fish and Wildlife to address greenhouse gas emissions, appealed the polar bear rule. In October 2011 Judge Emmet Sullivan in the U.S. District Court in Washington, D.C., rejected this claim but upheld another claim that the agency, in issuing the rule, had neglected to carry out an environmental analysis of the impact of the rule, as required under the terms of the National Environmental Policy Act.

The agency says that it has now completed the environmental analysis required by the court — the proposed new rule contains the findings of that analysis and is almost identical to the original rule. However, the proposed new rule exempts activities outside the polar bear's range from being considered as harassment, rather than activities outside Alaska.

Fish and Wildlife requires comments on its proposed rule by June 18.

—ALAN BAILEY

continued from page 3

REPSOL WELLS

went well for us — we had a strong logistics plan," Hardham said.

And it was a particularly cold winter, with multiple days where operations had to be shut in because of the low temperatures. The company even encountered a polar bear situation, with a sow and two cubs causing an interruption to the industrial operations.

"It approached our sea-ice road and so we had to close down our operations and monitor the bear," Hardham said.

Taking advice from locals, the field crew waited for the night and, with no traffic about, the bears crossed the road and headed north towards the sea.

Return next winter

Despite the challenges, Repsol plans to return to the North Slope next winter.

"We'll be looking at a program next winter," Hardham said. "We need to evaluate the results of the two wells that we drilled and we would be looking to permit at a minimum the two locations that we did not get to drill this winter, the Q-1 and Q-2."

Repsol feels confident about finding oil in its acreage. But, with expectations of finds that are fairly modest in size, development costs and production tax levels will be key factors in the viability of field development, Hardham said.

And Repsol hopes that the open manner in which company dealt with government agencies and the local communities when responding to the Q-2 incident has gained everyone's respect, he said.

"We hope we've gained some respect in how we reacted to this and how we conducted ourselves," Hardham said. "We're not disheartened going forward. Obviously it's a setback and it's costly, but we intend to proceed. The company is quite enthusiastic about the opportunities up here." ●

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ARCTIC REPORT

our members join together as syndicates to insure risks." Lloyd's says it's often the first to insure new, unusual or complex risks.

Arctic risks are in many ways particularly daunting, but companies are likely to brave those risks if, for example, oil prices stay high, the study says.

'Increasingly significant'

The Lloyd's report notes that prior to the 20th century, "the overall role and scale of the Arctic in the global economy was minimal." It wasn't until the second half of the century that the Arctic became a significant factor in oil production with the startup of Alaska's Prudhoe Bay field in 1977.

Today, the Arctic — comprising the Arctic areas of Canada, Denmark (Greenland), Finland, Iceland, Norway, Russia, Sweden and the United States — has about one-twentieth of 1 percent of the world's total population, the report says.

"The Arctic region is undergoing unprecedented and disruptive change. Its climate is changing more rapidly than anywhere else on earth," the report says. "The combined effects of global resource depletion, climate change and technological progress mean that the natural resource base of the Arctic — fisheries, minerals and oil and gas — is now increasingly significant and commercially viable."

In terms of Arctic access, however, the warming climate has "double-edged consequences." Sea-borne access is improving as ice cover dissipates. But on land, infrastructure such as roads and pipelines built on permafrost will become more expensive to maintain, the report says.

Oil and gas landscape

The report offers a brief country-by-country summary of oil and gas investments in Canada, Greenland, Norway, Russia and the United States, and discusses political, market, tax and environmental risk considerations.

"In general, the Russian Arctic is considered to be more gas-prone and the offshore Norwegian and American Arctics (including Greenland) more oil-prone," the report notes.

High oil prices, coupled with uncertainly about access to resources elsewhere, make Arctic projects more attractive to investors.

"Falling commodity prices would probably put many Arctic projects on hold," the report says.

"For the most commercially marginal Arctic oil and gas developments, the tax regime applied may be a decisive factor in determining their viability," it adds.

In Russia, the largest potential offshore project is the Shtokman gas development in the Barents Sea. Investment could reach $50 billion.

"However, the Shtokman project has been repeatedly delayed owing to concerns about drifting icebergs, negotiations over the tax regime with the Russian government, and concerns about export markets," the report says.

Investment in Norway's Arctic fields is more predictable, given that country's "arguably more stable regulatory and operating environment."

In Alaska, the report's authors make note of Shell's long-frustrated plans to drill in the Beaufort and Chukchi seas, and see "an increasingly supportive approach taken by the Obama administration to Arctic development."

Politics and risk

"Within most Arctic countries, oil and gas development is politically controversial on environmental grounds and can have a significant influence on the political dynamics between central and local governments," the Lloyd's report says.

In the United States, support for opening more Arctic areas to oil and gas exploration is strong in Alaska, but limited elsewhere.

"In Canada, Arctic energy and mining projects play into complex federal politics and the domestic politics of indigenous peoples across the north," the report says. "In Greenland, exploration for offshore hydrocarbons is widely accepted as a pathway to greater economic prosperity and a guarantee of self-government. In Russia, maintaining oil production and increasing production of natural gas is a strategic imperative. In Norway, government and public support for development is contingent on strong environmental regulation."

As for environmental risk, the remote Arctic presents a special case, the report says.

see **ARCTIC REPORT** *page 22*

continued from page 13

NUNA PROJECT

First drillsite design, facilities

Pioneer plans to build NDS1 first, using about 275,000 cubic yards of gravel.

NDS1will support drilling and production operations, the company said.

The drillsite will encompass about 23 acres, and be designed to support as many as 50 wells on 30-foot spacing.

The spacing between the wells is "based on potential drilling rigs capable of reaching the reservoir targets and to minimize the thawing of the permafrost soil," Pioneer said.

The pad is L-shaped with the base of the L to contain support facilities and the remaining area the row of wells.

Dimensions will be about 750 by 360 feet for the support facilities section and 300 by 1,600 feet for the well row, with a nominal thickness of 8-10 feet of gravel fill, bringing the surface elevation to about 12 feet mean sea level.

"Gravel bag slope erosion protection would be provided by a system of 1.5-4 cubic yard gravel-filled bags," Pioneer said in its operations plan.

Second drillsite

There is a chance the second drillsite, NDS2, would be developed with the first, but Pioneer said it "will probably be constructed near the end of the drilling campaign at NDS1.

NDS2 will be about 12 acres, designed for as many as 15 wells.

Also L-shaped, the dimensions will be about 750 by 360 feet for the support facilities section and 300 by 490 feet for the well row, with a nominal thickness of about 5-7 feet of gravel.

The amount of gravel fill would be about 120,000 cubic yards.

In Pioneer's plan heated modular buildings, production modules, would be installed at each drillsite. They would be 15 by 40 by 14 feet high.

Pioneer's proposed development schedule (see adjacent chart) includes module fabrication getting under way this year, the first pad built in 2013, and development drilling from 2014 through 2018. ●

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Petroleum news

Oil Patch Bits

Fairweather sponsors Petroleum Club event April 26


COURTESY FAIRWEATHER

Fairweather LLC, an Anchorage-based provider of remote medical, meteorological and expediting services, said April 16 that it will sponsor a social event Thursday, April 26, from 5 to 7 p.m. at the Petroleum Club of Anchorage to unveil details about its new medical clinic at Deadhorse Aviation Center on the North Slope.

Opening in June, the Fairweather Medical Services clinic will provide a full spectrum of acute care, emergency medicine and occupational health services, including advanced cardiac life support, on-site labs and ambulance services. The clinic will be open to the public and staffed around the clock, 365 days a year, with state licensed physician assistants, paramedics and occupational health technicians. Medical services will include teleradiology, EKG tests, physical exams, pulmonary function testing, respiratory FIT testing, audiometry testing, and drug and alcohol screenings, as well as return-to-work and fit-for-duty evaluations. The DAC clinic will offer 24-hour telemedicine consultation with the emergency room at Providence Hospital in Anchorage, as well as case management and MedEvac support for immediate hospital transport, if necessary.

The Petroleum Club of Anchorage is located at 3301 C Street, Suite 120. For additional information, contact Lori Davey at 907-267-4602, e-mail: lori.davey@fairweather.com, or visit www.deadhorseaviationcenter.com.

UAF makes mark at Shell Eco Marathon in Houston

COURTESY SHELL

Shell said April 5 that colleges and universities once again gathered in the sweltering heat of Houston, Texas to participate in the 2012 Shell Eco Marathon competition. But once again, it was the scrappy team from the coldest, northernmost university in the United States that garnered a great deal of the attention.

A team of ten UAF engineering students not only wrapped-up the 2012 marathon with anoth-

see OIL PATCH BITS page 21

Companies involved in Alaska and northern Canada's oil and gas industry

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

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PIPE DREAMS

But there is no longer anywhere for it to hide. By targeting an addition of 550,000 bpd, Kinder Morgan has surpassed the 525,000 bpd planned for Enbridge's Northern Gateway proposal.

It now hopes to file an application with Canada's National Energy Board in 2014, start construction in 2016 and commence shipments in 2017, close to the schedule set for Northern Gateway.

Support exists

The indications are that both projects have enough support to succeed.

During an extended open season, Kinder Morgan received binding commercial support for 660,000 bpd of pipeline capacity, all for 20-year terms.

Ian Anderson, Kinder Morgan's Canadian president, said the level of commitment equates to about 25 to 30 tankers a month (compared with the current five to 10) loading at the Westridge terminal in Port Metro Vancouver and navigating through a densely populated area to the Pacific Ocean.

He said the proposal has attracted so much interest from customers because it offers new access in Asia through a facility that already exists.

Anderson said the port, facilities, tanker pilots, tug operators and first-responders are already in place, supporting a belief that expansion of Trans Mountain and the Westridge terminal "has merit … and is a feasible way to go."

He said Kinder Morgan also has the backing of the Alberta government and Canadian Prime Minister Stephen Harper.

"We share respectful, open relationships with many communities and organizations interested in our business," Anderson said. "We are committed to an 18- to 24-month inclusive, extensive and thorough engagement of all aspects of the project with local communities along the proposed route and marine corridor …"

He said Kinder Morgan will consider providing financial support to communities for environmental initiatives.

Opposition to Northern Gateway from First Nations, environmentalists, landowners and municipal governments took years to surface, but has now coalesced into a formidable challenge.

Testing to come

But Anderson`s confidence that the people of British Columbia will ultimately support Kinder Morgan's proposal is about to be tested.

Opposition to Northern Gateway from First Nations, environmentalists, landowners and municipal governments took years to surface, but has now coalesced into a formidable challenge.

Feeding off that campaign, the same groups, bolstered by municipal governments in the Greater Vancouver region, have wasted no time tackling Kinder Morgan, setting the stage for a battle that could rival U.S. opposition to TransCanada's Keystone XL pipeline and far exceed Northern Gateway, which directly affects a small and scattered population.

Ben West, a spokesman for the Wilderness Committee, said the 40 percent increase in what Kinder Morgan had originally talked about will only strengthen public efforts to halt the project he described as "simply outrageous."

"Every new tanker that is in (Port Metro Vancouver) is carrying at least two to three times as much crude as the Exxon Valdez spilled. More tankers mean more risk," he said.

Ian Anderson, Kinder Morgan's Canadian president, said the level of commitment equates to about 25 to 30 tankers a month (compared with the current five to 10) loading at the Westridge terminal in Port Metro Vancouver and navigating through a densely populated area to the Pacific Ocean.

Opposition from Vancouver

Vancouver Mayor Gregor Robertson said he does not believe the people of his city endorse a "huge oil port. … It is totally at odds with our city brand and our identity and ethic."

"I am fiercely opposed to (an increased number of tankers) in Vancouver's harbor. We are gearing up as a city to deal with this, working with other local governments in the region and around the southern coast," he said.

Burnaby Mayor Derek Corrigan said the Kinder Morgan plan is a wrong-headed decision that will generate no economic benefit for his city.

"We are well aware of the potential dangers and even when people claim to have all the safety procedures in place human error can cause a serious problem," he said.

Corrigan acknowledged that the Canadian and British Columbia governments can override local concerns, but argued the Trans Mountain proposal is so politically charged that Kinder Morgan faces many obstacles.

A spokesman for Kinder Morgan conceded the company faces a "lot of work speaking to landowners and people on the (pipeline) right-of-way." ●

Contact Gary Park through publisher@petroleumnews.com

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OIL PATCH BITS

er impressive showing, they became the most talked-about team for their ability to use leftover scraps and parts to build cars that would eventually make it on the track. Making more with less, after all, symbolizes what Shell Eco Marathon is all about.

"This is the second time we've had UAF at Shell Eco Marathon and we are happy to have them back," said Shell Alaska VP, Pete Slaiby.

The idea behind Shell's annual Eco Marathon competition is to design and build a vehicle that uses the least amount of energy and travels the furthest distance.

Teams can enter futuristic "prototypes" that are designed to reduce drag and maximize efficiency or they can enter "urban concept" vehicles that meet the needs of today's drivers. Entries in both divisions use conventional fuels like diesel and gas, or they can rely on alternatives — gas to liquids, solar, ethanol, bio-fuels, or electric plug-in power.

Golf Classic tees off Wednesday, June 20

Calista Corp. said April 17 that it cordially invites you to kickoff the summer with the 13th Annual Calista Heritage Foundation Golf Classic Tournament, June 20 — the first day of the new season at the Moose Run Golf Course.

Please join by fielding a team or becoming a sponsor. There are many donation levels available for this well-attended event, but there are a limited number of team sponsorships. Be sure to take a swing at securing the hole-in-one prizes provided by Mercedes Benz of Anchorage and Yukon Equipment.

The Calista Heritage Foundation awards scholarships to Alaska Native students from the Yukon-Kuskokwim Delta Region. These scholarships enable them to study engineering, business, aviation, medicine and biology to acquire skills they can apply to their communities and society.

Last year, more than $200,000 was raised at the Golf Classic and the proceeds directly benefited more than 200 students from the Calista Region.

The registration deadline is June 6, but don't delay — teams fill up fast. For more information visit www.calistacorp.com or call 907-279-5516 to signup.

Editor's note: All of these news items — some in expanded form — will appear in the next Arctic Oil & Gas Directory, a full color magazine that serves as a marketing tool for Petroleum News' contracted advertisers. The next edition will be released in September.

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SPECIAL SESSION

Senate, with senators saying they needed more information before making tax changes.

So the session ended with no major changes in the state's oil tax system.

Within the hour of legislators gaveling out the governor had called a special session to begin April 18, with the oil tax issue, House Bill 9 (the in-state gas pipeline bill) and HB 359, sex trafficking, on the agenda.

'A new dynamic'

At an April 16 press conference the governor said he was interested in the approach the Senate took in HB 276, and said with the "Senate's action there's a new dynamic now at work that I think might lead to a compromise that could produce new production, both now and in the future."

Parnell said the Senate proposal wasn't the whole answer because any new oil discovered as a result of the credits wouldn't be going into the pipeline for a number of years, and he was concerned "that vast resources in our legacy fields will remain untapped."

The governor also said the Senate's approach, focusing only on new fields, "will cost the state billions of dollars across 10 years while we have declining production and no new revenues from new production."

He cited the example of a company proposing to spend $9 billion in the state over the next 10 years on new fields. Under the state's existing tax structure that company would get credits of between 45 and 65 percent, "so the state will pay half of the cost of that exploration across the next 10 years," meaning the state would have to come up with $4 billion to $6 billion in that timeframe, while production from existing fields is declining.

The governor said he wants to see a proposal which would incentivize new production from existing fields, along with new field production, and believes that with "a significant tax change in existing fields" the state could see as much as 100,000 new barrels a day "within a year and a half or two years."

"I want to see whether we can take what the Senate has already agreed is meaningful in the new field context and make it material enough to do the same in existing fields," Parnell said.

... with the "Senate's action there's a new dynamic now at work that I think might lead to a compromise that could produce new production, both now and in the future." **—Alaska Gov. Sean Parnell**

If the Legislature reaches an impasse, Parnell said he would understand.

"But I think it's worth a try to create a competitive environment where more production can be produced," he said.

HB 9

On House Bill 9, a bill moving along work on a small-diameter in-state gas pipeline, Parnell said that if the key provisions in HB 9 don't pass, "Alaska's gas line efforts, in my view, will be set back for one to two years."

The governor said he was asking the House and Senate to waive the uniform rules and take up HB 9 where it was when the session ended; both bodies did that April 18.

Parnell said he disagrees with House Speaker Mike Chenault on whether the Alaska Gasline Development Corp. needs to come back to the Legislature before a pipeline gets built, and said he's "not trying to empower AGDC at this moment to go and contract and have an open season and sanction a pipeline; I think we have to have some gates they have to go through where they are held accountable by the Legislature and by the executive."

On the other hand, the governor said he doesn't agree with legislators who believe AGDC's "efforts should be killed off."

"I'm not in that camp," he said, explaining that the state needs alternatives — the large line from the North Slope to markets and the smaller in-state line — because without an option, the process would slow down, as it did under the Stranded Gas Act negotiations "when one party's negotiations were swept off to the side and ... the process slowed down and the state had no other alternative."

The new bill

The governor submitted a new oil tax bill to the House and the Senate April 18, describing it as "a piece of legislation that blends the positions of the House and Senate into a comprehensive approach that will bring economic opportunity to Alaskans for generations to come."

New North Slope oil and gas production is incentivized with a 30 percent exclusion, based on gross value at the point of production or GVPP, from the production tax value used to calculate the base rate and progressivity for the first 10 years of sustained production. This applies to fields not in production or in a unit on Jan. 1, 2008 — which would exclude Point Thomson but include Oooguruk and Nikaitchuq.

For currently producing North Slope fields, there is an exclusion, but only from the value used to calculate progressivity: 40 percent of the GVPP would be excluded from the monthly production tax value used to calculate progressivity; progressivity would be capped at 60 percent.

The bill also extends tax incentives for well lease expenditures available elsewhere in the state to North Slope activities and allow producers to apply tax credits in one year.

The new-oil provision

So what would the 30 percent exclusion in calculating base rate and progressivity for the first 10 years of sustained production look like?

Senate Finance had PFC Energy model the lifecycle effects for a new small development — a 70 million barrel field with peak production of 10,000 barrels per day at $100 oil.

Finance co-Chair Bert Stedman, R-Sitka, said at the April 14 hearing when the proposal was first aired publicly that the "concept of the 30 percent gross revenue allowance was derived out of our previous work on trying to enhance new oil production" with a gross progressivity calculation, and is an approach to incentivizing oil outside of existing developments within the current ACES structure.

Gerald Kepes, a partner in PFC Energy and head of the consultancy's upstream and gas practice, showed models run at the 30 percent gross revenue allowance for new developments at three different development costs: $17 per barrel; $25 per barrel; and $34 a barrel.

Kepes said with a $17 per barrel capital cost under the current tax, Alaska's Clear and Equitable Share or ACES, a lifecycle analysis showed a net present value or NPV of $112 million and an internal rate of return or IRR of 16 percent, with total government take ranging from 67 percent at $60 oil to 75 percent at $100 oil and 79 percent at $150 oil.

With the gross revenue allowance of 30 percent applied to ACES, NPV rose to $201 million and IRR to 20 percent; government take ranged from 56 percent at $60 oil to 64 percent at $100 oil and 66 percent at $150 oil.

"So it's a substantial difference for these lower-cost new developments," Kepes said.

Capex of $25 a barrel

At development costs of $25 a barrel for the same new development, which Kepes said "is more in line with the costs that we see with these new developments ... away from existing infrastructure," NPR under ACES would be $24 million and IRR 11 percent, with government take ranging from 68 percent at $60 oil to 75 percent at $100 oil and 79 percent at $150 oil.

At the $25 a barrel capital cost with the 30 percent gross revenue allowance, NPV is $121 million and IRR 14 percent, with government take ranging from 51 percent at $60 oil to 62 percent at $100 oil and 67 percent at $150.

At a capital cost of $34 a barrel, which Kepes characterized as "among the higher or highest cost rates that we're looking at," under ACES NPV is a negative $90 million and IRR 7 percent, with government take ranging from 80 percent at $60 oil, to 77 percent at $100 oil and 79 percent at $150 oil.

With the 30 percent gross revenue allowance, NPV on this type of project is a positive $3 million and IRR 10 percent, with government take ranging from 49 percent at $60 oil to 62 percent at $100 oil and 66 percent at $150 oil.

Legislators received a letter from 70 & 148 LLC, a partner with Repsol in new developments which have been cited at capital costs of $9 billion over 10 years, expressing "strong support" for passage of the new oil provisions Senate Finance added to HB 276, calling the new field tax changes "exactly what is needed in order to have the oil industry focus on Alaska over other oil producing regions," but also noting that the company hopes modifications can be made in the tax code "that will make operations within the legacy fields more competitive as well." ●

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ARCTIC REPORT

"The resilience of the Arctic's ecosystems in terms of withstanding risk events is weak, and political sensitivity to a disaster is high. Worst-case scenarios may be worse in the Arctic because the ability to manage evolving situations is limited by environmental conditions and the lack of appropriate infrastructure."

The authors conclude that major spending on science and research is urgently needed to close "knowledge gaps" on the Arctic's environmental change and geological potential.

They further conclude: "Full-scale exercises based on worst-case scenarios of environmental disaster should be run by companies with government involvement and oversight to provide a transparent account of the state of knowledge and capabilities, to foster expertise and to assuage legitimate public concerns."

Find the 60-page report online at http://bit.ly/HDSRxo.

—WESLEY LOY

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TIGHT SITUATION

"Putting together a funding facility of this type is a significant milestone for Buccaneer Energy," said Dean Gallegos, executive director of Buccaneer Energy, when announcing the new financing. "We are pleased to be working with this prospective lender and we appreciate the cooperation of all our stakeholders while we work through the process. Buccaneer is firmly committed to its Alaska strategy and we are looking forward to progress on our Kenai Loop project, including our next well at Kenai Loop and our first offshore well later this year."

Buccaneer completed its first well at Kenai Loop, near Kenai airport, in May 2011 and, having made a natural gas find, proceeded to develop a gas production facility connected to the Kenai gas pipeline infrastructure. The company also drilled a second Kenai Loop well that turned out to be a dry hole.

The first well, the Kenai Loop No. 1, went into production in January, supplying gas at the rate of 5.1 million cubic feet per day.

Kenai Loop contractors

But it has emerged that Buccaneer still owes considerable sums of money to the contractors that have worked on the Kenai Loop project.

Employees of several of these contractors testified during the April 4 meeting of the Kenai City Council — the Kenai Loop surface facilities are located inside the city of Kenai and Buccaneer had asked the city to renew the company's land use permit which had expired on March 1.

Sagen Juliussen, NANA Construction vice president for business development, told the city council that his company had exhausted the options for coming to terms with Buccaneer and that he was concerned about Buccaneer's talk of further developments when the company had not yet paid for work already completed.

"If they continue to do business the way they're doing, they're going to run out of contractors and venues … in Alaska because people aren't going to jump on board," Juliussen said.

On March 30 Nana Construction filed a claim of lien for $5.1 million against Buccaneer for work that Nana had completed for the Kenai Loop project, including the tie-in in of the well head to the gas metering pad and a substantial amount of civil work at the facility.

"We're not here to shut anyone down," said a NANA Construction worker who told the council that Buccaneer had at this point paid a bit less that 10 percent of what it owed. "To the contrary we would like to make sure that there is more development in the state. But it needs to be responsible development."

Need payment

Mike Sheppard, district manager for Conam Construction, told the council that Buccaneer owed his company money. Commenting that everyone wants small companies like Buccaneer to progress new developments in the Kenai area, Sheppard said that the community had executed the Kenai Loop project safely and in an exceptionally short time. But the people now need payment, he said.

Representatives from Inlet Drilling said that their company had already paid money into the community as a consequence of its involvement in the Kenai Loop project but that Buccaneer still owed Inlet Drilling a substantial sum of money for the work.

"You could probably more than half fill this room with the people they owe money to," said one of the company's representatives.

During a discussion about the renewal of Buccaneer's land use permit members of the city council expressed sympathy with the contractors' plight while also saying that the city could not involve itself in a business dispute. Some council members also expressed their desire that Buccaneer's ventures in the Cook Inlet basin should succeed.

Short-term permit

However, concerned about the potential ramifications of a "mechanic's lien" against property on city land, the council voted to only issue a new special use permit for Buccaneer's operations up to May 4, rather than for the term of one year that Buccaneer had requested. The idea was to allow some time for the city administration to determine how to protect itself from any financial liability relating to the lien. The council anticipates making a decision on a longer term permit at its May 1 meeting.

In recent months Buccaneer has been describing ambitious exploration and development plans including the drilling of a further well at Kenai Loop; the shooting of a seismic survey and the drilling of an exploration well in the southern Kenai Peninsula; and a program of offshore drilling in the Cook Inlet using a jack-up drilling rig.

In a quote emailed to Petroleum News on April 19, Gallegos said that since the beginning of 2011 Buccaneer had put more than $30 million into the Cook Inlet region and had hired more than 130 vendors for a variety of projects.

"We are currently working with NANA to resolve the issues surrounding their invoices," Gallegos said. "Senior management has been in discussions with the company and continues to work toward a suitable resolution. We look forward to a speedy outcome, but more importantly to continuing our corporate citizenship with the state and to being a major employer for the citizens of Southcentral Alaska for years to come."

Glacier rig

In announcing the purchase of the Glacier drilling rig, the rig already used to drill the wells at Kenai Loop, Buccaneer says that it anticipates being able to lease the rig to other companies as well as using the rig for its own drilling projects.

"The purchase of the Glacier rig is a significant milestone and key component of our onshore Alaska strategy, as it will allow us to immediately secure enabling assets in the Cook Inlet," Gallegos said. "The purchase of the rig ensures timely drilling of our Kenai Loop project and also assists in the control of costs associated with the project."

The jack-up rig that Buccaneer plans to use for its offshore drilling has been purchased by a joint venture between Buccaneer and Ezion Holdings Ltd. involving a public-private partnership with the Alaska Industrial Development and Export Authority, or AIDEA. AIDEA is contributing up to $24 million to the jack-up rig acquisition.

AIDEA spokesman Karsten Rodvik told Petroleum News April 16 that AIDEA's only involvement with Buccaneer concerns the deal to obtain the jack-up rig. The rig is currently in a Singapore shipyard undergoing upgrades, in preparation to set out for Alaska in the late spring, he said.

"We're looking forward to it getting to Alaska and commencing work in the Cook Inlet this summer," Rodvik said.●

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EXPLORATION UPDATE

The reasons behind the lower-than-expected number of wells drilled included everything from a shortage of rigs or rig crews for UltraStar and Linc, to the challenges Repsol faced with getting approval from the North Slope Borough for five ice pads, three wells each. It started the season with green light to drill from four pads, but with only three rigs running at any one time.

Then Repsol had a blowout at one of its pads and although the equipment worked as expected, no one was hurt and no oil was spilled on the tundra, the company was forced to kill drilling plans at that pad and one other, as well as delayed from re-starting drilling elsewhere.

Brooks Range cut its well count from two to one at its Mustang prospect because it got all the information it needed from the first well, and is proceeding with development.

Savant's permitting was held up after the Repsol blowout — one agency wanted to give all well plans a closer and longer look — otherwise it would have likely been finished drilling by now.

—KAY CASHMAN

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