Petroleum news

page 3 Q&A: Giessel works LNG project, Arctic policy issues over interim

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Tug on duty

COOK INLET REGIONAL CITIZENS ADVISORY COUNCIL

The Bob Franco, seen here at the Homer dock on Nov. 12, is a newly built tugboat now stationed in Cook Inlet to assist tankers calling at the Tesoro refinery at Nikiski, on Alaska's Kenai Peninsula. The 120-foot, 5,360-horsepower tractor tug is specially designed to cope with the inlet's turbulent, icy conditions. The tug belongs to Seattle-based Harley Marine Services. It will operate under contract for Tesoro.

Oil revenue forecast down, driven by dropping oil prices, production

The Revenue Sources Book, released Dec. 4 by the Alaska Department of Revenue, projects a $2 billion drop for fiscal year 2014 (ending June 30, 2014) in all oil and gas revenues, which form the majority of the state's unrestricted general fund revenues.

FY '14 includes six months of oil taxes collected under ACES, Alaska's Clear and Equitable Share, the old production tax system, and six month of oil taxes collected under the changes enacted in Senate Bill 21, which the administration is now calling MAPA, the More Alaska Production Act, most of the provisions of which become effective Jan. 1.

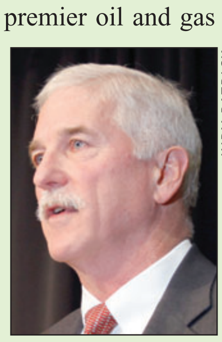
Unrestricted petroleum revenues for FY '13, which ended June 30, totaled $6.352 billion (with $15.8 billion from all sources, compared to the spring forecast of $17.696 billion from all sources), while the projected total for unrestricted petroleum revenues in FY '14 is $4.36 billion, $3.935 billion for FY '15 ($12.76 billion for all revenues in FY '14 and $12.342 billion in FY '15).

The largest portion of unrestricted oil and gas revenues comes from oil and gas production tax: $4.1 billion in FY '13 and pro-

see **REVENUE FORECAST** *page 14*

Massive resource: Prudhoe, Kuparuk dominate North Slope oil production

With hydrocarbons equivalent to around 80 billion barrels of oil discovered on the North Slope and much of this resource yet to be produced, the region remains a premier oil and gas province, Dave Lachance, vice president, reservoir development, for BP Exploration (Alaska), told the Resource Development Council's annual conference on Nov. 20. And around three-quarters of that discovered resource sits in two primary fields: Prudhoe Bay and Kuparuk, Lachance said.



JUDY PATRICK

DAVE LACHANCE

"As go Prudhoe and Kuparuk, so goes the North Slope," he said.

Economic underpinning

While the Kuparuk field, by itself, is massive, the Prudhoe Bay field, with around half of the total discovered hydrocarbons, has provided the economic underpinnings of all North Slope development.

"It's the reason we have the North Slope. It's the reason we have the (trans-Alaska) pipeline. It's what set everything up,"

see **PREMIER PROVINCE** *page 18*

NATURAL GAS

Going for gas sales

Cook Inlet Energy aims to become a direct marketer, but Enstar resisting

By WESLEY LOY
For Petroleum News

Cook Inlet Energy LLC plans to start marketing natural gas directly to commercial customers for space heating.

Direct marketing appears to offer the best opportunity for gas sales at present, company representatives told the Regulatory Commission of Alaska on Nov. 27.

"CIE's vision for direct gas marketing is that we'll provide some competition and that will be an improvement for the consumers," said Mark Slaughter, commercial manager for Cook Inlet Energy.

Slaughter and company President JR Wilcox told commissioners Cook Inlet Energy already had lined up its first customer, the O'Malley Sports Complex in Anchorage.

Cook Inlet Energy, however, would appear to face serious resistance to its direct marketing plan from Enstar Natural Gas Co., the main gas utility serving the greater Anchorage area.

Just hours before the Cook Inlet Energy managers made their presentation to the RCA, Enstar filed revisions to its tariff that likely would make it harder for direct marketers to grab customers.

Growing gas production

Anchorage-based Cook Inlet Energy is a sub-

see **GAS SALES** *page 15*

EXPLORATION & PRODUCTION

Doyon still encouraged

Corporation: Nunivak No. 2 well showed promise but no commercial discovery

By ALAN BAILEY
Petroleum News

Doyon Ltd. has announced the completion of its Nunivak No. 2 exploration well in the Nenana basin, in the Alaska Interior about 50 miles southwest of Fairbanks. The well encountered features indicative of an oil and gas system in the basin but did not find a commercial oil or gas resource, the Native regional corporation said Nov. 27. The well, about 16 miles west of the community of Nenana on the George Parks Highway, has now been plugged and abandoned, Doyon said. The corporation said that Nabors Alaska Rig 105 drilled the well to a vertical depth of 8,667 feet and also conducted some side-tracking from the well.

AARON SCHUTT

The Nunivak No. 1 well, drilled nearby to a depth of 11,100 feet in 2009 by a partnership including Doyon, also found promising subsurface indications of a petroleum system but did not encounter commercial quantities of hydrocarbons.

Oil and gas indications

"The Nunivak No. 2 drill program was only the second deep test of this basin," said Aaron Schutt, Doyon's president and CEO when announcing the drilling results. "Despite the disappointment of a non-commercial effort, other results from the well clearly indicate the potential for sig-

see **DOYON DRILLING** *page 19*

NATURAL GAS

A taxing time for BC

Province delays release of LNG fiscal regime; details likely in budget in February

By GARY PARK
For Petroleum News

British Columbia's Natural Gas Development Minister Rich Coleman has built a reputation during 12 years in the provincial government's cabinet as a cool head in pressure situations.

But even he, in a rare moment of candor, has conceded that his role as ringmaster in the LNG circus is the most complex of his political career.

RICH COLEMAN

During a conference call on Nov. 19, Coleman offered an insight into just how complex as he backed down from his goal of presenting the basic parameters of an LNG tax by the end of November.

He said the objective now is for the government to have its "internal decision completed by the end of December," and even then the details won't be made public.

"The intention is to get to a position where we can actually tell the industry, whether it be in a confidential way or not, what we think the formula is," he said.

Formalization confidential

"The formalization of tax law ... is highly confidential. We're not in a position to disclose that

see **TAXING TIME** *page 20*

contents

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

GOVERNMENT

Giessel works LNG, Arctic policy issues

Senator notes importance to Alaska of national Arctic policy, believes excessive natural gas tax would put state out of LNG market

By STEVE QUINN
For Petroleum News

Sen. Resources Committee Chair Cathy Giessel has been plenty busy during the interim and less than two months await the Legislature's return. Since adjourning, the Anchorage Republican has spent time learning as much as she can about the liquefied natural gas market and serving on the state's Arctic Policy Commission, work that's taken her to Barrow, Unalaska and Iceland.

Giessel spoke to Petroleum News about what she's learned during the interim and what the state might expect from the upcoming session.

Petroleum News: Let's start with Iceland. What were your takeaways from the trip?

Giessel: I attended two events while I was there. The first was an Arctic energy summit, which was sponsored by the Institute of the North and that was interesting because we talked a lot about ocean renewables and digital connections across the Arctic areas. There were several presentations from Alaska companies and Alaskans. About 200 people attended that conference and 30 to 40 of them were Alaskans so we had a significance presence. What was interesting is that all of their energy is produced through renewables and because of their very low cost of hydro power they attracted Alcoa Aluminum to site their plant there in Iceland, which is incredible. The raw materials are shipped to Iceland, but because of the low cost energy they were able to attract the large industry to their areas. The Icelanders were not used to having a large industry present. We have those up in the North Slope and that significant growth that we experienced during the construction of TAPS. This was a new experience for them. As far as the social environment, they are trying to get used to the compact, multifamily housing, which is not part of their culture.

The second meeting was the Arctic Circle. There were about 1,000 people there and again Alaska had pretty good representation. It used to be called the Arctic Imperative and it used to be held in Girdwood. It's a meeting put together by Alice Rogoff (Alaska Dispatch Publisher). She has a friendship with the president of Iceland and he said let's make this a bigger meeting. They talked about marine transportation and energy development. The president of Greenland spoke and she spoke about how they reached independence from Denmark. They are interested in developing uranium and their offshore oil and gas. The same is true of the Faroe Islands: Again, a possession of Denmark, very small islands, but wishing independence and developing their resources. This was helpful to me understanding the worldwide resources in the Arctic and how other countries are pursuing that resource development.

Petroleum News: There is often scrutiny when lawmakers take trips like that. How do you defend against any kind of scrutiny?

Giessel: I serve on the Arctic Policy Commission. The single goal is to assist the U.S federal government in writing Arctic policy. We live rather isolated in Alaska in that we don't necessarily have international exchange of ideas and goals. In addition the U.S. hasn't recognized itself as being an Arctic nation until recently. Seeing what other countries are doing and looking at the broader picture at the kind of international regulatory ideas being floated out there is helpful to me.

SEN. CATHY GIESSEL

For example, the energy summit, one of the breakout groups was on resource development and one of the ideas put forth was that all of the Arctic nations form a federation. That's significantly different than the type of United States representative republic that we are part of. Those ideas are becoming more prevalent in our world. These kinds of things we need to be aware of. Even now, we are signatories to the International Maritime Organization. They are working on a compulsory polar code right now. This will define what kind of vessels will be allowed to transit our oceans through the Arctic. Right now, we have an emission control area being enforced in North America and this is part of the IMO's regulatory regime. This area is requiring significant changes in the type of fuel our shipping vessels are using. In fact the type of fuel they are requiring is of such low sulfur content, that it's not available right now. This will significantly change the cost of Alaska's goods. We are going to be significantly impacted. This came from the IMO. It came from the U.S. signing on to this treaty. It's important for Alaska lawmakers to understand.

Petroleum News: Still in the Arctic, let's move onto the Arctic Policy Commission. What do you believe you folks have accomplished so far?

Giessel: The commission has been working really hard. We've met three times so far since the session ended. We are divided into three teams addressing specific matter based on our teams. Mine is the oil, gas and minerals development team. Two months ago we took on oil spill prevention and response. These are chapters in the overall commission report which will go to the Legislature by Jan. 30.

My team has been taking a deep dive into what resources the state has, but how we are developing them has been our main focus. What is our regulatory structure? Is it effective? Where are the gaps, if there are any? That's what we've been working on and the same types of questions have been applied to oil spill and response. It's been very informative and very encouraging. As an Alaskan I'm very proud of the way we develop our resources and protect our environment. Yet to dive into it, it's even more encouraging. We do a good job in these areas. We've learned a lot from the Valdez oil spill in terms of preparedness. What kinds of infrastructure, not only in materials but also people, need to be close by and readily deployable? At this point the commission is merging these reports. I've appreciated the residents who have been members of a commission. There are 10 members of the Legislature. The rest of the team are all private citizens who are subject matter experts. They are so informed and that's made it a good partnership. Listening to the reports of the other teams has been very informative.

Q AND A

Petroleum News: You mentioned adding the oil spill prevention duties to your group. Did the Kulluk incident have anything to do with that? The commission's first meeting during the session came on the heels of the grounding in Kodiak.

Giessel: No. The reason oil spill prevention and maintenance was added was, as we were working on our oil and natural gas development team, clearly spill response was part of oil development whether it was onshore or offshore. We went to the commission and said let's

see GIESSEL Q&A page 17

● GOVERNMENT

Canada launches sales pitch

Allocates C$40 million to promote energy sector, compared with government's entire advertising budget of C$65 million last year

By GARY PARK

For Petroleum News

The Canadian government is opening its wallet to spend C$40 million on a campaign to promote the importance of its energy and drown out its domestic and global critics.

Faced with relentless criticism of its role in developing the Alberta oil sands and its environmental stewardship in the oil and natural gas sector, the government has set a budget for Natural Resources Canada of C$24 million for international advertising and C$16.5 billion for the domestic market.

But the campaign clashes with further evidence that government will fall short of its commitment to cut greenhouse gas emissions to 17 percent below 2005 levels by 2020, with the latest statistics forecasting that Canada will produce 734 million metric tons of GHGs in 2020, 122 million metric tons above its target.

"The government has a responsibility to provide Canadians with the facts to assist them in making informed decisions," Natural Resources Minister Joe Oliver told a House of Commons committee, in defending the sales pitch.

"This engagement and outreach campaign will raise awareness in key international markets that Canada is an environmentally responsible and reliable supplier of natural resources."

Value of Keystone XL cited

The C$40 million compares with the government's entire advertising budget last year of C$65 million and the C$237,000 Natural Resources Canada spent in the 2010-11 fiscal year.

Asked to justify the spending, Oliver said that winning over U.S. support for TransCanada's Keystone XL pipeline is vital to create "tens of thousands of jobs."

Defending the promotion of just one industrial sector, he said: "You justify it by what it's going to achieve and there are billions, tens of billions of dollars, in play."

Peter Julian, the natural resources spokesman for the opposition New Democratic Party, said he did not see how the government could justify spending so much taxpayers' money on a job that should be the responsibility of the private sector.

He said the advertising would not work because the policy choices of Prime Minister Stephen Harper's administration have "killed the possibility" of gaining public support for major resource projects by slashing environmental assessments and restricting "meaningful public consultation" on pipeline proposals.

Julian argued the backlash has been "world wide ... Canada has a black eye. There's no doubt."

Panel working technology issues

To gain a "social license" to approve new projects, Oliver's department has asked a 13-mmber panel of the Council of Canadian Academies to chart a way forward for technologies that can help reduce the environmental footprint of oil sands development.

The council was created in 2005 with a 10-year, C$30 million government grant to provide peer-reviewed, science-based assessments to help shape public policy.

The government has frequently held out hope that technology will put Canada on the road to its GHG pledge, but Environment Minister Leona Aglukkaq admitted to a House of Commons committee that she is not yet ready to unveil long-delayed rules on curbing GHGs at the oil sands.

"We want to get this right for Canada and when I'm ready to release this information then it will be released publicly," she said.

Canadian negotiators told the international community last year that they were "working toward draft regulations for 2013," and a few months later Aglukkaq's predecessor Peter Kent said the government was "very close" to finalizing the regulations for oil and natural gas companies.

Lack of GHG regs an issue

John McKay, environment spokesman for the Liberal party, said Aglukkaq's promise to work with the provinces and territories on climate change were "a little late in the day" because of the Obama administration's pending decision on Keystone XL.

He said the Harper government's failure to deliver the regulations has turned Keystone XL into a proxy fight over climate change policy that could harm the Canadian economy.

"As long as we have no GHG regulations (President Barack) Obama is in a very, very awkward position" when it comes to deciding on Keystone XL, McKay said. ●

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CORRECTION

Draft discharge permits

The article titled "Geotechnical discharge permit proposed" in the Dec. 1 issue of Petroleum News incorrectly stated that the Environmental Protection Agency has issued general permits for discharges into the ocean from geotechnical operations on the federal outer continental shelf of the Chukchi and Beaufort seas. In fact, the agency has issued a draft permit for this type of general permit for both seas, in parallel with the issue of a similar permit by the Alaska Department of Environmental Conservation for state waters of the two seas. EPA and ADEC have set identical closing dates of Jan. 27 for public comments on their permits, have scheduled a joint agency public hearing in Barrow on Jan. 8 and have scheduled an additional hearing in the form of a teleconference on Jan. 10. Public meetings will also be held in Kaktovik and Wainwright.

● GOVERNMENT

Some keys to success in the Arctic

BOEM director says future oil exploration & development will depend on factors such as public confidence, respect for communities

By ALAN BAILEY

Petroleum News

As someone who grew up in Alaska, Tommy Beaudreau, the director of the Bureau of Ocean Energy Management, or BOEM, says that he understands the critical importance to the state of the oil and gas industry.

"In a very personal way energy and resource development are well understood to me to be the life blood of this state and what so many families in Alaska are dependent on," Beaudreau told the Resource Development Council's annual conference on Nov. 20.

At the same time Alaskans wish to protect the Arctic landscapes, he said.

Beaudreau focused on Arctic Alaska, where he sees six key factors required for successful resource development, in a situation where the sensitive environment is changing and where Native people depend on subsistence hunting for food and for maintenance of their culture.

"Arctic exploration poses substantial and unique operational challenges to resource development. It's an expensive place to work. There are difficult logistics involved," Beaudreau said. "Although there are those significant operational and environmental challenges, the resource potential is enormous. The Chukchi Sea, for example, is second only to the central Gulf of Mexico in terms of estimated undiscovered, recoverable oil and gas resources."

Safety and the environment

The first key to success in Arctic Alaska is a successful safety and environmental performance, Beaudreau said. He said that the National Petroleum Council, a federal advisory committee, had recently published the results of a study into prudent development conducted by a team of experts from industry; state and federal government agencies; conservation groups; financial institutions; and academia. That study emphasized that the critical path to sustained and expanded resource development in North America includes effective regulation and a commitment by industry and regulators to continuous improvement in eliminating or minimizing environmental risks, Beaudreau said.

JUDY PATRICK

TOMMY BEAUDREAU

"I think this is especially true in the Arctic," Beaudreau said. "And it also represents what I believe is a key and fundamental insight into the relationship between industry, government and public confidence."

In fact, public confidence that industry is operating responsibly, with strong, fair and independent regulatory oversight, is the second key to Arctic success, he said.

Contingency preparations

A third key is adequate preparation for all contingencies in the remote, inhospitable and unforgiving Arctic environment, especially offshore where there is a lack of support infrastructure.

"Contingency planning and preparedness are absolutely critical," Beaudreau said, commenting that operators spend huge amounts of capital and expend equally huge amounts of planning effort on contingency arrangements. Regulators spend much time focusing on questions such as how to deal with a worst case accident scenario, recognizing their responsibility to seek good answers and thus bolster public confidence while tamping down opposition.

Respect for communities

Having respect for Arctic communities, recognizing their needs and concerns is a fourth key, Beaudreau said.

"Concerns about food security and traditional ways of life in villages are real and they're significant," Beaudreau said.

At the same time, communities are interested in how exploration and development can bring them employment, revenue and new sources of income: Several companies have established relationships with the communities.

"The dividends are enormous and it is the right way to go about business," Beaudreau said.

Efficient permitting

Another key is coordination and efficiency in the permitting of exploration and development projects. In addition to being BOEM director, Beaudreau co-chairs the federal Interagency Working Group for coordinating the permitting of oil and gas projects in Arctic Alaska. Established by President Obama a couple of years ago, the working group has pulled together representatives from all the relevant agencies to address agency disconnects that in the past have plagued Arctic Alaska projects.

"Shell's 2012 operation became the test case for how that (permitting) process should work and I think we have a lot to be proud of through that process, and I think it worked pretty well," Beaudreau said. The working group is now applying its enhanced interagency coordination to projects such as ConocoPhillips' Moose's Tooth exploration in the National Petroleum Reserve-Alaska and Shell's planned Chukchi Sea drilling, he said.

Integrated management

A sixth key to success is the integrated management of Arctic permitting through a strategic vision for the region, Beaudreau said. Rather than permitting projects piecemeal, it is necessary to consider how the various projects might fit together, assessing any tradeoffs that might be involved and considering the priorities behind the permitting. For example, an exploration project in the Chukchi Sea might trigger a new offshore oil development that would require a new oil pipeline across the National Petroleum Reserve-Alaska. How would that interact with what companies are doing onshore? What would be the environmental concerns?

"We need to take the opportunity now on a very broad base and in an inclusive way to have a forum for working through all of those issues, and to have those considerations inform decision making on individual projects, so that we can be smart about how the pieces fit together to maximize the opportunities presented by the Arctic," Beaudreau said. ●

Contact Alan Bailey at abailey@petroleumnews.com

ASSOCIATIONS

AAEE to hear tidal, hydrokinetics talk

Doug Johnson, director of business development for Ocean Renewable Power Co., will discuss the economics of tidal energy and river hydrokinetics at the Anchorage Association for Energy Economics Dec. 11 at 12 noon at the BP Energy Center. The presentation will focus on the compelling nature of hydrokinetics and the economic challenges associated with its development. The presentation is free and open to the public.

—PETROLEUM NEWS

EXPLORATION & PRODUCTION

Kuukpik SAE permitting 3-D seismic

The state is taking comments on a multiyear 3-D seismic program that Kuukpik SAE LLC plans to conduct over the coming three winters across the central North Slope.

The proposed Umingmak 3-D seismic program is a joint venture between the seismic firm SAExploration Inc. and the Native corporation Kuukpik Corp. The program would cover some 3,681 square miles of largely on Kuukpik Corp. land around Nuiqsut.

The region includes the ConocoPhillips-operated Colville River, Mooses Tooth and Bear Tooth units and the Brooks Range Petroleum Corp.-operated Tofkat and Kachemach units, plus considerable un-unitized acreage in the so-called "billion-dollar fairway."

Kuukpik SAE described the program as being on behalf of "multiple clients."

The program would run during the tundra travel seasons from January 2014 to May 2016, covering between 200 and 400 square miles each winter, according to the company.

Kuukpik SAE plans to conduct the programs using 12 rubber-tracked vibrators in groups of three or four. The vibrator lines would be spaced at least 660 feet apart with receivers located every 110 feet along each line. The vibrators would have a frequency between 4 and 100 hertz, used between four to eight seconds for each "sweep," the company said.

The Division of Oil and Gas is taking comments on the plans through Dec. 30.

—A copyrighted oil and gas lease map from Mapmakers Alaska was a research tool used in preparing this story.

—ERIC LIDJI

● GOVERNMENT

NWT 'on track' for new era

Northwest Territories working regulations as it approaches taking over most of its onshore, offshore oil and natural gas activities

By GARY PARK
For Petroleum News

The Northwest Territories is within 18 months of gaining control over most of its onshore and offshore oil and natural gas activities, confident that "everything is on track" for the levers to pass from the Canadian government, Premier Bob McLeod said.

"There are a lot of moving parts, but we've finished an organization design, made job offers and introduced some of the legislation" needed to give the NWT powers that almost match those of Canada's 10 provinces, he said in an interview with Petroleum News.

The transfer of onshore jurisdiction over public land, water and resource development should still take place as scheduled on April 1, while a parallel agreement for the offshore should take place "fairly quickly, hopefully within a year of April 1," McLeod said.

He said five of seven aboriginal governments have signed the devolution agreement and "active discussions" are taking place with the other two, adding, "I don't think we will have any difficulties. We're getting closer (to a deal) all the time."

Energy regulator in works

The NWT is also working on the creation of its own energy regulator, with Industry Minister Dave Ramsay meeting with industry leaders and officials at the newly formed Alberta Energy Regulator, which is designed to consolidate the regulatory functions contemplated under the province's Responsible Energy Development Act.

But Ramsay told the Calgary Herald he is not certain what form the NWT's regulatory system will take, whether a tribunal structure makes sense and what role the National Energy Board should play.

He said the NWT intends to keep the industry informed about changes that will stem from devolution as well as understanding what steps the NWT can take to ensure companies continue to invest in Canada's North.

Regulatory hurdles cited

The biggest challenge was identified in October by Henry Sykes, president of northern explorer MGM Energy, who said regulatory hurdles are the main reason he believes that production growth in the NWT's Canol shale play in the Central Mackenzie Valley will have difficulty matching the prolific Bakken oil fields of North Dakota.

Sykes, who was part of an 18-member delegation of NWT government and aboriginal leaders who made a fact-finding tour of the Bakken in North Dakota and Saskatchewan, told the Globe and Mail: "It takes so long to get anything done in Northern Canada today that if more Bakkens develop in the U.S. by the time we finally decide that it's OK to develop the Canol we may find ourselves in the same position as the Mackenzie Gas Project (MGP) — nobody needs the product anymore."

He said MGM withdrew an application last year to drill its Canol acreage after the Sahtu Land and Water Board demanded an environmental assessment, which could "take years and cost millions of dollars and in the meantime you can't do anything."

Meetings with industry

McLeod, acknowledging the industry's unhappiness, said he held a "very good meeting" recently with most of the Arctic oil and gas companies, including Shell, Husky Energy, ConocoPhillips and MGM.

"We agreed to work together and meet on a regular basis," he said, noting that he is hopeful Imperial Oil and Chevron will start drilling within three years in the Beaufort Sea.

McLeod also said his government is "working very closely" with Alaska in exploring alternative options for getting NWT gas to market, possibly as LNG from Alaska, if the MGP plan to ship Mackenzie Delta gas to southern Canada and the Lower 48 "doesn't go through."

He said MGP operator Imperial believes that developing Arctic gas is cheaper than shale gas because fewer wells are needed. ●

Contact Gary Park through publisher@petroleumnews.com

● NATURAL GAS

Pros, cons of Alaska North Slope LNG

ExxonMobil execs review liquefied natural gas market, potential for Alaska, latest work on large-diameter line to Southcentral

By KRISTEN NELSON
Petroleum News

Alaska has advantages and disadvantages when it comes to a liquefied natural gas project, but there is potential for LNG from the state to go to Asia Pacific markets.

That was the message Richard Guerrant, vice president, LNG, ExxonMobil Gas and Power Managing Co., delivered to the Resource Development Council's annual conference Nov. 21 in Anchorage.


JUDY PATRICK
RICHARD GUERRANT

Guerrant began by highlighting differences between crude oil and LNG marketing and handling, including a vastly larger market for crude oil (some 4,000 oil tankers vs. 360 LNG carriers, with thousands of crude oil terminals compared to 87 LNG terminals); transportation costs for LNG four times that of crude oil; significant liquidity in oil markets compared to LNG, with regional supply and demand driving LNG prices compared to a global commodity market in oil; and a requirement for an LNG market to justify investment costs before development occurs.

The market for LNG is expected to grow about 5 percent a year through 2040, Guerrant said, from some 30 billion cubic feet a day in 2010 (200 metric tons a year) to approaching 90 bcf a day in 2040 (more than 600 metric tons per year), contrasting with a 1.5 percent annual growth overall for energy.

The estimated need in 2025 will be 200 million tons in additional suppliers, which is where Alaska has opportunities, he said.

There are challenges

But, Guerrant said, there will be competition for markets and for investor dollars in that 2020-30 period, with Wood Mackenzie listing 60 LNG projects under consideration, providing more than two units of supply for each unit of demand.

With that competition, only the most viable will proceed, he said.

Challenges for the Alaska project include commercial issues compared to the competition. The average construction time (final investment decision to project startup) is an average of four years compared to five to six years for Alaska, Guerrant said.

In addition to that longer construction timeframe, the Alaska project has the technical challenges of its remote Arctic environment and the risk that issues with obtaining U.S. permits could extend the time it takes for the project.

The commercial issue here, Guerrant said, is that the Alaska project requires customers to commit earlier than many competing projects. Financing for the project, likely to be the largest private sector project ever financed, is dependent on customer commitment.

Alaska advantages

The Alaska project also has advantages, Guerrant said, including its proximity to Asian-Pacific markets, the known gas resource and growth potential, Alaska's experience as a natural resource player and the experienced partners involved in the project.

But agreement on durable fiscal terms is required for the project to move forward, he said, as well as development of stable policies and regulations supporting the commercial and financial obligations required for the project.

Fiscal terms are key for an Alaska project to make the risk of the longer-term contract required before delivery worthwhile to investors, Guerrant said.

He said this was the time for government and producers to come together and work to ensure the Alaska LNG project has a place in the global market.

Integrated team significant

ExxonMobil's Steve Butt, project manager for the Alaska LNG project, said a significant difference in the LNG project, compared to earlier efforts, is that earlier projects didn't have all the skills working together.

With the integrated team (BP, ConocoPhillips, ExxonMobil and TransCanada) we can understand the system, Butt said.


JUDY PATRICK
STEVE BUTT

He reviewed project accomplishments, including agreement on a design concept in February and field studies this summer, and said the goal of the design and engineering work is to reduce project uncertainty — and to keep ramping up the engineering work, further reducing uncertainty.

The proponents have cited a project cost of $45 billion to $65 billion.

Butt said the goal is to get to $45 billion because given reliability, low cost wins when projects compete.

More field work

Field work this past summer saw 150 people gathering data required for permits, Butt said. In the summer of 2014, 300 people will be out in the field — and for a longer season, he said, with triple the work projected.

Engineering work continues, with a focus on licenses and permits, he said.

But, he warned, no one else is putting in a project this big in the U.S. and durable gas fiscal terms are needed so there is understanding of the commitment being made for 30 years by the builders, buyers and financiers, Butt said.

Natural gas at Prudhoe Bay is 12 percent carbon dioxide,

see NORTH SLOPE LNG page 9

● EXPLORATION & PRODUCTION

ANS month-over-month production up 4%

November averages 556,570 bpd of crude compared to 534,307 bpd in October; biggest increase at Prudhoe Bay, up 7.5% over October

By KRISTEN NELSON
Petroleum News

Alaska North Slope crude oil production averaged 556,470 barrels per day in November, up 4.15 percent from an October average of 534,307 bpd, but down 6.2 percent compared to November 2012 when the average was 581,940 bpd.

The largest month-over-month increase, 7.5 percent, was at the Slope's largest field, BP Exploration (Alaska)-operated Prudhoe Bay, which averaged 321,125 bpd in November, a 22,398-bpd increase over the October average of 298,727 bpd. Prudhoe Bay also had the largest month-over-month increase in October, up 2.6 percent, 7,577 bpd, from a September average of 291,150 bpd.

Prudhoe Bay production includes satellite production from Aurora, Borealis, Midnight Sun and Polaris, as well as from the BP-operated Northstar and Milne Point fields.

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

The ConocoPhillips Alaska-operated Kuparuk River field, the second largest on the North Slope, averaged 137,555 bpd in November, up 1.5 percent, 2,039 bpd, from an October average of 135,516 bpd. Kuparuk River production includes satellite production from, Meltwater, NEWS or Northeast West Sak, Tabasco, Tarn and West Sak, as well as production from the Eni-operated Nikaitchuq field and the Pioneer Natural Resources Alaska-operated Oooguruk River field.

AOGCC data for October shows Nikaitchuq production averaged 15,044 bpd in that month, down 2.4 percent, 365 bpd, from a September average of 15,409 bpd, while Oooguruk averaged 6,463 bpd in October, down 14.2 percent, 1,066 bpd, from a September average of 7,530 bpd.

AOGCC data for October shows that Cook Inlet crude oil production averaged 16,418 bpd in October, up marginally from a September average of 16,399 bpd.

Declines in production

Other North Slope fields all saw month-over-month production declines.

The ConocoPhillips-operated Alpine field, the farthest west field on the Slope, averaged 59,837 bpd in November, down 1.9 percent, 1,181 bpd, from an October average of 61,018 bpd. Alpine includes satellite production from Fiord, Nanuq and Qannik. AOGCC data for October shows that 65 percent of Alpine production in that month was from the main field, with 29 percent from Fiord and about 3 percent each from Nanuq and Qannik.

The BP-operated Lisburne field averaged 29,698 bpd in November, down 0.2 percent, 65 bpd, from an October average of 29,763 bpd. Lisburne production includes Niakuk, Point McIntyre and Raven.

The BP-operated Endicott field averaged 8,255 bpd in November, down 11 percent, 1,028 bpd, from an October average of 9,283 bpd. Endicott production includes Eider, Minke and Sag Delta, as well as production from the Savant Alaska-operated Badami field, the farthest east production on the Slope.

AOGCC data for October shows that Badami production averaged 1,235 bpd in that month, marginally down from 1,237 bpd in September.

Cook Inlet production steady

AOGCC data for October shows that Cook Inlet crude oil production averaged 16,418 bpd in October, up marginally from a September average of 16,399 bpd.

Two fields, both operated by Hilcorp Alaska, saw month-over-month production increases: Granite Point averaged 2,286 bpd in October, up 1.4 percent from a September average of 2,254 bpd, while Swanson River averaged 2,425 bpd, up 1.6 percent from a September average of 2,388 bpd.

All other Cook Inlet fields were down by at least a few barrels, with the largest per-barrel drop at the Cook Inlet Energy-operated Redoubt Shoal field, which averaged 1,644 bpd in October, down 155 barrels, 8.6 percent, from a September average of 1,799 bpd.

The Cook Inlet Energy-operated West McArthur River field saw the largest percentage drop, down 18.9 percent, averaging 515 bpd in October compared to 634 bpd in September, a difference of 120 bpd.

The Hilcorp-operated Beaver Creek field averaged 137 bpd in October, down 5 percent, 7 bpd, from a September average of 144 bpd.

The Trading Bay field, also operated by Hilcorp, averaged 2,138 bpd in October, down 4.3 percent, 97 bpd, from a September average of 2,234 bpd, while the Hilcorp-operated McArthur River field averaged 4,545 bpd, down 3 percent, 140 bpd, from a September average of 4,685.

Middle Ground Shoal, operated by ExxonMobil subsidiary XTO, averaged 2,198 bpd in September, down 2.7 percent, 61 bpd, from a September average of 2,259 bpd.

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

Contact Kristen Nelson at knelson@petroleumnews.com

● INTERNATIONAL

EIA posts new Russia energy overview

Government employs fiscal incentives to spur oil and gas development; progress seen as mixed on Sakhalin Island, LNG projects

BY WESLEY LOY

For Petroleum News

Russia isn't so different from Alaska in trying to encourage oil and gas development with tax and other fiscal incentives.

That's a key message gleaned from a new Russia overview from the U.S. Energy Information Administration. The report is posted at www.eia.gov.

Most of Russia's oil production comes from west Siberia, with the Sakhalin group of fields in the Far East contributing only about 3 percent of the country's total production, the EIA report says.

Russian companies are expanding into the Arctic and eastern Siberia, "spurred on by tax holidays and lower oil export tariffs," the report says. "While several new fields have come online since 2009, bringing additional fields into production will take time and may require a reformed oil tax regime from the government."

Global titan

Russia was the third-largest producer of oil, after Saudi Arabia and the United States, in 2012, the EIA says. It was the second-largest natural gas producer, after the United States.

"There are a number of proposals in various stages of planning and construction for new LNG terminals in Russia," including Yamal LNG, the EIA says.

Crude oil production was an estimated 9.9 million barrels per day in 2012, the report says.

Oil and gas is hugely important to the Russian economy, accounting for 52 percent of federal budget revenues and more than 70 percent of total exports in 2012, says the EIA, citing PFC Energy figures.

With traditional oil-producing regions in decline, east Siberia fields are expected to be central to expanding production in Russia, the EIA says.

The new 270-mile Eastern Siberia-Pacific Ocean Pipeline has boosted the region's potential, creating an outlet for east Siberian oil, the report says.

The 2009 startup of the Vankorskoye field, located north of the Arctic Circle, has dramatically increased production in the east Siberia region. Vankor, as the field is called, was the largest oil discovery in nearly three decades, and has produced about 430,000 barrels per day in 2013, the EIA says.

see **RUSSIAN PRODUCTION** page 14

EXPLORATION & PRODUCTION

Linc stakes two Umiat well locations

Linc Energy Operations Inc. recently staked two well locations at the Umiat field.

The subsidiary of the Australian exploration company Linc Energy Ltd. staked the Umiat No. 24 and Umiat No. 25 oil exploration wells on Nov. 27, according to the U.S. Bureau of Land Management, the agency that oversees resource development of federal lands.

Linc staked both well locations on lease AA-81726, a federal lease along the Colville River, and the location of other well locations permitted for the Umiat exploration program. It is also where Linc drilled the Umiat No. 18 vertical well earlier this year.

Earlier this year, Linc announced plans for a one-to-two well program this winter at the oil field in the foothills of the Brooks Range Mountains. The company said it would drill the Umiat No. 23H horizontal, and, time permitting, the Umiat No. 24H horizontal.

A notice of staking shows where a company is interested in drilling on federal land, but the company must still get traditional permits before moving ahead on drilling plans.

—ERIC LIDJI

PIPELINES & DOWNSTREAM

Royalty oil deal with Tesoro stretched

Tesoro is seeking an important change to a proposed deal to buy royalty crude oil from the state of Alaska.

As originally proposed, Tesoro was to buy the North Slope oil under a negotiated one-year contract.

Now the proposed deal is for two years. No other terms of the contract have changed, said Kevin Banks, a petroleum market analyst with the Alaska Department of Natural Resources.

Tesoro operates a refinery on the Kenai Peninsula at Nikiski. The plant is one of Alaska's main suppliers of gasoline, jet fuel and other products.

Royalty oil is the state's share of oil produced from leased, state-owned land. Royalty oil sales generate major revenue for the state.

Approvals needed

As only a one-year deal, the Tesoro royalty contract didn't require approval from the Alaska Legislature.

For the longer deal, however, legislative approval is needed, Banks said.

see **ROYALTY DEAL** page 14

continued from page 7

NORTH SLOPE LNG

CO_2, Butt said. That's a big deal, he said, and it's always been the Achilles heel of the project.

The CO_2 will be separated from the gas and reinjected. It has no value to the LNG project, Butt said, but does have value when put back into the ground.

Butt said the integration of Prudhoe Bay — prior to the acquisition of ARCO's Alaska assets by Phillips Petroleum (now ConocoPhillips) in 2000, ARCO operated one side of the field, BP the other — is a huge plus for the gas project because accessing gas can be understood in an integrated fashion for the first time.

Another challenge is keeping the gas cold as it is moved from the North Slope south. North of the Brooks Range there is continuous permafrost, which becomes discontinuous south to the Alaska Range. To keep the gas cold eight compressor stations, one about every 80 to 90 miles, will re-cool and re-pressurize the gas.

An Alaska LNG plant has some advantages, Butt said, because the compressors operate more efficiently at cold temperatures. It will be about 15 percent more efficient in Alaska than in Qatar, he said.

The liquefaction facility will include tanks, a jetty and two berths, with a ship expected about every two days.

Overall project construction will be modular, Butt said, noting that some of the first modules ever built were for Prudhoe Bay in the 1970s, so the LNG project would make use of a technique piloted in Alaska. ●

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EXPLORATION & PRODUCTION

BOEM asks Shell for more information

Having reviewed Shell's revised Chukchi Sea exploration plan, the Bureau of Ocean Energy Management has asked the company for more information. Shell, hoping to recommence its Chukchi Sea exploration drilling program in the summer of 2014, had filed its revised plan on Nov. 6. BOEM must deem the plan complete before releasing it for public comment. In a Nov. 29 letter to Shell, David Johnston, BOEM regional supervisor, Office of Leasing and Plans, said that additional information is needed before the agency can make that completeness determination.

Information that BOEM views as missing from the plan includes details of recent modifications to the Noble Discoverer drill ship.

Information that BOEM views as missing from the plan includes details of recent modifications to the Noble Discoverer drill ship. The agency also wants some additional information relating to the Polar Pioneer, the semi-submersible drilling rig that Shell has contracted as a replacement for its damaged Kulluk floating drilling platform. BOEM also says it needs more detailed information about some other vessels in Shell's drilling fleet, about an expanded man camp planned for Barrow and about some environmental issues.

BOEM also says that Shell's plan does not include sufficient information to adequately assess air emissions from the company's Chukchi Sea operations. The agency has taken over Arctic outer continental shelf air quality permitting from the Environmental Protection Agency but, rather than issuing an air permit, will assess compliance with air quality laws and regulations as part of its review of Shell's exploration plan.

Johnston, in his letter, confirmed that Shell has also filed an integrated plan for its proposed Arctic operations, as required by one of the findings from a Department of the Interior review of Shell's 2012 Arctic exploration activities. That plan, required to be more detailed than a traditional exploration plan, is still under BOEM review and may cover some of the information gaps identified in the exploration plan, Johnston commented.

—ALAN BAILEY

● GOVERNMENT

Transparency aim of Alaska oil regs

By BECKY BOHRER

Associated Press

The state has finalized rules to help determine what oil qualifies for special tax breaks under Alaska's new oil tax law.

The law championed by Gov. Sean Parnell and passed by the Legislature earlier this year is aimed at spurring more production. Alaska relies heavily on oil revenues to run state government, but oil production has long been on a downward trend.

The law, much of which takes effect Jan. 1, sets a base tax rate of 35 percent and provides a capped, per-barrel credit that the Parnell administration expects will apply to the vast majority of the legacy fields.

It also provides more generous tax breaks for so-called "new" oil. How best to define new oil was a sticking point during the legislative session. Metering would be used to calculate one of the most contentious types of oil that qualifies for tax breaks: oil coming from acreage that's added to existing producing reservoirs.

Companies seeking a tax break for this type of oil would be responsible for the metering. Mike Pawlowski, oil and gas program director for the state Revenue Department, said Dec. 2 that metering is a "very objective standard" that also provides transparency and predictability for the companies and the public. An earlier proposal also would have allowed companies to use an alternative methodology, but he said that left more discretion up to the department to decide what qualifies.

Separate meters would not be required for each well. Audit master John Larsen said the state would prefer companies aggregate wells from the expanded acreage and run them through a single meter for efficiency's sake.

Rep. Beth Kerttula, D-Juneau, worries the regulations could create a loophole that could allow oil from existing pools to get a better tax rate.

The law, much of which takes effect Jan. 1, sets a base tax rate of 35 percent and provides a capped, per-barrel credit that the Parnell administration expects will apply to the vast majority of the legacy fields.

According to the regulations, companies must show their plans have not been designed to cause wells in expansion areas to drain oil from an existing area if the oil could be extracted more efficiently by wells in the pre-expansion area. Kerttula said that provision is problematic if it means it's OK to produce oil from existing pools using new wells that qualify for tax breaks as long as it's more efficient.

Pawlowski said the provision actually is intended to protect the state and prevent drainage.

"It's theoretically possible to push oil to the new wells, but the cost and the time of it is incredibly inefficient," he said. The way the law was written, he said the state was willing to accept some drainage to new wells, but this provision in the regulations allows the state to take action if companies change their development plans specifically to cause drainage.

The regulations were released at the end of November. Kara Moriarty, executive director of the Alaska Oil and Gas Association, said by email that her group was still reviewing them to see if they addressed all the association's concerns.

Alaskans will get to vote next summer on whether to repeal the oil tax law in a referendum. Kerttula, a critic of the new law, said she doesn't expect the Legislature to address any lingering concerns with the tax overhaul during the upcoming session, which begins in January. "I think this is going to have to be a vote of the people to change this whole situation," she said. ●

● ENVIRONMENT & SAFETY

BOEM study analyzes North Slope spills

Finds that the number of spills relates to oil production rates but that large spills tend to be rare and somewhat unpredictable

By ALAN BAILEY
Petroleum News

The Bureau of Ocean Energy Management, or BOEM, has published the results of a study that the agency commissioned into the frequency and nature of oil spills from the Alaska North Slope oil infrastructure. Carried out by Nuna Research and Planning Group LLC, the study found that spills of oil volumes greater than 500 barrels are rare, random events. Small spills, on the other hand, appear to occur at frequencies that relate to oil production rates and tend to follow a somewhat predictable annual cycle.

But the dominance of just a few spills, much larger than the rest, obscures any statistical relationship between spilled volumes of oil and factors such as oil production.

1,577 spills

The study obtained data dating from 1971 to September 2011 from seven datasets sourced by BOEM, the Alaska Department of Environmental Conservation, the National Response Center and Nuka Research. The analysts only considered spills of one barrel of oil or more and did not include spills associated with the trans-Alaska oil pipeline. That resulted in a total count of 1,577 spills. Of those spills, 1,300 were of 10 barrels or less; 250 were between 10 and 200 barrels; and just two were greater than 1,000 barrels.

The largest spill, amounting to 5,053 barrels, was the 2006 spill at Gathering Center 2 in the Prudhoe Bay field. That one spill accounted for 15.5 percent of the total oil spilled on the North Slope, the study reported.

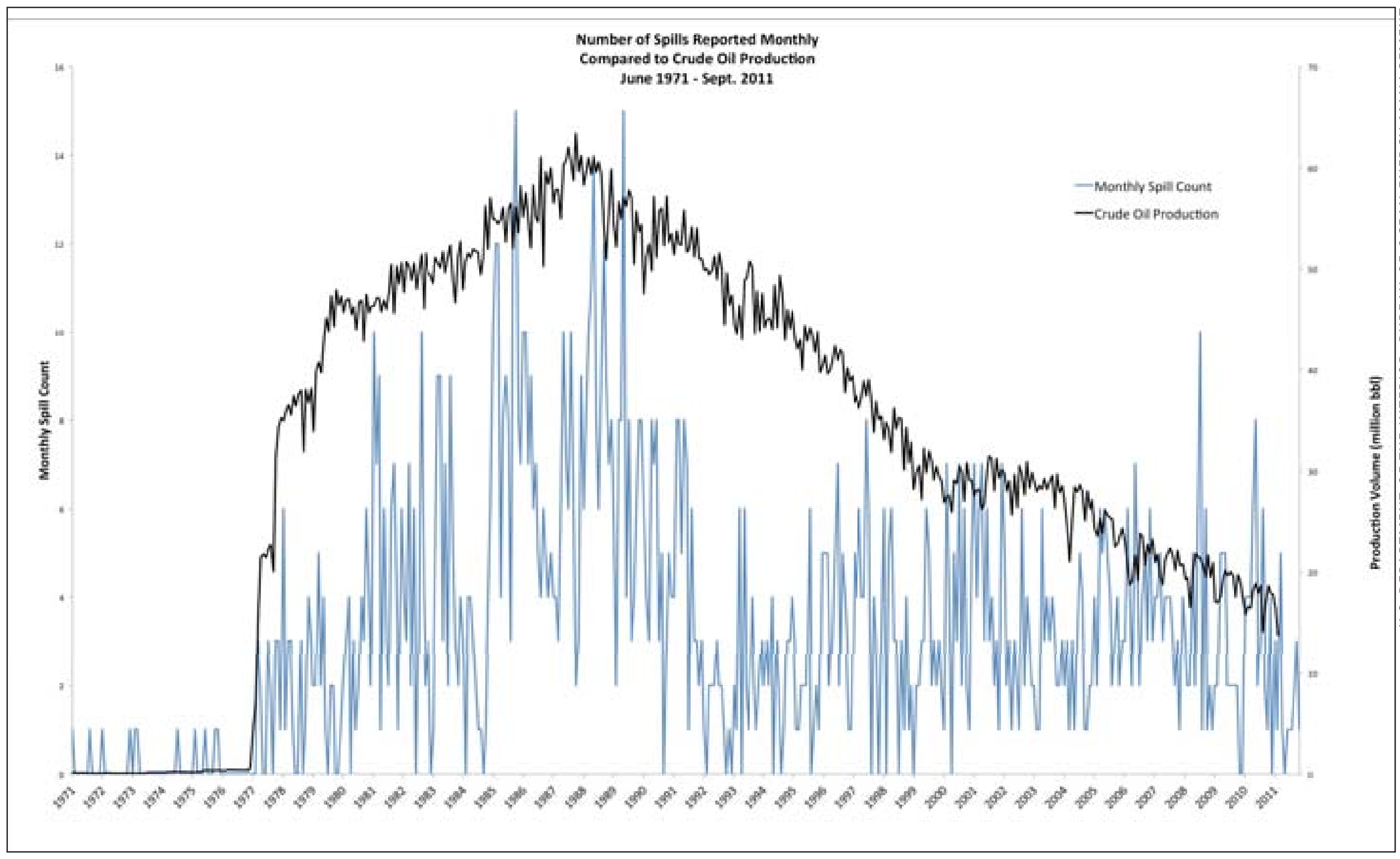
Mechanical failure

An analysis of the reasons for the various oil spills revealed some form of mechanical failure in the infrastructure to be the most common cause. Mechanical failure as a result of corrosion factored high in terms of volumes of oil spilled, a result strongly influenced by that Gathering Center 2 incident. Over-pressurization of equipment came second to corrosion in its contribution to the total spilled volumes.

Part of the purpose of the study was to conduct a statistical analysis of the spills, to try to identify parameters that might be used as predictors for the possible future occurrence of spills of various sizes. For this component of the study, the analysts decided to only use data from the 1,492 spills that happened between Jan. 1, 1980, and Dec. 31, 2010, thus eliminating some unreliable data prior to 1980 and avoiding the use of data from a partial year in 2011.

Pattern for small spills

Plots and statistical modeling of this data revealed that the frequency of small spills, especially spills of less than 10 barrels, followed a cyclical pattern during the course of each year, peaking in June and dropping to a minimum in October — the study report does not offer an explanation for this pattern. On an annual basis, the number of small spills tended to correlate with annual oil production, dropping over time as oil production declined. However, there was a break in this pattern in the early 1990s, at which time relatively few spills were recorded.



U.S. DEPARTMENT OF THE INTERIOR, BUREAU OF OCEAN ENERGY MANAGEMENT

Monthly figures for the frequency of oil spills on the North Slope show high levels of variability, but on an annual basis the spill frequency, especially for the smaller spills that dominated the data, roughly correlates with annual oil production. However, there were relatively few spills recorded in the early 1990s.

Larger spills do not exhibit any particular trend over time. Similarly, the study found that the total volume of oil spilled each year does not follow any evident pattern: Spills ranging in size from 10 barrels to 200 barrels accounted for the bulk of the volume spilled, except for the 2006 Gathering Center 1 spill, which generated a large spike in the profile of annual volumes spilled.

Correlation with production

A statistical analysis confirmed the correlation between the number of spills each year and the annual oil production from the North Slope, with low spill frequencies in the years 1992 to 1995 appearing as an unexplained anomaly. An analysis which split out separate data for the Prudhoe Bay, Kuparuk River and Milne Point fields indicated that the correlation between oil production and spill frequency is consistent across the fields,

see **SPILL STUDY** *page 13*

● PIPELINES & DOWNSTREAM

North Slope feeder lines changing rates

Increases and decreases reflect throughput changes expected for the year ahead; rates increasing on highest-throughput lines

By ERIC LIDJI
For Petroleum News

With the end of the year approaching, smaller pipeline companies on the North Slope are adjusting their in-state shipping rates for the coming year, as required by regulators.

ConocoPhillips is proposing increases on its three North Slope pipelines.

The Kuparuk Transportation Co. is looking to increase the rate it charges to ship oil along the 28-mile Kuparuk Pipeline to 36 cents per barrel, a 7-cent increase. The pipeline connects the Kuparuk River unit to Pump Station 1 on the trans-Alaska oil pipeline.

The proposed rates would also increase the cost to ship oil from the Milne Point Pipeline interconnection to Pump Station 1 to 25.4 cents per barrel, a 4.3-cent increase.

The state is taking comments on the proposal through Dec. 17.

The Alpine Transportation Co. is proposing to increase its shipping rate on the 34-mile Alpine Oil Pipeline. The change would increase the rate the company charges to ship crude oil from the Alpine field to the Kuparuk River unit by 15 cents, to $1.01 per barrel.

The state is taking comments on the proposal through Dec. 11.

The Oliktok Pipeline Co. is proposing to increase its rate for shipping natural gas liquids from the Kuparuk River unit to Pump Station 1 to $2.37 per barrel, a 55-cent increase.

The company plans to convert the 28-mile pipeline to ship natural gas next year, but said the rate is needed should the conversion take longer than expected to bring online.

The state is taking comments on the proposal through Dec. 10.

Four BP pipelines

BP is proposing a mix of increases and decreases on its four North Slope pipelines.

The Milne Point Pipeline Co. is proposing to lower its rate for shipping oil from the Milne Point unit to the Kuparuk River unit to $1.35 per barrel, a 56-cent decrease.

The Endicott Pipeline Co. is proposing to raise its rate for shipping oil from the Endicott production island to Pump Station 1 to $3.83 per barrel, a 57-cent increase.

The company is also proposing to raise its rate for shipping oil from its interconnection with the Badami Pipeline to Pump Station 1 to $2.43 per barrel, a 36-cent increase.

The Badami Oil Pipeline is proposing to lower its rate for shipping oil from the Badami unit facilities to the Endicott Pipeline to $9.42 per barrel, a $2.83 decrease. The decrease reflects the increasing throughput on the pipeline from increased Badami unit production.

The Northstar Pipeline is proposing to lower its rate for shipping oil from the Northstar facilities on Seal Island to Pump Station 1 to $3.40 per barrel, a $2.07 decrease.

The state is taking comments on those four pipelines through Dec. 17.

Cook Inlet oil

In the Cook Inlet oil market, the Cook Inlet Pipeline Co. is proposing to lower the rate it charges to ship from Granite Point or Trading Bay to the Drift River oil terminal to $3.15 per barrel, 92-cent decrease. The rate includes a 60-cent surcharge added by a settlement.

The state is taking comments on the proposal through Dec. 12. ●

Contact Eric Lidji at ericlidji@mac.com

● GOVERNMENT

Senators offer icebreaker building plan

Bipartisan amendment would have Navy construct up to four heavy icebreakers, then transfer the ships to US Coast Guard

By WESLEY LOY
For Petroleum News

U.S. senators representing Alaska and Washington have offered legislation to fund construction of a whole new fleet of heavy polar icebreaking ships.

Their approach involves amending the National Defense Authorization Act for Fiscal Year 2014 (S. 1197) to allow the Navy to build up to four icebreakers.

The Navy would enter into a memorandum of understanding to transfer the ships to the U.S. Coast Guard, which is responsible for icebreaking missions.

The amendment is the latest twist in what has been a long and sometimes contentious debate in Washington, D.C., over how to address the nation's lack of icebreakers.

Alaska elected officials have been adamant that more icebreakers are needed as shipping and industrial activity increase in the warming Arctic Ocean.

Icebreakers, however, are enormously expensive ships to build. And refurbishing the nation's existing icebreakers is likewise very costly.

'Race to the Arctic'

Co-sponsoring the amendment were Sen. Mark Begich, D-Alaska; Sen. Lisa Murkowski, R-Alaska; Sen. Maria Cantwell, D-Wash.; and Sen. Patty Murray, D-Wash.

"The Arctic nations are investing in the future to maximize the emerging opportunities there — Russia has 33 icebreakers while we have two at best — and even India and China are seeing the need for icebreakers to gain entry to this newly accessible region," said Murkowski, in a Nov. 26 joint press release. "The Coast Guard's own study showed they needed 10 icebreakers to fulfill their duty in northern waters, so I appreciate this bipartisan effort with the Washington delegation in order to protect our waters and remain at the table in pushing ahead in the Arctic."

The Polar Star is an old ship, commissioned in 1976, that recently was refurbished at great cost. It's one of the world's most powerful non-nuclear ships, capable of breaking through ice several feet thick. The senators said the Polar Star was to depart Seattle on Dec. 3 for Antarctica.

"Icebreakers protect America's Arctic interests and support Washington state shipbuilding jobs," Cantwell said. "The Arctic continues to open up, creating new routes for commerce and trade — which is why other nations are acquiring new icebreakers. This amendment is an important step forward to ensure the Coast Guard has the tools it needs to secure our interests and win the race to the Arctic."

Two icebreakers operational

Seattle is home base for the U.S. icebreaking fleet.

The senators note that the United States has only two operational icebreakers at present, the medium-duty Healy and the heavy-duty Polar Star.

In 2012, the Healy starred in an emergency icebreaking mission to deliver fuel supplies to Nome, an isolated city on Alaska's western coast.

The Polar Star is an old ship, commissioned in 1976, that recently was refurbished at great cost. It's one of the world's most powerful non-nuclear ships, capable of breaking through ice several feet thick. The senators said the Polar Star was to depart Seattle on Dec. 3 for Antarctica.

In recent years, the United States has been forced to contract foreign icebreaking services, the senators said. ●

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● GOVERNMENT

Report: Winning over First Nations key for resource projects

By GARY PARK

For Petroleum News

Proponents of more than 600 resource projects carrying an estimated value of C$650 billion face what may be their toughest barrier in Canada — figuring out how to get on side with First Nations, suggests a report by the Fraser Institute.

The conservative think tank said there is "not a single oil or gas project" in Western Canada that does not affect at least one First Nations community and the willingness of those communities "to participate in energy development can be the factor that determines the success of a project."

British Columbia poses the greatest challenge, with seven projects affecting an estimated 56 of 198 First Nations in the province, followed by Alberta with five projects touching 44 percent of the province's aboriginal communities. Although Saskatchewan has only two projects in the category they impact 23 percent of that province's First Nations.

Canada's aboriginal population grew by 45 percent from 1996 to 2006, compared with 8 percent of the non-Native population, but because aboriginal communities are located in mostly remote, rural areas they have an unemployment rate of 23 percent compared with 7.1 percent for Canada as a whole.

Untapped labor force

Ravina Bains, the report's lead author, said the energy development opportunities are the only hope in most cases to correct the job imbalance and the best chance to take advantage of potential labor force.

The report noted that the First Nations population has a median age of 26, compared with the non-aboriginal median of 41, presenting an untapped labor force to develop through skills training.

"There are obstacles in place, but we're at a unique point right now in terms of the demographics of these communities, in terms of the young population, that we can really tap into and make sure that we cultivate," Bains said.

There is also a need to overcome differ-

see **FRASER REPORT** *page 15*

PIPELINES & DOWNSTREAM

RCA takes Hilcorp consolidation case

State regulators have agreed to oversee efforts to consolidate four Cook Inlet pipelines.

The Regulatory Commission of Alaska will sponsor a settlement conference starting Jan. 7, 2014, to attempt to unite the Hilcorp Alaska LLC-operated Kenai Kachemak Pipeline, Kenai Nikiski Pipeline, Cook Inlet Gas Gathering System and Beluga Pipe Line into a single system. The proposed system would have a single tariff with a postage-stamp rate.

The conference will be open to Hilcorp, all shippers on all four pipelines, all Cook Inlet natural gas producers, regional gas and power utilities and state officials, among others.

Hilcorp proposed consolidation earlier this year as a way to improve efficiency and potentially lower costs on the pipelines, which work as a unit but can occasionally compete.

The conference will use "alternative dispute resolution," a process where any entity can petition the RCA to oversee a regulatory matter that is not currently on the docket. The RCA has appointed the contracted administrative law judge Blythe Marston to oversee the conference, but the RCA will not be a participant in the confidential conference.

The conference will be open to Hilcorp, all shippers on all four pipelines, all Cook Inlet natural gas producers, regional gas and power utilities and state officials, among others.

The length of the proceedings depends on how quickly those parties can come to terms.

—ERIC LIDJI

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SPILL STUDY

with differences in spill frequencies between the fields being accounted for by factors such as the total length of pipeline in operation in each field and differences in field oil production volumes.

The analysts, unable to identify any parameters that could be used as predictors of oil spill volumes, recommended making volumetric predictions by first estimating the numbers of spills likely to occur for different ranges of spill size, and then multiplying the number estimate for each range by the average volume of oil spilled within that range.

Few large spills

But the analysts found that large spills in excess of 500 barrels are rare and random, with an analysis of the historic records resulting in a prediction of zero to two spills of this magnitude for every billion barrels of oil produced on the North Slope. And, with loss of integrity of some part of the oil infrastructure being the most common cause of an oil spill, examining the spill records of individual facilities within the infrastructure and hence establishing spill occurrence rates for different facility types may provide additional insights into spill occurrence rates, the study report says. ●

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RUSSIAN PRODUCTION

Sakhalin, LNG efforts

Sakhalin Island, off Russia's eastern coast, features a number of large oil and gas fields.

Russian companies and international consortia are developing Sakhalin in phases, generally known as Sakhalin I through III.

But Sakhalin development appears to be somewhat stymied, the EIA says.

"Even though all of the consortia have extensive export plans via liquefied natural gas (LNG) terminals and export pipelines to the mainland, there has been little progress beyond the first two developments on the island: Sakhalin I and Sakhalin II," the EIA report says.

Sakhalin Energy's two-train LNG plant has been operating since 2009. Most of the LNG has been contracted to Japanese and South Korean buyers under long-term deals, the report says. Project partners plan to have a third train in operation by 2018, contingent on new gas supplies.

"There are a number of proposals in various stages of planning and construction for new LNG terminals in Russia," including Yamal LNG, the EIA says.

"The Arctic Yamal peninsula project is technologically, politically, and economically challenging," the report says. "The plant will be situated on unstable permafrost, and shipping will take place via the Kara Sea, which is icebound for about 10 months of the year."

The Shtokman LNG project is currently stalled and "highly uncertain," the EIA says.

Return to state control

After the collapse of the Soviet Union, Russian initially privatized its oil industry, the EIA says. But the sector has reverted to state control over the last few years.

The report notes, as an example, BP's recent sale of its stake in the TNK-BP partnership to the state-owned Russian oil giant Rosneft.

"With the possible exception of ExxonMobil, which signed an agreement with Rosneft to develop the Arctic shelf and the Black Sea, foreign operators experience difficulty operating in Russia," the EIA report says.

Among other interesting notes in the EIA report, 10 new nuclear reactors were under construction across Russia as of September. ●

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REVENUE FORECAST

jections of $2.1 billion in FY '14 and $1.7 billion in FY '15.

"This is a significant revision to our unrestricted revenue from the previous forecast," Revenue Commissioner Angela Rodell said in a statement. "It is clear that the single-most influential contributor to the revision is a reduced oil price expectation." In the spring forecast the Alaska North Slope crude oil price on the West Coast was projected at $109.21 per barrel; the actual came in at $107.57.

Rodell said the elimination of progressivity and capital credits under ACES are roughly offset by the new 35 percent base rate and per-barrel credits under MAPA.

"Alaska will see at forecasted prices a similar revenue stream between the current and previous oil tax systems," she said.

Oil price down

Production tax is the largest portion of unrestricted petroleum revenue, 63.8 percent in FY '13, the Revenue Sources Book says, followed by total royalty payments at 27.8 percent, corporate income taxes, 6.8 percent, and property taxes, 1.6 percent.

Major contributors to changes in the FY '14 through FY '15 revenue forecast include (in order of significance): reduced price expectation; increase in lease expenditures (deductible for tax purposes); increased transportation charges; and close-out of ACES North Slope credits in FY '14.

Compared to the spring 2013 forecast, Alaska North Slope production is down 18,400 barrels per day to a fall forecast of 508,200 bpd for FY '14, compared to a spring 2013 forecast of 526,600 bpd for FY '14.

The forecast for the FY '14 price of Alaska North Slope crude oil, $109.61 per barrel in the spring forecast, is $105.68 per barrel in the fall forecast, down $3.93 per barrel.

Projected deductible lease expenditures, however, are up: Estimated at $6.146 billion in the spring forecast, they are listed at $6.6 billion in the fall forecast, an increase of $454 million. Transportation costs are also up, from a projected $8.87 per barrel in the spring forecast to $10.11 per barrel in the fall forecast, an increase of $1.24 per barrel, based on a higher cost per barrel for moving fewer barrels.

Overall, the average production tax value of a barrel is down by $9.23 in the fall forecast.

The MAPA tax rate of 35 percent compares to an ACES tax rate of 34.9 percent for FY '14. For FY '15, with the price forecast at $105.06, compared to $111.67 in the spring forecast, and with production projected at 498,400 bpd compared to 512,800 bpd in the spring forecast, the MAPA tax rate of 35 percent compares to an estimated ACES rate of 32.6 percent.

Increased capital expenditures

Rodell said the department has increased its projection of increased industry investment to $10 billion over the next 10 years.

That includes announcements by companies, such as additional rigs, as well as projects not yet announced, but which industry has discussed with the state confidentially.

North Slope lease expenditures for FY '13 were capital expenditures $2.948 billion and operating expenditures of $3.11 billion, totaling $6.057 billion (up from $2.383 billion capex and $3.001 billion operating in FY '12, totaling $5.385 billion).

Forecast expenditures for FY '14 are $3.929 billion capex, $3.083 billion operating, totaling $7.012 billion; FY '15 $4.894 billion capex, operating of $2.893 billion, totaling $7.788 billion.

Alaska North Slope production, which averaged 531,600 bpd in FY '13, is estimated at 508,200 bpd in FY '14 dropping to 312,900 bpd in 2023.

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ROYALTY DEAL

The Alaska Royalty Oil and Gas Development Advisory Board will review the amended contract and provide a recommendation to the Legislature.

The board will hold a public hearing at 1 p.m. Dec. 11 in room 602 of the Atwood state office building at 550 W. 7th Ave. in Anchorage.

The eight-member royalty board's job is to "facilitate wise development" of Alaska's oil and gas royalty interests. Bob Roses, a former state legislator, is currently board chairman.

Legislators in April approved a five-year contract for the sale of royalty crude to Flint Hills, which operates a refinery at North Pole.

Contract terms

DNR previously made a preliminary finding that the royalty oil sale to Tesoro would be in the state's best interest.

Under the proposed contract, Tesoro would buy 5,000 to 15,000 barrels of royalty oil per day.

DNR estimated the one-year contract would provide $189 million to $568 million in revenue to the state.

The state has a long history of selling royalty oil to Tesoro. The state supplied North Slope crude to the Nikiski refinery through most of the 1980s and '90s. Sales totaled 230 million barrels under seven contracts, DNR said.

In addition, the state has supplied Tesoro with Cook Inlet royalty crude.

The state can cash in its royalty oil in two ways: sell it directly to refiners or other customers, or let North Slope producers market it with their own volumes. State law generally precludes direct sales at bargain prices, even if doing so might achieve some desired economic objective.

—WESLEY LOY

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GAS SALES

sidiary of Miller Energy Resources Inc., of Tennessee. Miller itself is a small company, but its shares are listed on the New York Stock Exchange.

Cook Inlet Energy launched as an Alaska producer in late 2009, acquiring a collection of west inlet oil and gas assets out of the bankruptcy of California-based Pacific Energy Resources Ltd.

Since then, the company has aggressively worked to revive shut-in wells and to explore for oil and gas.

The company produces gas from its Osprey offshore platform, and has drilled on gas prospects such as Otter and Olsen Creek, both in the vicinity of the ConocoPhillips-operated Beluga River gas field.

Cook Inlet Energy also is setting up for exploratory drilling on its state-licensed acreage in the Susitna basin, north of Cook Inlet.

And on Nov. 25, the company announced it had a nearly $65 million deal to acquire the producing North Fork gas field on the southern Kenai Peninsula. That deal with current operator Armstrong Cook Inlet LLC is expected to close by March 1.

Few sales options

In their presentation to the RCA, the Cook Inlet Energy managers explained that options for selling gas are now quite limited.

For years, electric and gas utilities hustled for supply as a gas shortage loomed in Cook Inlet.

But now, the utilities seem to have ample supply available from producers or from newly developed gas storage, the Cook Inlet Energy managers said.

What's more, the region's major industrial uses such as the Agrium fertilizer plant and the ConocoPhillips liquefied natural gas export facility remain shut down, they said.

Independent producers face a situation where there are "no significant openings" for gas, Slaughter told the commission.

And so, Cook Inlet Energy is now looking to match up its gas production with the commercial space heating market, Slaughter said.

But the company has been unable to reach agreement with Enstar on metering equipment, he said.

Cook Inlet Energy has proposed installing an accurate and inexpensive network of metering gear, while Enstar is insisting on a prohibitively expensive $5,000 unit at each location, said Slaughter, who formerly worked for Enstar.

Cook Inlet Energy would not be the first company to use Enstar's regulated distribution network to market gas directly to customers.

Aurora Power once served hundreds of commercial customer locations, and Marathon also had customers including the military in Anchorage. But Aurora dropped many of its customers in 2006 due to lack of supply, Enstar's Nov. 27 filing with the RCA said. And Marathon has exited Cook Inlet.

Enstar told the RCA that "the unpredictable coming and going" of customers dealing with direct marketers can harm Enstar's customer base. For example, when customers opt to take gas from an alternative supplier and then return to Enstar unexpectedly, the utility might have to buy expensive new gas. This has happened in the past, the Enstar filing said.

Enstar is asking the commission to approve a requirement that customers provide at least a one-year notice when switching between alternative suppliers and Enstar.

That idea isn't expected to sit well with Cook Inlet Energy.

In general, Enstar sounded less than enthused about a resurgence in direct gas marketing.

"Enstar remains very concerned about the wisdom of permitting direct marketing to Enstar's gas sales customers," the Enstar filing said.

"Contrary to the assertions of some," the filing said, direct gas marketing doesn't encourage efforts to develop Cook Inlet gas resources or expand the market.

Rather, it merely reshuffles the market and has the potential to disrupt settled, RCA-approved gas sales contracts, Enstar said. ●

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REVENUE FORECAST

FY '13 production declined 8.2 percent from FY '12, Rodell said, and the production forecast for the next couple of years has been reduced based on increased natural gas liquids reinjection for enhanced recovery of oil — as opposed to shipment of those NGLs down the trans-Alaska oil pipeline for sale — along with higher intensity of summer maintenance and decreased production expectations at legacy fields.

Rodell said that given all the changes, the impact of the change from ACES to MAPS is approximately $250 million to $300 million in FY '14, "primarily due to the impact of closing out ACES capital liabilities."

"In FY 2015, we can report that the two tax systems generate similar revenues at the forecasted price, expenditure and production levels," Rodell said, as the elimination of ACES progressivity and capital credits are roughly offset by the 35 percent base rate and new per-barrel credits under MAPA.

—KRISTEN NELSON

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FRASER REPORT

ences between First Nations and the resource industry, she said, noting that Enbridge's Northern Gateway pipeline and Kinder Morgan's Trans Mountain expansion face potential failure because of First Nations opposition.

Emerging relationships

However, Bains said there are examples of emerging relationships, including Haisla Nation participation in the Douglas Channel LNG partnership, the Kitimat LNG project by operator Chevron and Apache and Shell's LNG Canada venture.

The report calls for better communication and transparency in dealings between industry and First Nations and efforts by industry to understand the communities involved, while governments should play a more active role in ensuring consultations take place.

The report said there has already been success in Alberta from First Nations communities working alongside industry to benefit from oil and gas development.

In 2010 more than 1,700 aboriginal people were directly employed in oil sands operations and, over the past 12 years, aboriginal-owned companies have secured more than C$5 billion worth of contracts from oil sands developers. ●

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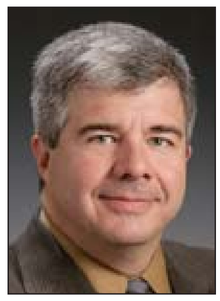
Petroleum news

Oil Patch Bits

CH2M HILL announces promotion of Bryan Clemenz


BRYAN CLEMENZ

CH2M HILL, a global full-service consulting, design, construction and operations firm, announced as part of its rapidly growing energy and chemicals portfolio the promotion of Bryan Clemenz to vice president of Program and Project Development Alaska, the company's Energy and Chemicals Business Group.

Clemenz has served over 27 years in the petroleum industry and joined CH2M HILL in an engineering leadership capacity in 2007. He maintains his professional engineering registration for both Alaska and South Carolina and has served in various leadership roles throughout his professional career including engineering manager, program manager, and business and project development manager. Currently he serves as president of the International Society of Automation Alaska Section, is an active member of the Government Affairs Industry Relations committee for the Alaska Industry Support Alliance, and serves as vice chair on the University of Alaska Fairbanks College of Engineering and Mining Advisory and Development Council Action Committee. Clemenz is heavily involved in representing CH2M HILL through participation in professional and community organizations that help train Alaskans and grow Alaska's economy.

"Bryan's understanding of the Alaskan market make him a huge asset to helping our clients develop successful projects," said Craig Pierrotti, CH2M HILL senior vice president of Business Development for the Energy & Chemicals Business Group. "He, along with our CH2M HILL colleagues, are always looking with an eye towards minimizing the total cost of ownership and maximizing value for all stakeholders."

Global Diving & Salvage announces Grennan as new CEO


DEVON GRENNAN

After over 30 years as founders and owners of Global Diving & Salvage, Inc., Tim Beaver and John Graham continue to remain excited about the future of the company. They are pleased to announce the newest chapter in Global's history; Devon Grennan, president for the past four years, will now also take on the position of CEO. Beaver and Graham will maintain ownership and continue to serve on the board of directors, but will step down from direct operational involvement.

Grennan began his tenure in 1995 as a marine environmental supervisor moving up the ranks to environmental division manager and by 2005 serving as the general manager. In 2009, Global formed its senior management team and he was moved into the position of president. As CEO/president his newest undertaking is to determine the overall strategic plan for the company and lead the senior management team and the board of direc-

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

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GIESSEL Q&A

move this as a separate topic. The team doing the Coast Guard subject matter felt like the spill response belonged in its own chapter, so my team raised its hand and said we'll do it.

Petroleum News: You committee leaders noted Defense Secretary Chuck Hagel's recent 14-page report on Arctic strategy for security and defense. What are your thoughts on it?

Giessel: I have read the Arctic Strategy put out by the Department of Defense. It's actually fairly specific, but it does have some vague terms that I have concern about. It talks about ensuring security of the U.S. and freedom of the sea. Those are great ideas, which I fully support: advancing U.S. security interests; advancing Arctic stewardship. What's interesting to me is this report, which is about 14 pages long, our name is only cited five times, and one of those times is in a photo caption. That piece is missing, that collaboration with Alaska. I don't know how much of that occurred. Part of my Arctic Policy Commission group is Pat Pourchot. He's with the Department of the Interior and he wasn't sure what collaboration occurred. As much as this report talks about U.S. sovereignty and national security, at the same time it has a statement that one of its goals is to "support the development of the Arctic Council and other international institutions to promote regional cooperation and the rule of law." That stood out to me because the Arctic Council is an advisory group only. It is not a policy writing group. It does not have the force of law. It concerns me when folks start talking about it that way.

Petroleum News: How do you work out some of these differences with the federal government? Is Arctic policy a good place to start?

Giessel: I think it is. I think it's not only a good place to start; it's a critical place to start. The U.S., until fairly recently, has not been aware they are an Arctic nation. Most people aren't aware that Alaska is stuck up here in the corner and we have a border with Canada all of our own. In any case, we have to participate in this to inform Washington, D.C., exactly what is going on up here. We have to be part of the discussion about policies going forward that are going to directly affect us.

So looking for commonalities — we are always looking for the positive — well there are a lot of things. They care about protecting the environment; so do we. They care about marine transportation through the Bering Strait; so do we. Choosing the commonalities and focusing on those like the secretary did. He's talking about national security. We care a lot about that. That's why we are pushing for more icebreakers and a Coast Guard station here in Alaska's west coast.

Petroleum News: Moving on to LNG, what is your take in listening to House Resources recently and hearing from the DNR on the Black & Veatch report, especially having an equity stake in a large-diameter pipeline?

Giessel: This summer, Legislative Budget & Audit sponsored a weeklong LNG symposium here in Anchorage for legislators. It was conducted by PFC's natural gas team, which is a group of specialists that constantly monitor the LNG world market. That symposium at

> *"We need to be more savvy and flexible in terms of what kind of production tax we are going to have. It's a different entity. It's not like oil."* **—Sen. Cathy Giessel, R-Anchorage**

its conclusion had some key takeaway points. No. 1 the natural gas market is extremely volatile; it's constantly moving and it's very complex. These contracts are not as transparent as it is with oil. Gas is a negotiated contract between buyer and seller, so we are getting into a very complex field in terms of marketing our natural gas. Excessive taxation of this hydrocarbon is going to put us out of the market. We are not going to be able to sell it in the world market. We've got a high royalty and a high production tax. So the takeaway for me is most of the provinces have negotiated an equity ownership position of the project.

So when Black & Veatch, which was hired by the Department of Natural Resources, came forward with their report, recommending some sort of ownership, I was not surprised based on the LNG symposium and what I heard at LNG 17, which was in Houston right after session. It happens every three years. The equity ownership idea seems to be the most prudent. It gives us a seat at the table. Will we be taking on risk? Definitely. I keep hearing if only we had taken ownership in the trans-Alaska pipeline, what a difference that would make in tariff negotiation and production and all of those things. I think this is a great opportunity for Alaska, but we are going to have to be very smart. We are going to have to know what we are doing and who we need to have as consultants and advisors in this process.

Petroleum News: So would an equity position force out TransCanada?

Giessel: I would ask why would it force out TransCanada? Taking an equity position only means buying in — in other words, contributing money to the whole affair. Perhaps it means contributing funds at the LNG project site. We will never, I hope, propose the state take over in building the pipeline. We simply don't have the experience and expertise there. We need a company that has a proven track record in building pipelines, so I don't see the state's equity ownership affecting taking over building a pipeline at all. That would be a frightening proposition to me. We are not good at building things like that.

Petroleum News: So you would like the natural gas tax separate from the oil tax?

Giessel: Our oil tax does link to gas. It puts us between 75 and 80 percent production tax. We can't sell gas like that. It would put us outside the market.

Petroleum News: Well the industry likes having oil prices linked to natural gas prices. So, with that in mind, what is wrong with linking oil tax to natural gas tax?

Giessel: Well, when you are talking about linking it, you are talking about Japan. Right now Japan buys gas linked to the price of a barrel of oil. Therefore they are paying $15 to $16 where the rest of the world is paying more in the $4 to $6 range, if I'm not mistaken. That is what the world market is paying right now. If we are going to be selling to Japan, they are in the process of negotiating with the rest of the world to stop linking their prices to oil because it is so very high. That's what I'm saying. We need to be more savvy and flexible in terms of what kind of production tax we are going to have. It's a different entity. It's not like oil.

Petroleum News: On to SB21. I know we've discussed this before the referendum to repeal the law was certified, but can you restate any concerns you have about investment being curtailed should this pass?

Giessel: You've probably heard from the companies, whether they are large or small, that a certainty has a huge impact on their ability to make an economic change in Alaska. That applies to all of us. If you and I were uncertain about what the federal government is going to take from our income tax, we would be pretty leery about working hard. We would think maybe the federal government is going to take 50 percent. Maybe they are going to change their mind. That kind of uncertainty changes how people approach taking risk. The companies, I am thankful for, have decided they are going to move ahead anyway, despite the referendum. BP has made several commitments; ConocoPhillips has got some new rigs coming up. They are beginning to look at the Mooses' Tooth development. Little Red Services, which is one of the support companies for oil industry up on the North Slope, have moved the construction of their heavy equipment trucks from Canada to a fabrication plant here to South Anchorage. That's a big deal. That's jobs for Alaskans who live here in Anchorage, not people coming in from out of state for two weeks on, two weeks off. These are people living here. We've got a new oil company who bought in on Pioneer's leases. They see the opportunity. Because of SB21, they are encouraged that this kind of investment is going to be helpful to them. Despite the referendum and the uncertainty it creates, it seems to me the companies believe Alaskans will understand the rationale and will understand that lower taxes means a more promising economic future for any kind of investment, whether it's a Wal-Mart or an Olive Garden or a Brooks Range.

Petroleum News: Do you see the Legislature working on bills to advance an LNG project?

Giessel: Well, I'm never one to predict the future, but this is so important to our future. So far we've been talking about selling overseas, but the ultimate goal for me is getting gas to Alaskans. We are talking about a trucking option for Fairbanks, but much more efficient would be a pipeline. That trucking option, I view as a Band-Aid, a short-term solution. Really getting that pipeline built and serving Alaskans is the main goal for me on monetizing our natural gas. I believe we will be doing something. I won't be willing to predict what that will be. I'm sure a lot of folks have ideas and we haven't heard from the governor's office yet on what he will propose. Certainly I believe something would happen.

Petroleum News: Do you believe that's the best first step, something coming from the governor's office?

Giessel: Just as the oil tax reform came from the governor's office, it won't emerge at the end of the day as he proposed it. But that's the process. That's the balance in government, so I look forward to the discussion. ●

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PREMIER PROVINCE

Lachance said. "When you have something of that magnitude, that size and that value, it enables the spending and the infrastructure, the people and the development to go up above the Arctic Circle and put all that equipment in place."

Increasing recovery

With an especially benign underground oil reservoir that can enable oil to flow at prodigious rates from oil wells, coupled with modern production techniques, the Prudhoe Bay field has delivered some 45 percent of its original oil resource, Lachance said. And BP anticipates upping that recovery factor to more than 50 percent in the future he said.

"We have the plans in place. We have a means to produce the reservoir. We have an idea how we'll get there," Lachance said.

On the other hand, with a more challenging, compartmentalized reservoir, oil recovery from the Kuparuk field currently sits at around 30 percent: ConocoPhillips is working hard to push that up to around 50 percent, Lachance said.

The use of techniques such as coiled tubing drilling enable the application of science to thread wells into isolated pockets of the oil reservoir, to access some of that remaining oil.

"The trouble is, that's expensive, but it allows us to hit the pockets of the reservoir once we figure out where to go," Lachance said.

Tax change

Lachance also commented that the recent revision to the Alaska production tax law — the passage of the tax bill titled Senate Bill 21 — has encouraged BP and its partners to ramp up their operations to develop more of the remaining Prudhoe Bay oil. The North Slope operations create many employment opportunities: BP currently has 2,300 direct employees in Alaska and generates more than 20,000 contractor jobs in the state, he said.

"In 2012 in Prudhoe Bay we were operating five drilling rigs. By the end of 2016 we'll be operating nine. We didn't have complete compliance with our partners at Prudhoe until the passage of SB21," Lachance said.

The production from Prudhoe Bay since the field went into operation 35 years ago has consisted essentially of light oil. But huge quantities of thicker oils — viscous oil that flows like syrup and heavy oil with a consistency more like yogurt — remain to be developed. In fact, the light oil produced to date only represents about a quarter of the total North Slope oil discovered, Lachance said.

BP has been producing viscous oil at Prudhoe Bay and ConocoPhillips has been producing the same resource at Kuparuk. But neither company has yet figured out a means of viably producing the heavy oil, a resource that Lachance characterized as "the big prize."

"We haven't even really cracked how to produce the heavy oil yet," Lachance said. "It's not really economic at this time. We're certainly doing quite a lot of work around it. We're moving in that direction."

There is also development potential in some smaller and shallower oil reservoirs at Prudhoe, he said.

Slowing the decline

And, although production from the aging Prudhoe Bay will inevitably continue to decline, continuing development efforts can slow the decline rate, Lachance commented.

"We can't stop the decline. We're producing a diminishing resource," Lachance said. "But we can substantially change the inflexion of the curve and we can move into some of those areas, the viscous and the heavy oil, the more isolated light oil, and work our way through to development and increased recovery across the field."

And, with changing patterns of oil production at Prudhoe Bay, BP is evaluating the potential of more than $3 billion of additional investment in the field's surface infrastructure, adding a couple of new drilling pads and changing some surface kit, he said.

Natural gas

North Slope natural gas, a resource that in terms of barrels of oil equivalent represents something in excess of 20 percent of the total discovered hydrocarbon resource, is of great importance as a source of energy for producing oil and for fueling the North Slope infrastructure, Lachance said. The amount of gas currently produced at Prudhoe Bay and mostly recycled through gas compressors would be sufficient to feed more than 10

see **PREMIER PROVINCE** *page 20*

Future of heavy oil development unclear

With an estimated total volume in place of 12 billion to 18 billion barrels, the heavy oil resource that lies in a shallow rock formation above the major oil fields of Alaska's central North Slope represents a tantalizing target for future oil production, with the possibility of recovering even a relatively small proportion of this huge resource representing a major boost to total North Slope oil output.

Heavy oil consists of oil with too thick a consistency to flow unaided down a pipeline and requiring specialized techniques for extraction from the subsurface.

BP built a $100 million facility in the Milne Point field to test the feasibility of producing North Slope heavy oil using a technique that involves drawing a mixture of sand and oil from the unconsolidated heavy oil reservoir and then separating the sand from the oil in a heated surface tank. The facility went into operation in 2011 and achieved well production rates of up to 500 barrels per day using a special type of downhole pump to draw the sand-oil mixture up the test wells. Although the wells successfully produced oil, mechanical issues with the downhole pumps would eventually cause the wells to fail.

In late 2012 BP announced the imminent cessation of heavy oil testing as part of the company's response to the state's high taxation levels under the ACES production tax regime. And in 2013 the company allowed the test wells to run to failure before mothballing the test facility.

Not economic

Despite the enactment of a new state production tax system with significant tax reductions, there still appear to be hurdles regarding the technical and economic feasibility of commercial heavy oil production — BP has not restarted the Milne Point test facility and on Nov. 20 Dave Lachance, vice president, reservoir development, for BP Exploration (Alaska), told the Resource Development Council's annual conference that, while BP continues to research the possibility of heavy oil production, heavy oil is "not really economic at this time."

Heavy oil is much more expensive to produce than light oil, especially given the need to mechanically extract the oil from the subsurface and use an energy-expending process to separate and dispose sand from the oil. The heavy oil has to be mixed with lighter oil for pipeline transportation and is less valuable than light oil when it reaches market.

—ALAN BAILEY

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OIL PATCH BITS

tors in Global's mission to provide quality marine service and discover new opportunities to better serve the maritime industry.

"I am very excited to take on this challenge. Global continues to develop new capabilities and uncover opportunities beyond the original vision of the founders," said Grennan, "With the foundation laid these past 30 plus years and the quality and experience of our people, we continue to transition from a traditional commercial diving company into a more well-rounded, marine and subsea service provider. Our four regional locations and diverse service lines allow us to serve an ever-expanding market, both domestically and internationally."

GCI welcomes J.J. Harrier to its team

J.J. HARRIER

GCI recently welcomed J.J. Harrier to its team as commercial marketing manager. He will help oversee the commercial marketing department, including public relations and communications for the large telecommunications company.

Prior to joining GCI, Harrier was vice president and communications director for the Anchorage Chamber of Commerce, where he was employed since 2008.

In this capacity, he was responsible for the organization's program and event branding, media communications, publications and organizing the weekly "Make it Monday" forums.

Before joining the Anchorage Chamber, Harrier was features editor for the Frontiersman, the Mat-Su Valley's thrice-weekly newspaper. He studied journalism and public communications at the University of Alaska Anchorage, where he received a Bachelor of Arts degree in 2001, and has a background in print journalism, writing numerous features articles for the Anchorage Press and outside freelance projects.

He currently serves on the board of directors for the School Business Partnership and Identity Inc.

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DOYON DRILLING

nificant commercial discoveries of oil and gas and we consider it a success. Follow-on studies are under way which will assist us in the development of our forward program."

Indications of a petroleum system included "excellent potential reservoirs, competent top seals, source rocks actively expelling wet gases and similar shows of likely migrated gas which are indicative of an oil and/or gas-condensate system," Doyon said.

James Mery, Doyon's vice president for lands and natural resources, told Petroleum News that, with multiple, very thick coal seams in the subsurface, the Nunivak No. 2 well had proved difficult to drill. In preparation for the next steps in its Nenana exploration program, Doyon is in the process of designing a couple of different seismic options in the basin, to start the permitting process for potential seismic surveying in the winter of 2014-15, Mery said.

Oil potential

After initially viewing the Nenana basin as having only natural gas potential, Doyon now sees the basin as showing significant potential for an oil find. Evidence gathered from the two Nunivak wells, from surface soil sampling and from re-evaluations of geophysical data in conjunction with new seismic data, has pointed to the possibility of oil in the basin. But, although oil is now Doyon's prime focus in its exploration efforts, the emerging possibility of a gas pipeline from the North Slope passing through the corporation's Nenana leases on its way to tidewater in Southcentral Alaska has spurred a review of the potential for gas in the basin. It may be possible to ship Nenana gas through the line from the Slope, Mery said.

Doyon is the sole owner of approximately 400,000 acres of state leases in the basin and also owns oil and gas rights to an additional 43,000 acres in the basin. The corporation had originally been exploring the basin in partnership with some other companies under the terms of a state exploration license. But Doyon's partners left the project after the drilling of Nunivak No. 1 — Doyon subsequently converted some of the license acreage to state leases and continued the exploration by itself.

Yukon flats

Doyon is also conducting an exploration program in another Interior Alaska geologic basin under the Yukon Flats, a

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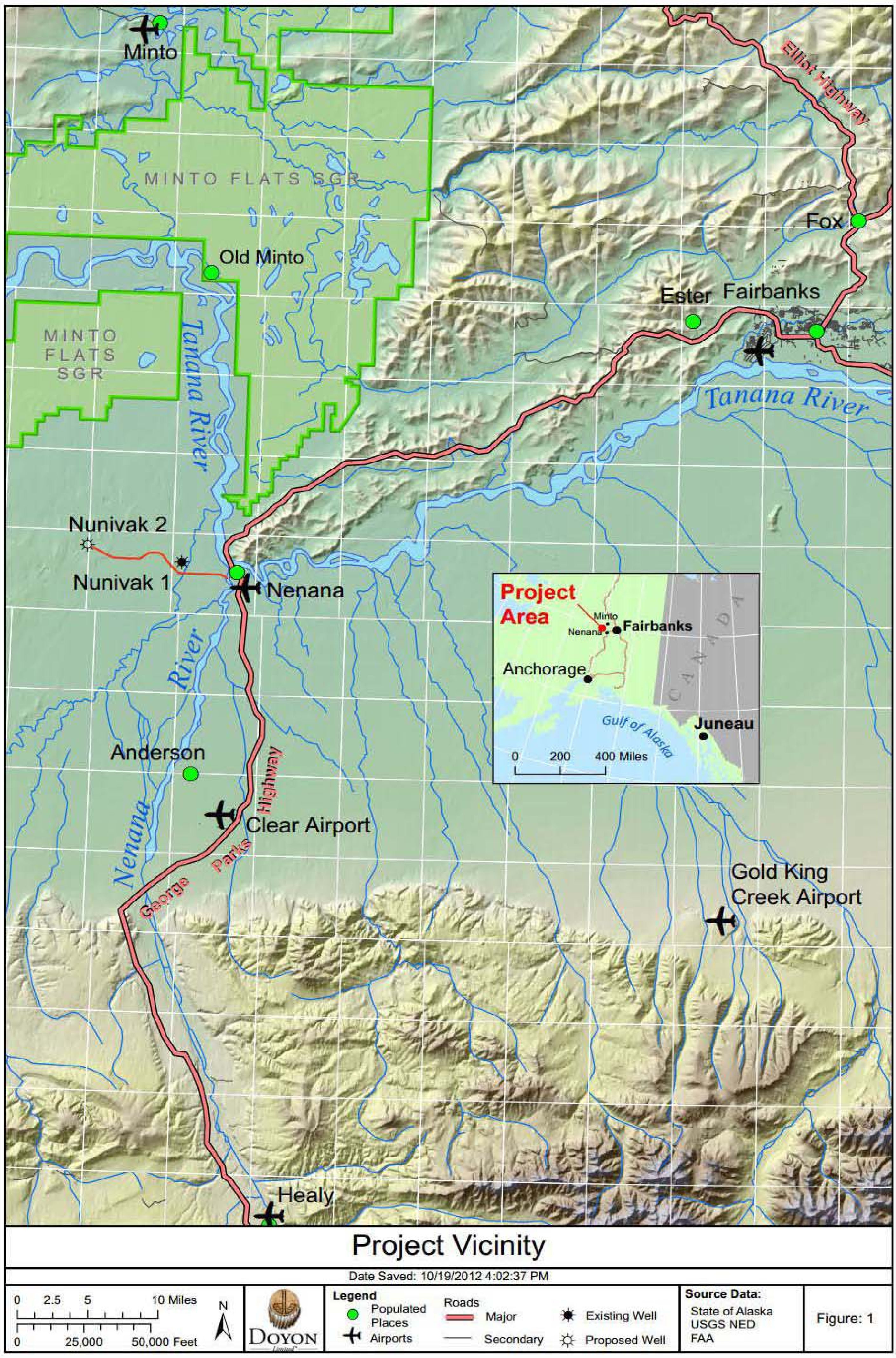

COURTESY DOYON

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TAXING TIME

until it's either presented in a budget or presented by legislation.

"We were asked by different (LNG) proponents, because we got into pretty detailed conversations about all the technical aspects that affect the cost of competitiveness worldwide, to take another month or so to have an opportunity to look at the combined cost with regards to other things that could affect the cost, relative to an investment decision.

"We said to them we'd give them another 30 days at the end of October, which we've done, so the end of (November) we will then set down and look at their competitive matrix," Coleman added.

"I have always said that I would ... circle back to the companies as we go through the process. This has proven to take a little longer than I thought it would because of the availability of people and technical teams to sit down with my folks."

The message to emerge from that explanation is simple: The tax is unlikely to be revealed until British Columbia introduces its 2014-15 budget in February.

Would tax be a tariff?

Coleman said the tax will be imposed on LNG output at the plant level, meaning it will also apply to any gas making its way from Alberta and Saskatchewan to Pacific Coast liquefaction facilities.

Left unanswered is whether such a tax would be interpreted as tariff.

If that is British Columbia's intention it could put the province at odds with the Canadian government which has the sole right to impose such export levies.

Driven by its hunger for fresh sources of revenue from royalties and taxes, British Columbia may also find itself in a fresh tangle with Alberta over the source of natural gas supplies for LNG, with a lot at stake.

Both provinces have taken severe punishment from Canada's declining export markets in the United States on top of prolonged weak commodity prices and the rapid expansion of shale gas development in the U.S.

Alberta's gas royalties have nosedived to a projected C$1 billion in the current fiscal year from C$8.4 billion in 2005-06, while British Columbia has slumped over the same period to C$228 million from C$2.9 billion.

Coleman insisted that Alberta and Saskatchewan are aware of British Columbia's objectives and have delivered no negative feedback.

Alberta wants its gas to play

But Alberta Energy Minister Ken Hughes said his government is doing all it can to ensure its gas plays a role in the LNG market, including a trip he made to Korea, China and Japan in October to assure potential LNG buyers that Alberta wants their business.

"My focus with respect to LNG and the West Coast is that we will be keeping a very close eye on all the projects as they proceed and we will be working to ensure that whatever happens on the West Coast that there is a clear link into the Alberta natural gas industry, so that we are part of the success story," he said.

Hughes suggested that LNG operators may see an advantage to exploiting Alberta's large and well-developed supplies as a way to reduce risk, echoing the view of industry leaders that Alberta gas — although more distant from LNG terminals than British Columbia's vast shale gas deposits — is richer in high-priced liquids than those in British Columbia.

Ed Kallio, director of gas consulting at Ziff Energy, a division of HSB Solomon Associates, said gas from the Duvernay and Montney plays in Alberta are the region's lowest cost supplies at the moment, convincing him that "Alberta gas will do just fine."

While British Columbia and Alberta engage in some quiet jostling, there is an even larger concern.

Ziff Energy has estimated that over the next seven years, the incremental growth in Asia's LNG market will be equivalent to gas production of 20 billion cubic feet per day.

Without even factoring in the global competition from Australia and East Africa, LNG projects currently on the table would consume about 15 bcf per day in Canada and 35 bcf per day in the U.S., Ziff projected. ●

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China submits massive LNG plan

China's state-run CNOOC is leading the way in designing an LNG project for British Columbia that could require 30.5 trillion cubic feet of gas feedstock over 25 years for Aurora LNG.

A year after gaining outright ownership of Nexen, CNOOC along with Japan's Inpex and JGC is seeking approval from Canada's National Energy Board for a permit to export 640 million metric tons of LNG (not exceeding 24 million metric tons a year, the gas equivalent of 1.14 tcf). The first shipments are targeted for the 2021-2023 period.

The filing is the fifth currently before the NEB totaling about 90 million metric tons a year, while approvals have been given to three projects totaling about 36 million metric tons a year.

Industry sources say Sinopec, China's largest refiner, is negotiating with Apache to buy a minority stake in Chevron-operated Kitimat LNG. Chevron and Apache currently hold 50 percent each.

That US$15 billion project has a license to export 12 million metric tons a year to Asia, starting in 2017.

Sinopec is also reported to be making overtures to other LNG backers.

The British Columbia government recently announced a land deal with Nexen involving a C$12 million non-refundable deposit for the Aurora plant to be located at Grass Point in the Prince Rupert area./

The NEB filing said new pipeline capacity will be required to deliver sourced gas to the Aurora project site, with a number of routes being evaluated that are expected to make use of existing pipelines and rights of way.

The LNG terminal is designed to include a marine jetty and LNG loading facility with cargo capacity of 240,000 cubic meters.

CNOOC's gas and power subsidiary is currently China's largest LNG importer at 12.3 million metric tons per year, with another 8.5 million metric tons per year under construction and plans to expand to 60 million metric tons per year by 2020.

The Liard and Cordova basin lands in British Columbia are in the initial planning and exploratory stages of development for Aurora, with Horn River at an early point of the development cycle.

—GARY PARK

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DOYON DRILLING

large area of lowlands to the north of Fairbanks. Following re-assessments of geophysical data from the Yukon Flats basin, the corporation sees the basin as having the potential for the discovery of a significant oil field within reaching distance of the trans-Alaska oil pipeline. As in the Nenana basin, surface geochemistry provides tantalizing indications of thermally generated hydrocarbons in the subsurface.

During the winter of 2012-13 Doyon conducted a 3-D seismic survey near Stevens Village, in the area of one of several deep sub-basins within the overall basin. Mery said that, despite difficulties in teasing information from the data from this survey, the data interpretation is making good progress and that Doyon hopes within the next few months to be able to use the data to identify potential drilling targets.

Winter road

Meantime, the corporation is seeking permits for a winter road to Stevens Village from the North Slope Haul Road, Mery said — the Haul Road passes to the west of the Yukon Flats. If there are suitable drilling targets and the necessary funding is available, exploration drilling near Stevens Village might start in the winter of 2014-15. The winter road would support the transportation of heavy equipment such as a drilling rig, Mery said.

The idea of early permitting of the road is to enable the clearing of at least some of the road route later this winter, to avoid the risks involved in trying to do all of the road construction along with the drilling in a single winter season, Mery explained. But working on the road during this winter is contingent on the necessary permits being issued and the results of the seismic data analysis being available, he said. ●

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PREMIER PROVINCE

typically sized liquefied natural gas plants elsewhere in the world, he said.

And, with any liquefied natural gas plant being completely dependent on a very stable and reliable gas supply, the abundance of gas in the Prudhoe Bay and Point Thomson fields on the North Slope means that the gas supply situation is the least questionable aspect of proposals for exporting gas from the Slope to an LNG plant in Southcentral Alaska, he said.

Overall, with such a massive hydrocarbon endowment, BP thinks that Prudhoe Bay and the fields around it could still be on line and operating perhaps 36 years from now, Lachance said. But those operations will be different from what happens nowadays, with much of the original light oil depleted and production more focused on the more difficult products, the viscous oil, the heavy oil and the gas, he said. ●

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