Petroleum news

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page 3 Murkowski: Alaska has important role in energy self sufficiency

February Mining News inside

The February issue of North of 60 Mining News is enclosed.

Conoco developing DS-2S in SW Kuparuk after 2012 appraisal

ConocoPhillips is developing a Kuparuk River unit oil field it proved up last year.

The company is applying for a U.S. Army Corps of Engineers permit to build a drill site and access road in the southwest corner of the second largest oil field in North America.

The DS-2S project would develop a discovery ARCO made with the KRU 21-10-08 well in the late 1980s and ConocoPhillips appraised with the Shark Tooth No. 1 well last year.

The two-phase project would begin next winter with ConocoPhillips using nearly 300,000 cubic yards of gravel to

see **DS-2S** *page 21*

Canada-US relations strained over upcoming Keystone decision

Within the next three months, President Barack Obama is expected to decide the fate of TransCanada's Keystone XL pipeline — a knotty choice for him between offending environmentalists who contributed so much to his re-election and turning his back on Canada, which is by far the leading external source of United States oil and natural gas imports.

The tension level was raised Feb. 8 when Canada's Foreign Affairs Minister John Baird held the first meeting with newly installed U.S. Secretary of State John Kerry.

Keystone was one of the topics, but all that Baird could extract was a promise from Kerry to reach a fair, transparent and prompt decision, without even hinting at the recommendation he will make to Obama.

see **KEYSTONE DECISION** *page 21*

EXPLORATION & PRODUCTION

Resetting Liberty

BP Alaska now aims to begin production from offshore field by end of 2020

By WESLEY LOY

For Petroleum News

BP, with the blessing of federal regulators, is hitting the reset button on its stalled offshore Liberty project.

The Interior Department's Bureau of Safety and Environmental Enforcement, or BSEE, has given BP Exploration (Alaska) Inc. two years to submit a new development and production plan for Liberty.

The company is now shooting to start production from Liberty by December 2020, a BSEE letter indicates.

Originally, BP had hoped to have oil flowing in 2011.

Liberty is located in shallow water, about 20 feet deep, in the Beaufort Sea about six miles offshore and 15 miles east of Prudhoe Bay. BP has estimated the field, discovered in 1997, holds more than 100 million barrels of recoverable oil.

Getting at the oil has proven a challenge.

BP had been working on an ambitious and technically daunting plan to drill into the reservoir from the neighboring Endicott field. Parker Drilling Co. built a monster rig for boring ultra extended-reach wells, and the rig components were barged to the North Slope in July 2009.

The rig was erected, but never went to work.

BSEE, with a Dec. 31 letter signed by Alaska

see **LIBERTY** *page 24*

NATURAL GAS

BC taints grand vision

Government views LNG as cash cow it can milk for up to C$260B over 30 years

By GARY PARK

For Petroleum News

British Columbia Premier Christy Clark is tying her flimsy hopes of clinging to power in a May 14 election on natural gas and LNG exports.

Her government issued two grand plans in February forecasting LNG exports could generate C$130 billion to C$260 billion in revenues over 30 years, assuming two large and three smaller-sized LNG plants, along with thousands of jobs.

But, just as quickly, Clark antagonized the industry by disclosing plans to impose a major tax on the exports of natural gas.

The government's strategy papers noted that Australia's natural gas tax and royalty regime is "up to one-third higher" than British Columbia's, noting that new taxes on gas exports could "maximize the benefits to British Columbians" without affecting the province's competitive edge.

A spokesman for the Finance Ministry said discussions are already under way with the industry to see what form a tax might take.

Reminder of Alberta battles

For the Calgary-based producers who dominate the companies holding potential LNG feedstock gas in northeastern British Columbia the prospect of tax hikes creates bitter reminders of the industry's recent battle over royalty increases with the Alberta government that cost billions of dollars in investment and

see **BC LNG** *page 23*

FINANCE & ECONOMY

Industry talks changes

No surprise, companies favor end of progressivity; credits needed to counter base

By KRISTEN NELSON

Petroleum News

The elimination of progressivity would be a good first step to reforming Alaska's oil and gas taxation system, but reducing the base rate of 25 percent or credits are needed to counter the high cost of developing resources in the state.

That was the message the Legislature's Resource committees heard from independent and major oil and gas companies Feb. 18 and 20 in hearings on Gov. Sean Parnell's proposed oil tax changes.

The governor has proposed eliminating progressivity, which increases the tax rate as the price of oil increases, along with changes to the existing credit system and the addition of the gross revenue exclusion for barrels of oil from new fields or new participating areas within existing fields.

Progressivity was introduced in changes made to Alaska's oil and gas taxation system in 2006. The previous taxation system was on the gross and is typically referred to as ELF because it contained an economic limit factor, designed to prevent overtaxing fields which were at the end of economic production. While the goal was to prevent early shutdown due to taxation, in application it resulted in very low to no production tax on healthy fields.

The 2006 Petroleum Profits Tax, PPT, effective for North Slope oil fields, was a tax on net profits. It added credits and had a 22.5 percent base tax rate, with progressivity increasing the rate at 0.2

see **OIL TAX DEBATE** *page 22*

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

● GOVERNMENT

Murkowski pushing Alaska gas for Asia

Disputes federal actions in state, says Alaska has important role to play in national energy self sufficiency across all resources

By STEVE QUINN
For Petroleum News

U.S. Sen. Lisa Murkowski paid her annual visit to Juneau so she could deliver her annual address to the state Legislature.

The Republican was to speak to lawmakers Feb. 21 then return to Washington, D.C., in time for a meeting with Japanese Prime Minister Shinzo Abe, a continuation of a recent trip Asia trip to gauge interest in Alaska's natural gas.


SHANE LASLEY
SEN. LISA MURKOWSKI

Murkowski, also a former three-term member of Alaska's House of Representatives, is the state's senior senator entering her 11th year in office.

Also the ranking member of the Senate Energy and Natural Resources Committee, Murkowski spoke to Petroleum News about her efforts to advancing Alaska and the country's energy development.

Petroleum News: You recently traveled to Asia. What drove that trip and what were you findings?

Murkowski: I have been seeking a series of meetings from leaders in Taiwan, South Korea or Japan to talk about Alaska's energy potential or specifically Alaska gas opportunities. After a series of meetings in the fall of last year, I determined that it would be worthwhile to visit Japan and also Taiwan to speak with not only cabinet ministers and industry leaders, but to gauge the extent of the energy issues that face Japan after the March 2011 tsunami and the impact on their nuclear industry. These were very successful in Japan. I am following up those meetings. I have been invited to a very small dinner with the prime minister of Japan. I feel quite honored to have been asked specifically by the prime minister to join him on Friday evening (Feb. 22). I think it's quite clear that my message was received in Japan and hopefully received favorably.

Petroleum News: So what was your message?

Murkowski: My message was that Alaska has a wealth of resources. We have an opportunity to assist our long-term friend and ally, Japan, who is in an energy vulnerable situation because of the pull back on nuclear power generation. I re-enforced the position that we are not only close to Japan in terms of geography, but that there is safety. We don't have any pirates between here and Japan. We don't have a Straits of Hormuz.

It's wide open water and coming from a friend and a state that has a long-time, long-term relationship for export of many things, be it timber or fish but also recognizing that Alaska has had the longest term export contract for anything and that is for our LNG coming out of Nikiski. Relationships matter in Japan and that was pointed out to me in just about every meeting I had.

There was a recognition that Alaska stands ready. Of course there was a great deal of concern about timing of Alaska's gas and whether it would mesh with the timing of Japan's immediate need. I was not able to give them comfort but the timelines match up. Japan will need a stable source of supply for not only the short term and midterm but truly the long term, and I think Alaska can be that long-term partner.

Petroleum News: What do you think it will take to advance a project that will market Alaska's gas?

Murkowski: We have seen a measure of progress that the governor has asked for and the producers have delivered in terms of timeline benchmarks that have been set forth. I think we can all agree that we wish it was coming along quicker. The fact that we do have alignment between the producers and TransCanada, the administration is working with them and in concern with this timeline that has been laid out. That's important.

Q AND A

As impatient as Alaskans get, I think it's important to have perspective. We are looking at a $50 (billion) to $65 billion project. The size and scope of this project is world class. It is something that requires the level of consideration that is going into this. In the meantime, Alaskans are getting antsy. They see what's going on in the Lower 48, they see that Alaska could be a major participant of meeting the needs in Asia and we are not in the queue. There is an anxiety there because we've been talking about this for 30-plus years. So I don't think we should become discouraged. We need to recognize the size and scope of what we are dealing with, the fact that we do have a process in place, but I think it could always be expedited somewhat.

Petroleum News: With all this in mind, what is your vision for Alaska's energy either nationally or globally?

Murkowski: Alaska is such an integral part of America's energy solutions. We have enormous potential in this country, and in a document that I released a couple of weeks ago entitled Energy 2020, I speak to America's energy potential and the fact that by the year 2020, we can be energy independent, recognizing our incredible potential, not only with our fossil fuels but also with our renewable energy opportunities.

What this energy independence includes is also a resource from Canada but what I'd like to do is get this country off of OPEC oil. That is absolutely a doable situation. There are also people out there who say it won't take us until 2020, we can do it in 2017. It's important for Alaskans to recognize that while the Lower 48 is booming from shale gas and is booming from oil production coming out of North Dakota and other areas of the country, Alaska is decreasing our production. If we truly are going to have an all of the above energy policy for the United States of America, Alaska needs to be a participant. We are not yet stepping up to the level of others stepping up. Our oil production is on the decline. Our natural gas, we are moving forward with it and I acknowledge that. Many will say Alaska needs to get into the game when it comes to American energy production. We can and should be doing more on renewables. This is where I believe America can be a leader. We are recognized for our oil production. I want us to be recognized nationally for our renewable production as well. Whether it is from hydro, whether it is geothermal, whether it is our biomass, whether it is our ocean energy potential, we have so much to offer when it comes to wind, so Alaska can be the leader in all areas. That's where I'll continue to push.

Petroleum News: What concerns do you have about the production decline?

Murkowski: We are all concerned about the declining projection and the reality that our pipeline is less than half full. There comes a level of throughput where through a host of different reasons, it becomes difficult if not impossible — and I hate to use the word impossible because it's a pretty tough word — but it becomes extraordinarily difficult and perhaps unsafe to continue moving oil through the trans Alaska pipeline.

We all know the issues that come about with the lower throughput. You've got temperatures that drop causing the waxy buildup. You've got issues that may cause stress to the line itself. I share Admiral Barrett's concerns. We don't want to get to that point where we are concerned about our ability to safely restart that line if we had to shut down in the middle of a cold winter.

Our reality is that we have an incredible piece of infrastructure bisecting our state that provides for jobs, opportunities and revenue for the state of Alaska but also a resource that is much needed for our country. We've got the resources to put in our line; we just need the ability to increase production. That will require us to access areas that have been limited or restricted, due to regulatory issues by our federal government which have hamstrung us, whether it's resources on the ANWR land, on the

see MURKOWSKI Q&A page 19

● PIPELINES & DOWNSTREAM

Race to the US Gulf Coast

New partnership of Enbridge, Energy Transfer Partners, launches plan to access eastern Gulf for Bakken and Western Canadian crude

By GARY PARK
For Petroleum News

A new joint venture by Enbridge and Energy Transfer Partners, ETP, is zeroing in on the Eastern Gulf Coast crude market, with plans to spend up to $3.4 billion to deliver as much as 660,000 barrels per day of crude from the Bakken and Western Canada.

Enbridge views the 3 million bpd capacity of the Louisiana market as an "excellent fit with our broader market access initiatives."

Steve Wuori, president of liquids pipelines at the Calgary-based company, said there is ample opportunity for crude on the 700-mile link from Flanagan, Ill., to displace imported crude in the Gulf Coast region.

Enbridge Chief Executive Officer Al Monaco said the eastern Gulf refineries are "configured nicely for a market that is screaming out for heavy crude" to offset the declining volumes from Mexico and Venezuela.

He said Enbridge's comprehensive bundle of projects will "go a long way" to ease price discounting "that Western Canadian and Bakken producers currently are facing as well as to meet the demand of North American refiners seeking reliable domestic supply."

Addressing crude bottlenecks

ETP President Marshall McCrea said the joint-venture project, which needs approval from the Federal Energy Regulatory Commission to reverse a portion of natural gas trunkline from Patoka, Ill., to St. James, La., would address crude bottlenecks on the North American pipeline network.

He said ETP looks forward to working with Enbridge to establish a "key transportation conduit to link a diversified slate of reliable, long-term crude oil reserves to refineries along that eastern Gulf Coast."

If FERC approval is received later this year, the new 30-inch diameter system could be in service by early 2015, with Dallas-based ETP as operator.

For Enbridge, it is also part of a strategy to recapture Bakken crude that is now being carried by rail.

The use of that option contributed to a 16 percent decline in the fourth quarter of 2012 in shipping volumes on the Enbridge pipeline system in North Dakota that is operated by subsidiary Enbridge Energy Partners, EEP.

EEP President Mark Maki told analysts earlier in February that the company`s strategy, including its Light Oil Market Access Program to access refineries in the U.S. Midwest, Ontario, Quebec and possibly farther east in the US and Canada, will remedy that loss of volumes "in due course."

Surge in rail movements

Wuori conceded that Enbridge in 2012 saw a "real surge in rail movements, especially out of North Dakota and somewhat out of (the Williston basin) in Saskatchewan," lowering utilization on the North Dakota system to 74 percent.

He said that to move discounted crudes like those found in the Bakken by rail to the St. James refinery hub costs $12-$17 per barrel, although a rail shipper still has a "better netback than on pipe."

Tudor Pickering Holt estimates that more than 60 percent of total Bakken production is leaving the basin by rail, but said that another 500,000 bpd of pipeline capacity to Louisiana and Texas would strengthen the thesis that after 2013 only minimal crude will be carried by rail from the Bakken to both the eastern and western Gulf Coast, while shippers use rail to access the eastern and western seaboards of the U.S.

Wuori noted that the tremendous demand in the St. James/New Orleans market for Bakken crude currently accounts for 400,000 bpd arriving by rail.

Seaway reversed

In the western Gulf, Enbridge and its partner Enterprise Products Partners recently reversed the 400,000 bpd Seaway pipeline from Cushing, Okla., and are working on a number of initiatives to debottleneck the downstream end of Seaway, although the partnership is not yet ready to estimate the eventual run rate for the pipeline.

RBN analyst Sandy Fielden warned that if TransCanada's proposed 830,000 bpd Keystone XL application is turned down by the Obama administration, the Enbridge-ETP pipeline would "create additional space from Canada. If Keystone goes ahead (the joint venture project) is already looking shaky."

He said shipper commitments in an open season expected to be held before mid-2013 would likely be limited pending a verdict on Keystone XL's fate.

The desire by Enbridge-ETP to go ahead was indicated in Monaco's comment that commitments or only 250,000 bpd, or "a bit less," would be needed in an open season to make the project economically feasible, although Enbridge said it has the ability to install less horsepower on the line to match the initial level of interest by shippers and enable the "project to proceed at a lower commitment level than would normally be the case." ●

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EXPLORATION & PRODUCTION

Linc starting preliminary work at Umiat

Linc Energy Inc. said it has installed conductor pipe and a cellar box for a disposal well at the Umiat oil field and said similar work is currently under way on an exploration well.

The local subsidiary of an Australian independent is planning a four to six well exploration program at the oil field in the foothills of the Brooks Range Mountains.

Linc has already received federal and state drilling permits for the Umiat DSP No. 1 Class II disposal well, and is waiting for permits for the Umiat No. 16, Umiat No. 18 and Umiat No. 23H wells. The company expects to begin drilling sometime in February.

—ERIC LIDJI

● NATURAL GAS

Parnell's next gas line benchmarks met

BP, Conoco, Exxon, TransCanada specify pipe size, volume of gas, location of gas treatment plant, compression stations, LNG plant

By KRISTEN NELSON
Petroleum News

BP, ConocoPhillips, ExxonMobil and TransCanada have met benchmarks for progress on a natural gas pipeline, Alaska Gov. Sean Parnell said in a Feb. 15 statement.

The governor had called on the companies to provide details by Feb. 15 on the size of the pipe, the daily volume of gas, location of a gas treatment plant, number of compression stations, size and scope of liquefaction plant and LNG storage facilities and number of off-take points for gas for local use by Alaska communities.

The companies said in a joint Feb. 15 letter that they "have completed the concept selection phase."

The pipeline is specified at 42-inch diameter, with a design rate of 3-3.5 billion cubic feet per day, some 800 miles in length mostly underground with up to eight compressor stations.

Other details provided by the companies included:

- The gas treatment plant would be on the North Slope near Prudhoe Bay;
- The liquefaction plant would have a capacity of 15-18 million tons per year with three trains;
- There would be two LNG storage tanks at 160,000 cubic meters per tank and a terminal with one loading jetty and two berths; and
- There would be five off-take points along the pipeline route with a design rate of 250-500 million cubic feet per day "based on demand."

Cost repeated

The companies also repeated the capital investment they released last year — an estimated $45-$65 billion.

The governor said his next benchmark is this spring, when the companies are required to finalize an agreement to enter the pre-front-end engineering and design phase, followed by a full season of field work this summer.

"Our companies are now working toward the next decision points," said the letter, signed by Randy Broiles of ExxonMobil Production Co., Trond-Erik Johansen of ConocoPhillips Alaska, Janet Weiss of BP Exploration Alaska and Tony Palmer of TransCanada.

And the companies noted that as they said in their Oct. 1 letter, "a competitive, predictable and durable oil and gas fiscal environment will be required for a project of this unprecedented scale, complexity and cost, to compete in global energy markets."

LNG site not set yet

What about the location for the LNG plant?

The window for that decision is a few months out, Steve Butt of ExxonMobil Development Co., the senior project manager for concept selection for the LNG project, told a House Resources "Lunch and Learn" group Feb. 19.

He said where in Southcentral has been narrowed down from some 20 possibilities to four or five, and the companies continue to work on site selection as it pertains to "cost of supply."

The cost of supply factor, he said, is how the market judges LNG projects. There are more LNG projects proposed than will survive, "and the key is to have this project be strong enough and competitive enough that it can survive. And the way the market measures that success is through the cost of supplies," Butt said.

On the web

See previous Petroleum News coverage:

"Pushing the big gas line," in Jan. 20, 2013, issue at www.petroleumnews.com/pnads/864630253.shtml
"Pegged at $45-65B," in Oct. 7, 2012, issue at www.petroleumnews.com/pnads/180157651.shtml
"TransCanada AGIA focus shifts to LNG," in May 6, 2012, issue at www.petroleumnews.com/pnads/711327347.shtml
"Gas players aligning, need fiscal terms," in April 8, 2012, issue at www.petroleumnews.com/pnads/995972168.shtml
"Alaska governor sets out gas line path," in Jan. 29, 2012, issue at www.petroleumnews.com/pnads/769935052.shtml
"Parnell wants gas to Pacific Rim as LNG," in Oct. 30, 2011, issue at www.petroleumnews.com/pnads/221607579.shtml

The alternatives

In focusing on the concept for the project the companies — BP, ConocoPhillips, ExxonMobil and TransCanada — began by looking at defining the right way to commercialize North Slope natural gas, and looked at LNG, gas to liquids and high-voltage direct current, HVDC, he said.

The project is enormous, and with a "project that big, you want to make sure you have a proven technology."

That led to the LNG decision, "because there are LNG plants all over the world, it's a growing market segment, and these other technologies are a lot less proven and they've never been done on this type of scale."

They also focused on LNG because of its efficiency: "About 95 percent of the energy that goes into an LNG facility comes out the other end."

Integrated design

What's different about this shot at commercializing North Slope natural gas as opposed to past projects that didn't make it?

Changes in the Lower 48 natural gas market were what ended the recent attempts to send Alaska North Slope natural gas into that market, Butt said.

Two things are new compared to previous LNG projects, he said: "We worked it together as a consortium of all the companies" and "as a result of our work we've got a completely integrated basis of design," including Point Thomson, Prudhoe Bay, the treatment facility, the pipeline and the LNG plant.

"And we look at all of that as one single system. And that is new; that's something that hasn't been done," Butt said.

He said this time around, "we know exactly how we want to integrate it into the existing operations and that's really important because the size of the project is so big that it's dependent on the existing facilities that the Prudhoe Bay operator and the other companies have already built."

The CO2 issue

The decision has also been made to put the gas treatment plant on the North Slope.

Prudhoe Bay gas has a very high CO_2 content, about 12 percent, much higher than in most fields, with Point Thomson by comparison having only about 4 percent CO_2, he said.

"Anytime a gas system has a lot of CO_2 it's very difficult to monetize because you have to deal with this product that doesn't carry revenue," he said.

The volume of CO_2, about 4 trillion cubic feet, will be pressurized and reinjected for pressure maintenance at Prudhoe Bay.

CO_2 is one of the competitive disadvantages of this project, along with the distance between the gas field and the LNG plant, and the fact that the Prudhoe Bay gas has been cycled for 30 years, so liquids have already been removed and sold, and aren't available for sale in this project.

The advantages of the project include a known resource, existing facilities at

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FINANCE & ECONOMY

Cenovus quits Williston

Canadian oil producer Cenovus Energy is quitting Saskatchewan's segment of the Williston basin after deciding it is unable to scale the assets up to a size that would be material to its portfolio.

It said the Bakken and Lower Shaunavon properties are up for sale because of competitive limitations on increasing its land base in the area.

Saskatchewan was once seen as a potential contributor to the company's goal of reaching 75,000 barrels per day of raising tight oil production to about 75,000 bpd by the end of 2016 and had attracted heavy capital spending to raise combined Bakken and Lower Shaunavon output exiting 2012 of 7,000 bpd, up 9 percent from a year earlier.

Cenovus hopes to complete the sale this year.

6,000 bpd by rail

In releasing results for the fourth quarter of 2012, Cenovus said it is currently moving 6,000 bpd of production by rail and hopes to add another 4,000 bpd, with the possible addition of insulated rail cars.

Don Swystun, executive vice president of refining, marketing and transportation, said the company is currently moving about 40,000 bpd of its 100,000 bpd of oil sands volumes and 77,000 bpd of conventional crude to tidewater

About 11,500 bpd moves on Kinder Morgan's Trans Mountain system to Vancouver for shipment to California and Asia and 20,000 bpd is carried on the Pegasus pipeline to the Gulf Coast.

He said Cenovus has committed a combined 175,000 bpd to Enbridge's proposed Northern Gateway pipeline and the planned Trans Mountain expansion, although both projects are facing stiff opposition.

Swystun said Cenovus plans "significant participation" in TransCanada's expected open season this year to establish a crude pipeline from Alberta to Ontario and Quebec refineries and possibly extending to the Atlantic Coast.

—GARY PARK

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BENCHMARKS

Prudhoe Bay, Alaska's location relatively close to markets and the colder weather in Alaska which makes LNG facilities more efficient, about 15 percent more efficient than in warmer climates, Butt said. And because Alaska is in the northern hemisphere it's in sync with markets, with compressors making more gas in the winter when the market wants more gas.

Butt said about 2 billion to 2.5 billion cubic feet a day of gas will come from Prudhoe Bay, with Prudhoe continuing to compress and re-inject some 8 bcf of gas a day. About 1 bcf a day will come from Point Thomson, which will require 14 additional wells, facilities to compress and move the gas and a gas pipeline between Thomson and Prudhoe.

There were no big surprises in the concept work done over the last year, Butt said, but they have been able to identify "small improvements, lots of small improvements," such as beneficial reuse of CO_2 on the North Slope.

Does it pencil?

Butt said there are issues of "underlying fiscal and commercial uncertainty" remaining.

He said while for the first time there are four parties involved, the fifth party — the state — isn't yet involved.

The project has strong benefits, particularly the large known resource on the North Slope.

There are ways to make it work with all five parties working together, but collaboration is required, he said.

The companies have called this an "unprecedented opportunity," Butt said, but "it has unprecedented challenges" and "unprecedented levels of collaboration" will be required for the project to pencil out.

What will be crucial for the project in the market will be cost of supplies, he said, "what you want to do is be in the right place at the right time ... and the way you do that is cost of supply." ●

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● PIPELINES & DOWNSTREAM

Liquid fuels: a question of efficiency

EIA says that people use gasoline, diesel as vehicle fuels because no other fuel contains as much energy in the same fuel volume

By ALAN BAILEY
Petroleum News

Liquid hydrocarbon fuels — gasoline and diesel — dominate the field when it comes to powering the vehicles that people use for road transportation. But, with interest in the use of electrically powered or natural gas fueled vehicles, for example, how do alternative fuels compare in efficiency with liquid fuel use? And what might be the efficiency trade-offs in switching to alternative fuels?

A Feb. 14 report from the Energy Information Administration, or EIA, using information from the National Defense University, compared different fuels that have been used or that are contenders for use in transportation. In making its comparisons EIA particularly focused on the energy density of each fuel, in other words the amount of energy in the fuel in proportion to the cost, weight or volume of fuel needed to be carried on a vehicle.

A second issue is the fuel efficiency of a vehicle's engine, the efficiency with which the engine converts energy from fuel into the propulsion of the vehicle.

Fuel comparisons

Using gasoline as a reference point, EIA said that diesel has a slightly higher energy density in terms of volume, while having an almost an equal energy density in terms of weight. Put another way, a diesel-fueled car would require a slightly smaller fuel tank but carry the same weight of fuel as a gasoline-fueled car with the same mileage range and an engine of equal fuel efficiency.

Compressed propane, by comparison, has a somewhat lower energy density in terms of volume, while being about equivalent to gasoline in terms of weight: Propane-fueled vehicles presumably require fuel tanks that are a bit larger than those of gasoline-fueled vehicles.

Liquefied natural gas only contains 75 percent of the energy content per unit volume compared with gasoline, while being a little more efficient than gasoline in terms of weight. Ethanol, a material associated with biofuels, contains less energy per unit volume than liquefied natural gas while also being a bit heavier to carry than gasoline of an equivalent energy content.

Compressed natural gas, being less dense than liquefied natural gas, has a substantially lower energy density in terms of volume than the liquefied gas.

Hydrogen

Hydrogen, which has been proposed as a potential transportation fuel, is relatively light and wins out over gasoline in terms of the energy it carries per unit weight. But liquefied hydrogen contains only about one-quarter of the energy per unit volume of gasoline, while compressed hydrogen gas fares even worse in terms of volumetric energy density.

As energy repositories, various types of battery, presumably including those used to power electric cars, come at the bottom of the energy efficiency ratings, being very much less efficient than gasoline both in terms of their volume and their weight. And although the fuel efficiency of an electric car is much higher than that of a gasoline fueled car, the fuel efficiency does not compensate for the very low energy density of the car's batteries, EIA said.

Gasoline and diesel

The high energy density and ease of on-board storage of gasoline and diesel fuel explains why 99 percent of fuel consumed by light vehicles in the United States in 2012 consisted of gasoline, with half of the remaining one percent of fuel consumption being diesel, EIA said.

"Fuels that require large, heavy or expensive storage can reduce the space available to convey people and freight; weigh down a vehicle, making it operate less efficiently; or make it too costly to operate, even after taking into account cheaper fuels," EIA said. "Compared to gasoline and diesel, other options may have more energy per unit weight, but none have more energy per unit volume." ●

Contact Alan Bailey at abailey@petroleumnews.com

● LAND & LEASING

BOEM wants OCS focus & transparency

Agency tweaking lease sale program to improve public participation; says Alaska OCS lease sales will no longer be areawide

By ALAN BAILEY
Petroleum News

With a mandate to promote the development of U.S. offshore resources, the Bureau of Ocean Energy Management's oil and gas lease sales on the federal outer continental shelf form a cornerstone of the agency's oversight of the nation's subsea assets. But, as the old Minerals Management Service has morphed into three new Department of the Interior agencies in the wake of the Gulf of Mexico Deepwater Horizon disaster, the Bureau of Ocean Energy Management, or BOEM, one of the new agencies, has adjusted its mission statement to elevate the emphasis on environmental protection, James Lima, BOEM minerals leasing specialist in Alaska, told the Alaska Forum on the Environment on Feb. 5.

"With the changes to our structure and with the changes in our mission, we've more elevated the role of the environment and environmental analysis in our decision making," Lima said.

And, along with that change in emphasis, the agency has made some enhancements to its five-year lease sale program, Lima said. Those enhancements will make the process for developing and maintaining the program more transparent to the public while also making the program more "regionally tailored" for different outer continental shelf, or OCS, planning areas, Lima explained.

Focused sales

In Alaska's Beaufort and Chukchi seas, the new tailored focus translates into an end to areawide lease sales in which all available tracts in a lease sale planning area are offered for lease in each sale, Lima said. Areawide sales will continue in the Gulf of Mexico where, Lima said, this type of sale make more sense because so many of the areas of interest to the oil industry are already leased.

The idea in Alaska is to exclude areas that have lower oil and gas potential but that have more important resource potential in terms of wildlife habitat, subsistence needs or other factors identified from BOEM's analysis, Lima said.

"For Alaska, based on the direction of our regional director and the secretary of the Interior, we have abandoned the areawide approach to lease sales for the Beaufort and the Chukchi," he said.

However, as part of the lease sale process, BOEM will invite industry to nominate areas of interest for leasing, Lima said.

Lease sale program

BOEM's latest five year OCS lease sale program became effective on Aug. 27, 2012, and will expire on Aug. 26, 2017. And, to allow time for the completion of scientific studies and the ensuing scientific analysis, the secretary of the Interior decided to schedule Alaska lease sales towards the end of the five-year cycle, Lima said. BOEM has tentatively scheduled one lease sale in the Chukchi Sea in May 2016; one lease sale in federal lands of the Cook Inlet in November 2016; and one sale in the Beaufort Sea in May 2017.

Lima characterized the BOEM lease sale program as the confluence of two distinct processes: the lease sale program process under the terms of the Outer Continental Shelf Lands Act, and the environmental review process under the terms of the National Environmental Policy Act, or NEPA.

Starts broad, ends narrow

The lease sale process starts broad, with BOEM's five-year lease sale program setting the stage for major areas to be offered for leasing and a planned lease sale schedule. The holding of a lease sale in a planning area narrows the focus of attention in that area. And then exploration and development plans proposed by companies who have purchased leases narrow the focus still further into specific oil and gas prospects.

As the focus of attention narrows through this process the potential environmental impact of an action also becomes more focused, with more precise predictions of environmental effects becoming possible, Lima said. And the NEPA process, involving environmental reviews and the development of environmental impact statements at key points, assesses those potential environmental effects as part of BOEM's overall decision making approach.

> *"For Alaska, based on the direction of our regional director and the secretary of the Interior, we have abandoned the areawide approach to lease sales for the Beaufort and the Chukchi."*
> **—James Lima, BOEM minerals leasing specialist in Alaska**

Opportunities for comment

Although there are numerous points within these processes at which the public may comment or raise concerns on what is proposed, the public comments have tended to become obscured in the depths of the process documentation, leading some people to wonder whether BOEM has taken account of issues raised, Lima said.

To overcome this problem, BOEM is implementing two new features on its website: a mapping tool and a tracking table, Lima said.

The mapping tool involves an interactive map portal, enabling members of the public to use the map system maintained by BOEM and the National Oceanic and Atmospheric Administration. Using the new public website portal, people will be able to document on maps subsistence information, wildlife locations and environmental data. People will be able to generate their own maps, perhaps suggesting areas where leasing may be beneficial or where leasing should be deferred, Lima said.

see **LEASE PROGRAMS** page 8

The OCS pyramid: Is there a better way?

The process that the Department of the Interior uses for managing oil and gas leases on the U.S. outer continental shelf has been likened to a pyramid: The leasing process starts at the very broad level of a five-year lease sale program, becomes more specific and focused as it homes in on specific lease sales, and then narrows down on specific tracts of land as companies submit exploration and development plans for leased acreage.

> *Interior conducts an environmental review at each stage of the process, assessing environmental risks and determining what mitigation measures may be necessary for the environmental protection of areas where industrial activities will take place.*

Interior conducts an environmental review at each stage of the process, assessing environmental risks and determining what mitigation measures may be necessary for the environmental protection of areas where industrial activities will take place. And the theory behind the process assumes that, as those impacted areas become increasingly tightly specified, the environmental issues will become increasingly clear, thus enabling increasingly specific environmental protection measures to be mandated as the process moved down the pyramid from the lease sale program to eventual development drilling.

Lengthy delays

But, as Shell has discovered to its cost, this apparently simple process can lead to delays of multiple years in progressing towards oil field discovery and development,

see **OCS PYRAMID** page 8

● FINANCE & ECONOMY

Pioneer budgeting $190MM for Alaska

The budget increase accommodates appraisal drilling and an expansion of a completion technique the company tested last year

By ERIC LIDJI

For Petroleum News

Pioneer Natural Resources Inc. is budgeting $190 million in spending for Alaska this coming year, the Texas independent said during a quarterly earnings call on Feb. 14.

The figure is up from a budget of $135 million for 2012 and $100 million for 2011.

Pioneer plans to spend some $3 billion across its portfolio this coming year. Of that, more than half, or $1.65 billion, would go toward its Permian Basin operations, while $575 million would go to the Eagle Ford shale and $185 million would go to the Barnett Shale.

This winter, Pioneer is running a one-rig development program from its near shore Oooguruk unit, where it plans to drill three wells into the Nuiqsut and one into the Torok.

Following "phenomenal" results last year, Pioneer plans to complete those wells using a reservoir stimulation method it began in Texas. The mechanically diverted fracturing system, also known as "plug and perf," aims to focus more energy at the point of the fracture and stimulate a larger portion of a reservoir. Using the system, a well into

This winter, Pioneer is running a one-rig development program from its near shore Oooguruk unit, where it plans to drill three wells into the Nuiqsut and one into the Torok.

the Nuiqsut last year produced some 5,600 barrels per day at its peak and continues to produce some 2,000 bpd "on a flat line," according to Chief Operating Office Tim Dove.

The company is currently mobilizing the considerable equipment required for the work and plans to begin those completion activities "in the next couple of weeks," Dove said.

The program could yield significant results. Considering that the first well completed using the system produced more at its peak than all the other Oooguruk wells combined, "We could have a pretty material bump in production if all goes well," Dove said.

Pioneer produced 4,102 barrels of oil per day from its Oooguruk unit during the fourth quarter of 2012, down slightly from 4,404 bpd during the third quarter but up slightly from 3,824 bpd in the fourth quarter of 2011. Companywide, Pioneer produced 164,812 bpd during the quarter, up 3 percent quarter over quarter and 20 percent year over year.

Pioneer earned $14 million in Alaska production tax credits during the quarter.

Appraising Nuna

This winter, Pioneer also plans to drill the Nuna No. 2 well. The well would offset Nuna No. 1, the onshore well that Pioneer drilled last winter to an offshore target in the southern reaches of the Torok formation, and the basis for a 50 million barrel discovery.

Last year, the Nuna No. 1 well produced some 2,000 bpd with facility constraints, according to the company. While those constraints remain, Pioneer said it recently brought the well back online and is now reporting production rates of around 2,800 bpd.

Pioneer will decide whether to proceed to front end engineering and design for a Nuna development pending the results of the wells, Dove said. Under current unit agreements, Pioneer must decide by June 30, 2014, whether it intends to sanction the project. ●

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OCS PYRAMID

after a company has sunk substantial sums of money in purchasing leases and taking steps to explore those leases. Not only does Interior's process itself take several years to navigate, but each step in the process can be subject to legal challenge, thus directing the process through the multiple layers and lengthy convolutions of the U.S. appeals system.

Two speakers at Law Seminars Internationals' Energy in Alaska conference in December commented on the issues that Interior's OCS leasing process raises.

Bradford Keithley, partner in the oil and gas practice of Perkins Coie LLP, told the conference that Interior's process creates substantial risk and uncertainty for companies wanting to find and develop offshore oil and gas.

Norway comparison

Saying that companies from overseas sometimes find the U.S. OCS leasing process "strange and cumbersome," Keithley compared Interior's process with the process that Norway uses for offshore leasing. Norway does most of the environmental analysis up front, so that by the time a company obtains a lease to work on the continental shelf, there is substantial confidence that exploration and development activities can proceed quickly, with little risk of significant delay.

"In Norway it takes a long time to get to leasing, because there is a process of consultation with local communities, to ensure that there is consistency between the desires of the local communities and the development of oil resources," Keithley said. "All of that is done before leasing."

Environmental perspective

Peter Van Tuyn, an attorney with Bessenyey and Van Tuyn who has represented conservation groups, Native Alaska groups and others in court cases relating to the regulation of the Alaska oil and gas industry, told the conference that the uncertainties inherent in Interior's process cause problems for environmental groups, triggering a need for legal challenges to Interior decisions.

Using a double entendre referencing the company at center of controversies over Arctic OCS drilling, Van Tuyn said that Interior's process encourages a "shell game," in which the ball of difficult environmental decisions tends to be punted from one process stage to the next without resolution.

"This system sets up a punt process, a shell game if you will, where you are hiding the ball until later stages, and that does create opportunity … and urgency to challenge decisions, because we're flying blind," Van Tuyn said. "We're making decisions without understanding their potential environmental impacts, and that's why you see that kind of controversy that happens here in the U.S."

Van Tuyn said that Interior's intentions of holding focused OCS leases sales in specific parts of a planning area, to impose seasonal restrictions on Arctic operations and to develop Arctic-specific standards will help address concerns with the current leasing process.

—ALAN BAILEY

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LEASE PROGRAMS

The new online tracking table, operating in parallel with the mapping facility, will document every environmental mitigation measure and every lease sale deferral suggested by the public. Information maintained in the table will enable the public to track each comment or suggestion, with people able to see how BOEM has responded to each idea.

Progress reports

As part of its revamped lease sale process, BOEM is also going to publish annual progress reports, containing sale statistics; information about newly enacted deferrals and mitigation measures; summaries of completed studies about sale areas; descriptions of significant new drilling activities; and accounts of any significant incidents that have occurred, Lima said.

Annual reports of this type are not new and have been produced throughout the history of the OCS lease sale program, Lima said. But previously the reports have been primarily published for internal agency consumption: Making the reports more public will help improve the overall transparency of the lease sale process, he said.

And one outcome of findings presented in an annual report could be changes to the lease sale plan. Although the secretary of the Interior will not necessarily make any plan changes, findings in the report could lead the secretary to delay, cancel or reduce the size of scheduled sales, Lima said. ●

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● ENVIRONMENT & SAFETY

Interior asks for polar bear rethink

Asks court to amend its decision remanding polar bear critical habitat designation; says 90 percent of habitat area still stands

By ALAN BAILEY
Petroleum News

In the latest twist in an ongoing battle over the question of appropriate protections for Alaska's polar bears, the U.S. Department of the Interior has asked the federal District Court in Alaska to amend its Jan. 11 ruling rejecting the U.S. Fish and Wildlife Service's designation of the animals' critical habitat.

"Defendants seek relief based on clear error and manifest injustice," Interior wrote in its petition to the court, filed on Feb. 11.

Issued in 2010

Fish and Wildlife issued the critical habitat designation in November 2010 following the agency's 2009 listing of the polar bear as threatened under the Endangered Species Act. The total critical habitat area amounted to 187,157 square miles and included most of Alaska's Arctic offshore, as well as territory that accounts for much of Alaska's oil production.

The polar bear listing results from concerns that global-warming-induced melting of Arctic sea ice threatens the bears' future existence, given the bears' dependence on sea ice for living and hunting.

But with concerns about the possible impacts of the critical habitat designation on economic activity, several organizations, including the Alaska Oil and Gas Association, the American Petroleum Institute, Arctic Slope Regional Corp., the State of Alaska and the Inupiat Community of the Arctic Slope appealed the designation in the District Court.

Overreach onshore

In the court's Jan. 11 ruling, Judge Ralph Beistline upheld Fish and Wildlife's specification of offshore sea-ice polar bear critical habitat, but he rejected the agency's specification of habitat on land along the coast and on offshore barrier islands. Beistline placed the entire critical habitat rule on remand, for rework by the government agency.

In essence, Beistline said that, while the agency had cited polar bear dens and some related components of the Arctic landscape as on-land critical habitat features, those features only occupy about 1 percent of the total land surface. The agency cannot designate all of the land around the coast and on barrier islands as critical habitat when so little of it contains critical habitat features, Beistline said.

Misunderstood

In its Feb. 11 petition, Interior said that in rejecting the on-land critical habitat designation the court had misunderstood the agency's specifications of the features that define the critical habitat areas. For example, the court had interpreted the on-land designation as indicating that essential habitat features consist of access between bear den sites and the coast, and the absence of disturbance from humans and human activities, features that would only occur in a small proportion of the territory.

But the designation in fact referenced all terrain deemed suitable for the digging of bear dens, not just known bear dens,

see **POLAR BEAR RULING** page 10

F&W confirms polar bear protection

The U.S. Fish and Wildlife Service has issued a special final rule under the Endangered Species Act, confirming that protection requirements for polar bears are those spelled out by the Marine Mammals Protections Act, or MMPA, and the Convention on International Trade in Endangered Species of Wild Fauna and Flora. Protections under the MMPA, which Fish and Wildlife says are more stringent than those afforded by the Endangered Species Act, have been in place for several decades for the polar bear, a species that was listed under the Endangered Species Act as threatened in 2008.

Following the listing in 2008, Fish and Wildlife issued a rule allowing continued protection of the polar bears under the terms of the MMPA. However, that rule was challenged in court, as a consequence of which the MMPA protection has been operating on an interim basis, pending completion of an assessment of the rule under the National Environmental Policy Act.

Following the listing in 2008, Fish and Wildlife issued a rule allowing continued protection of the polar bears under the terms of the MMPA. However, that rule was challenged in court, as a consequence of which the MMPA protection has been operating on an interim basis, pending completion of an assessment of the rule under the National Environmental Policy Act. With that environmental assessment complete, Fish and Wildlife is now re-issuing a final rule, unaltered from the rule issued in 2008. The rule will go into effect on March 22, following a 30-day public comment period.

"This rule effectively continues management of polar bears under the same guidelines that have been in place since the original listing in 2008," said U.S. Fish and Wildlife Service Alaska Regional Director Geoff Haskett on Feb. 19 when announcing publication of the final rule. "By maintaining the stricter MMPA incidental take prohibition, which include provisions stricter than those imposed by the ESA, we can assure protection of this iconic species while continuing to allow those who live and work in polar bear habitat to employ practices that will reduce bear/human interactions for the benefit of both polar bears and people."

The special rule does not affect the subsistence harvesting of polar bears or the production and sale of polar bear handicrafts by Alaska Natives, with these activities being allowed under the terms of both the Endangered Species Act and the Marine Mammals Protection Act, Fish and Wildlife said.

—ALAN BAILEY

ALTERNATIVE ENERGY

Susitna hydro project moves on

FERC approves 44 environmental studies as engineering and cost estimating continue ahead of license application in a couple of years

By ALAN BAILEY
Petroleum News

The Federal Energy Regulatory Commission, or FERC, has now approved 44 of the 58 environmental studies planned as part of the process leading to a FERC license application for a proposed major hydropower project at Watana on the Susitna River, Wayne Dyok, the manager of the Susitna-Watana project, told the Alaska Senate In-state Energy Committee on Feb. 19. Dyok's comments came as part of a presentation by Alaska Energy Authority staff on the status of the hydropower project. The Alaska Energy Authority, or AEA, anticipates FERC approval for the 14 other proposed studies on April 1, Dyok said.

Authorized in 2011

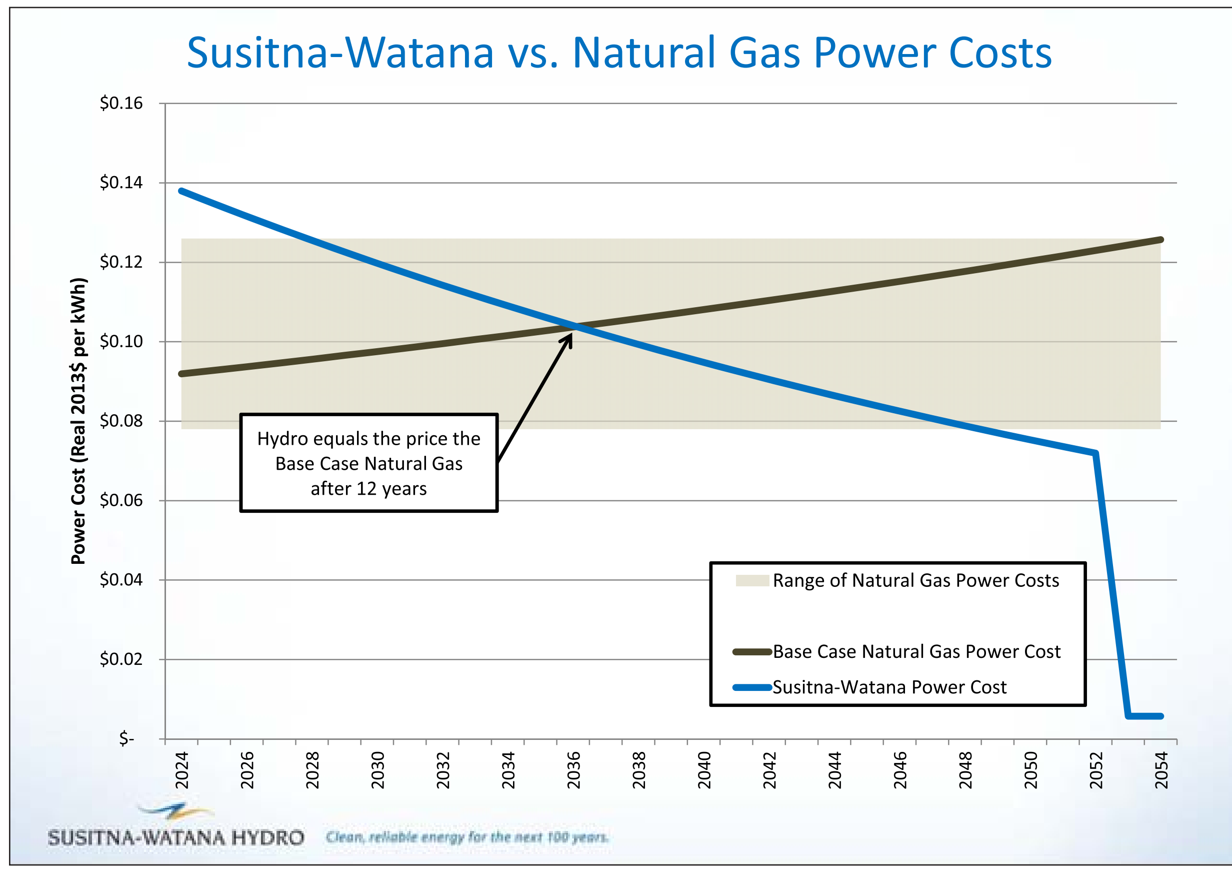
In 2011 the state Legislature authorized AEA to proceed with the 600-megawatt hydropower project, to assure long-term, stably priced electricity for the Alaska Railbelt and to help achieve a state policy objective of obtaining at least 50 percent of Alaska's power from renewable energy sources.

As well as being an essential prerequisite to applying for a FERC license, the results of the environmental studies will feed into the preparation of an environmental impact statement, triggered by the license application.

Environmental studies

Having filed a project pre-application with FERC at the end of 2011, the project team spent much of 2012 developing a robust study plan while also conducting some preliminary fieldwork, in part assessing any environmental changes since an original study of the project, conducted in the 1980s, Dyok said.

And, with FERC approval of many of the planned studies, the project team is now embarking on the project's two-year study period — some 180 people should be working in the field this summer, Dyok said. About 385 people have been engaged on the project, mostly from Alaska, but supplemented by people with appropriate experience, particularly from the Pacific Northwest, he said.



ALASKA ENERGY AUTHORITY

Adjusted for future inflation, the potential range of cost of power generated from natural gas may remain relatively constant, in terms of 2013 dollars. Meantime, the inflation-adjusted cost of power from the Susitna-Watana hydropower plant would drop, potentially falling below the cost of gas-fueled power after 12 years. After 30 years, when all of the debt required for construction of the hydropower system would have been paid off, the cost of the hydropower would plummet.

2024 completion

"The goal is to file the (FERC) license application … in September of 2015," Dyok said. "We wouldn't anticipate getting the license until the early part of 2017, and then there will be a seven-year construction period, and hopefully the project will be on line by 2024."

Meantime, in addition to preparing the project's study plan, in 2012 the project team reviewed the 3,000 reports prepared in the 1980s study of the hydro project, to evaluate how the findings in those reports fit into the current

see HYDRO PROJECT page 11

continued from page 9

POLAR BEAR RULING

together with access from that land to sea ice, an area that encompasses large swathes of land adjacent the coast, Interior said. Moreover, on the relatively flat coastal plain of the North Slope bears can easily move many miles inland to reach denning sites, the agency said.

96 percent accepted

Interior also questioned why the court had remanded and rejected the entire critical habitat designation while also accepting the offshore sea-ice component of the designation, when that offshore component represents about 96 percent of the total critical habitat area. If the court does not accept the designation of the onshore components of the habitat area, the court should give Fish and Wildlife the opportunity to further explain its thinking without meantime rejecting the agency's entire critical habitat rule, "thereby removing all protection afforded by the designation, including that provided by the sea-ice unit comprising the great majority of the species' U.S. range," Interior said.

In a separate petition, also filed on February 11, the Center for Biological Diversity expressed its support for Interior's position, asking the court to uphold the critical habitat designation. Alternatively the court should allow the designation to remain in effect while under remand, or there should at least be some required completion date for the remand process, the environmental organization said. ●

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HYDRO PROJECT

project. The information from the 1980s relating to rock and ground conditions at the project site is still valid, given that the rocks are still the same, although the project team spent time in 2012 filling in some gaps in that information, Dyok said. And the current project has been refining the design concepts for the project, incorporating new technologies such as the use of roller-compacted concrete and figuring out the optimum height of the dam.

"We've also brought on a panel of (world-renowned) experts," Dyok said, commenting that the idea is to review the project to ensure at an early stage that the project, as conceived, is a good fit for Alaska.

Outreach efforts

In 2013, in addition to working on the environmental studies, the project will continue its outreach efforts with project stakeholders, Dyok said. The key to filing a complete license application will be working with all stakeholders, to make sure that all issues relating to the project are identified and sufficiently fleshed out, he said.

The project team is also developing a plan to limit risks of cost overruns, as well as working on precedent agreements with Railbelt utilities, the future purchasers of power from the hydropower plant. The team also needs to carry out some further work, refining information about the project site and further optimizing the design of the facility.

Cost estimates

Rather than rely on a single engineer's estimate of the cost of the project, AEA commissioned professional services company AECOM to develop an independent cost estimate for comparison. AECOM, a company with a huge amount of hydropower and Arctic experience, confirmed the feasibility of the estimated timeline for the project and the applicability of the roller-compacted concrete design in Alaska, Dyok said. The company also suggested some ways of expediting the project by using techniques for winter construction and by starting to fill the reservoir before project completion, he said.

"Perhaps the most important finding, though, was the comparison between their cost estimate and that of our … engineer," Dyok said. "They were within 9 percent."

A cost probability distribution indicates a median likely cost of about $5.2 billion, with a 90 percent probability of the cost coming between $4.5 billion and $5.9 billion, Dyok said.

Cost of power

Nick Szymoniak, project economist with AEA, reviewed the anticipated cost of power from the hydropower plant, based on those estimated project costs and using some reasonable economic assumptions while also assuming no direct state financing. At startup in 2024 the cost of power would likely be around 18 cents per kilowatt hour, he said.

Szymoniak emphasized that, with the cost of power from the plant almost entirely resulting from the up-front capital cost of the construction project, the electricity costs would remain virtually constant out into the future, once the plant goes on line in 2024.

But the real cost of the power, adjusted for inflation, would in effect drop as the years go by. Expressed as the real future value of 2013 dollars, the power cost in 2024 would actually start at about 14 cents per kilowatt hour, rather than 18 cents, and then fall to 11 cents after 25 years, eventually reaching to 6 cents in 30 years. After 30 years, when the project debt is assumed to have been fully paid off, the cost of hydropower from the Susitna-Watana facility would plummet, Szymoniak said.

AEA anticipates a life in excess of 100 years for the hydropower system.

Gas comparison

A comparison with the possible future cost of power from natural-gas-fueled power generation suggests that the hydropower will initially be more expensive than power from natural gas; that the price differential will narrow; and that eventually the hydropower will become much less expensive. The time at which hydropower becomes less expensive than gas-fueled power depends on assumptions about future gas prices but could happen 12 years after startup of the hydropower plant, if middle-of-the-range gas prices are assumed, Szymoniak said.

And the use of hydropower would dramatically reduce future power cost uncertainty, when compared with a continuing high dependence on natural gas for power generation, Szymoniak said. ●

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ENVIRONMENT & SAFETY

Husky, Enbridge encounter NWT problems

Enbridge and Husky Energy were left red-faced by two incidents in the Northwest Territories.

For safety reasons, Canada's National Energy Board ordered Husky to stop operations at its Slater River oil exploration camp, while Enbridge dug up contaminated soil at two locations along its pipeline from the Norman Wells oil field to northern Alberta.

The order from the federal regulator involved a series of violations by Husky under the Canada Oil and Gas Operations Act, which the NEB's chief safety officer Brian Nesbitt said holds companies accountable for "their performance and the effectiveness of their management systems."

Husky said it took the matter seriously and agreed to suspend operations to conduct a safety review.

A company spokesman said operations would only be restarted when Husky and the NEB were satisfied all requirements had been met.

Husky is involved in building an all-weather road to a highly prospective oil play in the Central Mackenzie Valley, where MGM Energy and ConocoPhillips are also engaged in exploration activities.

The Enbridge pipeline, built in 1985, is currently carrying about 39,500 barrels per day from Norman Wells, more than 10,000 bpd below capacity.

The company said it needed to remove about 95 cubic meters of contaminated soil at two locations identified as potential weak spots on the pipeline.

But a company spokesman said further investigation is needed to determine if the spills actually came from the line.

The pipeline had experienced previous problems, including a sizeable spill in 2011.

—GARY PARK

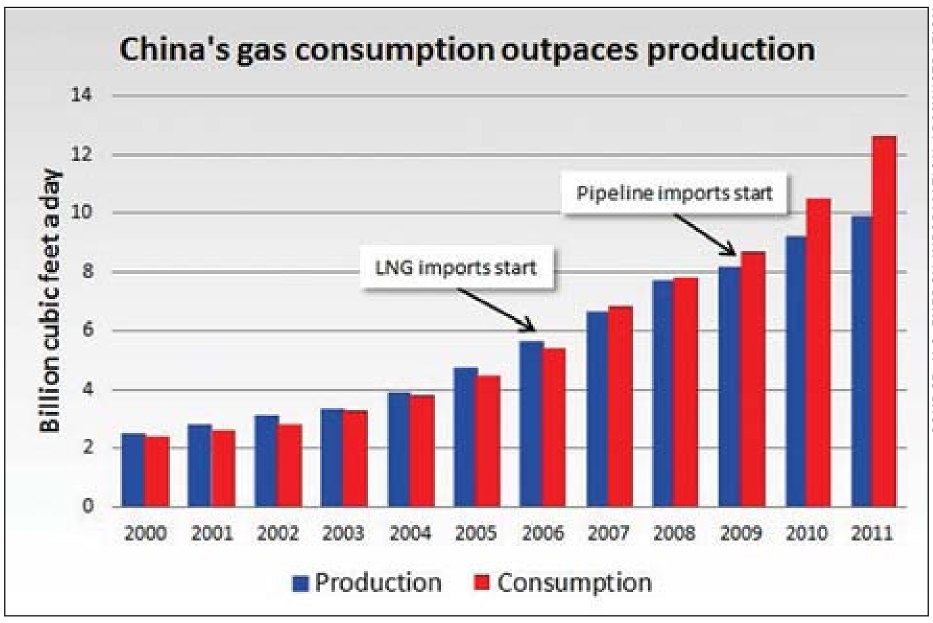
● NATURAL GAS

Stakes are big in Russia-China gas talks

Price, routing, participation all barriers to moving Russian natural gas to markets in China, which is largest gas

By BILL WHITE

Researcher/writer for the Office of the Federal Coordinator



SOURCE: U.S. ENERGY INFORMATION ADMINISTRATION

Buried across the vast Siberian steppe and taiga of Russia's Far East lie spectacular reservoirs of natural gas, largely untapped because there is little local demand — the land there is thinly populated and lightly industrialized.

But over Russia's southeast border, the Chinese economic colossus is thirsting for natural gas to help quench its growing consumption of fossil fuels.


BILL WHITE

Even as China is dotting its coast with new liquefied natural gas receiving ports and getting pipeline gas from far-flung Central Asia outposts, no gas pipelines cross the Russia-China border.

This is one of the great ironies of the world's gas trade, that what would appear to be a natural fit — a stranded supply finding a ready market in a nearby booming economy — has not occurred, even as other, more distant suppliers have rushed into the market.

Gas flows into China from Asia and the Middle East, Australia, Africa and South America. In 2011, China even received a shipment of U.S. gas, from the nation's only operating LNG-export plant, in Nikiski, Alaska.

Supplying China could be the great prize for future natural gas exporters, including a possible multibillion-dollar LNG project that would liquefy and export Alaska's North Slope gas. (The Nikiski plant in Southcentral Alaska processes gas from the neighboring Cook Inlet fields, not from the huge North Slope fields in the Arctic.)

Gas slakes only a small portion of China's energy demand. But the nation's consumption of gas has been soaring and is expected to continue doing so — possibly quadrupling in the next 20 years. China has been importing gas since the mid-2000s, after its gas consumption outstripped domestic production. Every year it imports more gas, even as the country tries to develop more fields internally to try to limit the need for costly imports.

1 2 SERIES

Over the past 20 years, Russian and Chinese officials have shaken hands, signed agreements in principle and made many announcements about how they're working together to bring Russian gas to Chinese power plants and other consumers.

Yet the smiles, words and pieces of paper have not yet led to any border-crossing pipelines. The two nations have been deadlocked. The reasons are varied, from historical baggage, to differences of opinion about pipeline routes and ownership, to each nation's geopolitical considerations within East Asia.

But the Great Wall that separates the two is an old bugbear that has scuttled many a business deal over the eons: The two sides have been unable to agree on a fair price.

The stalemate

Few Russia-China watchers are taking bets that the two nations never will come to terms on gas.

The stakes are too huge.

This winter's choking air pollution in many Chinese cities is accenting the call for reforms to steer the country away from vehicles burning dirty diesel and power plants belching coal ash. China consumes almost as much coal as the rest of the world combined.

China is quickly embracing natural gas. The country's leaders hope gas will account for 12 percent of the national energy mix by 2030, up from about 5 percent now.

A recent paper on the impasse with Russia says China needs to secure long-term supplies in the next few years to achieve that goal. Its ambitious embracing of natural gas likely will account for about one-third of global gas-demand growth through 2030, said author Keun-Wook Paik, senior research fellow at The Oxford Institute for Energy Studies in the United Kingdom.

And for Russia, Paik wrote, "A pipeline to China would open the door for its extension to both South Korea and Japan, providing all three with both pipeline gas and LNG import options. Cooperation among these top three gas importers could lay the foundations for the establishment of an Asian Gas Consumers Union."

The delay in Russian gas deliveries has frustrated both sides.

As a Chinese energy planner said in 2007, "The Sino-Russia pipeline question is one step forward, two steps back. Today is cloudy with a chance for sun, while tomorrow is sunny with a chance for clouds. One moment Russia is saying they have made a decision, the next saying that no decision has been made."

Still the stalemate continues. A Platts editor recently put it this way: "Continuing failure to agree would be a loss for both sides and other countries as well. It would deprive both countries economies of an obvious win, by finding a home for stranded gas reserves, as well as increase future global rivalry in the LNG market, with a knock-on effect on world prices."

Lots of talk, little action

The first steps on the tortured trail of supplying Russia gas to China occurred 20 years ago.

In the period leading to the early 1990s, Russia had discovered big oil and gas fields in its Far East, out beyond its vast internal and export pipeline networks. The resource was stranded in Siberia, unless a market could develop. BP and Statoil studied the potential, but backed away from a joint venture for lack of obvious buyers.

China was not perceived as a potential customer then. China and Russia were Cold War enemies. Their joint histories ran even deeper than that. The Chinese and Russians had fought many territorial wars and skirmishes in the centuries since the first Cossack loggers ventured to colonize the east.

In 1860, six months before the U.S. Civil War erupted, a weakened China ceded to Russia control of Outer Manchuria — a swath of China larger than Washington, Oregon, Idaho and Nevada combined that now comprises the southeastern-most portion of Russia. The

see **GAS TALKS** *page 14*

● EXPLORATION & PRODUCTION

Buccaneer to drill at West Eagle

State approves three-lease unit at the southern Kenai gas field, but requires Buccaneer to post two bonds to guarantee work

By ERIC LIDJI
For Petroleum News

Following the recent formation of a unit at the onshore gas field, Buccaneer Energy Ltd. is permitting a summer exploration well at its West Eagle prospect in the southern Kenai.

A local subsidiary of the Australian independent, Buccaneer plans to use the Glacier No. 1 rig to drill the West Eagle No. 1 well some 20 miles east of Homer this summer to target a potential natural gas reservoir suggested by previous drilling and seismic evaluations in the region.

The permitting documents came one day after the Alaska Department of Natural Resources approved the formation of the West Eagle unit over three Buccaneer leases covering some 8,843 acres. Buccaneer originally requested a unit over nine leases covering some 46,395 acres in the area, but Division of Oil and Gas Director Bill Barron determined that "not all of the acreage Buccaneer proposes supports forming a unit."

The six leases not included in the unit, as well as small portions of the three leases included in the unit, have now expired at the end of their primary term, retroactive to the end of September 2012. Of the three leases in the West Eagle unit, two were also set to expire in September 2012, but the third was not set to expire until February 2016.

The state approved the unit retroactive to Sept. 30, 2012.

Strict interpretation

While the state has taken a strict interpretation of its unitization regulations in recent years, it formed the shrunken West Eagle unit even after acknowledging that the potential benefits of development, as far as the state is concerned, "should not differ significantly whether or not the leases are unitized" seeing as Buccaneer is the sole lessee in the area.

But, according to Barron, the unit was justified because the accompanying plan of exploration Buccaneer proposed for West Eagle "offers protections to the state's economic interests." The unit decision requires Buccaneer to post two $600,000 bonds within 30 days to backstop its work commitments. The state would return the first bond if Buccaneer spuds West Eagle No. 1 by Sept. 1, 2013, and would return both bonds of the company drills and tests, or drills and plugs and abandons, the West Eagle No. 1 well by Sept. 1, 2013. The well must target a shallow interval of the Tyonek formation at around 6,000 feet.

Buccaneer plans to drill West Eagle No. 1 on a 1.38-acre drilling pad to be constructed "within the footprint of an existing material site on public lands and operated by a local company," and said the project would exclusively make use of existing road access.

If Buccaneer fails to complete the well by the deadline, it would voluntarily terminate the unit and two of the leases would expire retroactive to the end of their primary term.

Buccaneer plans to drill West Eagle No. 1 on a 1.38-acre drilling pad to be constructed "within the footprint of an existing material site on public lands and operated by a local company," and said the project would exclusively make use of existing road access.

The state is taking comments on the drilling plan through March 16.

A regional story

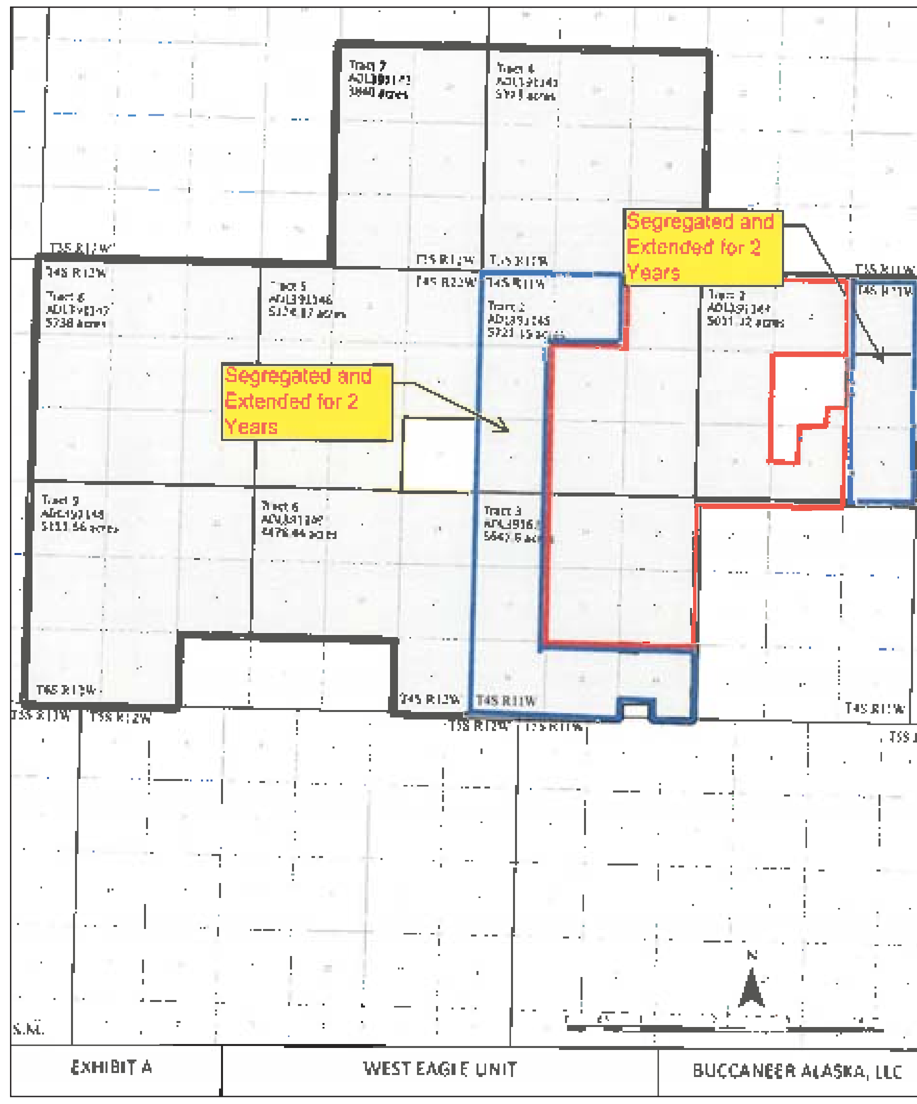
The southern Kenai Peninsula saw considerable drilling during the early days of Cook Inlet exploration, but is only recently becoming a site for development activities.

Only two wells have been drilled in the vicinity of West Eagle.

Standard Oil Company of California drilled the Anchor River No. 1 well in December 1961 to a depth of 6,896 feet. The well found no oil, but "strong gas shows" associated with coal seams and "weak indications of gas" associated with the lower Beluga and Tyonek sands. In April 1970, Gulf Oil Co. drilled the South Caribou Hills Unit No. 1 well two miles northwest of Anchor River No. 1, reaching 10,091 feet. The well found no oil shows and only "weak indications of gas" associated with the Tyonek formation.

While "multiple" seismic surveys have

see **WEST EAGLE** *page 14*



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WEST EAGLE

been shot around West Eagle, the most recent was in 1981, all have been 2-D and "the data quality is generally poor." Buccaneer recently reprocessed some 233 square miles of this older seismic that has "improved the interpretability of the data," and has previously proposed a 3-D survey over the region.

In the broader region, Armstrong Cook Inlet sparked renewed interest in the southern Kenai Peninsula when it brought the North Fork unit online in 2011, following a gas discovery Standard Oil Company of California made 10 miles north of Homer in 1965.

In late 2012, Hilcorp Alaska brought the Red Pad at the Nikolaevsk unit into production, following up on a gas discovery Union Oil Company of California made there in 2004.

To the west, Buccaneer plans to use its Endeavour jack-up rig this spring to drill at the Cosmopolitan prospect off the coast of Anchor Point. Pennzoil discovered the oil field in 1967. ConocoPhillips and Pioneer Natural Resources explored the field in the 2000s.

State responds to comments

The state received numerous comments concerned about the unit.

The primary concerns were environmental, particularly with regard to the protection of grazing lands, as well as potential sound, light and water pollution. The state said it included mitigation measures in the lease terms addressing those concerns and "may impose additional mitigation measures when Buccaneer proposes specific activities."

It also noted that unitization, as an administrative issue, poses no threat to water quality, but that proposed development would come under the purview of several agencies.

Other comments questioned the safety of drilling operations, but the state said the Alaska Oil and Gas Conservation Commission is largely responsible for regulating safety.

"Several" comments questioned whether the state should form a unit over leases on the verge of expiring, but the state noted that existing regulations and case law allow it to retroactively form a unit if the company submits an application before leases expire.

Finally, several comments requested a public hearing on the unit, but Barron said the state met its public notice requirements and saw no reason to expand upon those terms. ●

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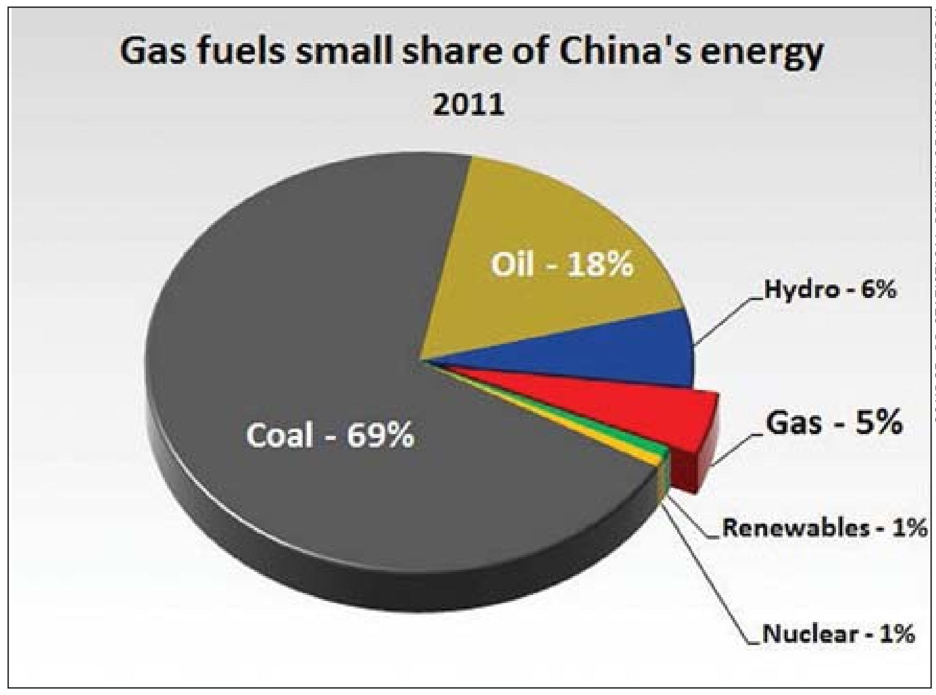

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GAS TALKS

loss still smarts with some Chinese. (Russia wasn't the only imperialist picking at China. The United Kingdom expanded its Hong Kong territory a month earlier.)

But in the early 1990s upheaval came. The Soviet Union fell apart. Communist China was beginning a dance with market economics. Relations thawed.

In 1993, China National Petroleum Corp. started negotiations to explore Siberian oil and gas prospects.

In the next six years, three memoranda of understanding got signed. The two countries agreed to work together to define the size of resources and study how to pipe the gas from the Irkutsk region to northeast and northwest China in two separate mega-pipelines.

For Russia, this was a chance to provide gas to locals, develop a petrochemical industry, and possibly even export gas-fired electricity as well as the methane itself to a new market. With further build-out of its pipeline network, Russia could position itself to route its ample gas reserves to Europe in the west or Asia in the east, giving it leverage to play one market against the other.

For China, leaders saw a crisis looming. Energy demand was skyrocketing but domestic oil production was stagnating, even falling in the industrial northeast. Meanwhile, the day approached when gas consumption would outpace domestic production. Facing a threat to their nation's expanding economy, Chinese leaders in the early 2000s got busy lining up new supplies.

Russian oil and gas weren't the only resources in play. The Chinese opened negotiations with Turkmenistan, Kazakhstan, Uzbekistan and Myanmar, all of which had huge reserves looking for a market. Unlike Russia, they quickly came to terms, and new gas pipelines from those four countries now are operating, expanding or under construction.

Russian oil and gas weren't the only resources in play. The Chinese opened negotiations with Turkmenistan, Kazakhstan, Uzbekistan and Myanmar, all of which had huge reserves looking for a market. Unlike Russia, they quickly came to terms, and new gas pipelines from those four countries now are operating, expanding or under construction.

A key difference is that Turkmenistan and Kazakhstan in particular welcomed Chinese investment along the value chain, from the wells and field development to pipelines.

Negotiations had a different tone with the Russians. Russia blocked Chinese equity stakes. Russia also wanted the shortest pipeline routes possible. Such as through Mongolia. But the Chinese wanted the pipe routed around that nation to keep the supply secure.

The talks dragged on.

In 2006, Russian gas company Gazprom and China National Petroleum Corp. signed a memorandum of understanding on two gas pipelines. They would be big — each as big as the possible Alaska North Slope gas pipeline or even bigger. One would carry up to 2.9 billion cubic feet a day to northwest China, linking to a Chinese pipeline hub there. The other line's capacity would be up to 3.7 bcf a day, delivering the gas to the northeast China industrial hub.

If those projects had been built and the pipelines were running full, they could supply China with about half of the natural gas the country consumes today. But they haven't been built. The companies couldn't agree on a price for the gas.

Price also is a barrier to consummation of Gazprom's 2010 announcement of a binding accord with CNPC to export up to 2.9 bcf a day to northwest China.

And price could blunt Gazprom's plan announced in October 2012 to build a gas trunkline from Irkutsk to the Far East port of Vladivostok, north of China, a project

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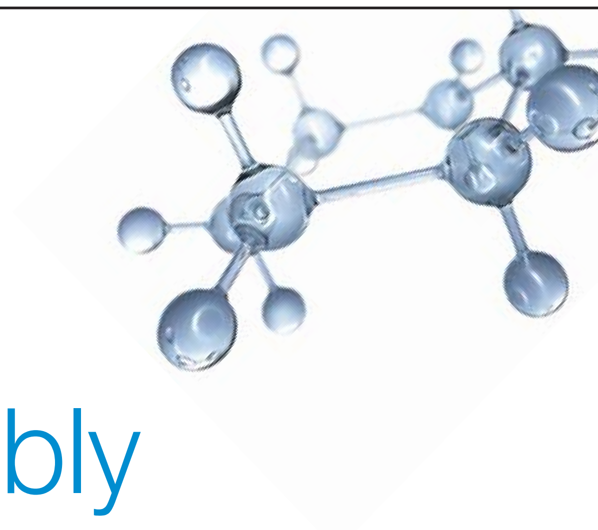

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● GOVERNMENT

NMFS issues IHA for Apache seismic

Authorization forms one of a series of permitting requirements for continuing 3-D seismic surveying in the Cook Inlet basin

By ALAN BAILEY

Petroleum News

The National Marine Fisheries Service, or NMFS, has issued Apache Alaska Corp. with an incidental harassment authorization for the accidental minor disturbance of marine mammals during seismic surveying operations in Alaska's Cook Inlet in 2013.

In a letter dated Feb. 15 to John Hendrix, Apache's general manager in Alaska, Helen Golde, NMFS acting director of protected resources, said that the authorization would allow "level B harassment" incidental to marine seismic surveying in the inlet between March 1, 2013, and March 1, 2014. Level B harassment involves animal disturbance without the potential to cause injury or death.

Apache is in the process of conducting a multi-year program of 3-D seismic surveys across large areas of the Cook Inlet basin, onshore and offshore, as part of a search for new oil and gas resources in the basin. The company sees 3-D seismic analysis of the subsurface as an essential prerequisite to exploratory drilling.

The company is using a high-tech system of wireless, nodal seismic receivers for its surveys.

Authorization needed

Annual incidental harassment authorizations form a key component of the permitting required for the offshore surveying. Without this type of authorization, any disturbance to marine mammals during survey operations could constitute a violation of the Marine Mammals Protection Act. Apache, having previously obtained a NMFS authorization for offshore surveying in 2012, had been expressing concern about the length of time it was taking for NMFS, a division of the National Oceanic and Atmospheric Administration, or NOAA, to issue an authorization for 2013.

"While I wish it hadn't taken this long I am pleased NOAA finally issued the permit," said Sen. Mark Begich in a press release issued after hearing about the new authorization. "I was just in Anchorage and Homer and heard a lot of concerns about Cook Inlet development and the possible gas shortage in Southcentral in coming years. While Apache's work is focused on oil exploration there is considerable gas potential as well."


JOHN HENDRIX

During a talk to the Alaska Association of Environmental Professionals on Feb. 20, Hendrix expressed his concern about the uncertainty surrounding the unpredictable timing with which federal agencies issue permits and he argued for more transparency in the permitting process.

"We need to work together to make sure we understand which direction we're going," Hendrix said.

A particular challenge is managing permits, to ensure that they all come together at the same time, without some maturing before the start of work, Hendrix said.

"If I don't have the permits at the right time, I don't have the access, and if I don't have the access we can't work. It's as simple as that," he said.

Apache is still waiting for the completion of an environmental assessment and the issue of a surface land use permit for the Kenai National Wildlife Refuge on the Kenai Peninsula, to conduct a seismic survey in Cook Inlet Region Inc. subsurface land which Apache has licensed for exploration.

Crabbing next?

Offshore, Hendrix questioned why the U.S. Army Corps of Engineers requires Apache to obtain a permit to lay marine seismic nodes from a vessel, an operation that Hendrix likened to laying crab pots from a fishing vessel. With crab pots being larger and heavier than seismic nodes, maybe the laying of crab pots would become the target of a Corps permitting requirement, he speculated.

Hendrix also expressed a wish that the federal government would require bonding from people who appeal against permits — the issue by NMFS of Apache's incidental harassment authorization for the company's 2012 Cook Inlet seismic survey is still the subject of an appeal in federal court.

"Right now environmentalists can stop anything without having a bond and taking accountability for their actions," Hendrix said.

Of particular concern in Cook Inlet is the potential for disturbance of the local beluga whales, animals that form a sub-species that NMFS has listed as endangered under the Endangered Species Act. Apache has said that it did not encounter any beluga whales during its 2012 offshore seismic survey operations. The company has said that it provided appropriate environmental training for its people, deployed licensed protected species observers with listening equipment, and conducted reconnaissance flights before carrying out each seismic shoot.

The NMFS authorization for Apache's 2013 offshore surveying stipulates a series of mitigation measures, to prevent wildlife disturbance, including the mandated use of protected species observers on boats, the use of a shore-based observation station to monitor for marine mammals and the use of daily aerial surveys, weather permitting.

Exclusion zones

An offshore survey involves the use of surface air guns to send sound waves into the rocks under the seafloor. The NMFS authorization requires that during seismic operations, observers must maintain oversight of a 180-decibel sound level exclusion zone around air guns for cetaceans and a 190-decibel exclusion zone for pinnipeds. There must be no animals of the appropriate types in the exclusion zones for at least 30 minutes prior to firing up the air guns, and a power-down must occur if an animal enters an exclusion zone during a survey. A 160-decibel exclusion zone will apply for beluga whales. There are also seasonal restrictions on seismic operations in an important beluga whale feeding and breeding area. ●

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GOVERNMENT

Governor introduces new permitting bill

Alaska Gov. Sean Parnell has introduced a bill which would allow the Department of Natural Resources to approve oil and gas or gas only exploration and development in a geographic area. The governor said the bill would "reduce the time required to get oil into production" and flowing through the trans-Alaska oil pipeline, while also protecting the environment.

In a Feb. 18 letter of transmittal Parnell said that currently DNR "grants lease exploration and development approval in conjunction with individual plans of operation for a lease or project," with separate public notice required for each approval "often resulting in repetitive approvals within the same geographic area."

The bill would allow "DNR to comprehensively evaluate oil and gas exploration and development in a geographical area, and define the criteria by which specific projects are evaluated and approved," with approvals valid for up to 10 years.

A fiscal note signed by Bill Barron, director of DNR's Division of Oil and Gas, said one non-permanent position would be required to prepare exploration approvals for existing oil and gas lease sale areas and contractual services for legal support, public outreach and notice and travel.

"On-going exploration and development approvals would be accomplished using existing staff as a result of efficiencies gained through implementing this bill," the fiscal note said.

—PETROLEUM NEWS

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GAS TALKS

that likely needs a spur to northeast China to take some of the gas. (Japan and South Korea could be export customers, too, keeping Russia from depending on a single customer.) Like much about Russia and China, this project would be almost unimaginably massive. The pipeline would span 2,500 miles — roughly the distance between San Francisco and New York — through swamps, mountains and earthquake zones. It would carry up to 5.9 bcf a day of gas.

Last fall Gazprom held a contest to name the project. "Power of Siberia" took the prize. The winner gets a trip for two to Siberia. ●

Part 2 of this story will appear in the March 3 issue of Petroleum News.

Editor's note: This is a reprint from the Office of the Federal Coordinator, Alaska Natural Gas Transportation Projects, online at www.arcticgas.gov/stakes-are-big-russia-china-gas-supply-talks.

● FACILITIES

AIDEA eying oil production facility

The public corporation is studying whether to invest $45 million in a facility at the Mustang field; could serve numerous companies

By ERIC LIDJI
For Petroleum News

The Alaska Industrial Development and Export Authority is considering whether to help finance a North Slope oil processing facility, the first project of its kind for the agency.

The board of the public corporation voted unanimously on Feb. 15 to spend up to $100,000 to perform due diligence and to structure a potential deal to help Brooks Range Petroleum Corp. finance a 15,000 barrel per day production facility at the Mustang field, a burgeoning oil development the company is pursuing in the Southern Miluveach unit.

Under the proposal, AIDEA would invest in the project by joining Mustang Production Facility LLC, a new joint venture that would build, own and operate the facility.

AIDEA would only pay $45 million of the estimated $190 million total cost of the project, earning a 10 percent rate of return on its investment over 10 years as well as a small working interest in the unit. AIDEA expects the Singapore-based Ezion Holdings Ltd. to contribute between $95 million and $125 million to the project and an as-yet-undetermined third party to contribute the remaining $20 million to $50 million.

Attracting additional capital

Even though AIDEA would be the smallest investor, it believes its contribution is crucial for attracting the additional capital needed to bring the project into production in a timely manner. The Mustang project is believed to be too small to interest the major companies able to fund a project out of pocket, but too big for traditional financing, according to Jim Hemsath, deputy director for project development and asset management for AIDEA.

"AIDEA's involvement brings access to capital and also provides the catalyst and security that helps pull together… a full financing plan for the project," Hemsath said, saying that the $65 million AIDEA plans to invest in Mustang between the proposed production facility and its previous contribution to road and pad infrastructure, could generate some $400 million in outside capital required to bring Mustang into production.

Hemsath said that both an unnamed equity partner and a lending institution were "very clear" that their involvement in the project was predicated on AIDEA's involvement.

The facility would primarily serve the Mustang field, but AIDEA hopes other leaseholders in the region such as Repsol E&P USA and Arctic Slope Regional Corp. would make use of the facility should they ultimately sanction projects in the vicinity.

AIDEA believes the project falls within its mission because it would create as many as 280 construction jobs and 25 full time operation jobs, and would generate some $1.2 billion in state revenues and $55 million in property taxes to the North Slope Borough.

With the $100,000 study, AIDEA would test the business case for its investment and the technical aspects of the project, and draw up a financing plan and associated agreements.

A major energy player

With the proposed project, AIDEA continues to find its niche in the energy sector.

After the troublesome Healy Clean Coal Project showed AIDEA the potential downside of owning energy infrastructure outright, AIDEA decided instead to partially invest in energy projects where its ability to offer low-interest financing might lure private capital.

Within the past 18 months, AIDEA has pursued this strategy through four projects: its $24 million investment in the $68.5 million Endeavour jack-up rig in partnership with Kenai Offshore Ventures LLC; its $20 million investment in Mustang Road LLC to help Brooks Range Petroleum fund $25 million in preliminary infrastructure build-out associated with the Mustang field development, including a gravel road and gravel drill site; its proposed $45 million investment in the $190 million Mustang Production Facility; and its potential role in managing up to $275 million in bonds and loans included in a Gov. Sean Parnell's proposed $355 million financial package to help a private company build a North Slope liquefied natural gas plant to serve Interior markets. ●

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INTERNATIONAL

New field to ship oil on Northern Sea Route

When Gazprom Neft's Novoportovskoye oil field in the southeast of the Yamal Peninsula, in the Russian Arctic, comes on line in 2015, the field will transport its oil production through the Northern Sea Route, Russia's marine transportation corridor around the country's Arctic coast, according to a report in the Barents Observer. With winter sea ice up to two meters thick and an ice-free season that lasts only around three months in the waters adjacent the new field, tankers shipping oil from the field's marine terminal will require assistance from icebreakers, the Barents Observer says.

And the export of oil from the Novoportovskoye field will cause a major increase in the shipment of oil through Russia's Arctic waters, the Barents Observer says. The field is thought to hold 1.6 billion barrels of oil and 9 trillion cubic feet of natural gas. Gas from the field would be shipped by pipeline, through Gazprom's pipeline network.

—ALAN BAILEY

● FINANCE & ECONOMY

Technology still driving oil boom

Producers continue to refine development techniques for tight oil, while pipeline companies are bringing more capacity online

By ERIC LIDJI
For Petroleum News

In 2012, the United States experienced the largest single-year increase in daily oil production since Col. Edwin Drake started the oil industry more than 150 years ago.

And Alaska had nothing to do with it.

In 2013, the U.S. Energy Information Administration expects domestic production will again increase by record levels. And Alaska won't have anything to do with that, either.

The EIA expects domestic oil production to hit 7.25 million barrels per day this year, up 815,000 bpd over 2012, and to hit 7.82 million bpd in 2014, the highest level since 1988.

In a recent publication examining the key drivers behind the growth in domestic oil production expected over the next two years, the statistical arm of the U.S. Department of Energy points to technological improvements in developing tight oil formations in North Dakota and Texas, a continental pipeline system adjusting to the new geography of oil production, and production increases from a slate of new Gulf of Mexico developments.

As for Alaska, the EIA expects oil production to drop to about 504,000 barrels per day in 2013, down from 526,000 bpd in 2012, and to keep falling to 474,000 bpd in 2014.

Tight oil is king

The increases in the Lower 48 come as producers are finding the best way to develop tight formations.

While the combination of horizontal drilling and hydraulic fracturing is responsible for making tight oil formations economic at current oil prices, the EIA points to a range of technologies responsible for bringing down the cost of tight oil development, and therefore increasing production this past year and likely for the next two years, as well.

Those technologies include: multi-well pads allowing producers to achieve economies of scale for both drilling and completion, horizontal laterals up to two miles long allowing greater contact with oil-bearing formations, micro-seismic imagining that improves the understanding of formations, drill bits designed specifically for shale and tight formations, and "walking" rigs that decrease the time needed to move from one pad to another.

These efficiency gains have quickly increased the economically recoverable tight oil resource base in the Lower 48, but the pace of growth should start to slow as the industry finds the optimal use for each technology, according to the EIA. Additionally, as producers run through the "sweet spots" of each play, they will be required to move into less productive regions, requiring more drilling and completions to maintain production.

Pipeline capacity up

It takes wells to increase oil production, but it also takes pipelines.

Within the past three years, capacity to the distribution hub in Cushing, Okla., increased by some 815,000 bpd, a boost primarily attributable to the 590,000 bpd TransCanada Keystone pipeline connecting Alberta to Oklahoma through Nebraska. The second phase of the project, which completed the link from end to end, came online in early 2011.

The EIA expects pipeline capacity to continue improving in 2013 and 2014, as several interstate projects launched at the beginning of the tight oil boom start to come online.

Those include the 250,000 bpd Enbridge/Enterprise Seaway expansion now online, the 700,000 bpd TransCanada Gulf Coast project planned for the fourth quarter and the 450,000 bpd Enbridge/Enterprise Seaway twin scheduled to come online in early 2014.

In addition to new pipelines, the EIA also noted how the 96,000 bpd ExxonMobil Pegasus pipeline reversed direction in 2006 to accommodate the new geography of oil.

Federal GOM returns

While onshore tight oil is the primary driver of the expected increases, oil production from the federal Gulf of Mexico increased 6 percent in 2012, and should keep rising.

The 13 projects that came online in 2012 have a combined peak production of 195,000 bpd and the EIA is tracking another 16 projects due to come online in 2013 and 2014.

The federal Gulf of Mexico should also see an increase in 2013 as the industry bounces back from Hurricane Isaac. While average daily production increased last year, production on an annualized basis actually fell as a result of shut-ins caused by the storm. ●

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● EXPLORATION & PRODUCTION

CIE to prep Kroto Creek gas prospect

The site is in Susitna basin, where company holds exploration licenses covering vast acreage; second Osprey gas well workover done

By WESLEY LOY
For Petroleum News

Before the spring thaw, Cook Inlet Energy LLC hopes to lay the groundwork for possible natural gas exploratory drilling in the Susitna basin.

The Anchorage-based oil and gas producer on Feb. 7 submitted a plan of operations to the Alaska Department of Natural Resources for work at what the company calls the Kroto Creek prospect.

The prospect is in the Susitna basin, a huge and lightly explored area north of Anchorage and west of the Willow community.

Cook Inlet Energy is proposing work to access the prospect. The job includes building a groomed snow trail and a compacted earth drilling pad. Reaching the site also involves crossing the Susitna River via an ice bridge.

To meet its schedule, the company says it must proceed with the work during March, before the Susitna thaws.

Winter access

Cook Inlet Energy told DNR it hopes to drill up to two gas exploration wells on the Kroto Creek prospect. The wells would be drilled during the winter of 2013-14.

The company identified the target structure using previously acquired seismic data, the plan of operations says.

The proposed Kroto Creek pad will be located about 12 miles northwest of Willow Creek Landing, a public access point on the Susitna River.

Across the Susitna, a groomed multiple use winter trail running west to the Yentna River will provide access to Kroto Creek and other Cook Inlet Energy prospects including Moose Creek and Big Bend, the plan of operations says.

Cruz Construction will build a spur trail north to the Kroto Creek prospect, the plan says. There, Cruz will clear the vegetative mat for a pad measuring 400 feet by 400 feet, covering about 3.6 acres.

"During or immediately after construction of the pad, a contractor will drill a water well and drive a conductor in the pad area," the plan of operations says.

A conductor is a length of large surface pipe installed before drilling an oil and gas well.

Exploration licenses

Cook Inlet Energy has been very active in acquiring state exploration licenses in the Susitna basin.

DNR's exploration licensing program complements its regular oil and gas leasing program. The idea is to encourage exploration in frontier basins with relatively low or unknown hydrocarbon potential, typically Interior land far removed from the state's existing oil and gas fields.

Cook Inlet Energy holds three Susitna licenses, giving

see GAS PROSPECT page 24

continued from page 3

MURKOWSKI Q&A

NPR-A land or offshore. Our resource potential is enormous and our frustration with seeing declining throughput is justifiable. It's not that we are running out of oil up there, it's that we are seeing such resistance from the federal landlord, from our own federal government in accessing a resource that our country needs, so it is about the safety and continued operation of a line, it's about energy security, it's about national security, it's about economic security. There are so many good reasons it fill up that pipeline.

Petroleum News: What are your thoughts on Shell's first year of exploration and the problems with the Kulluk?

Murkowski: It's important to recognize that the actual drilling they did up there was done without incident, without a front-page story. Granted they had to work under a truncated schedule. They had to move out of the way when the ice came. The whalers were able to meet their quotas. The operations that were conducted were done without incident. I think that bodes well for Shell and their continued operations up north. Of course the focus came about as Shell was moving its assets, most notably the Kulluk. When you look at what Shell has had to do with these drilling operations, I think they know and I certainly expect that all aspects of their work have been conducted with a level safety while meeting the high standards that have been set. That means moving your vessels safely and meeting the high standards set forth in the permits as difficult as they are. I think we all recognize the Arctic is a different part of the globe, and standards there are different from what you might see in offshore Gulf of Mexico where these operations have been ongoing for decades. Some would say that's not fair, the standards are higher. I want to make sure we've got a safe operation. Not only while the exploration and production, but also as the full operation coming and going is conducted. So the Department of the Interior will release its review in coming weeks. The Coast Guard will release its more comprehensive review in a manner of months. So we are going to be able to obtain what Shell learned in the Beaufort and the Chukchi in the Energy Committee. It's important for us to recognize that the exploration conduct was done so in a manner that met all the safety and environmental standards that have been put in place.

Petroleum News: With Arctic development, what are the chances of the revenue share issue being resolved?

Murkowski: I'm working on a bi-partisan revenue sharing bill now. I'm working with Sen. Widen as well as Sen. Landrieu. I had hoped we would introduce it last week, but we are working on some of the scoring of the bill. We have taken the approach that it's important to get support from as many senators as we can, so I'm not looking at a one-state focus on this. We are reaching out to folks who support renewable energy and land conservation. We recognize the importance of letting states decide their own path forward on energy and land issues. So what we do with this bill is we direct a share of the revenues to participating offshore energy producing states. This is also for offshore wind, tidal and wave generation. We establish permanent revenue sharing: 27.5 percent with a provision for partial payment to coastal communities. The way it would operate is 25 percent of the state's share would go directly to the coastal political subdivisions or the boroughs, the most affected by the offshore development. Then we allow an additional 10 percent to be directed to states if they establish a fund to support energy research and development, alternative and renewable energy. So what our proposal does is expand revenue sharing to include renewable energy production not only offshore but also onshore on federal lands, so it's a much more expansive measure. The way we are approaching this allowing for renewable is a way to bring other members into partnership with us. I believe we have a very good chance at moving legislation that is designed this way. I'm pleased Sen. Widen is working with us. I feel quite encouraged with where we are in revenue sharing right now.

Petroleum News: What do you want your takeaway to be from your speech to lawmakers?

Murkowski: I spend a fair portion speaking to issues coming up in Washington, D.C., that will have direct impact on Alaska, most notably what is happening with the budget reductions either through sequestration or we will see cuts come our way because we are dealing with a $16 trillion debt. How this impacts Alaskans and how it impacts policymakers here at the state level is going to be key going forward. It's not going to be all doom and gloom about budget. It's reminding former colleagues that we have great opportunities within the energy field to do more whether it's with natural gas or with our oil potential. I do speak to the fact that while we do have that potential there, we are more times than not held back by our own federal government through regulations, through permitting requirements that are at times overlapping and onerous. It's up to all of us working together to push back, to comment, to weigh in. It's important for us as a state to be strong and independent and have a good statewide economy. So my message is a mixture of caution from a budget perspective and a practical reality of how we move forward taking advantage of resources and the opportunities that we have.

Petroleum News: How hamstrung has Alaska been at the hands of the federal government?

Murkowski: It's been extraordinarily difficult. We can see the difficulties compound. For years we've been told don't look for oil in ANWR. That is an area that should be locked up. You should look to NPR-A. Well as soon as the producers looked to NPR-A, the agencies then said you can't put a bridge here or you can't put a road there. The fight to get CD-5 open was a five-year process, almost ridiculous. The good news is we were able to overcome that hurdle. Look at Shell, the billions of dollars that had been laid out to get to the first season and that was a six-week season to explore in the Beaufort and the Chukchi.

The most recent development that just has me furious is the Fish and Wildlife Service coming out and saying no to a 10-mile, one lane, gravel, non-commercial road that would travel for a small section of the Izembek ban refuge, a road that will not allow for resource development. This is not a project that will make someone rich. This provides for a safety corridor for the village of King Cove to access an all purpose runway in Cold Bay.

When we talk about our limitations on our ability to either access our resources or provide for the safety of Alaskans, when we realize the fight is against our own federal government, this is why Alaskans are up in arms about what they feel they receive from Washington, D.C. ●

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Petroleum news

Oil Patch Bits

Carlile recognizes employees for safety in 2012

Carlile Transportation said Feb. 20 that it recently honored employees for safe work performance at the sixth annual employee and driver safety awards banquets in Anchorage, Fairbanks and Tacoma. The banquets are held annually early in the year to recognize safety achievements from the year prior.

Recognized were the newest drivers to join the prestigious "Million Mile Club," including Chad Townsend, John Brown, Keith McCallie and Doug Hamrick. They join 40 other Carlile drivers with more than a million miles logged without an incident.

Operational employees from all the terminals were recognized for working the entire year of 2012 without a recordable incident. An impressive total of 411 employees were honored for 12 months of perfect safety performance.

"Our goal is to be the best, safest transportation company in Alaska and throughout North America," said Harry McDonald, Carlile's CEO. "Safe highways start with safe drivers and we need to communicate our support for their performance and make sure the driving public knows that's how we do it at Carlile."

Founded in 1980 by brothers John and Harry McDonald, Carlile has grown into one of Alaska's largest trucking companies. Carlile Transportation Systems is based in Anchorage and employs more than 680 people. Carlile services customers with terminals in Anchorage, Fairbanks, Kenai, Kodiak, Prudhoe Bay/Deadhorse, Seward, Blaine, Minn., Tacoma Wash., Houston, Texas, Edmonton, Alberta and also has a warehouse facility in Anchorage.

ASRC Energy Services' facility approved for program

As reported by State of Alaska Department of Labor and Workforce Development Feb. 15, Labor and Workforce Development Commissioner Dianne Blumer approved ASRC Energy Services' Grind & Inject Plant and Oily Waste Injection Facility for the Alaska Voluntary Protection Program renewal as a result of outstanding employee safety and health programs.

"ASRC Energy Services Inc. and its subsidiary AES Alaska Inc. are extremely proud to operate two VPP Star sites," said Don Gray, vice president of Health, Safety and Environmental Training. "Earning Star recertification for both the Grind & Inject Plant and the Oily Waste Injection Facility is in keeping with our Incident Free Culture and reflects our commitment to keeping everyone safe."

VPP recognizes and promotes effective workplace safety and health management through a cooperative program between a company's management, employees and Alaska Occupational Safety and Health.

As VPP Star recipients, AES Grind & Inject Plant and the Oily Waste Injection Facility won't be subject to random enforcement inspections for five years. Enforcement regulations remain in

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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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DS-2S

construct a drill site in the southwest corner of the unit and an access road to the existing road system connecting the Central Processing Facility No. 2 to the Meltwater satellite. The company would install pipelines and power lines the following winter. The winter construction schedules would require numerous ice roads.

Existing drill sites considered

In permitting documents, ConocoPhillips said it considered developing the field from many of the existing drill sites nearby, including 2K, 2L and 2M, but "determined that the reach of the current drilling technology would not allow for wells from these locations to extend far enough to adequately develop this area of the reservoir." Also, ConocoPhillips said those existing sites currently have no slots available to accommodate the 2S wells.

Originally, ConocoPhillips wanted to place the drill site around 1,000 feet to the southeast, which it said would have been optimal for accessing the reservoir, but chose the proposed location to avoid a small stream crossing, according to the company.

ConocoPhillips declined to provide reserves figures for the field.

Near Tarn satellite

ConocoPhillips used Doyon rig 141 to drill Shark Tooth No. 1 in early 2012, and while the company declined to provide details on the results, it subsequently issued a statement to investors saying the well had "discovered hydrocarbons in the Kuparuk sands, in accordance with expectations, and confirmed mapped volumes." It also described the well as being "critical for any future development of this part of the Kuparuk reservoir."

The proposed 2S drill site would be just east of the existing Tarn satellite based around drill sites 2L and 2N, in a section of the unit where there has been little prior drilling.

—ERIC LIDJI

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KEYSTONE DECISION

Gary Doer, the Canadian Ambassador to the U.S., said the decision "has to be made on merit and not noise. If people in Canada perceive that decision is made on noise there will be extreme disappointment."

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Possible repercussions

In the absence of any outright threats, the lower level political rumblings in Canada say a negative decision for the pipeline could have repercussions in other trade and border matters, notably Canada's current plans to purchase a fleet of U.S. F-35 fighter jets.

But Obama raised hopes among environmentalists that he will reject Keystone XL, cutting off 700,000 barrels per day of crude from the Alberta oil sands (equivalent to two-thirds of Venezuela imports), plus about 100,000 bpd from the Bakken, and forcing the U.S. to again rely on oil from such volatile regions as the Middle East, Nigeria and Venezuela.

In the first State of the Union address of his second term, he pledged to make climate change a top priority for his second term, four years after promising to reduce U.S. reliance on oil from politically unstable members of the Organization of Petroleum Exporting Countries.

Inspired by that message thousands — some said 35,000, others 20,000 — occupied a slice of the Mall in Washington, D.C., on a cold Feb. 17 to ratchet up the heat on Obama.

The president wasn't home, however. He was in Florida, playing golf with Tiger Woods.

While the protesters waved banners and rally leaders urged Obama to move forward on his climate change measures, speakers based much of their argument on the energy-intensive methods needed to extract and process oil sands bitumen — which could increase Canada's production to 6.2 million bpd from 3.2 million bpd by 2030.

There were also groups opposing coal-generated power, hydro electricity and the use of hydraulic fracturing to produce natural gas.

Getting out of coal

Far removed from that scene, Baird delivered a blunt message that Canada could teach the U.S. some lessons in reducing greenhouse gas emission, noting that Canada is the only country in the world that is committed to "getting out of the dirty coal electricity business. These are real, meaningful steps that will either meet or even exceed the work that has been done thus far in the United States."

Natural Resources Minister Joe Oliver joined that debate, noting that emissions from U.S. coal-fired power plants are 40 times greater than those from the oil sands, with the oil sands accounting for 48 million tons a year of carbon-dioxide emissions while coal-fired plants in the state of Wisconsin alone producing 43 million tons.

But David Pumphrey, an energy and security analyst at the Washington-based Center for Strategic and International Studies, said any attempt to fight coal plants poses a challenge.

"You can rally around the Keystone project and turn it into a slogan and make it into an icon in the climate fight. And it becomes less about facts and more about ideology."

The mood in Alberta and especially within the industry is becoming testy and edgy as the Keystone verdict looms.

Greg Stringham, vice president for oil sands and markets with the Canadian Association of Petroleum Producers, told the New York Times that a rejection of the Presidential Permit needed for Keystone XL "would be a significant change in the Canada-U.S. relationship. Canada, right now, with our potential growth in energy, is looking for security of demand wherever that might be throughout the world." ●

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OIL TAX DEBATE

percent per $1 over $40 net, a 20 percent capital credit and a maximum rate of 50 percent.

PPT was amended in 2007 under Alaska's Clear and Equitable Share, ACES, which has a 25 percent base net tax rate and progressivity increasing the tax rate at 0.4 percent per $1 over $30 net, 0.1 percent per $1 over $92.50 net and a maximum rate of 75 percent.

State revenues have grown dramatically under ACES: about $20 billion in additional revenues since it took effect, compared to projected revenues under the old gross system.

The fight for change

Responding to producers who said ACES made projects in the state noncompetitive with other options available, and steadily declining North Slope oil production, Parnell began an effort to change the North Slope production tax system in the 2011-12 legislative session. A bill was passed by the House it failed in the Senate.

For changes proposed in this year's Legislature, the governor set out four principles: changes must be fair to Alaskans; they must encourage new oil production; must be simple and restore balance; and must be durable and long-term.

The administration's proposed changes, in House Bill 72 and Senate Bill 21, are being worked jointly by the Department of Revenue and the Department of Natural Resources, with consulting assistance from economist Barry Pulliam, a managing director with consulting firm Econ One.

In presentations on the bills Pulliam said the biggest changes in the governor's proposal are elimination of progressivity, capital credits and the state purchase of credits from losses. The GRE, gross revenue exclusion, would eliminate 20 percent of new oil from production taxes. Carry-forward losses could only be applied against production, eliminating upfront payouts from the state and focusing on the governor's goal of increasing production by making investment in oil projects in Alaska more competitive with opportunities available in similar areas in the Lower 48 and abroad.

Who supports what?

The Alaska Oil and Gas Association, a trade association including producers, explorers, refiners and the trans-Alaska oil pipeline, supports elimination of progressivity but does not support repeal of qualified capital expenditure credits, AOGA Executive Director Kara Moriarty told legislators. AOGA supports extension of the small-producer tax credit and also recommends extending exploration credits.

AOGA opposes changes to the loss-carry forward credit which would bar transferability, requiring the credits to be taken against production.

The proposed GRE, gross revenue exclusion, which would reduce taxes on new production, does not apply to existing fields, and Moriarty said it misses 80-90 percent of potential production, which would come from existing fields.

AOGA also proposes changes not included in the administration bill, including allowing the Department of Revenue the option to rely on joint-interest billings. Currently, Moriarty said, the department audits each participant separately for its share of the same pool of expenses instead of doing one audit of the expenses of a joint venture, which are found in joint-interest billings.

The producers

ConocoPhillips Alaska, not a member of AOGA, had similar concerns, favoring elimination of progressivity, but telling legislators the changes don't contain sufficient investment incentives for legacy fields to offset the state's high cost environment and don't encourage investment at lower prices.

ExxonMobil told legislators that elimination of progressivity is a positive step, but said the base tax rate, 25 percent, is too high. Exxon called two aspects of ACES, the qualified capital expenditure credits and credits toward future production and infrastructure, positive, and recommended they be retained.

BP Exploration (Alaska) supported the repeal of progressivity, said the change in credits would harm some producers and recommended extension of the GRE to include new production in legacy fields.

On the issue of the complexity of ACES, Tom Williams, the company's senior royalty and tax counsel, provided legislators with examples of how difficult it is to model results from proposed investments under the state's existing tax system. He also illustrated the impact of the monthly calculation of production tax value, based upon changing oil prices. For the same total production tax value, at flat production rates, but with wildly fluctuating oil prices (comparable to monthly oil price changes in 2008, Williams said), the progressivity tax was 51 percent higher under the changing-price scenario than under the flat price, because progressivity is figured on a monthly basis.

Bill Armstrong's take

Smaller companies working in the state — whether producers or explorers — told legislators they favored changes to ACES, citing high taxes and the impact of those taxes when they look to bring in outside companies as partners.

Bill Armstrong, president of Denver-based Armstrong Oil & Gas, told legislators his company has been working in the state for 12-13 years, attracted by the resource opportunity. He said the company has identified prospects and brought partners to the state, partners like Pioneer Natural Resources which now has production at Oooguruk, and Eni which has production at Nikaitchuq. The company's most recent partner, Repsol, is exploring on the North Slope, while with another set of partners the company is producing gas on the Kenai Peninsula in Southcentral Alaska.

Armstrong said that because Alaska is expensive the company needs partners and what they hear when looking for partners is that while Alaska's resource base is recognized, the state isn't perceived as a good place to do business.

People who aren't here don't come because of ACES, Armstrong said.

He cited the few rigs running in Alaska compared to the number of rigs elsewhere, and called it "anemic" and "pathetic."

Armstrong said the governor's proposal isn't perfect and needs to be tweaked, but said he was a supporter.

Oil and gas companies are out there to make money, Armstrong said, and said they are voting with their feet, indicating that while Alaska is a great place to find oil, it's not a great place to make money.

Brooks Range caught in change

Bart Armfield, chief operating officer of Brooks Range Petroleum Corp., said the company came to Alaska in 2000 when oil prices were very low and they struggled to break even with Lower 48 prices.

What brought them to Alaska, he said, were big reserves and high production rates — and, in 2000, an acceptable cost of doing business in the state. But that was under ELF.

The world-class reserve base Alaska has to offer isn't the advantage it was then, he said, with high oil prices and technology advancements opening up opportunities in the Lower 48.

Armfield said it's very difficult to find companies interested in coming to Alaska. Brooks Range has been here 12 years and has yet to make a revenue

see **OIL TAX DEBATE** *page 24*

FINANCE & ECONOMY

Foley to head Pioneer in Alaska

Pat Foley, currently Pioneer Natural Resources Alaska's land and external affairs manager, will become president of the Alaska division in May. Todd Abbott, who has been president of Pioneer Natural Resources' Alaska division since November 2011, will be moving back to Texas to manage the company's business in Texas, Foley told the House Resources Committee Feb. 18.

Foley has been with Pioneer since 2002.

—PETROLEUM NEWS

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BC LNG

thousands of jobs before Alberta backed down.

A spokesman for the Canadian Association of Petroleum Producers raised concern about how the government is making it assumptions, including the projection of a new tax on LNG.

"I think it will cause the industry to reflect on its business assumptions," he told the Vancouver Sun. "I don't think it will send anyone running to the hills, but they are going to take a long look at this and decide what it might mean to them."

The spokesman said the LNG industry is competitive, capital is fluid and despite price differences of C$3.50 a unit in North America and C$15 a unit in Asia, the margins, once all the costs of development are considered, are quickly whittled down to just a few dollars per unit.

'Biting the hand'

Peter Doig, a former financial analyst, told the Globe and Mail that British Columbia has suddenly swung from subsidizing road construction to stimulate natural gas activity to "biting the hand that's going to feed" the province.

He said some of the economics of the government's targeted LNG goals are open to question.

"If you throw in higher royalty rates, that's a nail in the coffin," he said.

Steven Paget, an analyst with FirstEnergy Capital, warned that British Columbia is also faced with challenges from gas in Alberta that could be used in the same LNG pipeline networks.

Greg Kist, president of the Petronas-operated Pacific Northwest LNG project, suggested the industry could easily switch from financing LNG development to producing into a North American market if that offered better returns.

Those warning flags have already been waved by Chevron, which recently took over control of the Kitimat LNG project.

Its Chief Executive Officer John Watson has issued veiled cautions that it will take "substantial (LNG) prices to underpin developments (in British Columbia) of tens of billions of dollars and therefore some projects will go and some will not."

The Clark government's multibillion-dollar revenue estimates cover direct taxes paid by LNG facilities and royalties collected from natural gas extraction to support the projects, plus personal income tax revenues from jobs created by the LNG sector.

The grand objective held out by the government is that a minimum C$100 billion will be fed over 30 years into a newly created B.C. Prosperity Fund that could erase the province's debt, currently at C$58 billion, by 2028, although the fund could be used for other options, including eliminating the provincial sales tax. (Alberta is the only one of Canada's 10 provinces that is debt free).

"The safe recovery and export of our abundant supply of natural gas presents an opportunity for prosperity unlike anything we have ever seen," Clark said in a news release.

She said LNG is "poised to trigger approximately C$1 trillion in cumulative GDP within British Columbia over the next 30 years."

The government based its forecasts on analysis by independent consultants along with sector information gathered by the government from global natural gas and LNG forecasters and forecasts of potential natural gas production in British Columbia.

Concerns brushed off

Energy Minister Rich Coleman brushed off the concerns, predicting that by 2020 British Columbia, building on "trillions and trillions" of cubic feet of gas resources in the province's northeast, will have "very much matured into the marketplace."

He said there is also evidence that LNG investment in British Columbia will create a new demand for natural gas exploration and development over the long-term.

"The message really is that B.C. has an opportunity to participate in a new LNG market that could create lasting benefits for many years," he said.

Gary Leach, president of the Explorers and Producers Association of Canada, said any revenue projections stretched over several decades for any resource commodity are highly speculative, based as they are on assumptions about commodity prices, including global economic growth — especially in Asia — and competing energy supplies.

He said the Clark government needs to determine whether LNG proponents will be successful in extracting from Asian buyers the prices they need to justify going forward.

Leach noted that Chevron recently said that venture will need higher oil-linked prices or it will not proceed. ●

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OIL PATCH BITS

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.

There are 12 sites in Alaska with the AKOSH VPP designation. For a complete listing of the sites and more information about the program, go to www.labor.alaska.gov/lss/vpp-participants.html.

Larson Electronics adds explosion proof signal light

Larson Electronics said Feb. 18 that it has added EPL-TL-2X10W-C LED traffic light to its line of industrial grade LED lighting solutions. This heavy duty unit features explosion proof approval and cool running LED lamps for high output and excellent visibility and is ideal for use as a traffic control device in servicing and refueling areas where flammable gases and vapors are present.

The EPL-TL-2X10W-C explosion-proof LED traffic light provides an effective signal light solution for hazardous locations where vehicles, equipment and aircraft are routinely serviced or maintained. This two color signal fixture operates similarly to a standard traffic signal and features copper free aluminum lamp housings that have been powder coated for a durable finish that resists corrosion. The signal lamp housings can withstand 1490 pounds PSI hydrostatic pressure and are waterproof, making them well suited to use in wet locations such as marinas or areas where hose downs are a part of regular maintenance. The red and green signal lights are LED powered for bright illumination and a long 50,000 hour lamp life, and feature colored Pyrex cover globes for brilliant coloration and added durability.

For more information visit www.LarsonElectronics.com.

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LIBERTY

regional director Mark Fesmire, granted BP a suspension of production on Liberty unit leases OCS Y-1585 and Y-1650. The effect of the action is to extend the leases.

The agency made the decision after reviewing BP's Nov. 20 suspension request and revised plan of operation.

BSEE made reference to the "final design, fabrication and construction" necessary to achieve Liberty production by December 2020. But the two-page letter didn't specify exactly what sort of development BP now has in mind to tap the field.

Fesmire's letter said BP wanted "an unreasonably long period of time" to submit a new development and production plan.

The agency determined two years would be enough time. And so, BSEE gave BP a deadline of Dec. 31, 2014.

BP will need to provide progress reports every three months on its efforts to develop the plan, the letter said.

Once the plan is in, BSEE's sister agency, the Bureau of Ocean Energy Management, will conduct a regulatory review and prepare National Environmental Policy Act documents. Then BOEM will issue a "record of decision" on whatever BP proposes.

Gulf disaster, rig trouble

Exactly how to access the offshore Liberty field has been the subject of much thought.

The initial idea was to build a gravel island at Liberty with production facilities and a buried subsea pipeline to carry the oil ashore. That's what BP did for its Northstar field, which sits in federal and state waters northwest of Prudhoe Bay.

BP's Endicott field also runs on an island, but a causeway connects it to land.

Ultimately, BP chose to develop Liberty by drilling from a satellite island built onto the Endicott installation.

This approach offers advantages, such as reducing Liberty's footprint and avoiding potential impacts to bowhead whales important to Native subsistence hunters. From a practical standpoint, Liberty oil could be produced using the existing facilities, pipeline and road access at Endicott.

BP said the planned Liberty wells would be technological marvels. The wells would go down two miles and bend out horizontally for six to eight miles to tap the reservoir, making them among the longest extended-reach wells ever attempted.

But the Liberty project hit turbulence that never allowed it to get off the ground.

BP's Deepwater Horizon blowout in the Gulf of Mexico in April 2010 prompted the Obama administration to impose a temporary moratorium on deepwater drilling, and on exploratory drilling in the Arctic.

Although Liberty was exempted from the moratorium because the drilling would be done from the Endicott satellite island, close to shore, the project nevertheless drew increased scrutiny.

U.S. Sen. Frank Lautenberg, D-N.J., called for a halt to Liberty.

"In an attempt to escape federal regulation of offshore drilling, BP has built an artificial island in the Beaufort Sea and claimed its project is therefore being carried out 'onshore,'" Lautenberg said in a June 24, 2010, letter to the Obama administration.

BP also encountered problems with the Liberty drilling rig. In November 2010, BP said it was suspending the Liberty project, saying the rig needed an engineering review. Parker, in a filing with the U.S. Securities and Exchange Commission, said the review would include the rig's safety systems.

After the review, BP said the rig needed substantial modifications to its mud, hydraulics, pipe handling, heating and other systems. The company also said it believed the project costs would be at least double the original $1.5 billion estimate, and "it would take several more years before drilling could commence."

Concept selection

BP, however, stopped short of saying Liberty was dead.

Damian Bilbao, head of finance for BP Alaska, touched on Liberty during a Feb. 8 hearing of the state Senate Resources Committee.

"Has Liberty been canceled or set aside for a brief period of time or where are we on Liberty?" asked Sen. Peter Micciche, R-Soldotna.

Bilbao said BP had received the suspension of production from the federal government, and said Liberty "is still an attractive project that competes globally for capital."

BP Alaska spokeswoman Dawn Patience said the two-year suspension period would give the company time to identify potential development options for the Liberty unit.

"BP remains committed to the development of this resource for the benefit of Alaskans and U.S. energy security," she said.

What might the refocused project look like?

"Our concept selection process has been initiated," Patience said. "However, it may be a year or more before we determine the specifics regarding a development concept. During the initial project planning for Liberty, BP examined an island connected to land by a subsea pipeline similar to the Northstar design. We have successfully constructed and operated the Endicott and Northstar production islands."

And what will become of the behemoth Liberty rig?

"We are currently working to determine the best use for the rig," Patience said, noting it's still standing on the Endicott satellite drilling island. ●

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GAS PROSPECT

the company exclusive exploration rights over about 580,147 acres of state land.

The Kroto Creek prospect is located on what's known as Susitna basin exploration license No. 2.

Cook Inlet Energy executives have spoken highly of the Susitna basin's gas prospects.

Cook Inlet Energy is a relatively new company and a subsidiary of Tennessee-based Miller Energy Resources Inc. Miller itself is a small company, but is listed on the New York Stock Exchange.

Cook Inlet Energy operates a number of properties on the inlet's west side, including the West McArthur River oil field and the offshore Redoubt unit and Osprey platform.

The company is pursuing a program of reviving wells on the Osprey platform, which was shut-in when Cook Inlet Energy and Miller acquired it in a late 2009 bankruptcy sale.

On Feb. 12, Miller announced completion of a successful workover on a second gas well on Osprey.

Cook Inlet Energy has been scrambling to establish its own gas supply to power field operations and avoid costs of more than $450,000 per month to acquire fuel gas from third-party suppliers.

The workover of the RU-3 well involved "a complex fishing job to remove materials and equipment left in the wellbore" by a previous operator, a Miller press release said.

In January, Cook Inlet Energy put the RU-4 gas well into production after a recompletion.

The company expects to not only produce enough gas for its own needs, but to sell some gas as well.

Miller Energy also announced, in a Feb. 15 press release, that it had completed a public offering of preferred stock, raising gross proceeds of $14.3 million.

Net proceeds to the company will be used for "general corporate purposes," Miller said. ●

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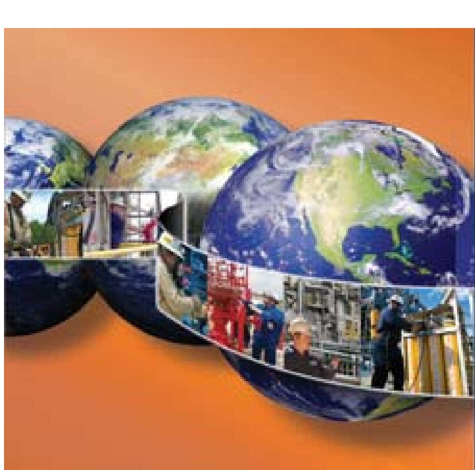

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OIL TAX DEBATE

stream, he said.

Credits under the present system have helped keep them going, he said, even though the company doesn't qualify for exploration incentive credits because it is working prospects which aren't far enough out to qualify.

He said Brooks Range supports elimination of progressivity but changes in credits are a problem, as credits have helped keep the company going.

On the gross revenue exclusion, Armfield said that because of its constraints it would not be applicable to areas the company is working which have been part of units in the past.

Pioneer in production

Pat Foley, land and external affairs manager for Pioneer Natural Resources Alaska, said the company came to Alaska in partnership with Armstrong Oil & Gas and when it put Oooguruk into production became the first independent operator on the North Slope.

But the state's tax system has changed, he said, noting that the company came to the state under ELF and Oooguruk development was approved under ELF.

PPT as proposed would have been a modest increase over ELF for Pioneer, Foley said, but as enacted with progressivity it was much worse.

The tax system in the state needs to be favorable and stable, he said.

He said the elimination of progressivity was a positive of the governor's proposal, as was the extension of the small producer credit, gross revenue exclusion and escalating the loss-carry-forward credit.

But, he said, the proposal disadvantages smaller new projects. The loss of capital credits is a disadvantage, as is the complicated carried-forward-loss calculation.

Foley said the lack of GRE for legacy fields was a disadvantage.

And, he said, as the company works to prove up its Nuna project, the Alaska development must compete for limited capital against low-risk, fast-cycle projects in the Lower 48. ●

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