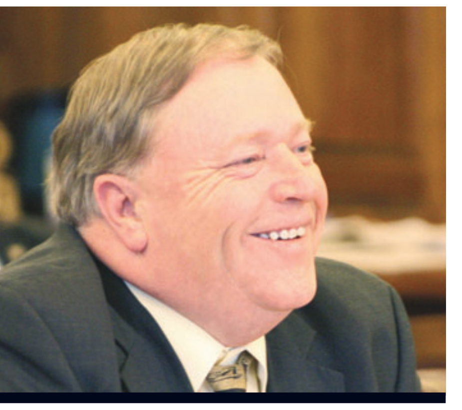
Petroleum news



page 3 Q&A: Chenault says gas tax could come up; time to get out of AGIA

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BUCCANEER ENERGY

The Endeavour jack-up rig

Buccaneer divests jack-up ownership but keeps jack-up involvement

A pair of Buccaneer Energy Ltd. deals involving the Endeavour jack-up rig highlights the intricate nature of the public-private partnership created to bring the rig to Alaska's Cook Inlet.

The Australian independent is selling its stake in the joint venture that owns the jack-up rig and is also selling its stake in the only offshore prospect in Alaska where the rig has been used since it arrived in the state in August 2012. But Buccaneer remains tied to the rig through contractual obligations, commercial arrangements and technical necessity.

The history of KOV

The Endeavour jack-up drilling rig is owned by Kenai

see **BUCCANEER MOVES** *page 23*

BP requests approvals for Liberty

BP has asked the Bureau of Ocean Energy Management, or BOEM, for approval to conduct a geotechnical and sea-bottom investigation in the Beaufort Sea in connection with a plan to develop the offshore Liberty oil field from an artificial island. The company says that it has also applied to state authorities and other government agencies for authorizations for the work, which would include reconnaissance and geotechnical investigations onshore for potential pipeline routing.

"The purpose of the investigation is to provide soils information for possible material sites, future pad locations, for evaluating proposed pipeline routing, and to provide a visual inspection of the sea-bottom environment," a BP official told BOEM in a letter dated Dec. 18.

After discovering the 150 million barrel Liberty field in

see **LIBERTY FIELD** *page 22*

AOGCC continues to gather data on Prudhoe NGLs, MI, propane

The Alaska Oil and Gas Conservation Commission heard from BP Exploration (Alaska) at a Jan. 7 hearing the commission scheduled to gather information "on the disposition of gas liquids in the Prudhoe Bay Oil Field."

The commission said it wanted evidence on whether it should alter Conservation Order 360 to require use of additional miscible injectant and on whether it had misinterpreted BP's evidence at a 2012 propane hearing on the quantity of recoverable miscible injectant per barrel.

The commission had asked BP a series of questions following the 2012 propane hearing. That hearing addressed a concern from Harold Heinze that because propane is not being produced for sale from the field, it might be wasted.

The commission determined, following the 2012 hearing,

see **GAS LIQUIDS** *page 24*

GOVERNMENT

Senator says export

Murkowski warns of oil glut, calls for ending ban on shipments out of U.S.

By WESLEY LOY
For Petroleum News

SEN. LISA MURKOWSKI

Alaska Sen. Lisa Murkowski is calling for the federal government to end the general ban on exports of U.S. crude oil.

In a Jan. 7 speech at the Brookings Institution, a Washington, D.C., think tank, Murkowski warned of a coming glut of crude, particularly "light tight oil" from hot plays such as the Bakken and Eagle Ford.

Failure to lift the export ban could lead to a refinery crunch, potentially crimping crude production, she said.

"Lifting the prohibition on crude oil exports will serve to increase domestic oil production, and the entry of this oil onto global markets will put downward pressure on international prices," said Murkowski, according to the prepared text of her speech. "All things equal, this combination will help the American consumer."

Murkowski's remarks add to growing sentiment to remove the oil export ban.

Energy Secretary Ernest Moniz recently suggested it might be time to reconsider the ban, in place since the 1970s when the Arab oil embargo

see **EXPORT BAN** *page 22*

NATURAL GAS

BC fracking challenge

Threat to LNG from Fort Nelson First Nation application to cancel water license

By GARY PARK
For Petroleum News

Existing in an almost tranquil atmosphere compared with the uproar surrounding plans to build crude bitumen pipelines to the Pacific Coast, British Columbia's LNG sector may be in for a jolt.

A small aboriginal community, with only 800 residents, is locking horns with the British Columbia government and the industry over the use of water for hydraulic fracturing.

The issue has moved from low-level muttering to the British Columbia Environmental Appeal Board which has started hearing an application by the Fort Nelson First Nation to cancel a water license issued to Nexen (now wholly owned by the China National Offshore Oil Corp.), which leads the Aurora LNG partnership.

"There is a gold rush on our water."
—Lana Lowe, Fort Nelson First Nation's land and resources department director

Fort Nelson is in the heart of British Columbia's shale gas region, which holds the key to supplying gas for LNG exports, with Nexen a leading player in the Horn River Basin.

Legislation being prepared

While the appeal is under way, British Columbia Environment Minister Mary Polak is trying to get ahead of fracking opponents by preparing new leg-

see **FRACKING CHALLENGE** *page 21*

OVERVIEW

Where from here for NS?

At the start of 2014 Alaska's oil production decline remains a prime concern

By ALAN BAILEY
Petroleum News

As 2014 gets under way the Alaska oil industry, showing its age but still having potential for the future, is evolving in response to aging oil fields, the need for new oil resources and changing world oil and gas markets.

The biggest single issue facing both the industry and the state is declining North Slope oil production, a factor that creates a headache for a state dependent on oil revenues and oil jobs. This headache extends to the operators of the trans-Alaska pipeline, the line that ships oil from the North Slope and forms Alaska's main economic artery: The slowing of oil flow through the line is creating technical problems associated with the cooling of the oil and increasing wax deposition in the line. Steps being taken to, for example, heat the oil on its way down the line can prolong the pipeline's life but add to oil transportation costs.

Prudhoe and Kuparuk

More than 35 years after oil first started flowing to market from the giant Prudhoe Bay field, and with the huge Kuparuk River field coming on line a few years later, these two fields remain at the fulcrum of oil production from the North Slope, underpinning the economics of the North Slope oil industry and the trans-Alaska pipeline.

Other active fields in and around the central North Slope are more modest in size and, while making sig-

see **NORTH SLOPE OVERVIEW** *page 16*

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Petroleum News *North America's source for oil and gas news*

● GOVERNMENT

Chenault says gas tax could be addressed

House speaker pleased with AGDC launch based on HB 4, wants to keep politics out of gas line; says it's time to get out of AGIA

By STEVE QUINN
For Petroleum News

House Speaker Mike Chenault knows this upcoming legislative session could be pivotal toward advancing a natural gas pipeline project, be it an in-state gas line or a large-diameter line leading to an LNG terminus in Cook Inlet.

Since the Legislature adjourned in April last year, the Alaska Gasline Development Corp. seated its board of directors and has been working toward holding an upcoming open season.

North Slope producers ExxonMobil, ConocoPhillips and BP, and pipeline builder TransCanada named Nikiski as the front runner for the terminus of an LNG line. Lawmakers listened to consultants discuss the LNG market; read reports commissioned by the governor's office and the recent budget summary from the Department of Natural Resources providing an outlook that could preclude AGIA.

Chenault is the co-author of House Bill 4's in-state gas line legislation and state's longest serving House Speaker, now in his third term.

The Nikiski Republican reviewed interim developments and offered a glance at the upcoming session with Petroleum News.

Petroleum News: There have been a lot of developments during the interim either in Cook Inlet or with AGIA or consultant reports. Most recently, DNR noted in its budget summary that the department is looking to transition out of AGIA. What are your thoughts on that?

Chenault: You know, I hate to be the guy who said I told you so, but there were a number of us who said since AGIA passed that it wouldn't work. So I hate to say I told you so, but that's exactly what's happening. It's past time that we move on from AGIA. I think the governor is transitioning in the right direction. It might not be as fast as some of us want, but I don't see where there is a benefit to that process in our current negotiations with the producers.

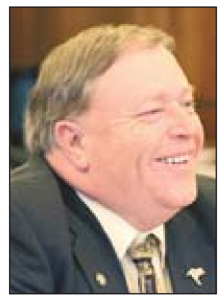
Petroleum News: Could this migration away from AGIA open things up for AGDC in its pursuit for an in-state line?

Chenault: I don't know about opening things up, but it surely would give them an opportunity to look at a bigger project than what they are currently limited to by the AGIA process we currently live under. It gives them more opportunities to talk to more and maybe larger investors who would be interested in a bigger project. This would, in turn, make it more economic for Alaskans to use some of the gas coming down the pipeline. Naturally a bigger line drives the costs down as far as ultimate costs for utility gas.

We tried to write HB 4 to give it the greatest flexibility to bring a successful pipeline project to the table. So when we put it together, that was the crux behind it. We wanted them to be as flexible as they could be. That way it enables them to get to a completed project.

Petroleum news: You've got your board and your new chairman. Is that significant or are those just getting figureheads in place?

Chenault: It's significant. That is something they are going to have to have to bring a project forward. The governor put some good people on that board. It gives them better flexibility and opportunities to negotiate and come up with a project to move forward on.


MIKE CHENAULT

We put them in a position, gave them most of the tools that they need to get to that completed project; now it's my job to stay out of the way and try to keep politics out of the project. In my opinion politics killed a number of gas pipelines across the spectrum and across the state for a number of years. Our best move is to stay out of it. Give them the tools they need. You've got the talent that's there and available to put a project together. We've got to stay out of the way.

Petroleum News: At what point would the Legislature come back into it, perhaps for more funding or otherwise?

Chenault: the funding put into HB 4 last year is enough funding to get through an open season and a sanctioning. We don't look to have to put any more money into it. The only way I see us having to meet again and look at funding would be if they came back with a project that required some state equity into a project. If that's the case, then the Legislature, the governor and citizens of Alaska would have sit down and have those conversations about whether we want to be an equity owner. If we do, what is that going to look like and how do we put it together and bring a gas pipeline down from the North Slope.

Petroleum News: Speaking of equity interest, as you know Black & Veatch produced a report that suggested the state seek an equity stake in a gas pipeline project. What are your thoughts on that?

Chenault: I've said for years that I think Alaska ought to be an owner of the project. Now how much that is, that needs discussing. Is that a 10 percent, is that a 20 or is that a 30 percent? I don't know that yet. And what form of ownership would that be? Would that be gas or would that be in steel? There are lots of ways to put together a project to make it successful. What we've seen and through some conversations we've had with industry folks, a way to put this project together to make it an economic project would be for the state of Alaska to own a piece of it. I'm willing to look at it and do the best we can to negotiate a fair position for the state.

Q AND A

Petroleum News: What is the value to having an equity interest?

Chenault: I'd say it's two or three fold. Projects like this, whether people want to believe it or not, if they are done on an economic basis, the state of Alaska would stand to receive a benefit from tariffs, so I can see us making money. Two, if that's what it took to bring gas to Fairbanks and a majority of Alaskans, and maybe even opportunities to bring gas to all Alaskans, then I think there is a value there to determine whether it's a good investment of our money.

Petroleum News: On the flip side, what are the areas that call for a cautionary approach if the state decides to pursue that?

Chenault: The biggest concern I would have would be the cost overruns. History showed the TAPS line was an $800 million project initially that ended up costing $8 billion. We need to make sure however this project is put together that we guard against these types of issues.

Petroleum News: Closer to home, there have been a lot of developments in Cook Inlet, whether it's new resource discoveries or ConocoPhillips requesting an export license. How are you seeing things?

Chenault: Cook Inlet is seeing a boom in exploration for gas and oil. All the companies that I'm aware of are out looking for oil but they also know they are going to find gas. There is a lot of money moving through the community. A lot of wells are being drilled. Gas is being found, being developed, put into pipelines and is being sold.

We've got ConocoPhillips saying they are going to reapply for the export license. That keeps roughly 70 Conoco employees and 50 contractors active. I've had Agrium folks saying if they could get a guaranteed supply of gas for a number of years, they would reopen their

see CHENAULT Q&A page 19

GOVERNMENT

Harper encounters pipeline foes in BC

Climate change activists penetrate security, disrupt speech in defense of oil sands pipelines; Harper says approval not assured

By GARY PARK

For Petroleum News

Canadian Prime Minister Stephen Harper started out 2014 where many thought he should have been long ago.

He made a week-long swing through Western Canada offering what he obviously viewed as a rationale argument for exporting oil sands bitumen and LNG.

Others showed they were more interested in disrupting his plans.

Harper was speaking at the Vancouver Board of Trade Jan. 6 when two climate change activists managed to dodge his Royal Canadian Mounted Police minders, get within an arm's length of him and raise signs carrying their message before they were hustled off stage.

Board of Trade CEO Iain Black described the incident as a "warm British Columbia welcome," while Harper quipped that it "wouldn't be B.C. without (a protest)."

STEPHEN HARPER

There had been a security screening for the event, including a bomb-sniffing dog to check bags and cameras.

But, whatever oversights allowed the event to happen, there was one clear warning: Opponents of Harper's plan to diversify Canada's energy export markets are formidable.

Equally daunting are the aboriginal communities, many of which have threatened to snarl the bitumen projects in legal action and civil disobedience.

Harper, who has experienced a drastic slide in public opinion polls over recent months with only 21 months until the next election, tried reaching out to both factions.

Go-aheads not assured

He also injected a note of surprise, telling his audience of 530 that a cabinet go-ahead for Enbridge's Northern Gateway, and Kinder Morgan's proposed Trans Mountain pipeline, are not sure things.

"We will not approve projects unless they are not only in our economic interests, but also meet the highest standards of environmental protection.

"We want to make sure that these kinds of projects are not just viable and give us lots of economic prosperity, but we want to make sure they are environmentally safe and every measure is taken to prevent any kind of serious environmental threat or other kind of disaster and, in the rare case that anything might happen, there are adequate responses," Harper said.

But he emphasized his government will make its decision on the "best scientific and expert advice available" and will settle for nothing less than "rigorous systems" of pipeline safety and marine operations.

He also said the bitumen pipeline projects might offer economic opportunities for aboriginals through employment and economic spinoffs.

"If handled correctly, this is an unprecedented opportunity for aboriginal people and their communities to join the mainstream of the Canadian economy" by seizing the opportunity for training in skilled jobs or working through aboriginal businesses.

Public opinion test

A test of public opinion on Northern Gateway will be held in the District of Kitimat, where tanker terminals are planned for Northern Gateway and LNG export projects.

A date for the non-binding, referendum-style vote will be set once the district council and staff have agreed on the wording for the plebiscite.

The council has remained neutral on the project pending an assessment of the Joint Review Panel's December approval and its 209 conditions.

But there is a growing element of optimism in the economically-struggling region that Kitimat will become a resource boom town.

Real estate values started to climb last year according to British Columbia Assessment's annual report issued Jan. 2 which showed single-family homes in the area shot up 26.7 percent last year to an average C$228,000, with similar increases posted in Prince Rupert, also a leading candidate for LNG terminals. ●

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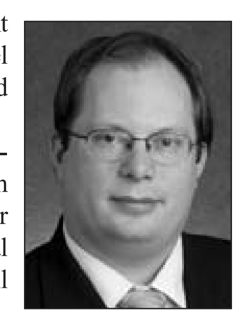
GOVERNMENT

New Revenue department officials named



MICHAEL PAWLOWSKI

The Alaska Department of Revenue said in a Jan. 2 statement that Revenue Commissioner Angela Rodell has named Michael Pawlowski deputy commissioner for strategic finance and Pamela Leary to lead the Treasury Division as state treasurer.

Pawlowski currently serves as petroleum fiscal systems advisor to the commissioner. A lifelong Alaskan, he graduated from Alaska Pacific University. Pawlowski previously worked for Alaska Permanent Capital Management Co., the Alaska Natural Gas Development Authority, and as an aide specializing in oil and gas, energy, and finance issues for the Alaska Legislature.

As deputy commissioner, Pawlowski will lead special projects and teams within the department.

Leary, the new state treasurer, has been state comptroller since 2007. She began her career as an auditor with Price Waterhouse and became a partner in the firm PricewaterhouseCoopers. After moving to Alaska, Leary owned and operated a business before reentering the accounting profession with the Alaska Permanent Fund

see REVENUE OFFICIALS page 5

● EXPLORATION & PRODUCTION

Kenai Loop case pits CIRI vs. Buccaneer

Buccaneer argues Alaska Oil and Gas Conservation Commission should decide; CIRI argues drainage, says court decision required

By KRISTEN NELSON
Petroleum News

Cook Inlet Region Inc. and Buccaneer Alaska are battling in Alaska Superior Court and at the Alaska Oil and Gas Conservation Commission over issues related to the Kenai Loop gas field, where Buccaneer is producing natural gas from wells on Mental Health Trust property and is in the process of drilling additional wells.

CIRI has adjacent acreage.

At the commission, a public hearing is set for Jan. 30 on a petition by CIRI requesting that AOGCC "provide relief based on a claim that Buccaneer Operations Alaska, LLC, is illegally producing gas from the Kenai Loop 1-1 and 1-3 wells." The Trust Land Office of the Alaska Mental Health Trust Authority and the Alaska Department of Natural Resources have intervened. Witness lists for the hearing are due Jan. 16 and hearing briefs Jan. 21, with the briefs limited to eight pages and the commission requiring that the parties include statements "of any claims made by the filing party against any of the other parties as well as any relief requested from the AOGCC."

In Alaska Superior Court, CIRI has appealed the commission's decision permitting the drilling, testing and completion of the Kenai Loop 1-4 well and, in a separate filing, sued Buccaneer for return of a CIRI lease, C-061667, also arguing that Buccaneer is draining CIRI acreage.

Drainage issue

In recent filings in the suit for return of the CIRI lease, Buccaneer asked the court to dismiss CIRI's drainage claims, arguing that CIRI has failed to exhaust administrative remedies and telling the court that AOGCC is currently adjudicating CIRI's claim that Buccaneer is draining natural gas from CIRI property and that CIRI is barred from seeking damages by the rule of capture.

Buccaneer told the court "CIRI's action rests, in large part, on the assertion that Buccaneer is violating AOGCC statutes and regulations," and argues that Buccaneer's operations at Kenai Loop comply with the law, since it has drilling permits and spacing exceptions from AOGCC for its producing wells.

Agencies have primary jurisdiction, Buccaneer told the court, and said: "This dispute is therefore best left to the AOGCC to adjudicate because it is the agency with the jurisdiction and subject matter expertise to resolve such claims and the technical training to evaluate CIRI's allegations."

Oral arguments on the motion to dismiss are set for Jan. 27.

CIRI cites damage issue

In its response to Buccaneer's request for dismissal of its drainage claims, CIRI said the crux of the drainage claims is based on Buccaneer's "failure to comply with regulatory pooling requirements" before production began at Kenai Loop "from wells that are unlawfully draining CIRI's property."

Only this court, CIRI said, "has jurisdiction to grant CIRI the remedy it seeks."

CIRI told the court that while Buccaneer focused on spacing requirements in its motion to dismiss, AOGCC regulations and state statutes include "the requirement to pool certain interests within a governmental section before a gas well begins regular production when the property is smaller than the governmental section ... and the requirement to file a pooling agreement" with AOGCC before regular production begins.

Following CIRI's objection to Buccaneer's latest requests for spacing exemptions, the commission required filing of a pooling agreement executed by Buccaneer, CIRI, DNR and MHT before production can begin from the Kenai Loop 1-4ST well.

"CIRI, the State, and the TLO are currently negotiating a pooling agreement, and no petition for compulsory pooling of the interests in Section 33 has been filed," CIRI told the court.

Section 33 is the area where Kenai Loop natural gas wells are in production.

In its response to CIRI's filing Buccaneer said CIRI's opposition demonstrates that the dispute belong before AOGCC, telling the court CIRI's argument "boils down to a forced interpretation of a technical AOGCC regulation and a selective reading of AOGCC Conservation Orders."

Kenai Loop

Buccaneer began producing natural gas from Kenai Loop in early 2012.

CIRI owns subsurface rights nearby, including acreage in section 33 of township 6 north range 11 west, Seward Meridian.

In 2011 CIRI issued an oil and gas lease in section 33 to Buccaneer and is suing to get the lease back, telling the Alaska Superior Court that Buccaneer has not fulfilled the terms of the lease.

Buccaneer told the court it had more than met the terms of the lease, and accused CIRI of not fulfilling its part of the lease agreement.

Production is coming from wells on acreage adjacent to the CIRI lease. The most recent production figures from AOGCC, for November, show production for that month of 130 million cubic feet of natural gas from two completions, and cumulative production of 4.4 billion cubic feet. ●

Contact Kristen Nelson at knelson@petroleumnews.com

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REVENUE OFFICIALS

Corp. She holds a bachelor's degree in economics from the Wharton School, University of Pennsylvania, and is a certified public accountant in the state of Alaska.

Taking the position as state comptroller will be Scott Jones, who has held the position of assistant comptroller since 2007. Jones has also served as an auditor. Jones holds a degree in business with an emphasis on accounting from the University of Alaska Southeast.

—PETROLEUM NEWS

● EXPLORATION & PRODUCTION

Hydraulic fracturing: an evolving scene

New techniques tackle concerns about environmental contamination, water usage and waste disposal while reducing production costs

By ALAN BAILEY
Petroleum News

By first creating a glut of cheap natural gas and then upping oil production to a point where U.S. output is set to surpass the country's imports, horizontal drilling and hydraulic fracturing techniques in shale hydrocarbon resources have up-ended the U.S. energy scene. But, while shale oil and gas enthusiasts have lauded the positive economic impacts of the new technology, others have raised concerns about the potential environmental impacts of widespread drilling, with the use of chemicals and huge quantities of water for "fracking" operations, and the possible contamination of groundwater through underground fractures.

In a talk to the Resource Development Council's annual conference on Nov. 20, Michael Watts, director of fracture stimulation affairs for Halliburton, discussed some of the controversies surrounding hydraulic fracturing and some of the emerging techniques for minimizing environmental impacts and improving operational efficiency.

Lack of understanding

Saying that many people's fears about fracking stem from a lack of understanding of the science involved in the technique, Watts argued for action based on objective science, rather than on emotion, and for the promotion of positive messages about the benefits to the United States of shale oil and gas. In fact, the U.S. oil industry has been using hydraulic fracturing for many years, with the first use of the technique dating back to 1949, he said.

A modern shale oil or gas development involves the drilling of horizontal wells deep underground and then using pressurized water to fracture hydrocarbon-bearing rocks, so that oil or gas can flow relatively easily into well bores. Sand injected with the water holds the fractures open after the fracking operation is completed, while small quantities of chemicals in the fluid perform functions such as killing micro-organisms that can clog the fractures.

Distant from aquifers

But the underground fracking operations take place far below near-surface aquifers, Watts said. In fact, a micro-seismic technique, involving the recording of sound from a fracking operation, enables the tracing of the locations of generated fractures — in the Barnett shale in Texas, for example, the shallowest fractures are many thousands of feet below the deepest aquifers, Watts said.

And a national registry called FracFocus now enables members of the public to obtain factual information about chemicals used in the fracturing, he said.

Well construction, which is subject to government regulation, involves multiple layers of cement and steel casing, to seal off the well bore that carries hydrocarbons from the producing rock formation to the surface, he said.

Holistic approach

Watts said that Halliburton has been taking what he characterized as a holistic approach to developing new technologies for hydraulic fracturing fluids, taking into account the cost of the fluid, the effectiveness of the fluid in enhancing hydrocarbon production, and those aspects of the fluid that relate to health, safety and environmental protection. That holistic approach spans the entire gamut of water use, including water-use minimization through recycling, the use of benign water chemistry and the reduction of trucking operations in association with fluid transportation.

"I think that water management is going to be one of the biggest and most exciting things that we've got going on out there," Watts said.

Benign fluids

Halliburton now assesses all of its hydraulic fluids, honing in on individual components, ranking the components and eliminating some less desirable materials from the fluid chemistry, he explained. One outcome of this process has been the development of a new fluid that uses materials derived from the food industry and that are recognized as safe by the Food and Drug Administration, Watts said. Perhaps surprisingly, this new fluid has actually proved more effective than most other fluids in stimulating oil production, he said.

Another innovation involves the use of ultraviolet light to destroy bacteria in the hydraulic fluid, thus eliminating the need for chemical biocides. And an electrical process for coagulating fluids in water recovered from hydraulic fracturing enables the removal of just sufficient waste material from the water for the re-use of the water for further fracking operations. Water re-use in this way minimizes the amount of waste that needs to be disposed of while also reducing the demand on new freshwater supplies, Watts said.

Water salinity

However, one of the challenges with water re-use is the high level of salinity often found in water produced from an oil well. To overcome this problem, Halliburton has developed and has been using a new system for dealing with the salinity and enabling the produced water to be used for fracking, Watts said.

"That's a phenomenal step change," he said. "Now we can take almost any kind of produced water and turn it into a usable frack fluid."

Other innovations include the use of a new dry polymer blending system that incorporates gels into hydraulic fluid, eliminating the need for diesel fuel as a solvent and, by replacing fluid solvents by a dry powder, reducing the amount of trucking needed in support of a fracking operation.

And micro-seismic, the technology used to track fractures generated during fracking, is now used to create a 3-D image of the subsurface fracture pattern, as a means of evaluating the effectiveness of the fracking, as a development project progresses. ●

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● EXPLORATION & PRODUCTION

December ANS crude oil production up 2%

Month-over-month North Slope increase to 567,600 bpd; Cook Inlet crude production continues to edge up at 16,701 bpd for November

By KRISTEN NELSON
Petroleum News

Alaska North Slope crude oil production averaged 567,600 barrels per day in December, up 2 percent from a November average of 556,470 bpd, a month-over-month increase of 11,130 bpd.

On a per-barrel basis the largest increase was from the BP Exploration (Alaska)-operated Prudhoe Bay field, which averaged 328,739 bpd in December, up 2.4 percent from a November average of 321,125 bpd, an average increase of 7,614 bpd.

Prudhoe Bay includes production from several satellite fields — Aurora, Borealis, Midnight Sun, Orion and Polaris — as well as from the BP-operated Northstar and Milne Point fields and the Prudhoe Schrader Bluff and Sag River oil pools, in addition to the main Prudhoe Bay oil pool.

Information for December comes from the Alaska Department of Revenue's Tax Division which reports North Slope oil production consolidated by major production centers and provides daily production and monthly averages. More detailed data, including Cook Inlet and individual North Slope fields and pools, is reported by the Alaska Oil and Gas Conservation Commission on a month-delay basis.

Kuparuk up 3.1 percent

The ConocoPhillips Alaska-operated Kuparuk River field averaged 141,812 bpd in December, up 3.1 percent, an average of 4,257 bpd, from a November average of 137,555 bpd.

Kuparuk River production includes West Sak and Northeast West Sak; satellite production from Meltwater, Tarn and Tabasco; and production from the Eni-operated Nikaitchuq field and the Pioneer Natural Resources Alaska-operated Oooguruk field.

November production data from AOGCC shows Nikaitchuq production averaging 16,218 bpd, up 7.8 percent, 1,174 bpd, from an October average of 15,044 bpd. Oooguruk production averaged 7,045 bpd in November, up 9 percent, 582 bpd, from an October average of 6,463 bpd.

The largest month-over-month percentage increase on the North Slope was at the BP-operated Endicott field, which averaged 10,666 bpd in December, up 29.2 percent from a November average of 8,255 bpd, an increase averaging 2,411 bpd. Endicott was producing in the 7,000-9,000 bpd range for much of November, climbing to the 10,000-bpd range late in that month and producing at the 10,000-11,000 bpd range for the majority of December.

Endicott production includes Sag Delta, Eider, Minke and the Savant Alaska-operated Badami field.

Badami production averaged 1,240 bpd in November, up 0.4 percent from an October average of 1,235 bpd.

Alpine, Lisburne down

December production from the ConocoPhillips-operated Alpine field averaged 57,426 bpd in December, down 4 percent, 2,411 bpd, from a November average of 59,837 bpd. Alpine production includes satellite production from Fiord, Nanuq and Qannik.

November data for the individual fields in the Colville River unit shows Alpine at 39,161 bpd; Fiord at 16,834 bpd; Nanuq at 2,155 bpd; and Qannik at 1,666 bpd.

There was also a month-over-month decline in production at BP-operated Lisburne, part of greater Prudhoe Bay. Lisburne averaged 28,957 bpd in December, down 2.5 percent, an average of 741 bpd, from a November average of 29,698 bpd. Lisburne production includes Niakuk, Point McIntyre and Raven.

Cook Inlet up slightly

Production from Cook Inlet edged up in November, averaging 16,701 bpd, a 1.7 percent increase over October at 16,418 bpd.

The largest month-over-month increases were at Cook Inlet Energy's Redoubt Shoal and West McArthur River fields and Hilcorp Alaska's Trading Bay field.

Redoubt Shoal averaged 2,009 bpd in November, up 22.2 percent from an October average of 1,644 bpd, an increase of 365 bpd, while West McArthur River averaged 903 bpd in November, up 75.4 percent from an October average of 515 bpd, an increase of 388 bpd.

Trading Bay production averaged 2,512 bpd in November, up 17.5 percent, 374 bpd, from an October average of 2,138 bpd.

Other fields with month-over-month increases included Hilcorp's Beaver Creek field, up 8.2 percent at 148 bpd; Hilcorp's Granite Point field, up 2.3 percent at 2,340 bpd; and XTO Energy's Middle Ground Shoal field, up 2.2 percent at 2,246 bpd.

Hilcorp's McArthur River and Swanson River fields had month-over-month declines.

McArthur River averaged 4,341 bpd in November, down 4.5 percent, 204 bpd, from an October average of 4,545 bpd, while Swanson River averaged 2,203 bpd in November, down 9.2 percent from an October average of 2,425 bpd.

ANS crude oil production peaked in 1988 at 2.1 million bpd; Cook Inlet crude oil production peaked in 1970 at more than 227,000 bpd. ●

Contact Kristen Nelson at knelson@petroleumnews.com

EXPLORATION & PRODUCTION

Royale seismic slated for February

Royale Energy Inc. is conducting its first Alaska seismic campaign in February.

The San Diego, Calif.-based independent and its Australian partner Rampart Energy Ltd. have contracted for SAE Exploration to conduct a 3-D seismic survey over 120 square miles of state acreage in the central North Slope, the companies announced Jan. 7.

The campaign fulfills the early terms of a farm-in agreement the companies signed in May 2013. The program also calls for the companies to drill two wells in 2015 to look for conventional and unconventional targets to be identified by the current seismic work. The companies expect the program to take 30 days.

—ERIC LIDJI

ALTERNATIVE ENERGY

Susitna-Watana schedule delay requested

The Alaska Energy Authority has requested a 120-day delay in submitting licensing materials for the Susitna-Watana Hydroelectric Project to the Federal Energy Regulatory Commission.

In a Jan. 6 letter to FERC, Wayne Dyok, the AEA project manager for Susitna-Watana, said the initial study report, or ISR, for the project is due Feb. 3. AEA is proposing to extend that deadline to June 3, submit a draft ISR Feb. 3 and modify the remaining project schedule to accommodate a 2015 study season.

Because only $10 million for the project was included in Gov. Sean Parnell's December budget for fiscal year 2015, and $110 million is needed to complete the study plan and prepare a license application in fiscal year 2015, AEA will be moving the majority of 2014 fieldwork to 2015, and will prioritize work from the FERC-approved study plan which "requires a winter study component during early 2014," Dyok said in the letter. He said the $10 million "demonstrates a continued strong commitment to the Susitna-Watana Hydroelectric Project," but "is short of the $110 million required to complete the Commission's approved study plan and prepare its license application during FY 2015."

In the revised project schedule submitted to FERC, filing of the final license application is moved to December 2016, which puts it in FY 2016.

Dyok said extensive field study work was conducted in calendar year 2013, based on a state commitment of more than $95.2 million, in addition to $77 million appropriated in previous years.

AEA said the Susitna-Watana project is estimated to provide about half of the Railbelt's electrical demand, with an average 50-year estimated cost of less than 7 cents per kilowatt hour.

—PETROLEUM NEWS

● ALTERNATIVE ENERGY

Coal gasification project remains alive

Cook Inlet Region Inc. is requesting return of reclamation bond for core holes; drilling in 2010 and 2011 showed promise

By WESLEY LOY

For Petroleum News

Cook Inlet Region Inc. is asking the state for return of a reclamation bond the company posted in connection with its underground coal gasification project.

But this doesn't mean the project is dead.

"We're still looking at it with our partner," CIRI spokesman Jason Moore told Petroleum News.

In fact, the company plans to meet soon with Alaska Department of Natural Resources officials to talk about the project, he said.

The reclamation bond was associated with 13 core holes drilled during the 2010 and 2011 field seasons, said a DNR public notice published Jan. 6.

Based on information CIRI submitted, plus the state's inspection of the core holes, DNR said it has determined the holes have been capped and sealed as required by regulation.

DNR said it currently holds a reclamation bond totaling $61,171.53. Of this, $57,754.10 is associated with the cost of capping and sealing the core holes and is available to be released.

"The remaining reclamation bond of $3,417.43 is required to cover the remaining reclamation associated with reestablishing vegetation at each drill hole location," DNR said.

'Coal energy without mining'

CIRI is the Alaska Native corporation for the Cook Inlet region.

In 2009, the company unveiled a plan to pursue an underground coal gasification project on remote CIRI land on the west side of the inlet. The plan included construction of a 100-megawatt power plant fired with synthesis gas, or syngas, derived from coal seams.

CIRI and its partner, Laurus Energy Inc., formed a joint venture in 2010 called Stone Horn Ridge LLC to pursue what company calls "coal energy without mining."

The partnership's website at stonehornridge.com describes how underground coal gasification, or UCG, works:

Injection and production wells are drilled into a deep coal seam. Operators pump oxygen into the injection well and initiate a controlled burn to gasify the coal. The syngas moves via a production well to the surface for processing.

"UCG is not coal mining, coal bed methane extraction or hydraulic fracturing," the website says.

"Stone Horn Ridge is moving to develop a UCG project to initiate commercial operations and production as soon as 2015," a company fact sheet says.

Exploration permit expired

In October 2011, a CIRI executive told an Alaska legislative committee the company's exploration program had confirmed a significant commercial coal resource in a geologic setting favorable for UCG development.

The 13 core holes went down about 700 to 2,600 feet.

The potential development site is called Stone Horn Ridge, located northeast of the Beluga River.

Laurus Energy, based in Houston, develops UCG projects in North America using proprietary technology, the company's website says.

Russell Kirkham, coal regulatory program manager for DNR, told Petroleum News on Jan. 8 that CIRI was issued an exploration permit in 2010.

The permit is now expired, but it can be renewed, Kirkham said. ●

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● OVERVIEW

Has the time come for North Slope gas?

Two gas line projects face significant hurdles as they work toward finding customers; much will hinge on cost, competitiveness

By ALAN BAILEY
Petroleum News

Almost since the birth of the North Slope oil industry, the idea of a pipeline to export natural gas from the Slope has remained a dream in the eyes of Alaskans, something to work toward but with its expected completion date perpetually decades into the future. But with recent moves to turn that dream into a reality, is the time approaching when the trillions of cubic feet of gas stranded in the Alaska Arctic can finally be delivered to market?

Following the shale gas revolution in North America, earlier ideas of shipping North Slope gas to the Lower 48 have fallen by the wayside: The focus now is on a pipeline to deliver gas to tidewater in Southcentral Alaska, where it would be converted to liquefied natural gas for export, probably to Asia.

Significant issues

A venture of this type faces a couple of significant issues if it is to compete on cost with gas from, say, Australia or the Middle East: the cost of removing from the gas the significant amount of carbon dioxide that relevant North Slope gas contains; and the cost of transporting the gas by pipeline over the 800 miles or so of rugged terrain to the Southcentral coast.

The viability of the project presumably depends on some combination of the cost efficiency of the pipeline and its associated facilities, and the price charged by the oil producers for the gas on the North Slope. But liquefied natural gas produced on the Southcentral coast would be conveniently located for transportation to Asia. And the North Slope gas is a known and established resource, rather than a speculative resource requiring exploration and delineation.

However, one question regarding the export of North Slope gas is the fact that, whereas it is true that the gas is stranded from market, the gas is not currently valueless. Much of the gas from oil fields such as Prudhoe Bay is continuously recycled through the fields to maximize oil production by maintaining the underground reservoir pressure and by using some of the gas to manufacture a solvent for flushing oil from rock pores. And oil being a significantly more valuable product than gas, there will be a tricky question in determining the point at which it becomes more expedient to export some of the gas, rather than use the gas to support oil production.

Two projects

Currently there are two gas pipeline projects in progress: The "big line" with a primary objective of exporting gas into world markets, and a smaller line primarily intended to ensure reliable energy supplies for Alaska communities, especially in the Fairbanks area and in Southcentral Alaska. And, since the larger line would have offtake points in Alaska, and since the possibility of two separate pipelines eventually being built seems inconceivable, the smaller line can perhaps be viewed as a "backup" arrangement, should the larger line fail to materialize.

The big line, with a throughput capacity of perhaps 3 billion to 3.5 billion cubic feet per day, has morphed from a TransCanada project to build a pipeline to connect with the Lower 48, becoming instead the Southcentral LNG export concept, sponsored by TransCanada, ExxonMobil, ConocoPhillips and BP. And, following a recent consultant report to the state, the question has arisen of whether the state should also become a participant in the project. TransCanada's involvement is based on that company's exclusive state license to construct the pipeline under the terms of the Alaska Gasline Inducement Act, or AGIA, passed in 2007.

Both North Slope gas line projects are currently working toward open seasons. Only after these open seasons have been held will people know whether either project will be financially feasible, and whether the long-cherished Alaska dream of exporting North Slope gas will become a reality at last.

The total cost of the project has been estimated at from $45 billion to more than $65 billion.

In October the companies involved in the project announced that they had chosen Nikiski on the Kenai Peninsula as the site for a Southcentral liquefied natural gas plant, at the southern end of the pipeline.

The AGDC project

The project for the construction of the smaller "in-state" pipeline is being conducted by the Alaska Gasline Development Corp., or AGDC, a state entity that the state is funding to the point of holding an open season in 2015. The open season will determine whether there are customers wishing

see GASLINE OVERVIEW page 12

FINANCE & ECONOMY

Sale of Oooguruk to Caelus not yet complete

The sale of Pioneer Natural Resources' Alaska assets, including the Oooguruk oil field in the nearshore waters of the Beaufort Sea, to Caelus Energy Alaska has not yet completed, Pioneer spokesman Casey Sullivan confirmed to Petroleum News in a Jan. 6 email.

"We are hopeful for a closing this month," Sullivan said.

When the two companies announced the sale in October they said they hoped to close the sale by the end of 2013.

Pioneer wants to sell its Alaska properties to raise capital for its shale oil program in the Lower 48.

In October James Musselman, president and CEO of Caelus, said his company has been interested in entering the Alaska oil industry and that it saw the purchase of Oooguruk as an excellent opportunity to do so. Musselman said that he anticipates investing $300 million in the Alaska assets and hopes to raise in excess of $1 billion for investment in Alaska, potentially spending $1.5 billion in the state over the next five to six years.

An immediate priority would be the development of Nuna, an as-yet undeveloped oil pool in the Oooguruk unit.

The Alaska Department of Natural Resources has been reviewing the purchase agreement between the two companies. In addition to transferring title to the Pioneer leases, the state needs to ensure that its interests are protected. Issues for review include arrangements for the transfer of obligations for the eventual removal of oilfield facilities.

"DNR and Caelus have been frequently meeting over the past two months regarding Caelus' acquisition of Pioneer's Alaska operations," DNR spokeswoman Elizabeth Bluemink told Petroleum News in a Jan. 6 email. "We are making progress in this regard and are working diligently on all aspects of the transaction, including royalty relief and DR&R (dismantlement, removal and restoration)."

—ALAN BAILEY

NATURAL GAS

DOE review won't delay LNG export license

According to a Jan. 3 report in Platts, an unidentified official in the Department of Energy has told Platts that an agency review of various plans to ship liquefied natural gas, or LNG, from the United States will not impede consideration of an application for a license enabling the re-opening of the LNG plant operated by ConocoPhillips on Alaska's Kenai Peninsula.

Faced with a growing line of applications for LNG exports from the Lower 48, DOE views the Alaska proposal as fundamentally different from the Lower 48 proposals and will consider the Alaska application separately, the official told Platts.

Faced with a growing line of applications for LNG exports from the Lower 48, DOE views the Alaska proposal as fundamentally different from the Lower 48 proposals and will consider the Alaska application separately, the official told Platts.

In response to a revival in the Cook Inlet gas industry and amid concerns about the need for market opportunities for Cook Inlet gas producers, in December ConocoPhillips applied for a license to export up to 40 billion cubic feet of gas over a period of two years from the Kenai Peninsula plant. The company had mothballed the plant earlier in 2013, shortly before a previous export license expired in March of that year. The plant had been experiencing difficulty in securing sufficient gas to maintain its export operations.

DOE can quickly approve an application to export LNG to a country that has a free-trade agreement with the United States, but must give more careful consideration to exports elsewhere. ConocoPhillips has not disclosed who might now buy Alaska LNG, although it appears that the company wants the option to sell to a non-free-trade country. LNG from the Cook Inlet has previously gone to Japan, which does not have a free trade agreement with the U.S.

—ALAN BAILEY

EXPLORATION & PRODUCTION

Exxon presses on with Point Thomson

ExxonMobil Development Co. has requested renewal of its state land use permit to allow for ice road and pad construction associated with the Point Thomson project.

Point Thomson is a new oil field ExxonMobil is building on Alaska's eastern North Slope. The company is aiming to start production from the field in early 2016.

ExxonMobil asked the state Department of Natural Resources to reissue the land use permit, as its current authorization expires on Jan. 27.

In its application, the company said ice roads and pads might be needed along the main supply route from Endicott to the Point Thomson central pad, within the Point Thomson field itself, and along pipeline rights of way.

DNR said in a Dec. 31 public notice that it intends to renew the permit until Jan. 27, 2019.

The department also indicated approval of certain permit changes. One concerns a stipulation in the existing permit that forbids vehicle refueling within the annual floodplain or tidelands.

"The majority of the ice road routes will be within an annual floodplain as the eastern coastal area is generally flat. It is not practicable to refuel only at upland sites due to their unavailability across the ice road routes," ExxonMobil told DNR.

The department proposes amending the stipulation to say: "Where practicable, vehicle refueling shall not occur within the annual floodplain or tidelands."

—WESLEY LOY

● EXPLORATION & PRODUCTION

Statoil's choice: Alberta or Newfoundland?

By GARY PARK

For Petroleum News

Statoil is rolling the dice on a gamble that has few if any parallels in the history of Canada's upstream.

Troubled by rising costs in the Alberta oil sands, the company, owned 67 percent by the Norwegian government, is giving serious thought to directing its investment money to major new oil finds it has posted in offshore Newfoundland.

It will decide within three months whether to proceed or stall plans for a multi-billion-dollar project to expand its existing Corner oil sands operation where it currently produces 15,500-18,500 barrels per day of bitumen from a steam-driven project called Leismer.

Stale Tungesvik, president of Statoil's Canadian unit, said growth in northern Alberta could take a back seat to Canada's East Coast, where they made a 600 million barrels discovery on the Bay du Nord prospect with Husky Energy and more wells are scheduled for this year.

A hint of what direction Statoil will take could emerge in February when it provides a strategy update, which could also reflect a "kind of reprioritization worldwide in our portfolio," he said, while adding he is "fighting for both" the oil sands and East Coast.

Worldwide difficulties

Statoil's dilemma captures the worldwide difficulties facing mega-companies with Canadian operations as they try to decide between separating bitumen from the oil sands by injecting steam deep underground, or securing complex, high-cost rigs for ever-deeper offshore prospects.

Tungesvik said the industry is "investing more than ever, but we see that it's much more costly to develop one barrels of oil today than it was earlier, so we are, like other companies, looking through our portfolio to see what we should do first" regardless of the rise in crude prices to $100 a barrel.

He also warned that companies such as Cenovus Energy and Suncor are "reluctant" to commit themselves to the oil sands at a time when there is deep uncertainty over the future of pipelines out of Alberta.

Activity has decreased "because people want to have some answers" on pipelines for their projects, while affected aboriginal communities are often left on the sidelines, making their decisions on oil sands development "really tough," he said.

Canadian based corporate powerhouses such as Encana and Cenovus have reinforced that view in recent weeks by rolling out cautious capital spending budgets and serving notice that they are hoping to sell assets to raise the cash needed for their best prospects.

Tungesvik said Statoil is running the numbers on Corner, which could be its second oil sands venture following Leismer, where it hopes to double output to 40,000 bpd. ●

Contact Gary Park through publisher@petroleumnews.com

● NATURAL GAS

Kitsault formalizes LNG export plans

By GARY PARK
For Petroleum News

Plans by a Canadian entrepreneur to turn a British Columbia mining ghost town into a hub for LNG exports and a possible oil refinery have taken a big stride forward, along with some innovative twists in the LNG sector.

Vancouver-based Kitsault Energy has formally entered the regulatory sphere by applying to Canada's National Energy Board for approval to export up to 20 million metric tons a year of LNG, equivalent to 960 billion cubic feet per year of gas supplies from the Western Canada Sedimentary Basin, WCSB.

The initial proposal involves the use of floating LNG liquefaction facilities, FLNG, constructed in modules with annual capacity of 4 million to 5 million metric tons per year each. The first unit is scheduled to come on stream in 2018.

Kitsault is wholly owned by Krish Suthanthiran, who has invested in medical research, commercial real estate and energy companies since immigrating to Canada from India 45 years ago.

Although the driving force behind the scheme, Suthanthiran has outlined ideas that see Kitsault using several models for exporting, including a tolling strategy or one where project partners will own their gas supplies and contracts and be responsible for sales and delivery.

The NEB application said the company may or may not be involved directly in the purchase and sale of gas used in LNG exports.

The company also said it is forming partnerships and commercial arrangements for access to LNG markets that position it to source gas in the WCSB.

A terminal would be located at the former town site at Kitsault, where a molybdenum mine was abandoned in 1982, but which still has infrastructure for a population of 1,200, including 90 occupant-ready family homes and 150 two- and three-bedroom condominium units.

The initial proposal involves the use of floating LNG liquefaction facilities, FLNG, constructed in modules with annual capacity of 4 million to 5 million metric tons per year each.

The site is at the head of a 30-mile long ocean arm and is 85 miles north of Prince Rupert, where six LNG proponents are evaluating plans for liquefaction plants and tanker terminals.

So far, the NEB has issued seven permits totaling about 92 million metric tons per year for LNG exports from British Columbia and is processing three applications for another 64 million metric tons per year, while four more proponents are conducting feasibility studies.

Kitsault said gas supplies will be transported to the LNG terminal by a 400-mile pipeline to be permitted, built and operated by an unidentified third-party pipeline company.

Each FLNG unit and subsequent liquefaction trains are expected to need 200 megawatts of power delivered to the project by a government-owned BC Hydro transmission line.

The company said gas sources will be owned by "the project, project partners or others accessing the LNG terminal on a tolling basis." ●

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OVERVIEW

The Cook Inlet oil and gas renaissance

Companies new to the Cook Inlet basin have stemmed the oil and gas production decline while also exploring for new resources

By ALAN BAILEY
Petroleum News

The Cook Inlet basin, the first petroleum province in Alaska to see a major oil field come on line, has been in decline since production peaked several decades ago. But a recent upsurge in Cook Inlet oil and gas exploration and development has started to stem that downward production trend.

The gas situation

In early 2010, with projections of gas supply shortages within a few years and worried about their continuing ability to ensure power and gas supplies for local residents, Southcentral Alaska utilities were discussing the possibility of bolstering Cook Inlet gas supplies by the import of liquefied natural gas from out of state. Cook Inlet oil production was also dwindling.

Concerned about the specter of a pending Southcentral energy crisis, in the spring of 2010 state lawmakers passed legislation, with tax credits to encourage new Cook Inlet oil and gas development, and with provisions to encourage the development of new gas storage facilities, facilities that the utilities viewed as essential to dealing with the huge swings in Southcentral gas demand between summer and winter in a scenario of tight gas supplies.

Several new names have appeared in the list of companies exploring for oil and gas or operating oil and gas fields. Oil and gas production has flattened or increased.

A study commissioned by the utilities had predicted imminent gas shortages in the absence of substantial new investment in gas drilling, while a report from the Alaska Department of Natural Resources indicated that that the Cook Inlet basin ought to hold enough gas to last well into the 2020s, if sufficient exploration and development drilling took place.

Dramatic change

Fast forward to the beginning of 2014, and the Cook Inlet situation has changed dramatically. Several new names have appeared in the list of companies exploring for oil and gas or operating oil and gas fields. Oil and gas production has flattened or increased. A new gas storage facility on the Kenai Peninsula is ensuring that utilities have enough gas to meet high winter demand. And worries about gas shortages have been deferred to at least 2018, and possibly beyond.

Hilcorp Alaska, a company specializing in bringing new life to old fields, has been leading the charge to turn around Cook Inlet production. Hilcorp, through an aggressive drilling campaign after purchasing oil and gas fields previously owned by Chevron and Marathon, has succeeded in increasing oil production from its fields. The company has also committed to filling shortfalls in utility gas needs through to early 2018, with an intent to

see COOK INLET OVERVIEW page 13

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GASLINE OVERVIEW

to ship gas on the line. If that open season proves successful, funding of project construction would come from appropriate bonding.

Under the terms of AGIA, the small pipeline is restricted to a maximum throughput of 500 million cubic feet per day, a throughput cap that would presumably limit some of the economies of scale that a larger line would enjoy but that the project proponents say could be financially viable.

But, with the full capacity of the line substantially exceeding internal Alaska utility gas demand, the viability of the line would depend on some form of industrial gas usage, probably the export of liquefied natural gas, as is envisaged for the big line.

Interaction with Cook Inlet

The construction of the small line would raise some intriguing questions regarding the interaction between gas supplies from the North Slope and Southcentral utility gas supplies from the Cook Inlet basin. Although there is much uncertainty at present over future gas production from the Cook Inlet, it does appear that significant volumes of gas may be produced from the basin for delivery to utilities well into the 2020s. But, if gas could be delivered more cheaply from the North Slope, would that put the Cook Inlet gas industry out of business? If, on the other hand, North Slope gas cannot compete on cost with Cook Inlet gas, would the North Slope gas become a marginal supply, filling in shortfalls in utility supplies from the Cook Inlet gas fields as necessary, with excess gas needing to be exported?

Both North Slope gas line projects are currently working toward open seasons. Only after these open seasons have been held will people know whether either project will be financially feasible, and whether the long-cherished Alaska dream of exporting North Slope gas will become a reality at last. ●

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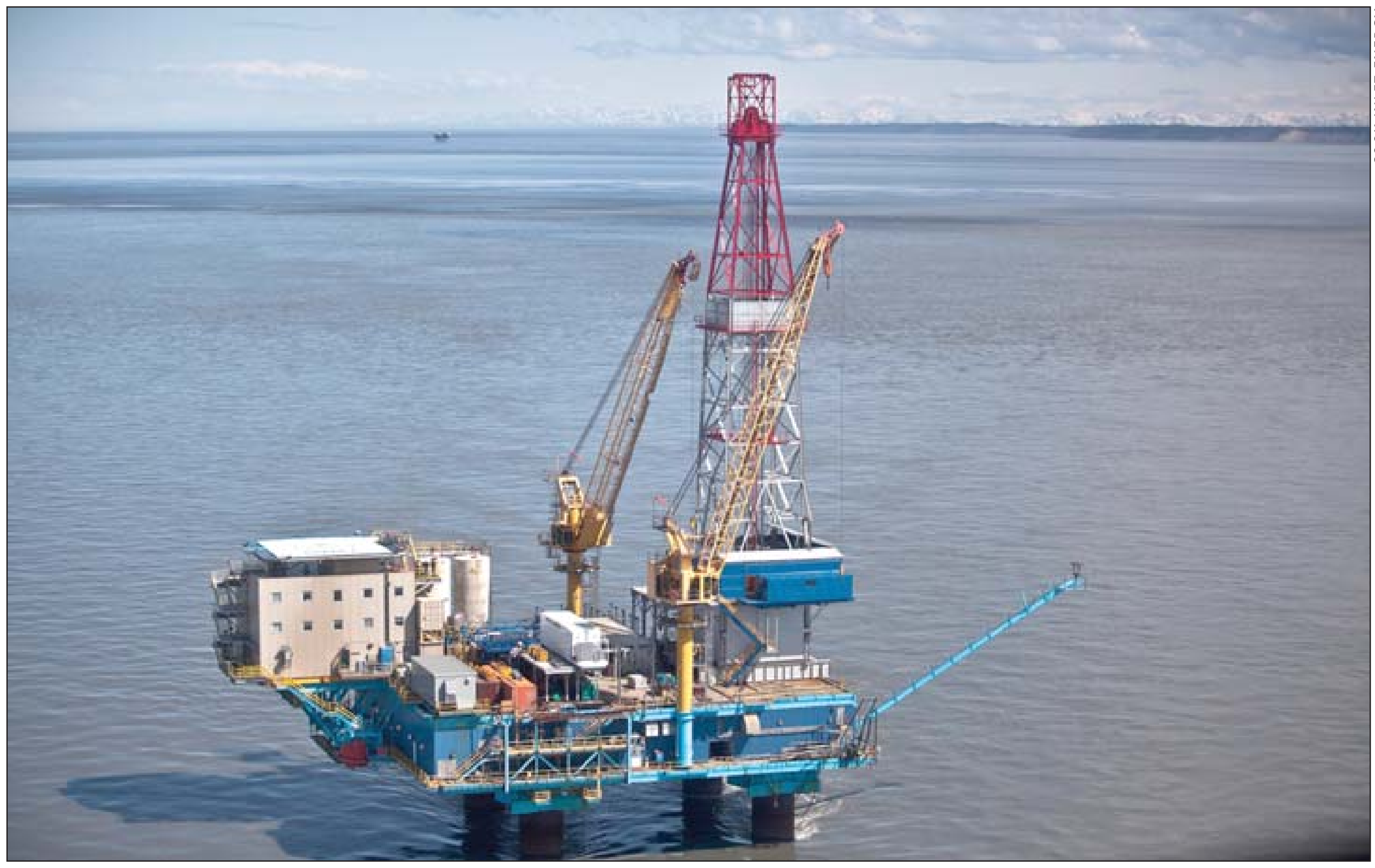
COOK INLET OVERVIEW


COOK INLET ENERGY

Cook Inlet Energy's Osprey Platform

contract further gas supplies a year at a time into the future.

Offshore the west side of the inlet, Cook Inlet Energy, a company formed in 2009, has resurrected one oil field and has been upping production from another. The company is also conducting an active exploration campaign and has recently purchased a small gas field in the southern Kenai Peninsula from a consortium led by Armstrong Oil and Gas. Armstrong had brought the field on line in 2011.

XTO Energy, a subsidiary of ExxonMobil, continues to operate the Middle Ground Shoal offshore oil field.

Gas market

With Hilcorp committed to filling near-term gaps in utility gas supplies, other companies have been expressing concerns about the need for market outlets for additional gas, to provide the economic underpinnings for further gas exploration and development. However, ConocoPhillips has applied for a new export license, to enable the restart of the Kenai Peninsula liquefied natural gas facility, mothballed since early 2013. There is even talk of the possibility of re-opening a Kenai Peninsula fertilizer plant that was shuttered in 2007 because of gas shortages.

ConocoPhillips continues to operate the large but aging Beluga River and North Cook Inlet gas fields.

Nordaq Energy has been moving ahead with the development of a new gas field in the northern Kenai Peninsula, but has not disclosed the size of the field. The company is also exploring on the west side of the Cook Inlet.

Buccaneer Energy, an Australian independent, came to the Cook Inlet in 2010 and is now operating a new, small gas field in the northern Kenai Peninsula. The company is conducting an active exploration program, offshore and onshore, in the Cook Inlet basin.

Jack-up rigs

For its offshore exploration Buccaneer brought a jack-up rig to Cook Inlet in 2012 in conjunction with the Alaska Industrial Development and Export Authority. The rig has been drilling at Cosmopolitan, a known oil prospect offshore the southern Kenai Peninsula, where the company has found a new gas pool.

Furie Operating Alaska, previously Escopeta Oil Co., has also brought a jack-up rig to the inlet to conduct offshore exploration. The company has made an offshore gas find which it says it hopes to bring on line in the fourth quarter of 2014 from a new offshore platform and pipeline to be installed in the inlet. The size of the find is not clear.

Meantime Aurora Gas, an independent gas producer that established a Cook Inlet presence in 2000, continues to operate some small gas fields on the west side of the inlet.

Apache Corp. arrived in Alaska in 2010, purchasing a large lease position in the Cook Inlet basin and announcing a major oil exploration program, including a multiyear program of 3-D seismic surveying onshore and offshore the inlet. The company has conducted seismic surveys onshore the west side of the inlet and across the northern portion of the upper Cook Inlet. But following disappointing results from an exploration well drilled on the west side of the inlet in 2013, and after expressing some frustration at the time taken to acquire some of the federal permits needed for its seismic work, the company has slowed down its Alaska program. ●

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● FINANCE & ECONOMY

US crude averaged 7.5 million bpd in 2013

EIA expects 2014 production figure to hit 8.5 million bpd, with 9.3 million projected for 2015; record was 9.6 million in 1970

By KRISTEN NELSON
Petroleum News

The U.S. Energy Information Administration says U.S. crude oil production averaged 7.5 million barrels per day last year, is expected to average 8.5 million bpd this year and to increase to 9.3 million bpd in 2015, the highest annual average since U.S. production peaked at 9.6 million bpd in 1970.

"EIA expects annual U.S. crude oil production to come close to setting a new record high in 2015," EIA Administrator Adam Sieminski said in a Jan. 8 statement.

With domestic crude oil production set to rise by 1 million bpd this year and almost that much in 2015, "U.S. oil production in 2015 could be the highest since 1972," Sieminski said.

EIA said in its January Short-Term Energy Outlook, released Jan. 8, that strong domestic crude oil production growth is expected, "primarily concentrated in the Bakken, Eagle Ford, and Permian regions, continuing through 2015."

Production from the Bakken formation in North Dakota and Montana averaged 880,000 bpd in 2013 and surpassed 1 million bpd in December, EIA said, while production from the Eagle Ford formation in South Texas was more than 1 million bpd last May, and reached an estimated 1.23 million bpd in December.

The Permian basin in West Texas and New Mexico averaged 1.32 million bpd in 2013, and EIA said it is projecting Permian production to grow more than any other region in the United States through 2015. Permian formations include the Spraberry, Bone Springs and Wolfcamp, and EIA said producers "are investing heavily in research and implementation of hydraulic fracturing in both vertical and horizontal wells. The stacked formations of the Permian allow vertical wells to reach several productive zones, while several horizontal wells drilled from the same surface location can target different formations or several pay zones within the same formation."

"The growth in domestic production has contributed to a significant decline in petroleum imports," Sieminski said, with the share of U.S. liquid fuels consumption met by imports expected to decline to 24 percent in 2015, "which would be the lowest level since 1970."

"The growth in domestic production has contributed to a significant decline in petroleum imports," with the share of U.S. liquid fuels consumption met by imports expected to decline to 24 percent in 2015, "which would be the lowest level since 1970."
—U.S. EIA Administrator Adam Sieminski

Non-OPEC growth

Production from areas outside the Organization of the Petroleum Exporting Countries, OPEC, is expected to grow by 1.9 million bpd in 2014, EIA said, exceeding 55 million bpd by the end of the year. The U.S. and Canada are expected to account for almost 70 percent of non-OPEC growth, while OPEC crude production is expected to decline by 500,000 bpd in 2014, "mostly as a result of some OPEC producers cutting back production to accommodate non-OPEC supply growth."

Non-OPEC supply growth is expected to be only 1.5 million bpd in 2015, just above a projected consumption growth of 1.4 million bpd.

OPEC crude oil production averaged 30 million bpd in 2013, down 900,000 bpd from 2012, "mostly as a result of increased outages in Libya, Nigeria, and Iraq," EIA said. A further OPEC decline of some 500,000 bpd is expected this year.

For 2015, EIA said some key members of OPEC are expected to continue to reduce output, but with growing produc-

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● FACILITIES

Arctic port recommendation due in March

US Army Corps of Engineers is working on draft feasibility report and EIS; Nome region appears most likely development site

By WESLEY LOY
For Petroleum News

The U.S. Army Corps of Engineers is aiming for an early March release of its recommendation for a seaport to support Arctic Ocean activity.

The release will include a draft feasibility report and environmental impact statement, Lorraine Cordova, economics team lead for the Corps, told Petroleum News on Jan. 8.

The report and EIS will be available for public review, and by December could receive the signature of the assistant secretary of the Army for civil works, Cordova said.

Alaska elected officials and others have been pushing for one or more seaports to support a rise in vessel traffic through the Arctic, where warming conditions are opening waters previously inaccessible due to ice.

Northern Alaska lacks major ports along the Arctic coast, most of which is very remote. That's a concern for industries such as tourism and shipping, as well as the U.S. Coast Guard.

Looking at options

In January 2013, the Army Corps issued a report titled "Alaska Deep-Draft Arctic Port System Study."

That report picked two sites for port feasibility analysis: Nome and nearby Port Clarence. Both these locations are south of the Bering Strait, gateway to the polar ocean.

The forthcoming draft feasibility report and EIS will examine the benefits and costs of a number of port "configurations," Cordova said. For example, the study will consider different options for dock length and port depth.

Ultimately, the alternative with the highest benefit to the nation will be identified, Cordova said.

The Corps and the Alaska Department of Transportation and Public Facilities are sharing the cost of the Arctic port studies.

Once the final alternative emerges, it would be up to Congress to authorize the port project and appropriate funding, Cordova said.

"Congress could direct us to build it at full federal expense," she said.

But more likely, some combination of federal, state, local and even private funding would be involved.

Sen. Begich pleased

In any event, it's not likely the Corps itself would operate the port, because that's not the agency's area of expertise, Cordova said.

U.S. Sen. Mark Begich, D-Alaska, welcomed the news that the Corps recommendation is drawing near.

"We know increased shipping traffic, oil and gas development, tourism and research in the Arctic will lead to a significant jump in vessel activity throughout the region," Begich said in a Jan. 3 press release. "In the last 10 years, traffic has already increased from just a handful of vessels every year to over 1,000 expected this summer. It is time for Alaska and our nation to step up and become leaders in shaping Arctic policy, transportation and resource development."

Begich chairs the Senate Commerce Subcommittee on Oceans, Atmosphere, Fisheries and Coast Guard.

In 2013, Begich introduced legislation to create an infrastructure fund to expedite development of an Arctic port, and to name an Arctic ambassador. ●

Contact Wesley Loy at wloy@petroleumnews.com

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EIA OUTLOOK

tion from other OPEC members, 2015 output is expected to be close to 2014 levels.

Oil prices

"December marked the sixth consecutive month in which Brent crude oil prices averaged between $108 per barrel and $112 per barrel. Brent oil's annual average price was $109 per barrel in 2013, $3 lower than in 2012," Sieminski said.

OPEC crude oil production averaged 30 million bpd in 2013, down 900,000 bpd from 2012

EIA expects the downward trend in the Brent price to continue, he said, "as growing non-OPEC oil supply continues to outpace world consumption, with Brent crude oil prices averaging $105 per barrel in 2014 and $102 per barrel in 2015."

The West Texas Intermediate crude oil price discount to Brent, "which fell to as low as $3 per barrel in July of 2013, averaged $13 per barrel in December," Sieminski said. "EIA expects this wide discount to persist in 2014 and 2015, averaging $12 per barrel in both years."

WTI, which fell from an average of $106 in September to $94 per barrel in November, increased to $98 per barrel in December "as a result of strong U.S. refinery runs," EIA said.

EIA said it expects WTI to average $93 per barrel in 2014 and $90 per barrel in 2015, with the $12 per barrel discount to Brent based on "increasing uncertainty of the existing refinery infrastructure's ability to absorb growing production of light sweet crude oil in North America at current prices."

Pipeline capacity expansions and reversals have created "ample capacity to ship crude oil via pipeline from the previous bottleneck in the U.S. Midcontinent to the U.S. Gulf Coast," EIA said, with the result that Light Louisiana Sweet crude oil, priced at a premium to Brent for must of the last two years, "has recently begun tracking WIT prices and selling at a discount to Brent." ●

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NORTH SLOPE OVERVIEW

nificant contributions to North Slope production, are also in decline. These fields consist of Niakuk; Milne Point; Endicott; Lisburne; Alpine and its satellite fields; Point McIntyre; and Badami, as well as various small satellite fields to Prudhoe Bay and Kuparuk. In the shallow nearshore waters of the Beaufort Sea are the Northstar, Oooguruk and Nikaitchuq fields.

The core product from all of these fields continues to be the valuable light oil that triggered the original field development. And, with substantial volumes of the original light oil in place already produced, field operators are using a variety of techniques to push the envelope for the recovery of light oil from the fields, thus prolonging field life for years into the future.

In addition to light oil, BP and ConocoPhillips have been developing viscous oil — oil with the consistency of syrup — from a reservoir formation above that of the main Prudhoe Bay and Kuparuk reservoirs. Development of this resource requires sophisticated horizontal drilling, to maximize the length of a well bore in contact with the reservoir.

BP EXPLORATION (ALASKA) INC.

BP's heavy oil test production facility at the Milne Point S Pad.

At a yet shallower level lie billions of barrels of heavy oil — oil that is too viscous to flow unaided down a pipeline. In April 2011 BP brought on line a $100 million heavy oil production test facility on a surface well pad in the Milne Point field. The company experienced some success in production testing but mothballed the facility in 2013. In December 2013 a BP official said that the company had not yet figured out a viable way to produce the heavy oil, but that it was still working on the problem, moving in the direction of eventual heavy oil development.

Other possibilities in the Prudhoe Bay field include the full development of an underdeveloped region in the extreme west of the field and some new development in a relatively thin reservoir above the main Prudhoe Bay reservoir.

Tax reform

But, with any new development in aging oil fields such as Prudhoe Bay and Kuparuk requiring expensive development techniques, the oil companies have been arguing that reform of state oil production tax is essential in assuring the business viability of new North Slope developments. And, to encourage the development of more North Slope oil, and hence to stem the decline in oil production, in 2013 the Alaska Legislature did pass tax reform in Senate Bill 21. Critics of this legislation claim that North Slope oil production is profitable and that the tax reform is actually a tax giveaway to the oil companies. A citizen's initiative to repeal Senate Bill 21 is scheduled to be put to Alaska voters in August.

Meantime BP and ConocoPhillips have announced funding for new projects in the Prudhoe Bay and Kuparuk River fields — the companies say that corporate approval of this funding has resulted from the passage of Senate Bill 21. BP has announced a 16-well development program for 2014 and 2015, with the ultimate possibility of 200 new wells and 200 million barrels of new oil production. ConocoPhillips has brought in an additional drilling rig for use in the Kuparuk field, is bringing a further rig to the field and has announced plans for the development of a new drilling site on the southwest flank of the Kuparuk River unit.

Other fields

Caelus Energy, the company in the process of taking over the Oooguruk field from Pioneer Natural Resources, the field's current operator, has said that it plans to move forward with the development of a new oil pool in the Oooguruk unit. Eni Petroleum, operator of the Nikaitchuq field, says it is evaluating an expansion of that field.

Savant Alaska has been making valiant efforts to stimulate production in the Badami field while also drilling nearby oil prospects, seeking other sources of production.

And, attracted by the possibility of developing new modest-sized oil fields close to

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NORTH SLOPE OVERVIEW

the existing North Slope oil infrastructure, Brooks Range Petroleum and Repsol have been conducting exploration in the central North Slope: Brooks Range is moving ahead with the development of a small oil field in its Mustang project.

Some distance to the east of the central North Slope, ExxonMobil is developing Point Thomson, a huge field containing a mixture of natural gas and condensate. The concept behind this technically challenging project is to deliver a modest-sized stream of condensate for mixing with oil from other fields for delivery by pipeline to the trans-Alaska pipeline. Condensate consists of a mixture of hydrocarbons, lighter than those found in typical crude oil but heavier than natural gas.

Other possibilities

So, what other possibilities are there for the development of new oil resources, in particular the major resources needed to really turn around the overall oil production decline in northern Alaska?

At the eastern end of the North Slope, the coastal plain of the Arctic National Wildlife Refuge, an area thought to be highly prospective for oil and gas, has long been the subject of controversy relating to environmental concerns and seems set to remain off limits to the oil industry for the foreseeable future. To the west, ConocoPhillips has been pursuing a policy of stepping out incrementally from its Alpine field in the Colville River Delta into the northeastern corner of the National Petroleum Reserve-Alaska, or NPR-A, a 23 million acre region of federal land encompassing much of the western North Slope and the western Brooks Range foothills. To the south of the North Slope, Linc Energy is hoping to develop a known oil field at Umiat.

Following a lengthy permitting delay, ConocoPhillips is now moving ahead with its NPR-A strategy, with the so-called CD-5 development, the first oil field to be developed in NPR-A. The company plans to develop another NPR-A oil pool to the west of CD-5 and to conduct further exploration drilling nearby.

NPR-A

The Bureau of Land Management, the federal agency that administers NPR-A, has published a new plan for the reserve, placing much of the coastal section of the reserve off limits to exploration. With this section of the reserve lying over a major structure related to the oil fields of the cen-

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JUDY PATRICK

Oooguruk island

North Slope shale oil: is it an option?

With the oil industry elsewhere in North America upended by shale oil development using horizontal oil wells and the hydraulic fracturing of oil bearing rocks, could this same approach to oil development work in Arctic Alaska, thus turning around the decline in oil production from the North Slope? Arctic Alaska is renowned for its prolific, world-class oil source rocks. Could these rocks be milked for oil, in a similar manner to, say, the Bakken in North Dakota?

Success in this type of development depends on the specific qualities of the target rocks, in particular the brittleness of the rock and its susceptibility to fracturing. The fluid pressure of the hydrocarbons in the rocks may also impact the ease with which oil can be recovered from the subsurface. And an Alaska shale-oil developer would have to negotiate the logistical and permitting challenges that would presumably be involved in drilling the large number of wells typically involved in a shale-oil development.

But the three major North Slope source rock formations appear to have at least some shale oil potential, with the Shublik, a major source of oil in some North Slope oil fields, having properties somewhat analogous to the prolific Eagle Ford shale in Texas.

Great Bear

Few people appeared to have given much thought to Alaska's shale-oil potential until 2010, when Great Bear Petroleum, a small, independent oil company, arrived on the scene, creating something of a stir when it picked up more than half-a-million acres of state leases south of Prudhoe Bay with a stated objective of pursuing shale oil development.

Great Bear moved forward with its plans, eventually staking six well locations conveniently close to the Dalton Highway. The strategy was to conduct a "proof-of-concept" exercise by first drilling some vertical wells for rock sampling and then, if tests of the rock samples proved promising, drilling some horizontal laterals through source rock for production testing. The company also shot some 3-D seismic over some of its acreage.

In 2011 Royale Energy, another small independent, also purchased some state leases in North Slope territory thought to have shale-oil potential.

And, amid heightened interest in the potential for North Slope shale oil development, in March 2012 the U.S. Geological Survey published an assessment of possible North Slope shale oil resources, saying that it may be technically feasible to recover anything from zero to 2 billion barrels of oil from those three Arctic oil source rocks.

Two wells

Great Bear, by then working in partnership with oil services company Halliburton, drilled the first two of its vertical test wells during the fall and early winter of 2012. The company reported that the wells had penetrated the expected source rocks but the company has since remained silent on any results from laboratory testing of source rock samples. The company did indicate that the testing might take several months to complete. Great Bear has not thus far drilled any horizontal wells and has remained silent on any further drilling plans. And having conducted a second seismic survey in its acreage in the winter of 2012-13, the company has said that it will conduct another seismic survey during the winter of 2013-14.

Royale has now formed a joint venture with Rampart Energy Ltd. to test North Slope shale oil potential in its acreage — the joint venture plans to shoot a seismic survey early in 2014.

Meantime the feasibility of Alaska shale oil development remains an unknown.

—ALAN BAILEY

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NORTH SLOPE OVERVIEW

tral North Slope, some people have expressed frustration at the closure of what they see as the most prospective area of NPR-A. But, using results from a recent NPR-A oil and gas assessment conducted by the U.S. Geological Survey, BLM says that the more central part of the reserve, which remains open for exploration, is likely to contain a preponderance of undiscovered NPR-A oil.

Viable development of an oil field in the remote territory of this more central area would presumably require the discovery of a huge oil resource. An alternative development approach would be an incremental development of the oil infrastructure into central NPR-A, developing a field at a time, along the lines of what ConocoPhillips is doing in the northeast. But an incremental step out of this type would presumably take many years to accomplish.

Beaufort and Chukchi seas

The outer continental shelves of the Beaufort and Chukchi seas offer some enticing possibilities for the discovery and development of new oil resources. The Beaufort Sea is known to hold some modest sized oil pools — BP has been trying to develop one of these pools, the Liberty field, for several years. After a failed project involving the drilling of ultra-extended reach development wells from the Endicott surface infrastructure, the company's latest concept is development from an artificial island.

Shell has been pursuing an exploration program in the Beaufort and Chukchi seas since 2005. In 2012 the company drilled the top-hole section of a single well in the Beaufort and a similar top-hole section of a well in the Chukchi. Following issues arising from the 2012 drilling project, Shell now hopes to drill again in the Chukchi in 2014 but has no immediate plans to return to the Beaufort. ConocoPhillips and Statoil also have Chukchi Sea exploration programs but have placed these programs on hold at present.

Shell anticipates shipping Chukchi oil to market through a pipeline to be constructed across NPR-A to the northern end of the trans-Alaska pipeline. But, assuming this happens, Chukchi oil will not bring near-term relief to declining oil throughput in the trans-Alaska line — Shell's CEO has said that his company anticipates finding major oil resources in the Chukchi but that it will likely be at least 2025 before oil will start flowing to market from the region. ●

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CHENAULT Q&A

facility or part of their facility. That plant employed about 300 to 400 company employees and about 100 contractors year round.

All of that will hinge on what's found and the cost of developing gas in Cook Inlet. If the explorers have a market they will spend the money to develop those projects. That's just how it operates. If they find the gas, but don't have a market for it or the development costs are high you won't see it for a number of years.

I think we are poised and well positioned. We have opportunities out there to provide explorers and consumers out there to utilize it. The newer technologies have helped go into old wells to not only find new gas but produce oil.

Petroleum News: And what about Nikiski being named the frontrunner for the LNG terminus?

Chenault: To me, it wasn't surprising. You have plenty of land available to build any infrastructure as far as any LNG plant or any chemical processing utilizing natural gas. You have access to the water. While it may not be a deepwater port to get huge tankers in there, Alaska's position globally — and where our market would be, it would be Japan, Korea or China — it doesn't warrant these huge tankers. A side that's not talked about too much, is there are not too many ports in the world that can accept these huge tankers. So it makes more economic sense as far as availability of ships and building these ships that you can transport LNG across the oceans.

You can get by with smaller ships. It's pretty early in the process to say Nikiski is the place. The bigger thing to take away from Conoco, BP and Exxon saying that Nikiski would be the terminus is that this is one of the first times in many, many years that I can think of that all three major producers have agreed to anything. To me, my takeaway, that's as important, if not more important, than deciding where they were going to go with it.

Whereas before, a couple years ago, you had Conoco and BP were studying on their own project and TransCanada and Exxon working on the AGIA process. You had that divide there. It seems to me like the three (producers) are coming together more. We need to try to facilitate that. At the end of the day, there are four big gas owners in the state: Conoco; BP; Exxon and the state of Alaska. All four of us have to come together and bring forth a project that is going to be economically viable and that will move a gas pipeline forward.

We are years away from an LNG plant being in Nikiski or in Kenai. We are moving forward. It's another step. The more steps we take, the closer we will get to a project. For years, we didn't do anything. I figured out, if you don't ever start it, you'll never finish it. The community is excited about it. As I told them, it's early in the process. It's something all three agreed to and that means we are moving forward in the right direction. Whether it's the AGDC line or the APP line. The projects will merge. I don't know what it's going to look like.

Petroleum News: Do you think TransCanada should be removed from the process? Several have said TransCanada doesn't bring to the project what the other parties do: natural gas.

Chenault: that's a discussion we need to take. I don't think we need to just move them to the curb. They do bring the experience in building pipelines in the north and operating pipelines in the north. So there is some experience there. How do you facilitate them into the project, I don't have all of the answers to that. Should they be given a seat at the table because they are TransCanada? I say no. We have been working with them on the AGIA process. There is a lot of information on the northern end of the project they have been working on as far as the gas treatment plant and environmental studies. I don't think we should kick to them to the curb. Just because they have been there, doesn't mean we give them a seat at the table. We need to see what they bring. If there is value in the things they bring to the table, then we need to consider that.

Petroleum News: OK, for the upcoming session, what are your priorities for advancing a gas line project?

Chenault: we still need to have conversations with the governor about the direction he is going with AGIA and make sure there are no legal issues there. I'm not afraid to take it up. As you well know Rep. (Mike) Hawker and I had HB 144 that would force the AGIA issue. It's something we prefer not have end up in court, but I don't see the need to spend money on the AGIA process anymore; it needs to away. I think the governor is on the right track there.

At some point we need to take up the gas tax. We can get through an open season. But what I want to see is a successful open season, and in order to get there, there are a number of issues. The biggest issue is how are we going to tax gas. It wouldn't surprise me if a gas tax bill gets introduced. It's important because we won't get to a successful open season until we do a number of things.

Petroleum News: HB 144 — that was designed to place the burden on TransCanada to prove that it's economic. Right?

Chenault: Right. The concern is if we just try to pull out of it, we may be opening up ourselves to trebled damages. I think people are still confused over whether that's three times the $500 million we committed to the project; is it three times the money we spent; or is it three times the money they spent. I'm not a lawyer so I don't know that. I would prefer to get out of it without a long-term lawsuit.

Petroleum News: A lot of lawmakers said they enjoyed the LNG symposium over the summer, but said they would enjoy more. Do you see the session being used for consultants to weigh in?

Chenault: I think so. I know I've had discussions with Rep. (Mark) Neuman and I know probably the first week that we get back down there, the in-state gas caucus will have at least one meeting to discuss where AGDC is now and what's on the horizon. If there is an interest in folks learning more about LNG and how we can use it as an economic driver for the state but also how we can utilize it better around the state then I can see Reps. Feige and Saddler (Eric and Dan, House Resources Committee co-chairs) would be more than willing to have hearings on it to get information out not to lawmakers but the public so they better understand what's being talked about.

Petroleum News: Closing out with the upcoming referendum to repeal SB 21, what are your thoughts on how things are?

Chenault: I couldn't tell you today whether it will pass or not. I don't think it will. I think Alaskans will see over the next eight months that what the Legislature felt will happen is happening, and that's more investment in Alaska. While it may take a year or two — or three or four — to actually see the value of that increased investment, that's what I think will happen. My biggest concern is that the indecision by companies looking to invest in Alaska and saying, 'we ought to invest, but well, wait a minute, let's see how the voter referendum goes.' That delays investment that could be happening today until after the election — whether it passes or not. I think that's the biggest problem and the biggest fear that I see out there: That indecision of being able to make that investment knowing what you are going to pay and how much investment isn't going to come to Alaska this year because of this voter referendum. ●

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Petroleum news

Oil Patch Bits

Alaska Rubber Group completes Washington acquisition

The Alaska Rubber Group, with three locations in Alaska, has announced the purchase of five additional locations in Washington, effectively doubling the size of its employee owned organization.

The five new locations all fell under the company formerly known as Pacific Rubber Group, serving the entire Pacific Northwest region and are comprised of Pacific Rubber Inc. located in Seattle; TIMCO Inc. at the Port of Tacoma; North Sound Hose and Fittings in Everett; Central Hose and Fittings in Pasco; and Inland Pacific Hose and Fittings in Spokane.

"We're always exploring opportunities for growth, and it is exciting to see where this new addition to our group will take us," said Janeece Higgins, president and CEO of Alaska Rubber Group. "Some of the former owners of the Washington stores, Don and Drennon Adams, were the original founders of our Alaska locations. We all started with a very similar model. It's kind of in our DNA. I have known some of the employees in the Washington stores for years, and the knowledge and experience they bring will help shape the future of the company. Everyone involved is critical to the team, and I look forward to their new ideas, hard work, and the growth that we will experience going forward."

Each location within the group will retain its original name; however, each will now be branded as an employee owned Alaska Rubber Group Company. For more information about the Alaska Rubber Group, please visit www.alaskarubber.com.

BP's Prudhoe Bay power station recognized for safety

As reported by the State of Alaska Department of Labor and Workforce Development on Dec. 6, BP Exploration Alaska's Central Power Station in Prudhoe Bay has again been awarded the Alaska Voluntary Protection Program's "Star" level for outstanding employee safety and health programs.

"The VPP Star re-certification is a testament to our team's proactive commitment to safety," facility managers Art Milan and Michael Dobesh said. "We have embedded this culture into the fabric of our facility and the team members are very proud of their accomplishment.

"As an employee driven process, the team facilitates weekly VPP meetings and manages their VPP funding through a well-established process. This process allows the team to have full control and accountability of all safety aspects in their facility. As the facility managers, we are very impressed with the level of involvement and commitment as we continue our journey to an incident free work place."

VPP recognizes and promotes effective workplace safety and health management through a cooperative program between a company's management, employees and the Alaska Department of Labor and Workforce Development's Occupational and Safety

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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FRACKING CHALLENGE

islation on the allocation of water rights.

With Japan's Inpex and JGC Corp. as minority joint-venture partners, Aurora has applied to export 24 million metric tons a year of LNG, representing a peak 30.5 trillion cubic feet of natural gas over 25 years.

The British Columbia government has estimated that the use of fracking currently requires 7 billion liters a year of water and if the LNG sector matches its expectations that demand will grow by 500 percent.

Polak said her planned Water Sustainability Act would see British Columbia impose its first fees on the use of groundwater and allow the province to limit water use in times of scarcity.

Concern with water removal

But Lana Lowe, director of the Fort Nelson First Nation's land and resources department, told reporters she doubts the legislation will affect the use of fracking.

She said water removed from her community's territory has multiplied 12-fold in the last two years.

"There is a gold rush on our water," she said, estimating that Nexen's water license will see an additional 2.5 billion liters a year removed from a lake north of the City of Fort Nelson in the midst of the First Nation's traditional land.

Water removal infringes on treaty rights allowing the aboriginal community to hunt and fish as it did before the treaty was signed in 1899, she said..

Lowe claimed changes in the water table have residents concerned about the possibility of contamination from fracking methods.

Polak told a news conference that the

> *The British Columbia government has estimated that the use of fracking currently requires 7 billion liters a year of water and if the LNG sector matches its expectations that demand will grow by 500 percent.*

legislation she expects to introduce will require government regulators to assess water flows before issuing withdrawal permits.

"The act will give us tighter control because we will have a better understanding, better monitoring, better reporting and the ability to step in where there is a risk to flows," she said.

Polak said the increasing transparency will "build trust in our regulatory regime."

Fracking study under way

The British Columbia Ministry of Health is also expected to complete a study this spring on whether fracking fluids contaminate drinking water, although Premier Christy Clark has insisted there has not been a confirmed case of contamination from industry activities in 50 years.

Lowe argued that the legislation is more likely to "make it easier for companies to get what they want for shale gas. We're trying to get out in front of that activity, which is a really tough position to be in. There is so much pressure on the government to get LNG moving."

Maude Barlow, chair of the Council of Canadians, a citizens' advocacy organization, said in a December report that Canadian policies at the provincial and federal levels are putting "our water supplies at risk," forecasting that global demand for water in 2030 will outstrip supply by 40 percent.

She said the North American Free Trade Agreement poses one of the biggest threats to Canada's "freshwater heritage" by allowing U.S. corporations operating in Canada "to sue for financial compensation if any changes are made to the policies or practises under which they first invested."

Barlow cited a report by the Canadian Center for Policy Alternatives which said the "inappropriate" use of water for fracking in British Columbia will contribute to "greenhouse gas emissions equivalent to 24 million cars on the road."

She called for more grassroots democracy to protect the "birthright of all people" and challenge the established "rules for trade (for which) the only motivation is corporate profit." ●

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OIL PATCH BITS

Section.

As a VPP Star recipient the BP Prudhoe Bay Central Power Station won't be subject to random enforcement inspections for five years. Enforcement regulations remain in effect, however, and cases of employee complaints, accident investigations or other significant incidents will result in an enforcement inspection. Participation in the program is voluntary.

For more information about the program, go to http://labor.alaska.gov/lss/vpp-participants.html.

Mahmood named manager for Marine Response Alliance

Samina Mahmood, former commercial manager for TITAN Salvage, has been appointed manager for Marine Response Alliance, an association of the top U.S. emergency responders providing OPA 90 Salvage Marine Firefighting.

Mahmood will lead the MRA administrative team and work closely with the alliance's emergency response center and the U.S.-based emergency response and salvage team.

Prior to joining TITAN and the MRA, Mahmood worked for Crowley Maritime Corp., TITAN's parent company, servicing oil and gas projects around the world. Recently she accepted on behalf of TITAN and MRA the Defense Logistics Agency's "Hurricane Sandy Award" at the Business Alliance Awards in Virginia, for the team's "unprecedented support" following the storm that devastated much of the Northeastern coast in late October 2012.

MRA, founded in 1994, combines experts in all facets of emergency response with salvage, firefighting and lightering equipment in all Captain of the Port Zones. Alliance members include TITAN, Crowley, Marine Pollution Control and McAllister Towing & Transportation. To learn more about MRA, please visit www.marineresponsealliance.com.

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 March.

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EXPORT BAN

rattled the nation.

Support for removal of the export ban, however, is far from unanimous.

Oil export exemptions

Murkowski is the top-ranking Republican on the Democrat-controlled Senate Energy and Natural Resources Committee.

In conjunction with her speech, she released a number of memos from the nonpartisan Congressional Research Service, including one that explains how export of U.S. oil is generally prohibited, but not completely.

Some exemptions are allowed, such as exports to Canada and exports of foreign-origin crude, the memo says.

Citing data from the U.S. Energy Information Administration, the memo says 83.5 million barrels of crude were exported from the United States from 2008 to 2012. Nearly all of that oil went to Canada, with very small volumes to two other countries: Costa Rica and Mexico.

Companies wishing to export oil that qualifies under an exemption must first obtain a license from the Commerce Department's Bureau of Industry and Security, the memo says.

Another export exemption applies to Alaska oil from Cook Inlet and North Slope oil sent through the trans-Alaska pipeline.

Thus, Murkowski's argument to lift the federal export ban isn't that relevant for her home state.

"It really isn't about improving the situation for Alaska, because we're already there," said Kevin Banks, a petroleum market analyst in the state Division of Oil and Gas.

Some Alaska oil was exported in the past, but nowadays it goes aboard tankers mainly to West Coast refineries, he said.

Refining mismatch

Murkowski, in her speech, said the export ban also should be lifted for condensate, a very light oil.

The senator said she believes the Obama administration has statutory authority to lift the oil export ban on its own.

"Although the president has the authority to declare it in the national interest to lift the ban, another path is for the Department of Commerce to approve an application for export of crude oil or condensate under a provision in the law permitting the application if it can be demonstrated that those fuels 'cannot reasonably be marketed' here in the United States," Murkowski said.

Domestic oil production is indeed facing the lack of a U.S. market, as much of the nation's refinery sector is geared for heavier grades of crude compared to the rising volumes of light tight oil, she said.

If the administration is unwilling to act, Murkowski said she is prepared to offer legislation to lift the export ban.

"Opponents of oil exports will of course raise the specter of rising gasoline prices — I think, to scare off elected officials," she said.

Opponents come out

Even before Murkowski's speech, one of her colleagues was urging Obama not to ease the oil export ban.

"When Congress first enacted limits on crude exports in the 1970s following the oil embargo, these laws were designed to enhance American energy security and protect U.S. consumers from volatility and price spikes," Sen. Robert Menendez, D-N.J., said in a Dec. 16 letter to the president. "Despite changes in the global energy market, these goals should remain priorities in our nation's energy policy. Easing this ban might be a win for Big Oil, but it would hurt American consumers."

Menendez noted that American consumers have seen average gasoline prices rise from about $1.50 a gallon in 2003 to $3.50 today.

"Crude oil that is produced in the U.S. should be used to lower prices here at home, not sent to the other side of the world," he wrote.

The Houston Chronicle, in a Jan. 8 story, reported a number of domestic refiners also were opposed to easing the oil export ban.

The story noted refiners were enjoying domestic crude priced well below the London benchmark, while selling record volumes of gasoline, diesel and other finished products to foreign consumers. ●

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Murkowski outlines energy export reforms

In addition to ending the export ban on crude oil, U.S. Sen. Lisa Murkowski wants other changes to what she terms "the architecture of U.S. energy exports."

The Alaska Republican lays out her ideas in a new 22-page white paper available online at http://1.usa.gov/1koAUYq.

"While many Americans have by now learned about the oil and gas revolution currently transforming the nation's economy, far fewer know about a concurrent surge in energy exports that is remaking the global energy trade," the paper begins. "Simply put, the United States is both producing and exporting more energy than ever."

But the regulatory structure that governs energy exports is "antiquated" and unevenly applied across the sector, Murkowski argues.

But the regulatory structure that governs energy exports is "antiquated" and unevenly applied across the sector, Murkowski argues.

"There are types of energy sources that are largely prohibited from export due to outdated regulations that have accumulated over the better part of a century," the white paper says. Meanwhile, other energy supplies trade freely.

Murkowski argues that U.S. exports are important for alleviating "energy poverty" around the world.

LNG reviews lagging

The white paper covers a wide range of energy segments, from coal and crude oil to nuclear and renewable energy technologies.

Regarding natural gas, Murkowski argues the Department of Energy needs to speed up its review of applications to export liquefied natural gas, or LNG.

"Multiple studies have concluded that the domestic price impacts of LNG exports will be minimal and, in any event, will be far outweighed by the net gains to the U.S. economy," the paper says. "Further, geopolitical benefits will accrue from helping our friends and allies overseas, dependent as many of them are on a limited number of suppliers."

Murkowski further argues federal environmental review of gas projects should not include potential climate change impacts.

The white paper says exports are proceeding smoothly with respect to certain energy supplies including coal, refined petroleum products such as gasoline and diesel, and natural gas liquids such as butane and propane.

—WESLEY LOY

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LIBERTY FIELD

1997, BP considered developing the field from an artificial island in the Beaufort Sea. But the company subsequently decided on an alternative development approach: the drilling of ultra-extended reach wells from an enlarged island at the Endicott field adjacent the Beaufort Sea coast. And the company proceeded to have the island enlargements made and a specially commissioned, massive drilling rig installed on the island, in readiness for what would have been record-breaking extended reach drilling operations.

But following technical problems with the rig and faced with regulatory complications following the 2010 Deepwater Horizon disaster in the Gulf of Mexico, in June 2012 BP announced that it was abandoning the extended reach drilling project. The drilling rig remains unused at Endicott.

BP subsequently decided to return to the original artificial island concept for the Liberty development, with that decision becoming public in the fall of 2013.

—ALAN BAILEY

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BUCCANEER MOVES

Offshore Ventures LLC.

Buccaneer created Kenai Offshore Ventures in late 2010 to apply for tax-exempt bonds available under the 2009 federal stimulus program. It intended to use the bonds to purchase a jack-up rig for the Cook Inlet basin. As the state agency responsible for the program, AIDEA, the Alaska Industrial Development and Export Authority, was close to approving $60 million in bonds when Buccaneer expanded its business strategy to include the Arctic, which disqualified the project for the bonds.

Instead, AIDEA and Buccaneer decided to buy the rig together. Under the plan, AIDEA would invest up to $30 million in the project, Kenai Offshore Ventures would invest $5 million and the remaining $50 million would come from a private financial investor.

As the deal was coming together, Buccaneer sold a 50 percent interest in Kenai Offshore Ventures to the Singapore-based marine company Ezion Holdings Ltd.

In May 2011, Gov. Sean Parnell signed a bill allowing AIDEA to invest in limited liability corporations, which allowed AIDEA to invest in Kenai Offshore Ventures.

In mid-2011, Kenai Offshore Ventures purchased the Transocean Adriatic XI jack-up rig and renamed it "Endeavour — Spirit of Independence." Toward the end of the year, the AIDEA board approved a deal to invest as much as $30 million in the Endeavour project.

By contributing some $23.6 million to Endeavour, AIDEA became a preferred member of Kenai Offshore Ventures. Buccaneer and Ezion invested some $30.4 million to the project as common members. Oversea-Chinese Banking Corporation (OCBC) Ltd. invested the remaining $66 million needed to fund the estimated $120 million project.

AIDEA currently owns 82.5 percent of Kenai Offshore Ventures, while Buccaneer and Ezion each own 8.75 percent of the company, according to the state corporation filings.

The business of KOV

As part of the AIDEA deal, Kenai Offshore Ventures signed a "bareboat charter" agreement with a Buccaneer Alaska Drilling subsidiary called Kenai Drilling LLC.

The five-year agreement runs through Oct. 29, 2017, and requires Kenai Drilling to pay Kenai Offshore Ventures some $70,000 per day to use the rig. Kenai Drilling earns money by leasing the rig to companies looking to drill offshore wells in Alaska.

While Kenai Drilling is responsible for marketing the rig, Spartan Drilling LLC is the contractor responsible for actual day-to-day operations. Kenai Offshore Ventures originally hired Archer Drilling for the job, but the companies parted ways after disputes over payment and are currently in court, each claiming damages against the other.

To date, the Endeavour rig has drilled one well in Alaska, the Buccaneer-operated Cosmopolitan No. 1. When Buccaneer used the rig, its daily rate was closer to $24,500 because of rebates associated with the Alaska's Clear and Equitable Share tax credit program, according to the company. Buccaneer currently holds an exclusivity agreement on the rig, but the Kenai Offshore Ventures business model intends for third parties to eventually rent the rig. Those companies would lease the rig from Kenai Drilling.

In February 2013, AIDEA estimated the charter agreement would generate some $27 million each year for Kenai Offshore Ventures, which would flow back to its investors.

After paying for a limited range of operating expenses, revenues to Kenai Offshore Ventures must go first toward paying down the OCBC loan, then toward paying down the AIDEA loan and finally to recoup the investments of the two common members, Buccaneer and Ezion. AIDEA expects to be repaid over six years at 8 percent interest, but the interest rate jumps to 10 percent for any payments made after six years.

AIDEA also added a provision that would give it an overriding royalty interest on a small percentage of all of Buccaneer's properties should Buccaneer default on the deal.

Ezion takes over

Under a deal announced Jan. 1, Buccaneer is selling its stake in Kenai Offshore Ventures to an Ezion subsidiary called Teras Investments Pte. Ltd. for some $23.95 million.

As the preferred member of Kenai Offshore Ventures, AIDEA must approve the sale.

"Buccaneer Energy advised AIDEA that they would be selling their common shares in Kenai Offshore Ventures to Ezion Holdings, the other common owner," AIDEA spokesman Karsten Rodvik told Petroleum News. "This action requires AIDEA consent as the preferred member in KOV. We are working on our due diligence regarding the transaction. This change in ownership does not impact Buccaneer's agreement with AIDEA, nor does it impact the KOV operating agreement or the Bare Boat Charter."

Rodvik continued, "We believe that with this consolidation, Buccaneer will be better positioned to continue its Cook Inlet exploration and development. Ezion is an experienced player in offshore oil and gas support, and we are very pleased to continue our partnership with them in the development of Alaska oil and gas resources."

How much will it make?

Even if AIDEA approves the deal, Buccaneer would remain involved with the rig.

By selling Kenai Offshore Venture but keeping Kenai Drilling, Buccaneer achieved a goal: "to sell ownership in the rig while maintaining control of the asset for its drilling operations in Alaska." The agreement also involves marketing the rig to third parties.

The actual day rate for the rig is proprietary, but in December 2012 Buccaneer described it as being "comparable" to the rates for the same class of rig in "similar regions," pointing to the North Sea, where day rates ranged from $138,000 to $162,000 per day between July and December 2012, according to the IHS Petrodata North Sea Rig Report.

In preparing the deal, Kenai Drilling said it had identified between five and 10 wells that could be drilled in Alaska using the rig during the five-year term of the agreement, plus the potential for significant plugging and abandonment work in the Cook Inlet basin.

The AIDEA agreement requires Buccaneer to drill at least four wells using the rig. The deal envisioned Buccaneer drilling two wells each at its offshore Southern Cross and Northwest Cook Inlet units. As the deal was coming down in 2011, Buccaneer suggested it might drill another seven to 10 wells on top of its obligations, pending early success.

Additionally, AIDEA identified 22 wells in the basin that could potentially be drilled using a jack-up rig. The list reflected possibilities, but not necessarily expressed interest.

The partners also discussed the potential for using the rig for offshore drilling in the Beaufort and Chukchi seas, although those plans are hypothetical for the time being.

A separate deal gave Buccaneer exclusive use of the rig for its significant workload in the Cook Inlet. The workload grew after the deal closed. Buccaneer subsequently acquired the Cosmopolitan field and the deep oil rights at the ConocoPhillips-operated North Cook Inlet unit, in addition to its Southern Cross and Northwest Cook Inlet units.

Cosmopolitan delays

The idea behind acquiring Cosmopolitan was to create an opportunity to use the rig during the winter months, when drilling is prohibited in the northern end of Cook Inlet.

The plan half-worked this past year.

Buccaneer drilled the Cosmopolitan No. 1 well in early 2013, but testing went longer than expected, which delayed wells at Southern Cross and Northwest Cook Inlet.

By missing deadlines at Southern Cross and Northwest Cook Inlet, Buccaneer is now facing the possibility of losing both units. The Alaska Department of Natural Resources is currently deciding the fates of the two units, but had made no decision as of Jan. 6.

Buccaneer is now selling its 25 percent stake in Cosmopolitan to its majority partner, the privately held Fort Worth independent BlueCrest Energy Inc., for some $41.25 million.

The deal requires BlueCrest to use the rig for at least 50 working days each winter for the next three winters, at a rate of $175,000 per day. To backstop the deal, BlueCrest must file a $5 million letter of credit that stays in place until it has used the rig for 150 days.

As the deal was coming together, Buccaneer was permitting a Cosmopolitan No. 2 well, which the company had hoped to drill sometime this winter. Those plans hit a snag when Buccaneer asked the Alaska Oil and Gas Conservation Commission to determine whether the proposed 5,685-foot well would avoid oil at the field. The AOGCC recently said it didn't have enough information to make the decision.

Buccaneer believes that the determination requires it to significantly modify its oil spill contingency plan. The changes could add up to four months of studies and additional public comment, which would make it impossible for BlueCrest to start drilling this winter.

The Alaska Division of Oil and Gas must also approve a transfer of the Cosmopolitan leases before BlueCrest could officially take over the field and its plan of operations.

If all the deals go through, BlueCrest would pay Kenai Drilling, which would pay Kenai Offshore Ventures, which would pay OCBC Ltd and its three joint venture partners.

If BlueCrest ultimately uses the rig for 50 days each winter at a rate of $175,000 per day, Kenai Offshore Ventures would stand to make some $8.75 million in annual revenue.

The figure is about one-third of the $27 million per year AIDEA estimated during its due diligence. The remaining revenue would come from additional drilling, such as the wells Buccaneer hopes to drill at Southern Cross, Northwest Cook Inlet and North Cook Inlet. ●

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GAS LIQUIDS

that propane was not being wasted.

Issues of concern

But it came away asking whether it should revisit Conservation Order 360, issued in 1995, which addressed a dispute between working interest owners at Prudhoe over whether natural gas liquids, NLGs, should be maximized for shipment down the trans-Alaska oil pipeline or maximized in miscible injectant, MI, to increase enhanced oil recovery. The dispute arose because at the time the owners held different percentages of the oil rim and the gas cap at Prudhoe. Gas cap owners benefitted more when NGLs were sold along with crude oil, while owners with a larger percentage of the oil rim benefitted more when NGLs were used to generate MI, increasing oil production through EOR, enhanced oil recovery.

Ownership at Prudhoe was aligned over the oil rim and gas cap as part of the sale of ARCO's Alaska assets to Phillips Petroleum, now ConocoPhillips.

In CO 360, the commission found in favor of maximizing sales of NGLs. It also found that expected MI production would be sufficient for identified EOR projects.

Enough MI?

In the course of the propane hearings the commission understood BP to say that it didn't have enough MI, which caused the commission to question whether the sale of NGL down the pipeline should continue to be maximized.

BP also said that maximizing MI as opposed to maximizing NGLs would primarily affect butane, not propane, "because most of the propane that is captured in the CGF processing is already utilized as MI."

The commission asked BP a number of questions and there was an exchange of correspondence between the two over a period of months.

Finally, the commission called a public hearing to gather information.

BP prefiled its testimony, providing a summary at the Jan. 7 hearing, and that appeared to answer most of the questions the commission had. BP did leave the hearing with a list of questions Commission Chair Cathy Foerster wanted answered, including whether BP had ever provided a follow-up report required by CO 360. The record was left open for that information to be supplied.

BP was represented at the hearing by Bruce Laughlin, BP's Alaska North Slope reservoir management team leader.

In prefiled testimony signed by Laughlin, BP said the commission should not alter CO 360 to require the Central Gas Facility to be maximized for MI manufacture, instead of being maximized for "the extraction and sale of blendable NGLs."

"On a strictly volumetric basis, extraction and sale of maximum blendable NGLs results in greater ultimate recovery of oil and gas," BP said in the prefiled testimony, estimating that maximizing manufacture of MI would result in recovery of an additional 17 million barrels of EOR oil, but would reduce the amount of NGLs sold by 45 million barrels, a reduction of 28 million barrels of hydrocarbon liquids.

"Extraction and sale of maximum blendable NGLs also ensures that NGLs are not stranded without transportation to market," BP noted.

The company also said expected recovery of EOR oil when CO 360 was issued was 400 million barrels, whereas the current EOR program is expected to recover 470 million barrels, and said it "is meeting the MI needs for current field development," with substantially more EOR recovery than was projected in 1995.

Response to order 75

BP said that in the commission's response to the propane hearing, Other Order 075, there are findings and a conclusion "that appear to be premised on a misunderstanding of BPXA's testimony," with the commission's finding that the injection of a barrel of MI for EOR results in the production of 0.7 barrels of EOR oil plus recovery of 85 percent of the MI mistaken.

"The correct information is that injection of a barrel of propane used as MI for EOR today, over multiple cycles of reinjection and recovery, is estimated under certain parameters to result in the production of 0.7 barrels of EOR oil," while the 85 percent figure refers to the efficiency of the Central Gas Facility, CGF, rather than to the return of MI, which BP said may be retained in the reservoir, produced with crude oil or cycled through the reservoir and returned to the CGF.

BP said that the cost to modify facilities to maximize production of MI for EOR "would be added expense that further degrades the value of increased marginal EOR production resulting from maximizing manufacture and injection of MI."

The propane issue

BP also said that maximizing MI as opposed to maximizing NGLs would primarily affect butane, not propane, "because most of the propane that is captured in the CGF processing is already utilized as MI."

The company acknowledged the potential interest in purchasing propane for use in energy generation in rural Alaska.

"The primary differences between marketing NGLs via export through TAPS and marketing propane on the North Slope are: (i) the facilities exist to extract and export NGLs, but such facilities do not exist for propane; and (ii) a competitive market exists to secure value for NGLs on a comparable basis to that of oil, including EOR oil, but there is no similar market for propane extracted and sold at the North Slope. As such, the essential missing element in any plan to supply propane for rural energy generation is a competitive market value for propane sales."

BP said the commission's order on propane found the use of propane in MI did not constitute waste, but suggested the commission might want to do a technical correction on the issues it identified related to relative volumes of propane, EOR oil and recovered MI.

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