Petroleum news

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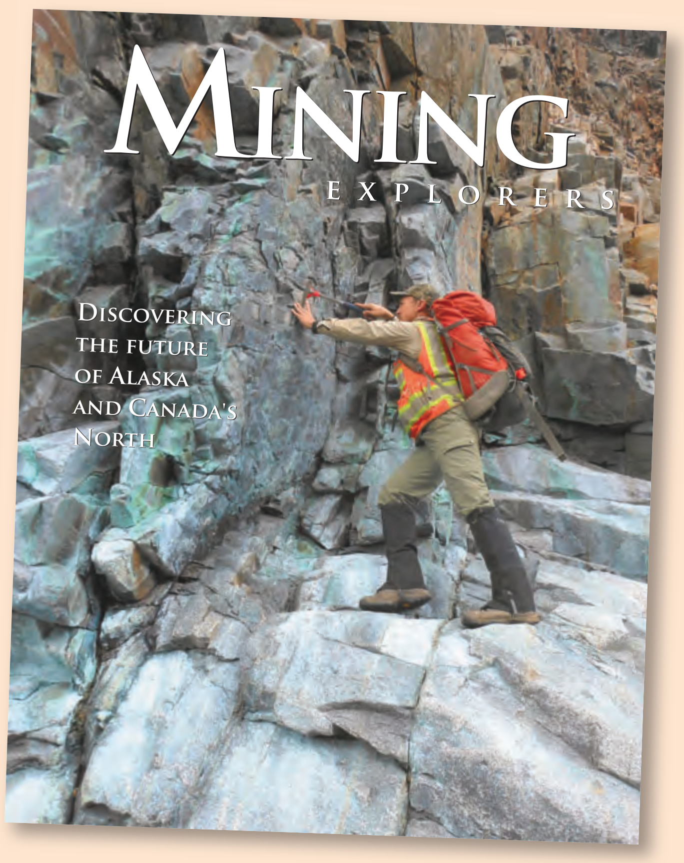
page 5 Q&A: Feige sees state's role as Alaska LNG partner as significant

2014 Mining Explorers inside



Mining Explorers provides a comprehensive overview of the mining companies investing the capital and time needed to unlock the enormous mineral potential of Alaska and northern Canada.

Shell asks for 5-year extension for Beaufort and Chukchi leases

JUDY PATRICK

PETE SLAIBY

Shell spokeswoman Megan Baldino has confirmed a report that Shell has requested the federal Bureau of Safety and Environmental Enforcement to issue five-year extensions to the company's Alaska Arctic outer continental shelf oil and gas leases.

"The request reflects the extent of the actual delays we have experienced as a result of court decisions and agency actions for the last several years," Baldino told Petroleum News in an Oct. 27 email.

The report originated from a Freedom of Information Act request to the Bureau of Safety and Environmental Enforcement from environmental organization Oceana.

see **LEASE EXTENSION** *page 15*

BC finds no easy path to LNG riches, but says it's competitive

For all of its 140-year-plus history as a province of Canada, British Columbia has built its economic engine from parts assembled out of the natural resource sector.

But beyond lumber, minerals and fish there has never been much evidence of a Plan B to cover its budget and spending needs, confining British Columbia to its role as a hewer of wood and drawer of water.

Until less than a decade ago, the province — despite building evidence of untold natural gas riches in its northeastern region — was even gearing up to import LNG.

Then came a breakthrough from the use of horizontal drilling and multi-stage fracturing to release gas from shale deposits, coupled with the insatiable demand for LNG in Asia, with customers forking over US$18 per million British thermal units.

In no time, global energy giants were assembling natural

see **BC LNG** *page 15*

EXPLORATION & PRODUCTION

Conoco sanctions 2S

Drill site is the first at Kuparuk in 12 years; 3S appraisal set for winter

By ERIC LIDJI
For Petroleum News

In two separate but similar projects, ConocoPhillips Alaska Inc. has sanctioned a new drill site and is permitting an appraisal well at opposite ends of the Kuparuk River unit.

The Houston based independent recently received partner approval for the Drill Site 2S project in the southwest corner of the North Slope unit and intends to drill the Drill Site 3S-620 Moraine exploration well in the northwest corner of the unit this coming winter.

The $500 million Drill Site 2S project includes a pad, a new gravel road and associated power lines, pipelines and surface facilities. With preliminary gravel work completed earlier this year, ConocoPhillips can build the pad over the winter, start drilling by the middle of next year and bring the pad online by late 2015, according to a company timeline. The drill site is expected to produce some 8,000 barrels per day at its peak.

In addition to operator ConocoPhillips, the Kuparuk River unit owners include BP Exploration (Alaska) Inc., Chevron USA Inc. and ExxonMobil Alaska Production Inc.

To the north, ConocoPhillips wants to drill the DS3S-620 Moraine well to gain "additional reservoir information in this area and narrow uncertainty around reservoir description parameters including oil-water contact, sand quality and thickness,

see **DRILL SITE 2S** *page 18*

NATURAL GAS

A Kitchen Lights enigma

The pieces of the puzzle are falling into place, but how much gas is there?

By ALAN BAILEY
Petroleum News

Furie Operating Alaska's Spartan 151 jack-up drilling rig is safely moored at Port Graham for the winter, having completed another couple of exploration wells this year, seeking oil and gas in the Cook Inlet Kitchen Lights unit. And the company's Kitchen Lights gas production platform is moving south to Seattle, to overwinter there, with Furie now planning to install the platform in the waters of the inlet in the spring of 2015.

But just what has the company found as a consequence of its Kitchen Lights drilling? To date the company has completed a total of five Kitchen Light wells and has announced a gas field development centered on one of these wells. The Kitchen Lights unit straddles the center of Cook Inlet, off the northern coast of the Kenai Peninsula.

Furie's efforts to bring a Kitchen Lights gas field into production, coupled with some tantalizing announcements of discovered gas resources, have caused speculation over how much gas the company may be able to bring on line. And documents relating to the drilling of the first of the company's Kitchen Lights wells have recently been released by the Alaska Oil and Gas Commission, adding a further piece to the incomplete puzzle of figuring out what Furie has discovered.

The sequence of Kitchen Lights wells has broadly followed the requirements spelled out in Furie's exploration plan, filed with the Alaska

see **FURIE DRILLING** *page 19*

FINANCE & ECONOMY

Buccaneer selling out

Bankruptcy independent seeks court approval for sale to lender AIX Energy

By ERIC LIDJI
For Petroleum News

Buccaneer Energy Ltd. is selling its Alaska assets to its largest creditor for $44 million.

After holding an auction on Oct. 27, the Australian independent is asking a federal bankruptcy court in Texas to approve a sale to the Houston-based AIX Energy LLC.

The proposed $44 million sale price represents a credit bid, which allows a secured creditor to offer the amount of its debt against cash bids from other potential buyers.

A court-approved sale process allowed Buccaneer to either hold an auction or sell its assets directly to AIX Energy, should a solicitation fail to yield any qualified bids.

The only qualified bid came from the Miller Energy Resources Inc.-affiliate Cook Inlet Energy LLC, which offered $35 million for the properties in a bid made Oct. 24. Miller had previously announced its intentions to bid between $40 million and $50 million.

Buccaneer used the $44 million credit bid from AIX Energy as the opening bid for the auction. Cook Inlet Energy declined to increase its initial bid, which ended the auction.

Should the AIX Energy sale fall through, Buccaneer would sell the assets to Cook Inlet Energy for $35 million. Buccaneer is asking the court to approve both contingencies.

see **BUCCANEER SALE** *page 17*

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PIPELINES & DOWNSTREAM

Alaska - Mackenzie Rig Report

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status

Alaska Rig Status

North Slope - Onshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Doyon Drilling			
Dreco 1250 UE	14 (SCR/TD)	Prudhoe Bay DS 15-28A, workover	BP
Dreco 1000 UE	16 (SCR/TD)	Prudhoe Bay W-26A	BP
Dreco D2000 Uebd	19 (SCR/TD)	Alpine CD4	ConocoPhillips
AC Mobile	25	Prudhoe Bay DS 11-39	BP
OIME 2000	141 (SCR/TD)	Kuparuk 2F-21	ConocoPhillips
Kuukpik	5	Prudhoe Bay	Available
Nabors Alaska Drilling			
AC Coil Hybrid	CDR-2	Kuparuk 2F-18	ConocoPhillips
Dreco 1000 UE	2-ES (SCR-TD)	Prudhoe Bay	Available
Mid-Continental U36A	3-S	Prudhoe Bay	Available
Oilwell 700 E	4-ES (SCR)	Prudhoe Bay	Available
Dreco 1000 UE	7-ES (SCR/TD)	Kuparuk	ConocoPhillips
Dreco 1000 UE	9-ES (SCR/TD)	Kuparuk	ConocoPhillips
Oilwell 2000 Hercules	14-E (SCR)	Prudhoe Bay	Available
Oilwell 2000 Hercules	16 (SCR/TD)	Prudhoe Bay S-108	BP
Emsco Electro-hoist-2	18-E (SCR)	Prudhoe Bay	Stacked
Emsco Electro-hoist Varco TDS3	22-E (SCR/TD)	Prudhoe Bay	Stacked
Emsco Electro-hoist Canrig 1050E	27-E (SCR-TD)	Deadhorse, under contract to ExxonMobil for 2015	
Emsco Electro-hoist	28-E (SCR)	Prudhoe Bay	Stacked
Oilwell 2000	33-E	Prudhoe Bay	Available
Academy AC Electric CANRIG	99AC (AC-TD)	Deadhorse	Availablel
OIME 2000	245-E (SCR-ACTD)	Oliktok Point	ENI
Academy AC electric CANRIG	105AC (AC-TD)	Deadhorse	Available
Academy AC electric Heli-Rig	106-E (AC-TD)	Deadhorse	Available
Nordic Calista Services			
Superior 700 UE	1 (SCR/CTD)	Prudhoe Bay Drill Site E-34	BP
Superior 700 UE	2 (SCR/CTD)	Prudhoe Bay Well Drill Site 2-32C	BP
Ideco 900	3 (SCR/TD)	Kuparuk Well 1A-25	ConocoPhillips
Parker Drilling Arctic Operating Inc.			
NOV ADS-10SD	272	Prudhoe Bay DS 18	BP
NOV ADS-10SD	273	Prudhoe Bay DS W-59	BP

North Slope - Offshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
BP			
Top Drive, supersized	Liberty rig	Inactive	BP
Doyon Drilling			
Sky top Brewster NE-12	15 (SCR/TD)	Spy Island SP21-NW1 L1	ENI
Nabors Alaska Drilling			
OIME 1000	19AC (AC-TD)	Oooguruk ODSN-02	Caelus Alaska

Cook Inlet Basin – Onshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Miller Energy Resources			
Mesa 1000	Rig 37	Mobilized to North Fork to begin drilling this winter	Miller Energy Resources
All American Oilfield Associates			
IDECO H-37	AAO 111	Going over to Trading Bay to perform a workover starting on 10/3/14	Cook Inlet Energy
Aurora Well Services			
Franks 300 Srs. Explorer III	AWS 1	Sterling, Stacked out at D&D yard	Available
Doyon Drilling			
TSM 7000	Arctic Fox #1	North Kenai, stacked	Nordaq
Nabors Alaska Drilling			
Continental Emsco E3000	273E	Kenai	Available
Franks	26	Kenai	Stacked
IDECO 2100 E	429E (SCR)	Kenai	Stacked
Rigmaster 850	129	Kenai	Available
Saxon			
TSM-850	147	Ninilchik Unit, Bartolowits pad drilling Frances #1	Hilcorp Alaska
TSM-850	169	Swanson River	Hilcorp Alaska

Cook Inlet Basin – Offshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
XTO Energy			
National 110	C (TD)	Idle	XTO
Spartan Drilling			
Baker Marine ILC-Skidoff, jack-up		Spartan 151 Upper Cook Inlet KLU#1	Furie
Cook Inlet Energy			
National 1320	35	Osprey Platform RU-1, workover	Cook Inlet Energy
Hilcorp Alaska LLC (Kuukpik Drilling, management contract)			
		Monopod Platform, Drilling Trading Bay ST A-31	Hilcorp Alaska LLC
Patterson UTI Drilling Co LLC			
	191	West McArthur River Unit #8	Cook Inlet Energy
Kenai Offshore Ventures			
LeTourneau Class 116-C, jack-up	Endeavor	Port Graham	Buccaneer Energy Ltd.

Mackenzie Rig Status

Canadian Beaufort Sea

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
SDC Drilling Inc.			
SSDC CANMAR Island Rig #2	SDC	Set down at Roland Bay	Available

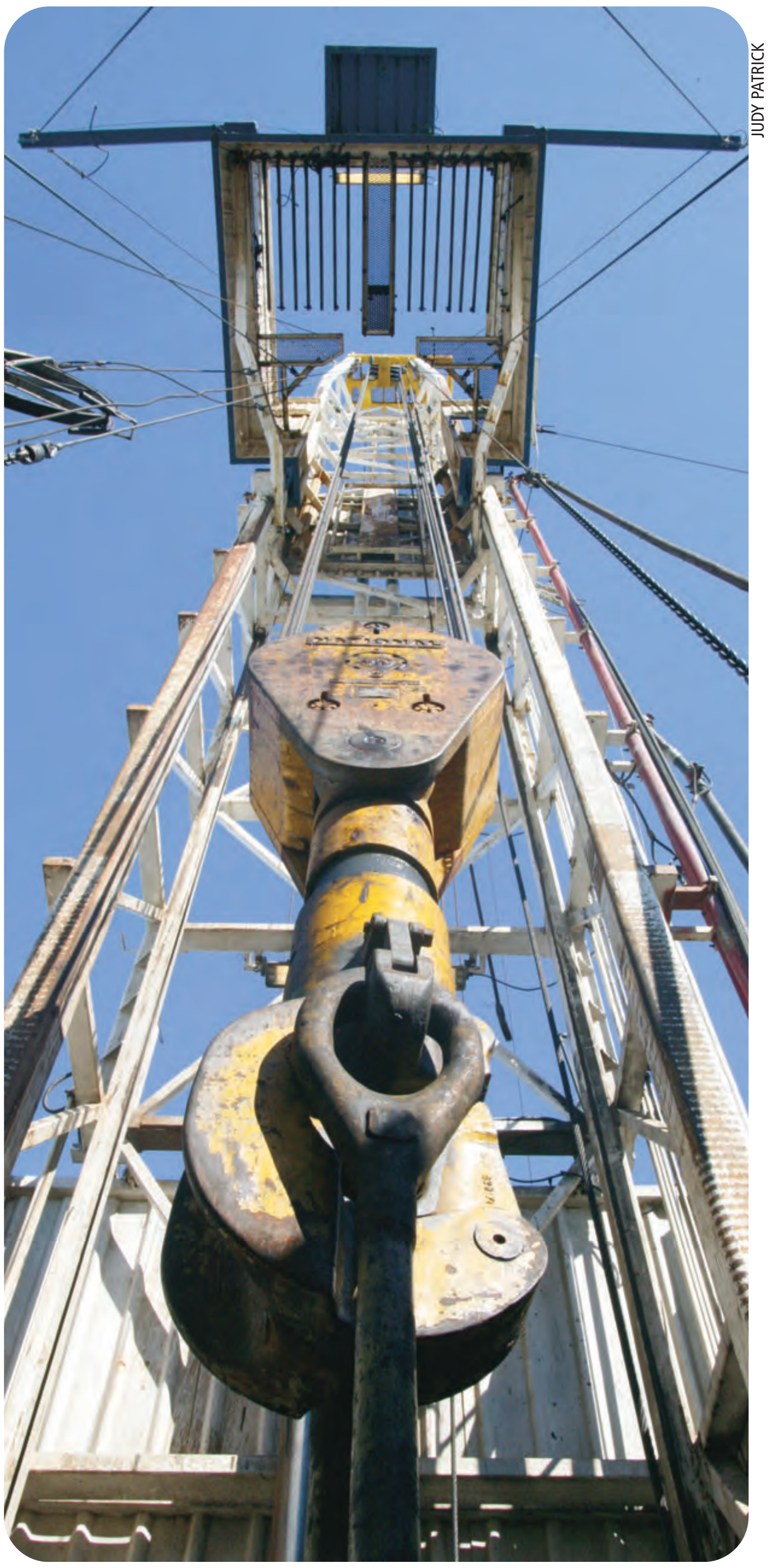
Central Mackenzie Valley

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Akita			
TSM-7000	37	Racked in Norman Well, NT	Available

The Alaska - Mackenzie Rig Report as of October 30, 2014. Active drilling companies only listed.

TD = rigs equipped with top drive units WO = workover operations
CT = coiled tubing operation SCR = electric rig

This rig report was prepared by Marti Reeve



JUDY PATRICK

Baker Hughes North America rotary rig counts*

	Oct. 24	Oct. 17	Year Ago
US	1,927	1, 918	1,738
Canada	426	417	404
Gulf	53	55	60

Highest/Lowest		
US/Highest	4530	December 1981
US/Lowest	488	April 1999
Canada/Highest	558	January 2000
Canada/Lowest	29	April 1992

*Issued by Baker Hughes since 1944

The Alaska - Mackenzie Rig Report is sponsored by:

● PIPELINES & DOWNSTREAM

US tribes oppose Trans Mt pipeline plans

Tribal leaders tell Canada's NEB Kinder Morgan's expansion poses serious consequences for way of life, Pacific Coast environment

By GARY PARK
For Petroleum News

An unprecedented intervention from the United States is pitting Washington state Indian tribes against Kinder Morgan's plans to expand its Trans Mountain crude pipeline from Alberta to the Pacific Coast.

Tribal leaders testified before Canada's National Energy Board to voice their concerns about a dramatic increase in the number of oil tankers that would result from increasing the pipeline's shipments of crude bitumen from the oil sands to 890,000 barrels per day from 300,000 bpd.

The existing pipeline delivers crude to Burnaby in Metro Vancouver and to Washington state.

Under the expansion, Trans Mountain could load 34 tankers a month — compared with about five currently — at Burnaby's Westridge dock from where they would generally travel through Haro Strait west of San Juan Island and the Strait of Juan de Fuca on their way to markets in Asia and the United States.

The tribal leaders, marking the first time U.S. tribes had appeared before the NEB, said the dangers of such an increase in tanker traffic posed a threat to their way of life, culture and the environment.

Brian Cladoosby, chairman of the Swinomish Indian Tribal Community near Anacortes, told the regulatory panel that his 900-member tribe relies on salmon, shellfish and other natural resources.

Leonard Forsman, chairman of the Suquamish Tribe on the Kitsap Peninsula, said "the more traffic there is, the more oil there is, the more opportunity there is for a catastrophic spill. We're concerned about (what that would do) to the ecosystem."

Although the U.S. tribes don't speak for Canadian citizens they are "profoundly impacted by the project" and share a culture with the Coast Salish people in Canada, said Jan Hasselman, a lawyer with Earthjustice representing the tribes.

Gary Youngman, the lead for Trans Mountain's aboriginal engagement, said Kinder Morgan respects the tribes' input and values its relationship with them.

He promised every effort would be made by Kinder Morgan to minimize impact and protect the environment.

The NEB panel is expected to release a final report in January 2016 with a recommendation to the Canadian government.

Survey can continue

Separately, the drawn out battle between Kinder Morgan and the City of Burnaby has seen the company claim a rare success.

The NEB issued an order allowing Kinder Morgan to continue survey work that could see it reroute the pipeline through a mountain in Burnaby.

But Burnaby Mayor Derek Corrigan said his council will not give up the fight given that the survey work will take place on city land.

"It's not surprising that the (NEB) will attempt to extend their authority to run our city. I'm not surprised by it," he said. "If we are going to resolve this issue it will end up in federal courts.

"We are not going to accept this as being the final word for us," he said, indicating the city will likely appeal after consulting its lawyers.

In the meantime, Kinder Morgan, which did not comment on the NEB decision, must give the city 48 hours written notice before resuming survey work.

The NEB also ruled it had the authority to consider the constitutional question of how far its powers extended, while the City of Burnaby argued the matter should be handled by the British Columbia Supreme Court.

Agreement with Paul First Nation

The company also reported a milestone agreement with the Paul First Nation, an aboriginal community of 2,000 occupying land on the Trans Mountain right of way 30 miles west of Edmonton.

The mutual benefits agreement covers education and training related to pipeline construction and business opportunities for the First Nation's own companies and its joint-venture partnerships.

Paul Chief Casey Bird said the agreement extends beyond his community's traditional lands to include timber used to build mats that protect soil and reduce environmental impact. ●

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NATURAL GAS

Interior Energy Project hits milestones

A project to bring natural gas to the Fairbanks North Star Borough by 2016 recently reached milestones at its upstream and downstream components, according to sponsors.

All permits for the North Slope liquefied natural gas facility are in place, according to the Alaska Industrial Development and Export Authority. And the Interior Gas Utility is now taking bids for the plastic distribution pipelines to be installed in North Pole next year.

With the permitting program for the North Slope plant complete, AIDEA said it can now move toward closing on the financial arrangements with its private sector partner and then start procurement. AIDEA intends to hit both of those targets by the end of the year.

AIDEA and the global infrastructure firm MWH Americas Inc. signed a concession agreement in September. The agreement established a legal framework for AIDEA to own and MWH subsidiary Northern Lights Energy LLC to build and operate the plant.

Within Prudhoe boundaries

The partners intend to build the North Slope LNG facility within the boundaries of the Prudhoe Bay unit. With assistance from unit operator BP Exploration (Alaska) Inc., AIDEA significantly sped up the process of securing the final air

see **ENERGY PROJECT** *page 6*

GOVERNMENT

Feige: SB 21 benefit with low oil prices

Outgoing House Resources co-chair says role of state as partner in LNG project significant; encouraged by companies working together

By STEVE QUINN
For Petroleum News

House Resources co-chairman Eric Feige is winding down his four-year career in the Legislature, a two-term commitment that put this Chickaloon Republican on the front lines of some critical oil and gas legislation.

Feige, who did not win his primary race, led the committee through hearings on Gov. Sean Parnell's oil tax change (Senate Bill 21) and natural gas pipeline and LNG export legislation (SB 138) among others.

Feige recapped his tenure as co-chair with Petroleum News.


REP. ERIC FEIGE

Petroleum News: What do you think characterized your four years as co-chair?

Feige: The last four years there certainly were some pretty major issues we waded through and basically got laws changed to improve the investment climate for oil in this state. SB 21 was certainly a major accomplishment. It was a long battle to roll back ACES. It was gratifying to see the people defeat Ballot Measure 1.

Petroleum News: As you look at SB 21, do you think it's durable? Is there any component in there that may need tweaking two, four, six years down the road?

Feige: I think it's probably a little too early to tell. Right now the price of oil is about $80 a barrel. That was certainly not forecast. One of the things I looked back on as we were putting that bill together, we were knocking down the tax rate at the upper prices levels.

One of the things we did with SB 21 that is coming in handy now is that we actually raised the prices at lower taxes. So below $90 a barrel, the state is actually taking in more because of the minimum tax clauses we put in. The improvements to the investment climate have certainly started to show results. We'll see how long this price retraction lasts and we'll see how much that affects the investment. As far as SB 21 goes, we've got to resist the urge to keep tweaking things all the time. We need a stable investment climate and we need consistency.

Petroleum News: There was still concern about getting a meaningful definition of new oil, say as opposed to more oil. Do you see that being a problem ahead?

Feige: that was something we spent a lot of time on. The oil that's there in the legacy fields and already has wells punched into those formations; that oil was going to be produced one way or the other. It might have been produced under ACES at some point, maybe later rather than sooner. But what we were looking to do was improve the investment climate so that companies could go after those new pools of oil.

New oil is oil that comes from a reservoir that has not been tapped into, as yet undiscovered, previously uneconomic, or for whatever reason it had not been developed at the time we passed the bill. It's going to take investment to bring that oil to market. The way we all looked at it was this was oil we do not have now and would not see in the near future because of the way ACES had been implemented. Given a lower tax rate on new oil and it results in that oil coming to the surface, going to market and it the state collecting a royalty and production tax on it, that's one we could not have counted on under ACES.

Petroleum News: Do you think the state will be able to differentiate between new oil and more oil?

Feige: I think we use the definition in the statutes then it will be new oil. Will the people of the state understand the difference? Yeah, it's kind of a technical nuance. People can say what they want. We looked at the legacy fields as oil that would be produced no matter what. We were looking to get additional oil out of there.

Petroleum News: People who favored ACES said it needed time to work when it first came out. Do you believe that should be afforded to SB 21?

Feige: Time will tell. I think it's important for Alaska to kind of sit on what we have and give it time to work. Just in the short term we were looking to improve the investment climate and bring more investment to the state. Certainly in the short term, that happened. You are seeing more drilling rigs committed to the slope. Commitments to purchase or lease, then bring up new rigs, plus the additional jobs that come with those new rigs. The anecdotal evidence I hear talking to people in my district who work up on the slope, they've never seen it busier. I think that is good news. It helped guide people's decision to uphold SB 21.

Petroleum News: Speaking of development and anecdotal evidence, Conoco just announced a new pad sanctioned. Is that what you had in mind?

Feige: I believe that's 2S, which is basically new oil, which they proposed. I'm happy that it's a new pad, and that means you're drilling in a new area. That's going to count as new oil. That would be my guess. That's what we intended. From my perspective, it's gratifying that ConocoPhillips as a company has decided to commit hundreds of millions to developing new sources of oil. If they did it because of a change we made in the tax structure, that's what we intended.

Petroleum News: You've flown people to the slope for your work; do you see your work picking up now that you can devote time year round?

Feige: Oh, I don't know. I'm optimistic that there will certainly be more work. It depends on what the price of oil does and what the companies feel the price is going to be in the near future. I think most of them look at this as a relatively short-term retraction, then it will go back above $100.

Petroleum News: Now that the debate over oil taxes has died down do you think it will be easier for the Legislature to move forward on other things?

Feige: I think the Legislature should set aside oil and let the work the 28th Legislature did, well let it work. Will they be able to do that, there are so many things that drive that, but I'm optimistic they will be able to let it lie for the time being.

Petroleum News: Let's move on to the natural gas line and LNG export project. You folks delved into it and capped it off with some late meetings, but came away with a product most seemed to like thus far. What are your thoughts on how SB 138 played out?

Feige: That was a major achievement. I think we made significant progress. The idea of having the state act as a partner, both in taking on risk as well as increased reward is a good thing. And there was a lot of back and forth with the executive branch and the companies, and then within the Legislature some of the enhancements that we felt were necessary to basically cover the interests of the state. Things like the property tax revenue and payment in lieu of taxes and how those impacts in those communities, along the pipeline route, how those impacts will be dealt with. We saw a great spirit of communication, not only with the governments along there, but the companies. I think they will all be able to work together to address those issues. Quite frankly, I was pretty encouraged by the level of cooperation that the companies exhibited not only working with the state but also working among themselves.

Petroleum News: The debate over this bill wasn't nearly as contentious as the oil tax debate and public differences didn't linger as with the oil tax discussion. Why do you think that was?

Feige: I think both sides of the aisle realize the gas pipeline project will bring significant benefits to the people of the state. Not only revenue going to the government, but just that lower cost energy that will be distributed through the state as much as we can do that.

Petroleum News: Should we be optimistic about the developments such as the applications to FERC and Energy Department or was this really to be expected?

Feige: Each one of those actions was part of the timeline when we put this thing together. I guess on one hand, I'm encouraged that everything the partners said would happen did happen and it happened on time. They obviously are moving forward on their work. Hopefully it continues. Hopefully this retraction of oil prices does not have a significant impact on the project moving forward. There are a lot of things going on external to the state in the global LNG market. There are a lot of entities fighting

see FEIGE Q&A page 17

● EXPLORATION & PRODUCTION

Villagers reject Corps CD-5 explanation

Say that reasoning behind decision not to modify SEIS relies on unsupported and conflicting statements relating to project changes

By **ALAN BAILEY**
Petroleum News

A group of residents from the village of Nuiqsut on the North Slope have told the federal District Court in Alaska that a report filed in September by the U.S. Army Corps of Engineers has failed to provide an adequate explanation of why the Corps did not prepare an SEIS, or supplemental environmental impact statement, when permitting ConocoPhillips' CD-5 oilfield development in the northeastern National Petroleum Reserve-Alaska, the first field to be developed in the reserve.

Dredge-and-fill permit

The permit at the center of the dispute is the Corps' dredge-and-fill permit. The villagers launched an appeal against the permit in federal court in February 2013, saying that the CD-5 project had changed and new information had become available since the Corps published an FEIS, or final environmental impact statement, in 2004. The FEIS encompassed the potential development of several satellite fields to the Alpine oil field, including CD-5. Under the terms of NEPA, the National Environmental Policy Act, the changed circumstances of the CD-5 project require revisions to the FEIS, the villagers claimed.

In May of this year U.S. District Judge Sharon Gleason ruled that the Corps had violated NEPA by not explaining why it had decided not to prepare a revised EIS for the CD-5 project. The judge ordered the Corps to prepare an explanation for its decision. But, noting that the plaintiffs in the appeal had not filed suit until more than a year after the Corps had filed the dredge-and-fill permit, Gleason declined to cancel the permit, thus allowing ConocoPhillips to proceed with its CD-5 development while the appeal case is being resolved.

Judge Gleason has yet to rule on the legal adequacy of the Corps' supplemental information report.

Supplemental report

In September the Corps complied with the court order by filing a supplemental information report, setting out the reasoning behind its decision not to rework the FEIS. The report says that in 2011 the Corps conducted a review "in light of the most current information about the potential impacts of the proposed activities and determined that there were no significant changes that altered the analysis underlying the 2004 FEIS." Neither had there been any changed circumstances at the CD-5 development site, the report says.

The plan for the CD-5 project that ConocoPhillips finally permitted fell within a mid-range of alternatives considered within the FEIS, with project changes "encompassed within the concept" of the Corps' preferred alternative for the project, as documented in the FEIS, the report says. And almost all the changes mitigated potential adverse impacts noted for that alternative, it says.

Changes to the CD-5 project plan since FEIS publication consist of the relocation of a bridge for crossing a channel of the Colville River; the re-alignment of the CD-5 access road; an increase in the size of the CD-5 pad and a re-alignment of the pad; the construction of two small bridges as alternatives to culverts; an increase in the impacted area of waters of the United States; and some additional measures for reducing project environmental impacts, the Corps reported. The Corps presented detailed justifications for not viewing any of these changes as invalidating the FEIS, saying for example, that the revised bridge location lies within a range of locations considered in the FEIS.

Villagers respond

In a response filed on Oct. 14 the villagers who are appealing the Corps permit argued that the CD-5 project changes are substantial. The changes involve a 30-percent increase in gravel fill, and 43 percent lengthening of the access road, as well as the addition of more and larger bridges, the villagers wrote. The Corps has failed to present a reasoned analysis of why the project changes should be viewed as insignificant, they said.

"The project necessarily created new impacts to the area's complex hydrology, wildlife, tundra, soils and aquatic habitat," the villagers wrote.

And the villagers disagree with the Corps' view that the changes fall within the scope of alternatives considered in the FEIS.

"The road and bridge locations were also shifted several miles south and completely rerouted from their original location — or any location considered in the 2004 FEIS," they wrote. "The Corps cannot avoid supplemental NEPA review by simply 'cobbling together' portions of alternatives that had been analyzed earlier."

New information

New information that has become available since the FEIS was completed includes new insights into climate change, and its potential impact on the project, and the potential cumulative impacts of other projects in the CD-5 region, the villagers have argued. The Corps says that there has been no new information of sufficient impact to warrant a revisit of the FEIS, while the villagers say that the Corps has acted in an arbitrary manner by not formally assessing how new information may require some rethinking of the project impacts.

Judge Gleason has yet to rule on the legal adequacy of the Corps' supplemental information report. ●

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ENERGY PROJECT

quality control permit and associated reports, according to AIDEA Executive Director Ted Leonard.

"We are grateful for BP's help on moving this critical part of the Interior Energy Project forward," Leonard said in a statement. "Their assistance allowed for a thorough and prompt analysis of the air permit application, and meant that AIDEA did not have to expend valuable time and resources on gathering base data for the final permit needed to build the plant."

The Interior Energy Project will truck LNG to the Fairbanks North Star Borough, where it will be re-gasified and delivered to consumers on at least two distinct grids.

The Fairbanks Natural Gas grid is already operational, although the utility intends to expand its operations within the city of Fairbanks using a $15 million AIDEA loan.

The municipal Interior Gas Utility is building a new grid in the city of North Pole that will expand throughout the borough. The utility is now taking bids. "To begin construction as soon as possible in 2015, this large amount of pipe needs to be ordered before December 2014," Interior Gas Utility Project Manager David Prusak said in a statement. "We are grateful to work with AIDEA representatives who continue to be flexible and understand the complexity of this project and the aggressive timeline before us."

—ERIC LIDJI

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● NATURAL GAS

Jury out on BC's LNG tax regime

Subdued reaction to new policy, critic convinced it will discourage development; industry tackles costs, labor, regulatory process

By GARY PARK
For Petroleum News

The response to the British Columbia government's big push to entice global energy giants to launch the province's LNG industry has remained mostly subdued and non-committal as companies gird themselves for the next phase in their decision-making process.

While that takes shape some analysts are voicing hope that the province could now be within months, or perhaps a few years, of corporate sanctioning for a handful of the larger ventures.

British Columbia's key selling features remain its vast natural gas deposits and its proximity to the Asian markets.

But there is still a delicate balancing act between the obvious upside and the doubts all players have over the capital costs, the availability of skilled labor, the slow pace of regulatory approvals and other taxes and regulations.

Some of the sharpest criticism comes from Jack Mintz, director of the School of Public Policy at the University of Calgary, who wrote in the National Post that the new fiscal regime "discourages LNG development."

He said the policy "should be taken for what it is: A revenue grab without much thought given to economic or policy objectives."

"It sets a precedent of taxing differently one form on business activity compared to others, distorting the allocation of capital and labor in the economy.

"Instead of moving to a smart efficient tax system with respect to resource development, the province has created a poor public policy precedent for the coming years," Mintz said.

Separate decisions

Gaetan Caron, a former chairman of Canada's National Energy Board and a colleague of Mintz's at the University of Calgary, said that regardless of whether the projects are controlled by foreign governments or the private sector, each proposal will make its own decision based on cost structures and the complexities of their proposals.

He suggested to the Financial Post that it is unlikely proponents will react in unison to the tax regime, which is set at an initial 1.5 percent of operating income followed by 3.5 percent after the recovery of investment costs.

That is minimally offset by a 0.5 percent tax credit for the cost of natural gas provided to an LNG facility of up to 3 percentage points of corporate taxable income (thus lowering the corporate tax rate to 8 percent from 11 percent).

Greg Pardy, an analyst at RBC Capital markets, said in a report to clients that his firm views the tax structure as "a positive development in the context of intensified LNG supply competition from the United States, East Africa and elsewhere. It would appear that British Columbia's LNG tax would not unduly burden a sector that has yet to come into existence."

Peters & Co, the Calgary-based investment banker, said the tax represents a modest 30 cents per thousand cubic feet of gas for an integrated project.

It told clients that although that is an incremental cost for developers, LNG exports from the British Columbia coast are likely to proceed, with up to three projects commissioned by 2025.

Tough competition

Ernst & Young said British Columbia faces tough global competition, notably from some U.S. projects that are moving ahead faster than expected.

"The market continues to develop and tax is only one of the factors that will determine the competitiveness of a Canadian LNG project," the firm said. "Global supply/demand considerations, costs (both capital and operating), environmental approval conditions, First Nations support and the state of the global debt and equity capital markets will all be critical for a viable project."

FirstEnergy Capital said in a report that the greater risks still stem from initial construction costs and the eventual selling price of LNG in Asian markets.

It said a landed price of US$13 per million British thermal units could keep project economics and rates of return "relatively attractive."

But FirstEnergy suggested that oil prices, which the Asian LNG customers want to apply as a benchmark, pose a risk.

At Brent crude prices of US$100 per barrel the LNG price in Japan is about US$15 per million Btu, while a US$90 price translates into US$13 for LNG.

Petronas most vocal critic

Malaysia's Petronas, operator of the proposed Pacific NorthWest LNG project and the most vocal critic of the directions being pursued by the British Columbia government and the pace of the regulatory process, said only that it wants more time to digest the tax regime before commenting.

But the company issued one cautionary note, telling all levels of government that they must "recognize the need to remain competitive with other jurisdictions around

see **TAX REGIME** *page 9*

BC favors LNG with new climate-change law

The British Columbia government has rolled out a new law for greenhouse gas emissions that Environment Minister Mary Polak said will allow the province to meet its climate-change targets without jeopardizing its chances of an LNG industry.

But achieving that balance will mean tougher action on GHG emissions in other sectors to compensate for the new industry.

If the government attains its revised goal of five LNG plants (from the 18 currently being floated), British Columbia's emissions would total 13 million metric tons a year, requiring further cuts in transportation and buildings to reach the goal of 41 million metric tons in emissions cuts by 2020.

"Sure, it's going to be really difficult," Polak conceded to reporters.

"We are going to have to be drilling down to more and more of the everyday things that we can do" to lower GHG emissions, she said.

To avoid driving away potential investors, Polak said companies will have "flexible options" to meet the government's 2020 benchmark, including the ability to purchase offsets or to contribute to a fund that is designed to drive innovation in cleaner technology.

But she would not estimate how much the government will pay towards incentives to help LNG facilities achieve the benchmark.

David Keane, president of the British Columbia LNG Alliance, representing five prospective investors, said the GHG standards will have to be weighed along with the new LNG tax structure, especially given that the GHG benchmark is "very low."

The government is not including upstream emissions that result from gas exploration, extraction and transportation.

Andrew Weaver, the lone Green Party member of the provincial legislature, said

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● LAND & LEASING

BLM releases Mooses Tooth final SEIS

Bureau of Land Management preferred alternative includes road, but is not ConocoPhillips proposal; drilling pad, access road moved

By KRISTEN NELSON
Petroleum News

The Greater Mooses Tooth 1 development in the National Petroleum Reserve-Alaska is one step closer to moving ahead — but not exactly as operator ConocoPhillips Alaska requested.

The federal Bureau of Land Management released the final supplemental environmental impact statement for GMT1 Oct. 29, but said its preferred Alternative B was not Alternative A proposed by the company.

The agency said Alternative B "focuses on keeping the proposed road and pipeline outside of the BLM-established Fish Creek buffer, and has two fewer stream crossings than Alternative A."

The agency said it would formally publish the document in the Federal Register on Nov. 7 with a record of decision to be issued "at least 30 days after the publication of the final SEIS."

GMT1 is the development of a discovery made at Lookout and originally proposed as drill site CD-6. When it was determined that CD-6 was not in the same reservoir as the Colville River unit, drill sites CD-1 through CD-5, CD-6 was renamed GMT1, part of the Greater Mooses Tooth unit.

Drilling pad, road moved

BLM said the main differences between Alternative B and Alternative A include moving the drilling pad some 700 feet to the southwest; routing the access road and pipeline from GMT1 to the CD-5 drill site south of the Fish Creek setback; a new tie-in pad for the pipeline east of the CD-5 drill site; eliminating a bridge over Crea Creek and a culvert at Barely Creek.

BLM said Alternative B would have a slightly larger footprint and greater fill requirement than Alternative A and said the route "may be more technically challenging for road construction and maintenance (e.g., poor soils, thaw stability) due to the extent of thaw basins along the route."

Both alternatives include an 11.8-acre gravel pad, 33 wells and gravel supply from the Arctic Slope Regional Corp. mine site.

Alternative B has a mile more of access road, 8.6 miles compared to 7.6 miles for Alternative A, and 18.2 miles of elevated pipelines on vertical support members compared to 17.9 miles for Alternative A.

The total gravel footprint of Alternative B is larger at 80.4 acres, compared to 72.7 acres for Alternative A.

Other alternatives considered in the final SEIS were C, which evaluated Nuiqsut as a hub for industrial activity with upgrades of roads and the Nuiqsut Airport; Alternative D1, with no year-round road access between GMT1 and existing Colville River unit facilities at Alpine; Alternative D2, similar to D1 but with only seasonal drilling; and Alternative E, the no action alternative.

Congressional delegation disagrees

The Republican members of Alaska's congressional delegation, Sen. Lisa Murkowski and Congressman Don Young, objected to BLM's assessment.

Murkowski said in an Oct. 29 statement that Interior's final SEIS was released "after months of delay," and rejected ConocoPhillips' preferred alternative in favor of "a longer and more expensive road option."

"Though I'm glad Interior has finally issued this review, I am concerned about the critical project decisions that are being left for the record of decision, which could impact whether this project moves forward or not," Murkowski said. Interior needed to finalize the SEIS by the end of October to allow the U.S. Army Corps of Engineers and the Environmental Protection Agency "sufficient time to complete the permitting process in time for ConocoPhillips to begin production by 2017," but, Murkowski said, BLM will leave its final decision open until the Corps and EPA finish their reviews.

"Federal leaseholders need to have a permitting process that is timely and predictable in order to invest the billions of dollars it takes to develop America's energy resources," she said.

Young said he was "pleased to see a plan that includes an access road," but said he shared "some of the same concerns expressed today by industry representatives that this assessment leaves us with too many unanswered questions regarding the future of this project and dismisses a preferred road alternative."

He also said the BLM assessment leaves the Greater Mooses Tooth project "up against pending reviews by the EPA and Army Corps of Engineers, which have previously held up a number of Alaskan projects, including production within CD-5."

"It remains to be seen what mitigation and other requirements will pile onto this process, but for now I am happy to see it move forward," Young said.

Conoco has objections

In an Oct. 29 statement provided to Petroleum News by email, ConocoPhillips said:

"We are pleased that the BLM has chosen a roaded alternative as their preferred alternative for GMT1. However, the roaded alternative the agency has chosen, Alternative B, is not the alternative that ConocoPhillips proposed. The proposed project, which is Alternative A, has the lowest environmental footprint, requires the least amount of gravel, and remains the best Alternative in ConocoPhillips' view. We are currently pursuing a Corps of Engineers 404 permit for Alternative A. The Corps has not yet determined which alternative is the 'least environmentally damaging practicable alternative' (LEDPA). ConocoPhillips expects that the BLM has flexibility to approve the alternative selected by the Corps." ●

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● GOVERNMENT

EPA releases emission rule information

Publishes new data, ideas as part of public comment period for proposed power plant GHG emissions regs; adds Indian Country rule

By ALAN BAILEY
Petroleum News

On Oct. 28 the Environmental Protection Agency announced that it was making available some new information and ideas, in connection with the public comment period for the agency's proposed regulations, establishing limits for carbon dioxide emissions from U.S. power plants. The agency also announced that it proposing an emissions rule that would apply to the handful of power plants that are located inside Indian Country. The proposed regulations set emissions targets on a state-by-state basis — the proposed new rule would bring Indian Country into the regulatory scheme.

Comments on the proposed regulations are due by Dec. 1.

State-based limits

The regulations, which apply to large, commercial power plants, would set each state a limit on the amount of carbon dioxide that can be emitted per unit of power generated. States must develop plans for achieving their emissions limits by 2030 through some combination of power generation efficiency, changes in generation technologies and improved efficiency of power use. There are required dates for plan submission. And, if a state does not end up with an EPA-approved plan, EPA will prepare and mandate a plan for the state.

The target emissions limits are based on a percentage of each state's power-generation-related carbon dioxide emissions in 2012.

EPA says that it has already received more than 1.5 million public comments on its proposals and that, at this point, it is publishing ideas and issues that these comments have consistently raised. During what remains of the comment period, people can consider these ideas and issues while formulating their own comments, the agency says.

Wide range of ideas

During a press conference announcing the release of the new information, Janet McCabe, acting assistant administrator for EPA's Office of Air and Regulation, said her agency had heard a wide range of ideas and issues from states, stakeholders and the public about the proposed clean power plan.

The additional information that EPA is publishing reflects questions that people have commonly raised and does not relate in any way to making the regulations either more stringent or less stringent, she said.

She said that, in particular, the notice of information discusses three issues that have emerged from the comments that EPA has received:

• The possibility of having credits for early emissions curtailment, and the use of other more flexible arrangements to meet the requirements of a proposed trajectory of emissions reductions between 2020 and 2029;

• Additional ideas for using natural gas for emissions reductions, beyond the possibilities discussed in EPA's proposed regulations; and

• The possibility of a more regional approach to establishing renewable energy targets.

The notice also discusses alternative ways that have been suggested for calculating state emissions goals, she said.

EPA is also making available emissions data for the years 2010 and 2011, in addition to the information already available for 2012. That will enable people to assess the impact of using multiple years rather than a single year as the baseline for the emission levels, McCabe said. ●

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TAX REGIME

the world that currently, or plan to, export LNG" — a reference in part to labor and construction costs.

Petronas has, for now, shifted its attention to lobbying the Canadian government to provide financial relief for LNG export terminals.

It has failed in the past in trying to persuade the federal government to make tax concessions related to asset depreciation rates, noting that the federal tax classification of LNG plants will be vital in determining the economic viability of a project, including capital cost allowance rates.

A British Columbia LNG project in the Class 47 tax category would take 27 years to depreciate the bulk of its assets, compared with only seven years for a manufacturing operation in Class 43, the Canadian Association of Petroleum Producers has estimated. Faster depreciation allows companies to make tax deductions sooner. ●

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LNG FAVOR

the proposed legislation is "shameful ...we had leadership on the climate change file, but now we have given that up."

He said the changed rules plan to target the "intensity level" of pollution rather than the absolute quantity of pollution.

Weaver called for hard caps on emissions from LNG and a plan to aggressively reduce emissions overall.

He accused the government of promoting a "grand illusion ... to convince British Columbians that we can have wealth and prosperity from a hypothetical LNG industry and still meet our climate targets and continue to be good stewards of the environment."

Matt Horne, from the Alberta-based Pembina Institute, said the 2020 target would be a challenge "even without LNG," noting the government has "stalled out" after hitting its target in 2012.

—GARY PARK

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EXPLORATION & PRODUCTION

DOE announces hydrate research project

Selects project to characterize the properties of subsea methane hydrate resources in the Gulf of Mexico outer continental shelf

By ALAN BAILEY
Petroleum News

The U.S. Department of Energy has announced that it has awarded a $41 million grant to a team that will collect samples and conduct analyses, to better characterize methane hydrate resources that are known to exist in sands under deepwater areas of the Gulf of Mexico. The idea is to gain insights into the physical properties of the deposits for the purpose of methane hydrate resource appraisal.

Researchers from the University of Texas at Austin, the Ohio State University, the Columbia University-Lamont Doherty Earth Observatory, the Consortium for Ocean Leadership and the U.S. Geological Survey will conduct the project, which will be managed by the Office of Fossil Energy's National Energy Technology Laboratory.

Potential gas resource

Methane hydrate consists of methane, the main component of natural gas, trapped in an ice-like lattice of water molecules. The material, which is stable within a certain range of somewhat elevated pressures combined with low temperatures, is known to exist widely in some subsea settings, and straddling the base of the permafrost on land in Arctic regions such as northern Alaska. Given the vast quantities of methane trapped inside methane hydrate deposits, the deposits could become prolific sources of natural gas, should some viable means of developing the hydrate resources be developed. On the other hand, there are concerns that the natural decomposition of the hydrates could release the methane, a potent greenhouse gas, into the atmosphere.

The Department of Energy has led a methane hydrate research program since 2000, in collaboration with other federal agencies, universities, industry and international programs, to advance the scientific understanding of the material's resource potential and its environmental impacts. In recent years DOE has provided funding assistance for the drilling of two methane hydrate test wells on Alaska's North Slope, to evaluate the properties of permafrost-related hydrate deposits in that region.

Measurement and sampling

The new research project that the department is now sponsoring will follow up on some previous research in the Gulf of Mexico that successfully documented the presence of hydrate deposits in certain regions of the gulf. The new project will collect in-situ measurements and core samples to characterize the deposits. The research team will assess the potential for producing natural gas from the deposits and will further delineate the extent of the deposits on the U.S. outer continental shelf.

The research will involve an offshore drilling program, the collection of samples and the gathering of downhole log data. Tests will include the measurement of the hydrate reservoir response to short-duration pressure perturbations, DOE says. Field data and laboratory analyses will enable determinations of in-situ hydrate concentrations, and the physical properties and thermodynamic state of the hydrate bearing sands, the agency says.

Although this new research is aimed at the outer continental shelf, DOE says that it remains interested Alaska's methane hydrate deposits and that it intends to further evaluate production methods for terrestrial hydrates in the state. ●

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EXPLORATION & PRODUCTION

Report points to energy independence

Wood Mackenzie says US will export more energy than it imports by 2025 thanks to higher oil and gas production, lower oil demand

By ALAN BAILEY
Petroleum News

A report issued on Oct. 23 by research company Wood Mackenzie says that the United States will achieve energy independence by 2025, based on current trends in U.S. oil and gas production and consumption.

"A country can achieve energy independence through two channels, it can either produce more or consume less, and the U.S. is doing both," said senior analyst James Brick. "Over the past seven years the U.S. has added 3 million barrels per day of tight oil and 27.5 billion cubic feet per day of shale gas to the global energy mix, a spectacular 42 percent increase in U.S. oil and gas production."

At the same time, improving efficiency in the use of oil for transportation is causing oil demand to drop, he said.

Export ban

A key to accelerating the rate at which energy independence can be achieved is the lifting of a ban on the export of U.S. crude oil. If the opening up of exports were to lift the price of U.S. crude by, say, $5 per barrel, that could increase oil production by 350,000 to 450,000 barrels per day, an increase that would require about $5 billion of additional investment, Brick said.

But Brick acknowledged that upstream oil producers would gain most from the lifting of the export ban, although oilfield service companies and rig manufacturers would also benefit.

And, regardless of what happens to the export ban, evolving technologies will likely continue to push up oil and gas production, Brick said. In particular, techniques such as enhanced oil recovery and the re-fracturing of wells are showing much promise and could double hydrocarbon recovery rates, he said.

Fuel efficiency

Although Wood Mackenzie has forecast the fuel efficiency of the U.S. vehicle fleet to improve by more than 40 percent by 2030, fuel efficiency could improve more quickly than that, driving down both oil demand and net oil imports. It is also possible that there could be an increased tendency for people to use cars in preference to less efficient light trucks and sport utility vehicles.

Factors that could jeopardize the achievement of energy independence include delays in developing critical export facilities; the imposition of regulations that discourage well fracking; and energy policies aimed at reducing carbon dioxide emissions, thus pushing a greater use of natural gas for power generation, Brick said.

Wood Mackenzie concludes that, while the investments leading to energy independence will bring economic benefits to the United States, the direct impacts of that independence will be more muted. And U.S. energy markets will remain linked to international risks, Wood Mackenzie thinks.

"Irrespective of the timing of independence, the U.S. has started its transformation from energy consuming giant to prominent exporter," Brick concludes. "With this role shift come obvious economic benefits but also shifting risks and new responsibilities." ●

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● NATURAL GAS

Why LNG doesn't trade like oil

Transportation another difference between oil and gas and long-term contracts make natural gas pricing opaque, unlike crude oil

By JEANNETTE LEE

Researcher/Writer, Office of the Federal Coordinator

1 2 SERIES

Constraints on LNG transport

LNG shipments are also relatively inflexible. They need special, and very expensive, terminals for supercooling the gas to minus 260 degrees and then regasifying on delivery, and the gas usually is contractually bound to specific destinations under the long-term deal signed by seller and buyer. Oil, on the other hand, is more easily put on tankers and unloaded wherever it is needed.

Transportation constraints have historically limited LNG to production, trade and delivery in either of two basins — Pacific and Atlantic. Until Japan's demand jumped and prices soared after the Fukushima nuclear disaster in 2011, there was minimal cross-basin traffic. At which point increased demand and higher prices drew more Atlantic Basin LNG to Japan.

Transportation by sea could one day connect the major gas regions into a worldwide market, but many more tankers would need to be built.

There are about 4,000 oil tankers in the world, 500 feet long and larger, according to Poten & Partners, a global broker and commercial adviser for the energy and ocean transportation industries. During 2013, about 360 LNG tankers were in service. An additional 108 LNG carriers were on order, according to an end-of-year report by the International Gas Union. There, too, oil has it beat — 600 oil tankers were on order, said an August 2014 report by Poten & Partners.

The expansion of the Panama Canal will help smooth the way for the budding LNG export trade along the U.S. Gulf Coast and cross-basin traffic. Most LNG carriers are too big to pass through the canal, but the expansion will enable 90 percent of LNG tankers to transit the isthmus.

Most LNG carriers are too big to pass through the canal, but the expansion will enable 90 percent of LNG tankers to transit the isthmus.

The Panama Canal Authority said in 2013 that voyages to East Asia from Cheniere Energy's Sabine Pass LNG export plant under construction in Louisiana will be slashed by 20 days, round-trip. (Even so, the round-trip voyage could still take more than six weeks.)

Liquefaction is expensive

The price tags of contemporary LNG projects, both proposed and under construction, commonly reach the billions if not tens of billions of dollars. Estimates for the Alaska LNG project to export North Slope gas to Asia range from $45 billion to $65 billion for a gas treatment plant to remove carbon dioxide and other impurities, 800 miles of 42-inch-diameter high-strength steel pipe, a huge liquefaction plant, LNG storage tanks and a marine terminal.

The cost to process and ship oil to a refinery is small by comparison.

As an example, it costs less than $10 to pipe a barrel of Alaska North Slope crude almost 800 miles to the terminal at Valdez and send it by tanker to U.S. West Coast refineries — leaving 90 percent of the value of $100-a-barrel oil for production costs, taxes, capital investment and profit.

But for LNG, the pipeline, liquefaction and tanker costs of North Slope gas delivered to Japan could consume two-thirds of the fuel's value at summer 2014 Asian spot-market prices. Simply put, the profit margin for investors is much slimmer.

The liquefaction process is a big reason for the significant added expense to LNG. Liquefying Alaska North Slope gas will cost more than moving it 800 miles by pipe to the tidewater plant.

Smaller market, fewer players

The ubiquitous need for oil means many parties are either in the business of selling or buying it.

The huge number of crude oil buyers and sellers worldwide has enabled the creation of a transparent and liquid market.

Not so for LNG, which inhabits a much smaller realm. Oil pretty much has the transportation-fuel sector all to itself, while natural gas has to compete in the heating and electricity sectors with an array of energy sources including coal, nuclear, solar, wind, hydroelectricity, geothermal and even oil.

"Not every country in the world uses gas, and if they do, the quantities will be highly variable, because power generation fuel mixes vary so dramatically," Nelly Mikhaiel, a New York City-based senior consultant at FACTS Global Energy, wrote in a July 2014 email interview.

And for consumers who do use natural gas, only a minority will be part of the LNG trade because pipeline gas deliveries cost less. In 2013, about 69 percent of gas traded between countries flowed via pipeline. The United States, the world's largest gas producer and consumer, burns only a trickle of LNG.

For some customer nations, LNG is used to guarantee supply diversity and supplement existing pipeline imports, but in other cases, like Japan, it is a much more crucial part of the energy supply.

Japan buys LNG because no natural gas pipelines have been built to the island nation. In a move that shook the world LNG market, Japan's purchases jumped 20 percent following the 2011 meltdown at Fukushima, a catastrophe that prompt-

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LNG TRADING

ed the Japanese government to take all its nuclear plants offline.

The dearth of LNG-producing and consuming countries — or lack of market depth — is one impediment to LNG becoming a globally traded commodity, like oil.

"The huge number of global oil producers, consumers, traders and shippers were a factor in the creation of a truly global crude oil market," Mikhaiel said.

She noted global LNG trade has grown in recent years, with new buyers and sellers joining the roster and more on their way over the next couple of decades. New or expanded LNG export plants in a dozen countries started production in the mid-2000s. Even the United States is poised to join the rush by 2016 when the first Lower 48 export project is scheduled to start shipping cargoes from Sabine Pass, La.

The World Energy Council predicts that between 2020 and 2050 global natural gas exports by pipeline and as LNG will almost triple. The push for cleaner-burning fuels is driving much of that demand growth, along with expanding economies in China, India and elsewhere.

Nonetheless, the enormous increase forecast by the council will not raise the numbers of buyers and sellers to the levels of those trading oil.

"It cannot and will not approach the sheer number of players that comprise and literally shape the world's crude oil market," Mikhaiel said. "LNG will never have the penetration enjoyed by oil, and hence, will remain comparatively small."

How much is it, really?

With high-speed electronic deals around the world, traders know how much oil costs at a particular moment. Not so for LNG.

Over the past 30 years, three streams of crude have emerged as the primary price benchmarks for the oil trade: West Texas Intermediate, Brent Blend and Dubai. For any contracted amount of oil, one of these benchmark prices is plugged into a formula that also takes into account all sorts of variables that affect price, including quality, transportation and refining costs.

"The global prices of various grades of crude oil are exceedingly transparent, and can be learned by anyone with a telephone and/or an internet connection," Mikhaiel said.

But because of the different market conditions that prevail in various regions of the world, there is no such thing as a global LNG price. Rather, natural gas and LNG prices can generally be categorized by region.

They tend to trade regionally in large part because of transportation costs and logistics.

Each natural gas market —Asia-Pacific, Europe and North America — has separate internal dynamics that dictate their pricing. Their gas markets have different histories, sources of supply and varying degrees of reliance on imports:

Pricing in North America's gas market is pegged to gas-on-gas competition; with so many producers and so much gas in the United States and Canada, the competition is every other supplier with the same access to the same pipelines.

Asia's gas prices rise and fall with oil prices, as oil-derived products are a key alternative source of energy.

Europe's system tends to be a blend of the two.

Oil's benchmarks are based on spot crude prices. But spot LNG markets

The dearth of LNG-producing and consuming countries — or lack of market depth — is one impediment to LNG becoming a globally traded commodity, like oil.

aren't deep enough to serve as benchmarks, so they must rely on the closest substitute fuel to serve as an approximate price marker. In Asia, it's the crude oil price — calculated on an energy-equivalent to gas — because LNG and oil were used interchangeably there for electricity and heating in the 1970s.

Most of Asia does not have the option of pipeline gas imports, which is one reason its LNG contracts remain chiefly pegged to crude oil prices. Buyers and sellers generally negotiate a pricing mechanism in their contracts called an S-curve to protect both sides in times of high and low oil prices. The curve softens the effects of the oil-price linkage, helping buyers when oil prices are high and ensuring that sellers don't give up too much when prices are low.

Change is possible

In recent years, Asian buyers have led the call to delink the historical price connection to oil and instead would like to see upcoming North American LNG deliveries priced against the publicly traded U.S. gas market price. (If Lower 48 LNG export plants were operating in the summer of 2014, and their cargoes were pegged to U.S. prices, the LNG would be delivered to Asia at a significant discount to the traditional, long-term oil-linked prices.)

Some North American LNG project developers have balked at this, arguing that volatile U.S. gas prices would not provide the security they need to underwrite costly liquefaction plants. But other export project developers, particularly on the U.S. Gulf Coast, are open to the new pricing structure, as long as the customer takes the market price risk and they get paid a fixed rate for their liquefaction services regardless of gas market prices.

"One indexation is not necessarily better than the other. It simply depends on how much risk an individual buyer is willing to assume in order to have the price-risk diversity they want," Mikhaiel said.

While price negotiations continue, several gas buyers already have signed contracts for LNG from Gulf Coast and East Coast plants pegged to the U.S. gas pricing point at Henry Hub, Louisiana, giving them the new supply and price diversity they want.

In addition to changing benchmarks, LNG pricing could become more transparent in the future. Because so many deals are made privately in long-term contracts, prices are often hard to pinpoint. The Japanese government in April 2014 took a small step to clarify pricing by releasing average prices for spot-market liquefied natural gas sales.

The move by Japan's trade ministry, according to Reuters, was intended to "add transparency to an opaque market" amid concern about rising costs in the wake of the shutdown of nuclear plants after the Fukushima crisis.

But reshaping LNG pricing and markets to more closely resemble the oil trade will be a long, slow process.

In its 2013 report on establishing a gas trading hub in Asia, the International Energy Agency said the transition from a market dominated by long-term contracts and oil-index-based pricing to a competitive market with short-term contracts and market-based pricing "doesn't happen overnight." ●

Editor's note: Part 1 of this story appeared in the Oct. 19 issue.

Editor's note: This is a reprint from the Office of the Federal Coordinator, Alaska Natural Gas Transportation Projects, online at www.arcticgas.gov/why-lng-does-not-trade-like-oil.

FINANCE & ECONOMY

Miller close to sealing Savant purchase

Deal would give Tennessee company control of Badami oil field on Alaska's North Slope; new Cook Inlet well nears completion

By WESLEY LOY
For Petroleum News

Miller Energy Resources Inc. says it's close to wrapping up its acquisition of Savant Alaska LLC.

The deal would give Miller control of the small Badami oil field and related assets on Alaska's North Slope.

In an Oct. 29 press release, Miller said it "has received nearly all the regulatory approvals for its acquisition of Savant," and that the transaction is expected to close in November.

"Miller estimates that contractual purchase price adjustments from the May 1, 2014 effective date, as a result of ongoing production, will lower the effective acquisition price to approximately $5.8 million, down from $9.0 million," the company said.

Upon closing, Miller said it expects the acquisition would add net production to the company of about 600 barrels of oil per day.

Savant is the current operator of the Badami field, the easternmost producing field on the North Slope. BP originally developed Badami, which performed poorly. Production started in 1998.

Miller announced in mid-May that it had a binding agreement to acquire Savant.

Under the deal, Miller is expected to acquire a 67.5 percent working interest in the Badami unit, with ASRC Exploration LLC remaining as a 32.5 percent working interest partner.

Tennessee sell-off

Tennessee-based Miller is a small, publicly traded company listed on the New York Stock Exchange.

The company recently reported total net production of just over 3,000 barrels of oil equivalent per day. Miller's production comes primarily from Alaska's Cook Inlet region.

In the Oct. 29 press release, Miller announced it had reached an agreement to sell "substantially all of its Tennessee oil and gas assets and related liabilities for approximately $3.3 million in cash."

The Tennessee deal is expected to close in November, Miller said.

Miller further announced that it "continues its discussions with Buccaneer Energy and its principal lender to purchase substantially all Buccaneer Energy's Alaska operating assets out of bankruptcy."

Well nears completion

Miller, via its Anchorage-based subsidiary Cook Inlet Energy LLC, operates the Osprey platform in the offshore Redoubt unit.

Miller said it was finalizing completion of a new well known as RU-9.

"During drilling and logging RU-9, we saw prospective zones in both the Tyonek as well as the deeper Hemlock formations," said David Hall, Miller's chief operating officer. "We decided first to perforate and test the Hemlock formation. Initial results revealed high-quality oil with a low water-cut and variable flow rates that, at times, appeared well in excess of our expectations."

Hall added: "Given indications of potential formation damage around the well-bore incurred while drilling, we decided to re-perforate the Hemlock formation and conduct a reservoir analysis. We also decided to perforate the Tyonek formation while these procedures were taking place and prior to running final completion."

Following completion of RU-9, Miller said its drilling plans include "several low-risk development oil wells at Badami." ●

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FINANCE & ECONOMY

Oil exports could reduce fuel costs

But the lifting of the export ban would also cause the price of US oil to rise and increases US environmental risks, GAO says

By ALAN BAILEY
Petroleum News

The GAO, or Government Accountability Office, has published the results of a study into the implications of lifting restrictions on the export of crude oil from the United States. The study reached the apparently contradictory conclusion that, while the removal of the export ban would cause the price of U.S. crude oil to rise, the ban removal would also cause a drop in fuel prices for U.S. consumers.

The study reached the apparently contradictory conclusion that, while the removal of the export ban would cause the price of U.S. crude oil to rise, the ban removal would also cause a drop in fuel prices for U.S. consumers.

The GAO conducted its study by reviewing four studies on crude oil exports, including two sponsored by industry, and by seeking the views of a variety of stakeholders, including experts from academia and industry.

Response to embargo

The U.S. introduced restrictions on the export of domestic crude oil almost 40 years ago in response to an Arab oil embargo and the economic recession that the embargo triggered. But with a recent rapid growth in U.S. oil production, net oil imports have dropped from about 60 percent of U.S. oil consumption in 2005 to 30 percent of consumption during the first five months of 2014, the GAO says. And net imports are expected to remain well below 2005 levels in the future, the agency says.

With U.S. oil prices tending to be a few dollars lower than international prices, the entry of U.S. oil production into the international market would likely raise U.S. domestic oil prices by about $2 to $8, the GAO says. But the consequent changes in the international oil market would probably bring international crude oil prices down, reducing international fuel prices and hence reducing U.S. prices for fuels such as gasoline and diesel, the agency says.

However, the GAO cautioned that some stakeholders have pointed out that uncertainties over the extent of U.S. oil production increases, uncertainties over the ability of U.S. refineries to absorb these increases; and uncertainties over the possible response of the global crude market to U.S. exports all lead to corresponding uncertainties in assessing the impacts of oil exports.

Heightened U.S. oil prices as a result of exporting oil could increase domestic oil production by 130,000 barrels per day to 3.3 million barrels per day over the years 2015 to 2035, the GAO suggests. And the resulting increased economic activity would enlarge the U.S. economy. But the additional crude oil production could also pose risks to environmental factors, such as the quality and quantity of groundwater, the emission of greenhouse gases and the impacts of oil spills, the agency cautioned.

Strategic petroleum reserve

The GAO also commented on the implications for the U.S. strategic petroleum reserve of increased U.S. oil production — the reserve, a stockpile of stored crude oil, was established at the same time as export restrictions were introduced, to act as a buffer against oil supply disruption.

But times have changed. In May 2014 the reserve held a 106-day supply, coupled with private industry reserves of 114 days. These reserves were much higher than the levels of 90 days of net imports required by the International Energy Agency, the GAO pointed out. The GAO recommends that the Department of Energy should re-examine the petroleum reserves needs, with the possibility of selling any reserves that exceed requirements.

Sen. Lisa Murkowski, ranking member of the U.S. Senate Committee on Energy and Natural resources, welcomed the GAO report.

"Removing export restrictions are expected to increase the size of the economy, with implications for employment, investment, public revenue, and trade," Murkowski said. "For example, removing restrictions is expected to contribute to further declines in net crude oil imports, reducing the U.S. trade deficit." ●

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EXPLORATION & PRODUCTION

AIDEA completes Mustang project deal

The Alaska Industrial Development and Export Authority said Oct. 29 that it has completed deal structuring with CES Oil Services to jointly finance and own oil and gas production and processing facilities at the Mustang field on Alaska's North Slope.

AIDEA and CES will own the facility; Brooks Range Petroleum Corp. will build and operate the facility. AIDEA will invest up to $50 million.

AIDEA previously invested $20 million for the construction of the Mustang road and pad.

(See full story in Nov. 9 issue of Petroleum News.)

—PETROLEUM NEWS

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BC LNG

gas exploration rights and staking out sites on the Pacific Coast to build liquefaction and tanker facilities.

Changing provincial views

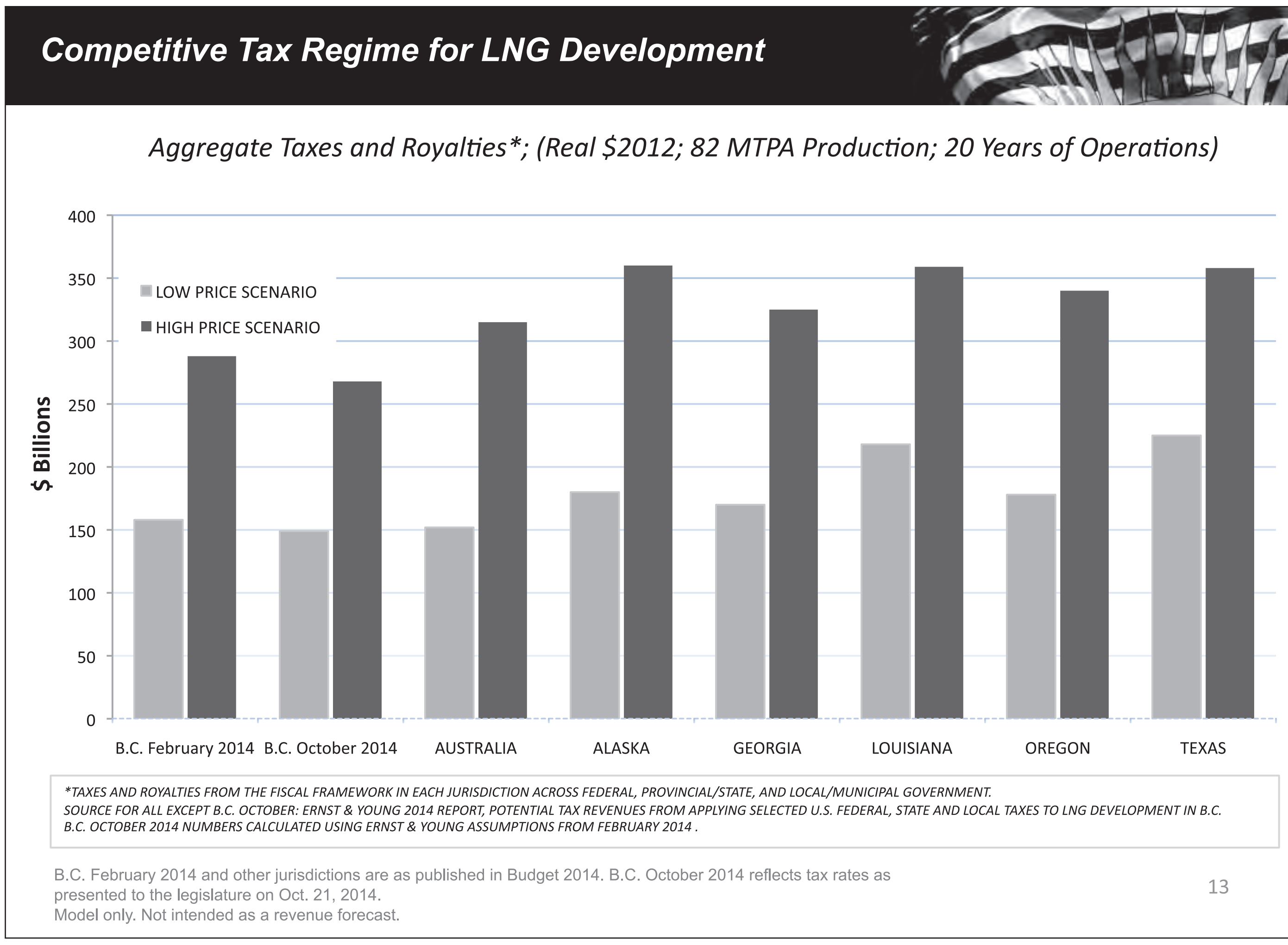
The glowing outlook allowed Premier Christy Clark, an unfailingly cheerful person in even the gloomiest of times, to sell the notion of a new industry that would invest C$1 trillion over 30 years, spawn 100,000 jobs and allow her government to build a C$100 billion Prosperity Fund to wipe out British Columbia's debt (currently at C$60 billion), while covering the cost of all imaginable services and infrastructure.

That shaped a dramatic comeback from months of polls pointing to a resounding defeat for her Liberal Party administration and got her re-elected by a sweeping margin in May 2013, all before the healthy margins in global LNG started to evaporate along with the Prosperity Fund before it had even been established.

The reversal of fortunes was evident on Oct. 20 when the government delivered its new LNG tax regime that effectively cut in half the royalty tax it counted on collecting, all to entice the energy behemoths to make their final commitments to LNG projects.

Now British Columbia is not even sure it will play host to an industry, although there could be healthy returns if a handful of companies does start producing from the province's shale gas basins.

Finance Minister Mike de Jong, while conceding the outlook for LNG is "not quite as lucrative as it once was," said he is satisfied British Columbia has made a case for investment in the sector by striking an "appropriate balance that is fair and reasonable for the proponents and fair and reasonable for British Columbians themselves."



He estimates the government would collect nearly C$800 million from a medium-sized LNG plant in the first year of production and that would grow modestly over the next decade.

In addition, an LNG plant would generate additional corporate, motor vehicle fuel, property and carbon taxes as well as royalties from natural gas.

De Jong brushed off criticism that the government had been bullied into lowering its tax rate by LNG proponents, saying only that those companies had "aggressively" advanced their position.

Report shows appeal

To bolster its case within the highly competitive global industry, British Columbia commissioned a report from Ernst & Young that shows its tax and royalty regime should be slightly more appealing to companies than Australia and the U.S. states of Alaska, Georgia, Louisiana, Texas and Oregon when the fiscal framework in each jurisdiction is totaled up across federal, provincial/state and local governments.

But the margins — based on low- and high-price scenarios — are slender in an analysis that did not cover Qatar, the world's No. 1 LNG producer, or Russia, which has the world's largest reserves and recently inked a major gas deal with China, which remains the largest prospective customer for British Columbia LNG.

What the analysis does not cover is the cost of extracting the gas feedstock for LNG, building and operating pipelines to coastal terminals and shipping the liquefied product across the Pacific.

—GARY PARK

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LEASE EXTENSION

Oceana asked for a letter that Peter Slaiby, vice president, Shell Alaska, sent to the agency on July 10, requesting a five-year suspension of operations on Shell's Beaufort and Chukchi Sea leases, an action that would in effect extend the original lease terms by five years.

Returned in 2005

Shell returned to Alaska in 2005, with plans to conduct exploration in the state's Arctic outer continental shelf but since then has run into multiple issues relating, in particular, to lawsuits against the government permits that it needs and against the government leasing actions. To date, the company has only succeeded in drilling the top-hole sections of two exploration wells, one in the Beaufort Sea and one in the Chukchi Sea. Although a series of issues relating to that drilling, conducted in 2012, appears to have been a prime reason for the company deciding not to drill in 2013, a continuing appeal case challenging the legality of the 2008 lease sale in which Shell purchased its Chukchi Sea leases has caused the continuing postponement of further drilling. Shell is also waiting to evaluate the possible impact on its program of new Arctic offshore drilling safety regulations that the Department of the Interior has yet to release for public comment.

Some of Shell's Beaufort Sea leases expire as soon as 2017. The company's Chukchi Sea leases were issued in 2008 on 10-year terms, but are currently under suspension with no exploration activity allowed, because of the appeal against the 2008 lease sale.

> *"The limited primary (lease) terms and lack of certainty on whether additional time may be granted on the leaseholds pose a significant challenge to Shell's ability to continue to invest in the Alaska OCS."* **—Shell Alaska Vice President Pete Slaiby**

Beaufort Sea plan

In his July 10 letter Slaiby said that Shell, having originally purchased Beaufort Sea leases, planned to conduct drilling in those leases in 2007 and 2008. But the company abandoned this plan, in part because of a court decision upholding an appeal against government approval of the company's exploration plan, Slaiby wrote.

Then, following a legal challenge to the five-year lease sale program under which Shell had purchased its Beaufort Sea leases, Shell abandoned a plan to drill in the Beaufort Sea in 2009, he wrote. The company then hoped to drill in the Chukchi and Beaufort seas in 2010. But following a delay in the issuance by the Department of the Interior of a new environmental sensitivity analysis, and then with a halt to offshore drilling permitting following the Deepwater Horizon oil spill, Shell's 2010 drilling hopes came to naught, Slaiby wrote.

A July 2010 decision by the federal court in Alaska to require the Department of the Interior to rework its environmental impact statement for the 2008 Chukchi Sea lease sale, following the appeal against that sale, caused Shell to lose its 2011 Arctic drilling season, Slaiby wrote. And contributing to the loss of drilling seasons in the years 2007 to 2011 came difficulties, delays and legal challenges in the issue of air permits that Shell needed for its drilling fleet, he wrote.

2014 court ruling

A January 2014 ruling by the 9th Circuit Court of Appeals, upholding the continuing appeal against the 2008 Chukchi Sea lease sale, and a subsequent further rework of the lease sale environmental impact statement, nixed Shell's hopes of returning to the Chukchi Sea for the 2014 drilling season, Slaiby wrote.

Shell has diligently carried out its obligations as a leaseholder and has spent more than $6 billion on its Arctic Alaska venture, Slaiby wrote. But the delays and uncertainties, exacerbated by the challenging nature of operating on the Alaska outer continental shelf, have impacted Shell's ability to conduct a sustainable strategy.

"The limited primary (lease) terms and lack of certainty on whether additional time may be granted on the leaseholds pose a significant challenge to Shell's ability to continue to invest in the Alaska OCS," Slaiby wrote. "Suspending the leases for five years now would provide Shell assurance that any further investment of the billions of dollars and effort to proceed with exploration and development will not be lost due to expiration of the remaining lease portfolio that would be necessary to support a commercial development."

Oceana, in its response to Shell's letter to BSEE, said that Shell was aware of the risks it was taking when purchasing its Arctic leases.

"Shell spent billions of dollars fully aware of the risks to that investment, and the government should not bend the rules to allow the company to continue business as usual," said Susan Murray, Oceana's deputy vice president. "Shell deserves no special treatment and, to the contrary, has a track record of irresponsible choices that warrants close scrutiny and the highest standards."

Other companies apply

Conoco Phillips spokeswoman Amy Burnett has confirmed to Petroleum News that BSEE has turned down a ConocoPhillips lease extension request similar to Shell's and that the company has appealed the decision.

"ConocoPhillips will continue to engage with the government and other leaseholders to help ensure a clear and stable regulatory program prior to drilling in the Chukchi Sea," Burnett said in an Oct. 30 email.

Statoil spokesman Jim Schwartz also confirmed to Petroleum News that his company applied to BSEE in July for Chukchi Sea lease extensions. Schwartz said that Statoil is concerned about committing to the huge cost of Arctic offshore exploration without certainty about being able to use its leases.

"Given the realities of working in the Arctic and the long lead times … we believe it's prudent to confirm if lease extensions will be granted before contracts are agreed to that have some significant funding commitments associated with them," Schwartz said.

—ALAN BAILEY

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Petroleum news

Oil Patch Bits

Calista Corp. begins shareholder outreach tour

Calista Corp. is set to begin an outreach effort to provide information to shareholders regarding an important resolution. Shareholders will decide whether to enroll descendants as shareholders in a binding resolution vote at the 2015 annual meeting. This effort was authorized by shareholders through an advisory vote at the 2013 annual meeting of shareholders.

"The decision whether to enroll descendants as shareholders is a major turning point for Calista Corporation," said board Chairman Willie Kasayulie. "There are many factors for shareholders to consider before making a decision to vote yes or no. Calista will provide many options for shareholders to get the information they need for an informed vote."

CALISTA CORPORATION
www.calistacorp.com

Calista's outreach includes a tour of more than 20 communities. The tour will include videos in English and Yup'ik, and a presentation by Calista's shareholder relations committee followed by a question and answer period. By late November, www.CalistaVote.com will feature the videos, committee presentation, a detailed list of frequently asked questions, and a list of tour dates and locations. By early 2015, a DVD with the videos will be sent to each tribal council and ANCSA village corporation in the Calista region.

If more than 50 percent of all shares voted on this resolution vote yes, the resolution will pass. Should the resolution pass, Calista estimates it will issue the new classes of shares in the first half of 2017.

Explore Fairbanks unveils destination marketing video

Explore Fairbanks announced that it has unveiled its new destination marketing video at the 2014 Alaska Tourism Industry Assoc. conference.

The video incorporates summer and winter images, a host of Fairbanks locals, various modes of transportation, places to visit and an assortment of activities, dining and more.

The 3 minute 41 second video artfully and energetically highlights the many qualities that define Fairbanks, the Interior, Denali National Park and the Arctic. A local band, Young Fangs provided the background music for the video, performing their song "Show Me the Way" and is also featured.

"I've been fascinated by the mystique of Interior Alaska for years, everything from the landscapes and wildlife to the aurora borealis. … I consider Fairbanks to be my second home and I can't thank Explore Fairbanks enough for trusting me to help them share the region with the rest of the world," said director and producer Joseph Sliker of Gah! Films.

The original video will be used to market Fairbanks and the region to potential visitors via the website, through multiple social media outlets, during events and more. Additionally the

see **OIL PATCH BITS** *page 17*

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

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

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BUCCANEER SALE

Earlier in the bankruptcy proceedings, AIX Energy had agreed to be the "stalking horse bidder" in an auction, committing to bid more than $58 million for the Alaska assets.

What's included

The sale covers "substantially all" of Buccaneer's assets.

The most valuable among those assets is the Kenai Loop gas field. The "field" includes seven leases (two with the Alaska Mental Health Trust, one with Cook Inlet Region Inc. and four with the state of Alaska), four wells and their data files, two drilling pads and associated field infrastructure, all geological and geophysical data and existing permits.

The sale also includes considerable office equipment, furniture and software.

The field is currently involved in a correlative rights dispute before the Alaska Oil and Gas Conservation Commission, which scheduled a public hearing for December. The field has been illegally draining from neighboring lands owned by the state, CIRI and the Trust Land Office, respectively. The AOGGC could require pooling or unitization.

Additionally, some of the Kenai Loop leases are under appeal or in litigation.

The sale also includes a tract at the former Northwest Cook Inlet unit in the waters of Cook Inlet and a tract at the onshore West Nicolai prospect on the west side of the Inlet.

The buyer will assume 13 contracts from Buccaneer. Those include three gas sales agreements with the Enstar Natural Gas Co.-affiliate Alaska Pipeline Co.; three separate interruptible gas sales agreements with Tesoro Alaska Co., Cook Inlet Energy and ConocoPhillips Alaska Natural Gas Corp., respectively; a liquids sale agreement with Tesoro Alaska involving condensate, and six leases, easements or other contracts.

Who is AIX?

To pursue its broad ranges of projects across Cook Inlet, Buccaneer assumed considerable debt, including a large credit facility with Meridian Capital CIS Fund.

Meridian Capital CIS Fund was affiliated with Meridian Capital International Fund, which became Buccaneer's largest shareholder in mid-2013 with 19.9 percent interest.

Meridian sold the debt to AIX Energy in April 2014. AIX Energy incorporated in Alaska in early May 2014, according to the state. Buccaneer filed for bankruptcy in late May.

Early in the bankruptcy proceedings, a group of unsecured creditors raised questions about the relationship between Meridian and AIX Energy. The Official Committee of Unsecured Creditors called AIX Energy "a newly formed shell entity comprised of individual oil and gas operators with whom Meridian had long-standing prior personal relationships." According to the committee, AIX Energy used a "mirror loan" from Meridian to buy the loan, making the transaction "little more than a book entry."

The creditors later reached a deal where AIX Energy agreed to pay $10 million into a trust that would be included in liquidation plans designed to repay unsecured creditors. ●

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FEIGE Q&A

for the a piece of that LNG markets share. On the one hand, you've got folks buying the LNG want to delink it from the JCC — the Japanese Crude Cocktail — and you've got people who want to link it. That's a market battle. We need a certain price going forward. We'll have to let the market play out. Again, in five years, it will tell the tale.

Petroleum News: I realize we are only in pre-FEED with this project, is there anything that concerns you now?

Feige: I think the only thing that concerns me is who wins the governor's seat. I'm hoping that Sean Parnell stays on as governor. I think that would provide a high degree of consistency and sort of steadiness and purpose. I'm not so optimistic if Bill Walker and Byron Mallott come into office. I'm just not certain as to exactly how Bill Walker will treat this project if he comes in as governor. He's made enough conflicting statements over the last couple of years. I think the most important thing the state can do in the future is be consistent. We've put the state on this particular path right now as a partner. All those little relationships are part of the deal. If you start mucking with that, you have the potential to blow up the deal and we go back to square one. The most important thing for both the executive and legislative branch is to stay on path, be consistent and not muck with what's been agreed to.

Petroleum News: Do you think the current path now that the project is on will foster future exploration?

Feige: Oh, without a doubt. One of the things that's hindered oil exploration up north was the possibility that you go looking for oil and you find gas and you have no way to get the gas to market. With the expansion potential we built into this project and the state made allowances for in SB 138, companies may go looking for more oil, but if they find gas it's not such a negative as it has been in previous years. So yeah, overall we are going to see more exploration. A lot of it will certainly be driven by price. I'm pretty optimistic that between the reforms of SB 21 and the project that we outlined in SB 138, we've greatly enhanced the investment climate up on the North Slope as well as the rest of the state.

Petroleum News: With revenues in decline, do you think the state can afford to be a partner?

Feige: You know it all depends. We are looking at a final investment decision that wouldn't occur for five years. You have to take the position of conserve our cash as best we can. The Legislature will have to address low oil prices and cut back things accordingly. A certain amount of that is already in the works. The recent price changes the last three months is going make that go faster. The state has really no other choice but to cut back on the money that it spends whether that's in the capital budget or the operating budget. I'm optimistic they will rise to the occasion.

Petroleum News: Let's go back to the exploration topic but farther north into Arctic waters. What are your thoughts on the prospects of that moving forward?

Feige: Well, it depends on who sits in the White House. So far, the federal government has not exactly been a willing partner. They seem to be more of an obstacle in developing those federal lands than anything else. The market seems to be willing. The companies are certainly willing. It's the federal government that's either not leasing the lands or throwing up all kind of road blocks. Just look at what they did in the National Petroleum Reserve. That needs to change. That can provide a lot of income for the nation. As far in debt as this nation is right now, why aren't we developing those resources to get us out of debt?

Petroleum News: NPR-A will have its lease sale in November. Some say it's window dressing for a sale that really isn't substantive, others say they are good first steps. How do you see it?

Feige: Well, they've had leases come up in NPR-A before. The last few years they have taken a lot of that land off the table. They are calling it de facto wilderness. Under the spirit of it, you are supposed to go to Congress to get a wilderness declaration. This administration has basically tried to go around Congress on a lot of fronts. I think the federal government could be better at promoting resource development around the country, not just Alaska.

Petroleum News: Still on the Arctic, there are concerns that the White House wants to focus its efforts in the Arctic on climate change rather than economic development when it takes over as chair for the Arctic Council?

Feige: I can see that happening. That seems to be consistent with the theme that this administration has been following.

Petroleum News: So what would you like to see for Alaska on the resource front, either with oil or natural gas pipelines?

Feige: On the oil and gas side, we need to be consistent. We've spent a lot of political capital these last three or four years getting ACES essentially repealed and replaced with SB 21. I think we need to give it a chance to prove itself. ACES certainly had almost six years and it was pretty clear that it wasn't working the way the folks who conceived it originally had foreseen. SB 21 needs to be given a fair chance. We passed it believing it will do certain things and we have to give it time to do that. We have to be consistent to our investors and put forward a steady hand, not one that is reacting to the whims of whoever happens to be in whatever seat at the time, whether it's the governor's seat or the resources chairman's seat. We have to be consistent because Alaska developed a reputation of changing its tax regime several times within a certain period. Alaska got a bad rap. The politics are now swinging around to favor resource development in the U.S. as opposed to other places. We just need to steer a steady course and stick with it.

Petroleum News: You mentioned the state being inconsistent of going from one tax regime to another. Doesn't that present a double-edged sword by changing it again?

Feige: The question was, is this the right tax system now. I think we need to develop our other-than-oil economy. The problem is that it's kind of difficult. We need to develop more of our economy but at the same time make sure we keep oil and gas strong.

Petroleum News: I'm not trying to get you to second guess yourself, but is there anything you might have done differently in your four years as co-chair?

Feige: No, I don't think so. I wasn't one of the legislators who picked up on the latest fad and went with it. If I saw something that needed to be fixed, we tried to fix it. I put in what I thought was the best course of action based on what we knew at the time.

Quite frankly, I think we made some pretty good calls. Take the price retraction we have going on. At the time we put SB 21 in place, the price forecast was to be $100 to $110 a barrel for the next four years. We are a year and a half later and the price is down to $80 a barrel.

We also put into SB 21, one of the House Resources revisions to the bill that actually raised the tax rate at the lower end. It was a fair trade, giving the companies more on the upside and we protected ourselves more on the down side. That was one of the things that we had to think about and put in the bill on the eventuality that prices didn't go in the direction we thought back then.

We put a lot of thought into all of the legislation that we moved through the Resources Committee.

I have to say I had a great committee, especially the last two years. I had some of the longest serving legislators, certainly in the House. A lot of them had been through them all: PPT, ACES, AGIA. So they had some pretty good perspectives and good experience in putting together these types of legislation and they delivered. ●

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OIL PATCH BITS

video will be used to attract and inform a wide variety of stakeholders and visitor industry professionals such as tour operators, meeting planners, airline executives, travel agents and media. To view the video please visit: http://youtu.be/UT7L9QDcfU0.

Vigor delivers 15,000 barrel Maxum Petroleum barge

The Seattle divisions of Vigor Fab and Elliott Bay Design Group said the 15,000-barrel tank barge Global Pilot has been delivered to Maxum Petroleum.

Designed to balance performance with fabrication cost, the 15,000-barrel tank barge features a recessed machinery space aft for improved visibility and a state-of-the-art tankerman's office. It also has dimensionally identical cargo tanks, corrugated plate tank bulkheads and plate seams arranged to maximize material usage of standard 8-foot and 10-foot plates.

"The ability to collaborate closely with Elliott Bay and Maxum throughout this project was the perfect model for an efficient new build," said Bryan Nichols, director of sales at Vigor Fab. "Our Seattle shipbuilding team is extremely proud to have fabricated a quality barge which will expand Maxum's multiple supply capacity in the Puget Sound for years to come."

"We've been looking forward to seeing the final product," stated Mike Complita, EBDG's vice president of shipyard services. "It's always exciting when a new design becomes reality and goes into service."

The 15,000-barrel tank barge is one of several barges that have been delivered by Vigor to EBDG's designs over the past decade. EBDG provided the contract design to Maxum and provided Production Support services to Vigor.

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DRILL SITE 2S

and oil viscosity," according to recent filings with the state Division of Oil and Gas. "This information is critical for any future development of this part of the Kuparuk reservoir."

Drill Site 2S

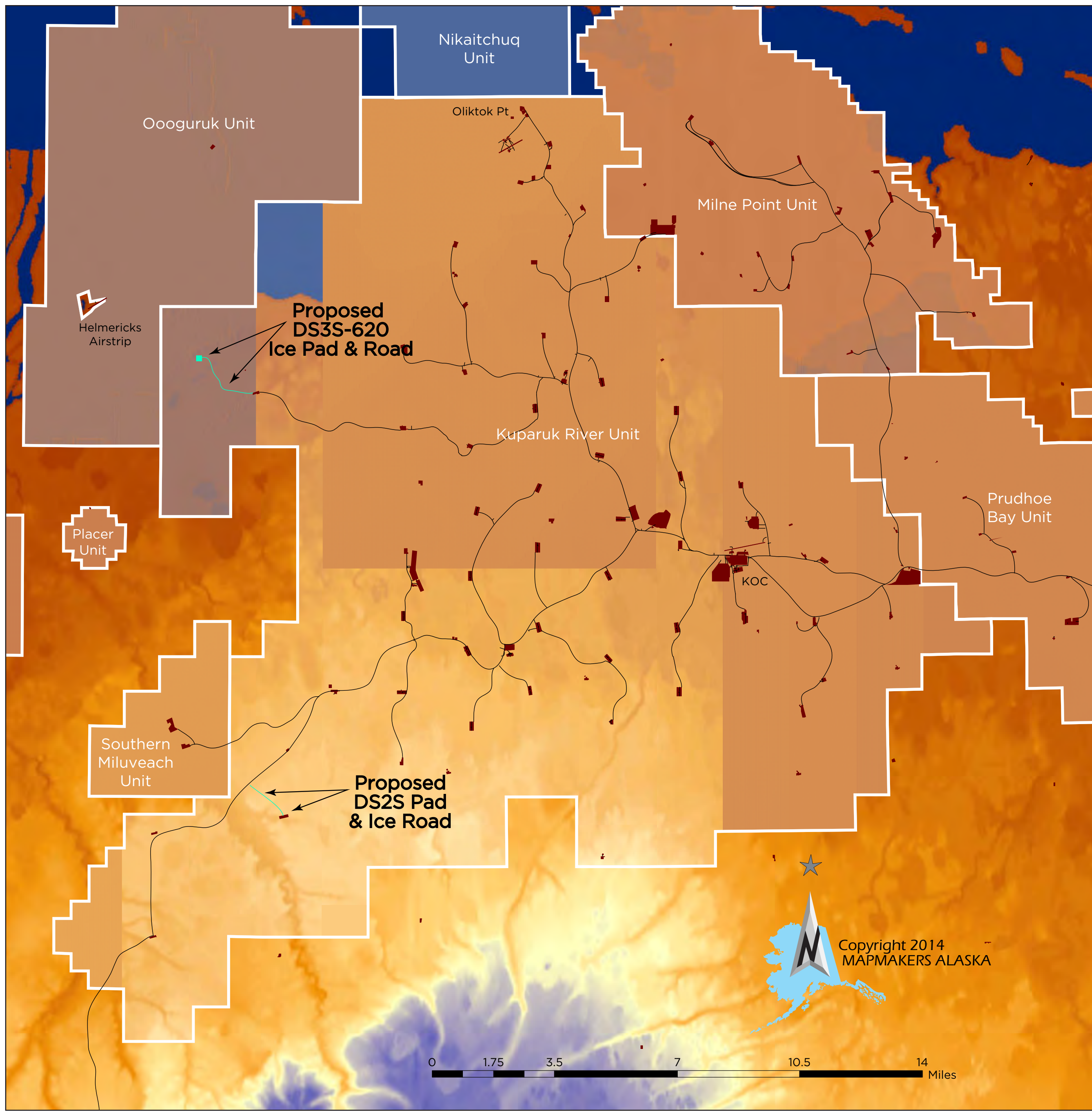
ARCO discovered an oil accumulation in the Kuparuk reservoir in the southwest corner of the unit in the late 1980s with the KRU 21-10-08 well but never pursued development.

ConocoPhillips appraised the discovery in early 2012 with the Shark Tooth No. 1 well, which the company drilled from an ice pad located some four miles from Drill Site 2K.

At the time, the company told regulators that the well was "critical for any future development of this part of the Kuparuk reservoir" because it would "provide additional reservoir information in this area and narrow uncertainty around reservoir description parameters including oil-water contact, sand quality and thickness, and oil viscosity," language identical to how the company is currently describing the Drill Site 3S well.

Toward the end of 2012, ConocoPhillips said the well had "discovered hydrocarbons in the Kuparuk sands, in accordance with expectations, and confirmed mapped volumes."

The southwest corner of Kuparuk was already home to three drill sites — 2L, 2M and 2K — but developing Shark Tooth from any of those facilities would have pushed the limits of existing drilling technology, according to ConocoPhillips. Therefore, the company decided to commission a new drill site, the first at Kuparuk in nearly 12 years.



Drill Site 3S

That last pad was Drill Site 3S, which ConocoPhillips built to support the Palm satellite.

Phillips Alaska Inc. discovered the Palm satellite at the western edge of Kuparuk in 2001.

The Palm No. 1 well encountered 30 feet of oil-saturated Kuparuk sandstone. An un-stimulated test of the associated Palm No. 1A sidetrack flowed at some 2,500 barrels per day. The company estimated recoverable reserves in the range of 35 million barrels.

ConocoPhillips brought the satellite online in November 2003 from Drill Site 3S. The accumulation is in a Kuparuk C4 interval now known to be in communication with the main Kuparuk reservoir. Palm is generally managed as part of the main Kuparuk field.

In the winter of 2012-13, ConocoPhillips conducted a pilot test on DS 3S-19, one of the original development wells drilled at Palm in 2003. The test involved adding a perforation to the well and performing hydraulic fracturing operations to gauge the potential of developing the overlying Cretaceous Brookian Moraine interval. "Any development would, of course, require adequate appraisal and study to prove commerciality," the company told state officials in its 2013 plan of development, a sentiment the company reiterated in its 2014 plan of development this past June.

The current project aims to appraise the commerciality of the Moraine interval.

ConocoPhillips plans to drill the DS3S-620 Moraine well from an ice pad on ADL 025528. The pad would connect back to Drill Site 3S using a 2.5-mile ice road.

The state is taking comments on the plan through Nov. 24.

Increased seismic

Both projects resulted from increased seismic activity over the past decade.

The Kuparuk West Sak 3-D seismic survey in 2005 gave ConocoPhillips "a significant number of leads for infill or sidetrack drilling," as the company explained in its 2014 plan of development. ConocoPhillips commissioned a custom built coiled-tubing drilling rig, which has been steadily working through those drilling candidates since May 2009.

ConocoPhillips launched the Western Kuparuk 3-D seismic survey in 2011. The results of the program led to an "infrastructure-led exploration strategy," which focuses on opportunities near existing infrastructure, as opposed to the wildcats ConocoPhillips drilled in the far reaches of the National Petroleum Reserve-Alaska in the early 2000s.

A crowded region

As the westernmost pad in the northern half of the Kuparuk River unit, Drill Site 3S has been an important staging area for other exploration companies exploring to the west.

Pioneer Natural Resources intended to build a gravel road connecting DS-3S to its Nuna development, a scheme that successor Caelus Natural Resources may bring to fruition.

Repsol built an ice road from DS-3S to support exploration activities in early 2012. The company is currently preparing development strategies based upon that exploration work.

DS-3S is just northeast of the ASRC Exploration-operated Placer unit. The exploration arm of Arctic Slope Regional Corp. formed the unit to explore a prospect that was contracted from the Kuparuk River unit. The Placer unit is under administrative appeal. ●

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FURIE DRILLING

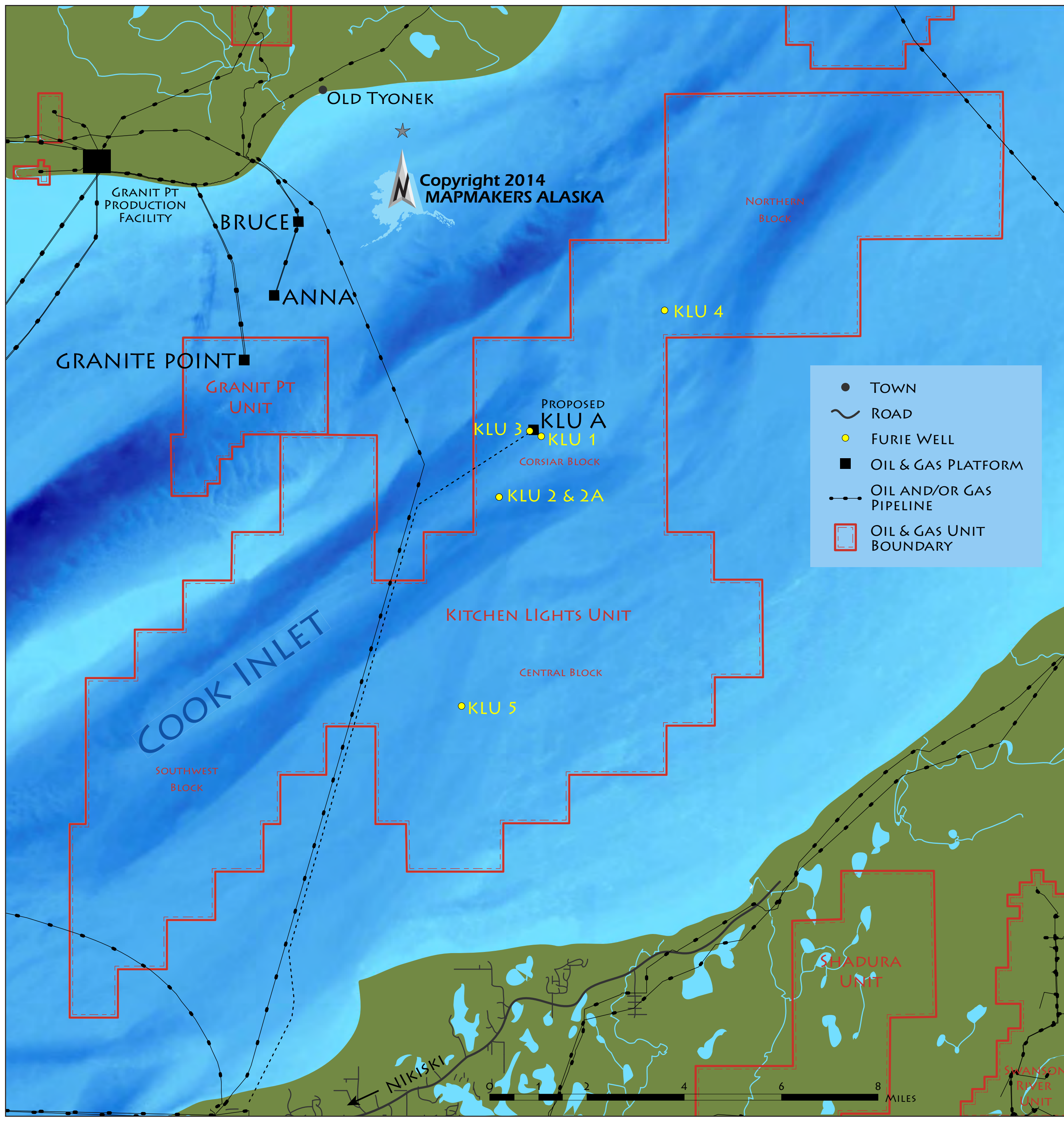
Department of Natural Resources. That plan views the Kitchen Lights unit as four distinct exploration blocks: the southwest and central blocks in the more southerly part of the unit; the Corsair block in the central part of the unit and the northern block in the unit's northeastern sector. The plan of exploration says that Furie must drill wells in several of those blocks.

Discovery announcement

In the fall of 2011 Escopeta Oil Co., the company from which Furie was subsequently spun off, started its drilling campaign with the Kitchen Lights unit No. 1 well in the Corsair block, announcing on Nov. 4, 2011, that it had made a 3.5 trillion cubic feet of gas discovery. That announcement, which met with some skepticism, was followed in March 2012 by a more scaled down estimate of gas reserves of 750 billion cubic feet.

In 2011 Furie had suspended the drilling of the No. 1 well at a depth of 8,805 feet. And in the summer of 2012 Furie used its Spartan rig to re-enter the well, continuing the drilling to a depth of 15,298 feet. Later that year the company drilled the Kitchen Lights unit No. 2 well and a sidetrack to that well, while in the summer of 2013 the company drilled the No. 3 well to a vertical depth of 10,391 feet.

All three of these wells are in the Corsair block. However, later in 2013 Furie proceeded to follow the exploration plan requirements by starting the drilling of the Kitchen Lights No. 4 well, this time in the northern block. The company completed that well this summer and, also this year, drilled the No. 5 well in the central block. The company plans to drill a sixth well in 2015, with that well lying in the southwest block, the last of the blocks to be drilled.



Furie Operating Alaska has now drilled wells in three of the four exploration blocks in the Cook Inlet Kitchen Lights unit. A gas field development that is under way is centered on the Kitchen Lights unit No. 3 well in the Corsair block. In 2011 Furie announced a major gas find in the nearby Kitchen Lights unit No. 1 well.

Resource delineation?

Although Furie has obviously drilled each of its wells in hopes of finding new hydrocarbon resources, the fact that the No. 1 and No. 3 wells are only about a quarter of a mile apart would seem to suggest that a purpose of the No. 3 well would have been the delineation of the discovery made in the No. 1 well. That conclusion appears confirmed by the fact that Furie's planned development centers on the No. 3 well rather than the No. 1 well, the original discovery well.

In May 2012 Damon Kade, then president of Furie, told Petroleum News that the purpose of the No. 2 well was to further delineate the company's gas find, in addition to seeking new resources.

In July 2013 Furie filed a formal statement of a gas discovery with the Alaska Department of Natural Resources. That statement documented a discovery made in the No. 3 well, saying that the well had encountered multiple productive gas pools in the Sterling and Beluga formations at depths ranging from 3,618 feet to 6,228 feet. The statement said that modular dynamic testing had been conducted on 28 gas pools and that six pools had been flow tested.

Furie has not announced any other results from its drilling.

Drilling records

However, the recent publication by the Alaska Oil and Gas Conservation Commission of documents relating to the drilling of the Kitchen Lights unit No. 1 well shed a little more light on the situation, while falling short of providing data needed to assess the scale of Furie's gas find.

These documents include a letter dated Dec. 21, 2011, to Alaska's Division of Oil and Gas from Bruce Webb, now Furie's vice president for government and regulatory affairs, stating that the intent had been to drill the No. 1 well to a depth of 16,500 feet. Webb's letter explained that a series of drilling delays had prevented the completion of the No. 1 well in 2011, but that the company anticipated re-entering and completing the well in 2012. That re-entry was indeed accomplished.

Although not mentioned in Webb's letter, other records from the drilling indicate that a 16,500-foot depth would place the bottom of the well in the mid-Jurassic, below the base of the Tertiary strata that host all of the current producing Cook Inlet oil and gas fields. A 2010 law passed by the Alaska state Legislature providing for a $25 million tax credit for the first company to drill into the pre-Tertiary of the Cook Inlet from a jack-up rig would have provided a strong incentive to drill into those Jurassic rocks.

Many tests

The drilling reports from the Kitchen Lights unit No. 1 well confirm that Furie did indeed encounter gas during the 2011 drilling project, with records of substantial flows of gas into the well at various depths, and of modular dynamic testing of potential gas resources at multiple levels. A summary of the various modular dynamic tests indicates 18 tests at depths between 4,247 feet and 4,828 feet in the Sterling formation; 15 tests at depths between 5,047 feet and 7,392 feet in the Beluga formation; and one test at between 8,700 feet and 8,727 feet in the Tyonek formation.

The continued drilling of the No. 1 well in 2012 stopped more than 1,000 feet short of its original 16,500-foot target depth, with the bottom of the well reaching the deeper part of the Tertiary section, rather than the Jurassic. Drilling reports from the well suggest that the well only encountered minor quantities of gas below 8,805 feet. And there is no indication of an oil find. Furie did not conduct any tests on the portions of the No. 1 well drilled in 2012, the drilling documents state.

Substantial find

The scale of the gas-field development that Furie is now engaged in, including the construction of an offshore platform and the laying of a subsea pipeline, implies that the company did make a substantial gas find with its Kitchen Lights No. 1 and No. 3 wells. The company's plan of operations for its Kitchen Lights development says that its offshore platform will be centered on the No. 3 well, with an initial subsea gas line to shore capable of carrying up to 100 million cubic feet of gas per day. The plan includes the possibility of adding a second, twin pipeline, also with a 100 million-cubic-feet-per-day capacity. The plan of operations also says that development of the Kitchen Lights resource is expected to result in the production of up to 30 billion cubic feet of gas per year.

Meantime, further development at Kitchen Lights, and perhaps some further insights into the project, will need to wait for the melting of the sea ice in 2015, at the end of the coming winter. ●

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