Petroleum news

page 3 Kawasaki, a 'no' vote on SB 138, concerned about enabling measure

Vol. 19, No. 19 • www.PetroleumNews.com A weekly oil & gas newspaper based in Anchorage, Alaska Week of May 11, 2014 • $2.50

FURIE OPERATING ALASKA

The monopod leg and platform for Furie Operating Alaska's Kitchen Lights unit A platform. The platform is soon to be shipped from Texas to Alaska's Cook Inlet.

Furie preparing to move platform; to arrive in Cook Inlet in July

Fabrication of the offshore platform for Furie Operating Alaska's Kitchen Lights gas field in Cook Inlet is nearing completion, Damon Kade, president of Furie, told Petroleum News in a May 2 email. The platform, the Kitchen Lights unit Platform A, is scheduled to be loaded onto a barge at Ingleside, Texas, at the end of May for shipment to Alaska — the platform is expected to arrive in Cook Inlet in July, with completion of the offshore installation anticipated in early September, Kade said.

Land dearing started

Meantime, land clearing has started at the site of Furie's planned gas processing facility near East Forelands on the Kenai Peninsula. A twin subsea pipeline will connect the offshore platform to the processing facility, which will feed gas into the Kenai Peninsula gas pipeline system.

Outfitting of the vessels and barges needed to install the platform and lay the pipelines is under way in Washington state, Kade said. The vessels and barges will start arriving in Cook Inlet in June he said. The platform will be located about 10 miles north of Boulder Point, near Nikiski, on the Kenai Peninsula.

Furie has previously said that it anticipates that gas production

see FURIE PLATFORM page 20

A dose of LNG reality; economist says BC revenue projections high

As fast as British Columbia gets ready to celebrate an LNG success it seems someone pricks the party balloon.

On the same day Shell Canada upped its stake in the LNG Canada project to 50 percent from 40 percent in its joint venture with Asian giants PetroChina, Mitsubishi and Korea Gas, strengthening the hopes of a final investment decision within 18 to 24 months, a Canadian research organization dumped lukewarm water on the province's grand dreams.

Marc Lee, a senior economist with the Canadian Center for Policy Alternatives, said the projections that LNG tax revenues could tally C$100 billion over 30 years, wiping out the province's debt and building a prosperity fund, is at best a long shot.

"At more plausible Asian prices (for LNG) and production levels, combined royalties and LNG taxes would likely be much smaller," he said in a report.

Lee cautioned that government costs covering regulatory processes, infrastructure, public services and environmental protection had to be weighed alongside revenues.

He said infrastructure needs alone would "greatly eat into the gap between Asian and North American natural gas prices, as a result of which small declines in Asian LNG prices would

see LNG REALITY page 19

FINANCE & ECONOMY

Conoco: $598M in 1Q

Profits and spending up, taxes and production down, in first quarter review

By ERIC LIDJI

For Petroleum News

ConocoPhillips Co. reported $598 million in adjusted earnings in the first quarter in Alaska.

The earnings represent a 10 percent increase year-over-year and a nearly 8 percent increase quarter-over-quarter despite falling production, steady oil prices and increased spending, reflecting changes to the fiscal system put into place earlier this year.

"Our first quarter production taxes would have been about the same under the old tax system as under the 2013 More Alaska Production Act," ConocoPhillips Alaska Vice President of Finance Bob Heinrich said in a statement, referring to the

ConocoPhillips believes its currently slate of programs could add more than 40,000 barrels of oil equivalent per day of new oil production from Alaska by 2018.

old Alaska's Clear and Equitable Share system. "The difference is that the More Alaska Production Act will encourage industry to spend more to increase production, because the new tax law allows the industry to keep a more equitable share of the benefits of higher oil prices."

Those opposed to the new fiscal system saw the profits as proof that the law favors industry over the public. "Under the previous oil tax structure,

see CONOCO EARNINGS page 17

LAND & LEASING

$5.2M Cook Inlet sale

State receives 40 bids on more than 100,000 acres in inlet; 3 in Alaska Peninsula

By KRISTEN NELSON

Petroleum News

The Alaska Division of Oil and Gas took in more than $5.25 million at two areawide oil and gas lease sales, Cook Inlet and Alaska Peninsula, May 7, based on preliminary results from bids as read at the opening.

The majority, more than $5.2 million, came from 35 tracts at the Cook Inlet areawide sale, some 108,000 acres which brought in an average of almost $48 an acre.

Alaska Division of Oil and Gas Director Bill Barron said after the bid opening that the division was pleased to have another strong Cook Inlet sale. In a statement after the sale Barron said the sale results "show continued optimism among investors about the hydrocarbon resource potential of these two regions, and that state-owned acreage is considered highly prospective for oil and gas development. The sale results also demonstrate continued growth in the market potential for Cook Inlet oil and gas."

As bids were opened for the Alaska Peninsula areawide sale, Barron noted that these were the first bids the state has received for an Alaska Peninsula sale since 2007.

In the Cook Inlet areawide sale the minimum bid was $25 per acre, the leases have 10-year terms and the rental rate is $10 an acre in years one through seven of a lease, and $250 an acre in years eight

see LEASE SALE page 18

FINANCE & ECONOMY

ELF tussle continues

Parnell administration defends 2005 tax change that cost industry dearly

By WESLEY LOY

For Petroleum News

Alaska Gov. Sean Parnell has taken plenty of criticism for promoting tax relief for the oil industry in hopes of spurring production.

But even the governor's generosity is limited, apparently, as administration lawyers continue to defend a 2005 policy change that took away a lucrative tax break for North Slope crude producers.

At stake in the dispute, which began under former Gov. Frank Murkowski, is "several hundred million dollars of production tax revenue," state lawyers told legislators during the recently completed 2014 session.

The matter is now lodged in Anchorage Superior Court, where oil companies are appealing an administrative law judge ruling that favored the state Department of Revenue.

'Aggregating' oil fields

The dispute centers on Alaska's largest oil field, Prudhoe Bay, and some smaller "satellite" fields in the vicinity.

These satellites include Aurora, Borealis, Midnight Sun, Orion, Polaris and Point McIntyre.

For many years, oil produced from these satellite fields enjoyed a much lower tax rate, due to the application of a tax break calculation known as the "economic limit factor," or ELF.

The purpose of the ELF was to prevent mature,

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GOVERNMENT

Kawasaki on opposition to Senate Bill 138

Fairbanks Democrat, one of 4 'no' votes in the House, has concerns with enabling legislation for participation in an LNG project

By STEVE QUINN
For Petroleum News

House Rep. Scott Kawasaki sat on the Resources Committee during seemingly endless hours of testimony and debates over amendments on Senate Bill 138, Gov. Sean Parnell's gas line legislation. Kawasaki has been in office since 2007, having voted for Gov. Sarah Palin's Alaska Gasline Inducement Act and House Bill 4 last year, drafted by House colleagues Mike Chenault and Mike Hawker. But Kawasaki, a Fairbanks Democrat, did not approve of SB 138.

Kawasaki discussed his views on advancing a gas line with Petroleum News.

Petroleum News: You voted for HB 4 last year, but didn't vote for SB 138. I realize they are different bills, but the missions may meld together. What drove you to a no vote on SB 138?

Kawasaki: It's very difficult to vote against such a bill that promises so much. Former Majority Leader Ralph Samuels was the only vote against the Alaska Gasline Inducement Act at the time when people bandied about the words historic and momentous and that can make it a real challenge to vote against a bill that promises so much. Ultimately I felt I had to vote against it. I did a lot of research on it. We sat in the Resources Committee for a long time delving into the issues like the economics. Ultimately there were questions that were never answered, chief among them whether state ownership was a good deal and whether we actually have an opportunity in the future to either exit that plan or bring it back for the Legislature to deal with what it really means. Those were the big hang ups in my mind, so that's ultimately what I had to vote no.

Petroleum News: What are some of those other hang ups — that is if you want to break out your position further?

Kawasaki: There were no guarantees in the enabling legislation that oil taxes wasn't going to be part of the discussion in the future gas line. It seemed like the administration believed that was so, but they wouldn't put it on paper. That made a skeptic out of me. The other provisions that were in there dealing with like who was going to pay for the infrastructure. Again it was part of the HOA (heads of agreement) and it was discussed in committee. That was something I felt should have been in the legislation. I felt the marketing contracts should have been in the body of legislation. The other things even dealing with gas offtake and how the state will be protected, I don't think were ever answered. Fairbanks being a stop point in my mind for any sort of gas line, I wanted to make sure Alaska gets some sort of benefit for its gas. If we are taking a lot of risk in moving the gas, we share that risk among other folks.

Petroleum News: You've said in the past that you were concerned about openings for expansion under this approach. Do you still feel that way?

Kawasaki: That was one of the signature provisions in the Alaska Gasline Inducement Act was a consideration of basin control. When you've got the three resource owners in Prudhoe Bay, the question has always been how are other entrants going to be considered. The future of that is to have the basin unlocked so there are lots of explorers, lots of players, lots of developers, not just a few. I think we've seen that with the TAPS line where it's very difficult to get into the game if you are a junior or smaller player. One of the provisions of AGIA in order to make it different than the pipeline we have now, let's allow for some real pro-expansion principles that allow independents and junior players get in the game.

REP. SCOTT KAWASAKI

Petroleum News: You said it was tough to vote no on something that offered such promise; was there anything about the bill or the agreements underpinning the bill that you liked?

Kawasaki: Again, I think we skipped way over the issue of state ownership in putting ourselves into a position where we are suddenly a junior partner in a large pipeline project. The issue of dealing with being a regulator as well as being a sovereign I think poses some risk. While some legislative consultants for the administration said this is how it's done in other parts of the world, the examples are not similar to Alaska.

They mentioned Brazil, the mentioned Russia, they mentioned other oil and gas sovereigns that have their own infrastructure, that have their own oil and gas companies or corporations. Alaska doesn't do that. We are not in that kind of business model. I think it was apples to oranges when we are trying to compare how we would operate similarly to Russia or Petrobras in Brazil or Venezuela. It was a thoughtful idea, I think. Again, we skipped over the ownership stake and went directly into saying this is how some other folks do it, so why can't we. I don't think it was a good comparison — an intriguing idea, but not a good comparison.

Petroleum News: So then what concerned you about the prospects of being an owner?

Kawasaki: I think the issue of being a regulator and part owner in a line poses some potential conflicts when it comes to environmental damage and when it comes to our own sovereignty. Their priority is ensuring for instance they make the most profit. Our interest as a sovereign should be to get the maximum benefit for the people of the state of Alaska. The maximum benefit is a real moving target. It might not be dollars and cents. It might be getting cheaper value at the beginning of the line or at the end of the line, or somewhere along the line. That was a particularly troubling thought that the state would engage itself in a lot of risk, put all of our eggs into one basket, then suddenly we would be competing with similar projects across the world. This is our only project. It will be a number of projects they are involved in across the glove. That's not a good competitive advantage as a sovereign.

Petroleum News: So what could to ease your concerns between now and when the contract comes back at the end of 2015?

Kawasaki: I think getting some of those unanswered questions answered will be necessary: how the gas marketing will work in a global market; how the off takes will allow for consumers in my community in Fairbanks to benefit; how property taxes are handled in a borough like Fairbanks are being treated. I will be very uncomfortable signing one. The real threat and real problem in a bill like this, is you are going to advance this bill to a point where it gets so far down the line it will be difficult for any legislator to say no this is not the contract we want to see go forward. We've seen that time and time again. The only time when it gets challenged is when you have an unpopular

see KAWASAKI Q&A page 15

● NATURAL GAS

CINGSA applies for pressure increase

Tells AOGCC that an unexpected gas pocket in the gas storage reservoir creates a need for higher gas pressure than anticipated

By ALAN BAILEY
Petroleum News

Following an application to the Alaska Oil and Gas Conservation Commission for approval to increase the maximum gas pressure allowed in its Kenai Peninsula gas storage facility, Cook Inlet Natural Gas Storage Alaska Inc., or CINGSA, presented its case to the commission in a May 6 hearing. The company has asked the commission for an approved maximum pressure of 2,200 pounds per square inch, rather than the existing 1,700 pounds per square inch limit.

The CINGSA facility, which went into operation in 2012, provides gas storage services for Southcentral gas and power utilities, enabling the utilities to store gas during the summer for use during the winter, when gas demand is high. CINGSA says that without approval for a higher reservoir pressure it cannot fully meet its contractual commitments for gas storage.

Six wells

Richard Gentges, a consultant for the company, told the commission that the storage facility has six wells penetrating five distinct sand units within what is referred to as the Sterling C reservoir. The Sterling C is a depleted reservoir of the Cannery Loop gas field, immediately south of the city of Kenai.

Wells two to six target the more southerly part of the reservoir structure, while the number one well targets a part of the structure more towards its northerly end, Gentges said. And, given that gas reservoirs in the Cook Inlet basin tend to be compartmentalized, typically consisting of multiple sand-filled ancient river channels, the plans for the drilling of the wells accommodated the possibility of encountering gas in an isolated channel, he said.

Gas pocket

The number one well, the first well to be drilled by CINGSA, was completed on Jan. 29, 2012, with the well penetrating all five reservoir sands. A rise in the pressure within the well suggested that the well may have encountered an isolated gas pocket. And subsequent stability of the pressure, at a moderate level, suggested cross-flow of gas between that pocket and other reservoir sands. An analysis of the temperature log for the well bore appeared to support that interpretation: The well had probably penetrated an isolated sand channel, containing relatively high-pressure gas that had never been tapped as part of field production.

Using data for the number six well, the only well in the storage facility to have been used for gas production when the Sterling C reservoir was part of the gas field, CINGSA has been able to construct a graph showing how the reservoir pressure varies with the volume of gas in place in the reservoir, Gentges explained. Although that data was obtained as the gas volume declined during field production, the characteristics of the reservoir should remain consistent, as gas is added or withdrawn during use of the reservoir for gas storage.

Pressure measurement

Each spring and fall CINGSA temporarily closes the storage facility for pressure and mass balance testing, in part to assure the integrity of the reservoir. And each of those shut-ins provides a gas pressure measurement. Following the third shut-in, in November 2013, CINGSA had established three pressure measurements, with those three measurements providing points that lie in line on the pressure-volume graph. That line of points indicated a significantly higher gas pressure than would be expected, based on the known volume of gas that had been injected into the reservoir, Gentges said.

And a pressure reading from this year's spring shut-in almost directly overlays the pressure reading from the spring of the previous year, he said.

The graph showed that the reservoir actually contains more gas than would be expected from CINGSA's gas storage injection and withdrawal, with that additional gas likely to have originated from the isolated gas pocket encountered by the number one well. A subsequent analysis of the data indicated the presence of 14.5 billion cubic feet of gas, additional to what CINGSA had injected, Gentges said.

Insufficient space

But, with 14.5 billion cubic feet more gas in the reservoir than had been assumed as part of the storage facility design, there is only sufficient space in the reservoir for 8.2 billion cubic feet of the 11 billion cubic feet of working gas that facility is committed to hold, unless the reservoir pressure is allowed to exceed the approved level of 1,700 pounds per square inch. The requested new maximum of 2,200 pounds per square inch corresponds approximately to the pressure in the reservoir when the original gas field was discovered. Pressure testing in wells penetrating the reservoir has indicated that the requested maximum pressure would be only 63 percent of the threshold pressure at which fracturing of the rock would take place, Gentges said.

The 2,200-pounds-per-square-inch pressure limit would allow the storage of around 18 billion cubic feet of working gas, Gentges said in response to a question from Commissioner Cathy Foerster.

Moira Smith, CINGSA vice president and general counsel, commented that, although the gas volume accommodated by a maximum pressure of 2,200 pounds per inch actually exceeds current storage requirements, mandating a maximum below that level could limit potential future expansion possibilities for the facility. ●

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Petroleum News and its supplement, Petroleum Directory, are owned by Petroleum Newspapers of Alaska LLC. The newspaper is published weekly. Several of the individuals listed above work for independent companies that contract services to Petroleum Newspapers of Alaska LLC or are freelance writers.

OWNER: Petroleum Newspapers of Alaska LLC (PNA)
Petroleum News (ISSN 1544-3612) • Vol. 19, No. 19 • Week of May 11, 2014
Published weekly. Address: 5441 Old Seward, #3, Anchorage, AK 99518
(Please mail ALL correspondence to:
P.O. Box 231647 Anchorage, AK 99523-1647)
Subscription prices in U.S. — $98.00 1 year, $176.00 2 years
Canada — $185.95 1 year, $334.95 2 years
Overseas (sent air mail) — $220.00 1 year, $396.00 2 years
"Periodicals postage paid at Anchorage, AK 99502-9986."
POSTMASTER: Send address changes to Petroleum News, P.O. Box 231647 Anchorage, AK 99523-1647.

CORRECTION

Kuparuk River field, not unit

A story in the April 27 issue referred to increased oil recovery due to improved technology at the Kuparuk River unit. The increased oil recovery was at the Kuparuk River field, rather than the unit of which the field is the largest part.

—PETROLEUM NEWS

● NATURAL GAS

BC answering LNG pressure

Provincial government may introduce tax legislation this summer; initial framework open to change as players outline financial plans

By GARY PARK
For Petroleum News

Just getting LNG out of the starting blocks in British Columbia is turning from a tranquil and measured long-distance journey into a frenzied scramble, with one eye on a clock that is fast winding down.

The pressure on the British Columbia government since it rolled out the framework for a fiscal regime in mid-February is forcing the administration of Premier Christy Clark to buckle under the weight of global companies that want greater clarity before they commit to spending billions of dollars.

In offering the first details of the regime in his 2014-15 budget, Finance Minister Mike de Jong promised to enter a round of bargaining with the province's LNG proponents before introducing legislation this fall, in hopes of obtaining at least one final investment decision in 2014.

So far the province has attracted 14 LNG proposals, although none have been officially launched.

Negative response

But the negative response from players such as Royal Dutch Shell could see the government advance the release of its fiscal plan to this summer, Steve Carr, British Columbia's deputy natural gas minister, told reporters at a Calgary investment symposium in April.

He emphasized that the two-tier LNG tax released in February is far from a done deal in the government's mind.

The first tier was set at 1.5 percent, with a second tier rising to 7 percent once projects had paid off their capital investments.

"I really want to stress the 'up to 7 percent' — we have not landed on the 7 percent and we are continuing to look at our competitive position," Carr told business executives in Toronto.

He said the government will engage with proponents over the next few weeks "since they are the experts and can tell us about their industry," including the confidential details of their financial plans.

Progress: FID rests on tax plan

Michael Culbert is chief executive officer of Progress Energy Canada, whose parent company, Malaysia's state-owned Petronas, is the lead player in the Pacific NorthWest LNG project, among the largest on the books for British Columbia.

He said the hope of making a commercial decision in 2014 is awaiting the details of the LNG tax.

The heat on the government is intensifying as companies compare the costs of proceeding in British Columbia against those in the United States, Australia, West and East Africa and the Middle East.

"The fiscal regime is one of the great many things that's going to determine whether the British Columbia LNG projects are competitive or not," said Barry Munro, oil and gas leader in Ernst & Young's Calgary office.

Tax as revenue grab

The tax proposed by de Jong has been increasingly cited as a potential barrier to investment.

University of Calgary economist Jack Mintz said it is "far from clear what purpose the LNG tax has besides being a revenue grab by the province ... (the tax) could destroy the goose that lays the golden egg."

Natural Gas Development Minister Rich Coleman, who heads the LNG file, dismissed Mintz's critique by simply saying he has read the economist's report.

"We think the LNG tax is a fair approach, to make sure that B.C. gets some benefit out of this resource, from British Columbia and other portions that might come through from other jurisdictions," including gas supplies sourced in Alberta and Saskatchewan, he said.

Coleman said the government needs a license from British Columbians, who own their gas resources and want to see benefits from job creation, business opportunities,

see **BC ANSWERING** *page 7*

LNG tussle will be 'fierce'

One of the trickiest calculations underlying all LNG decisions is the potential impact Canadian and U.S. LNG exports might have on global LNG contract pricing structures, said a report by Ernst & Young.

Barry Munro, the professional service firm's Canadian oil and gas leader, said in a statement that "it is one of the most complicated issues for the LNG sector."

"High LNG development costs have generally required ironclad long-term off-take agreements. And those have historically been oil price based," he said.

But he explained that recent high crude prices have translated to high LNG prices for Asian buyers — "much higher than, on the surface, the current price of North American natural gas suggests should be the case."

"We're seeing expensive projects trying to sell to increasingly more price-sensitive buyers.

"High oil prices and low natural gas prices in North America have strained the traditional approach to LNG pricing. Asian buyers are now looking to modify or possibly replace their long-standing and, in the current environment, expensive pricing model of gas prices tied explicitly to oil prices," Munro said.

He said that when LNG prices are taken into account, developers will have to balance the pressures of being competitive with the need to generate sufficient returns.

"Proposed increases in LNG supply have made the traditional oil-linked pricing structure more difficult to justify," Munro said.

"We're seeing industry players now explore alternative pricing structures to remain competitive, often referenced to Henry Hub prices."

The report said that although Henry Hub pricing is initially challenging to LNG project developers, the move in that direction could increase choices for buyers and sellers, add liquidity to markets and allow buyers to hedge financially and physically, while giving suppliers the confidence to sanction projects before securing export contracts.

"At the end of the day there will always be competitive pressures from new suppliers and, at the same time, buyers will always look to obtain the lowest cost, least-risky supply, with the explicit understanding that security-of-supply is of high strategic value, but comes at a cost," Ernst & Young said.

Munro noted that solving the pricing structure puzzle is "just one of the many challenges Canadian LNG players must manage to compete for capital."

"When the pricing structure is right, both LNG buyers and consumers will win," he said, delivering a final cautionary observation to Canadians.

"We're not the only country looking to establish an LNG export industry. Competition will be fierce," Munro said.

—GARY PARK

ALTERNATIVE ENERGY

Energy options for rural communities

Developers of tidal, river-current and wave-action power generation systems see commercial opportunities in remote Alaska communities

By ALAN BAILEY
Petroleum News

Given the high cost of conventional energy supplies such as diesel fuel in rural communities, emerging technologies involving the harnessing of natural water power from tides, ocean waves and river currents are economically attractive in many parts of Alaska, developers of these types of system told the Business of Clean Energy in Alaska Conference on May 1.

Referred to in general as "hydrokinetics," there are a variety of technologies that convert the natural energy of flowing or undulating water into electrical power. But these technologies are in their infancy. And, with high up-front implementation costs, they can struggle to compete on cost with conventional energy sources in major power grid settings.

Market in Alaska

But there is a market for these technologies in rural Alaska, Monty Worthington, director of project development for Ocean Renewable Power Co., or ORPC, told the conference. ORPC is in the process of shipping a water turbine system to Alaska, for testing power generation for the village of Igiugig, at the southwestern end of Lake Iliamna, using water flow in the Kvichak River that flows out of the lake.

But, in the absence of funding incentives that would create a necessary technology incubator environment, Cook Inlet tidal power cannot currently compete on cost with the relatively cheap power already available in the Alaska Railbelt, Worthington said.

An in-current turbine generation system of this type works somewhat like an underwater windmill, converting river or tidal flow into power in a similar manner to power generation in a wind farm.

The hydrokinetics industry, although nascent, is developing rapidly, learning some lessons from the wind energy industry, Worthington commented. ORPC has recently implemented a tidal power system in Maine, using in-current turbines — this is the first power-grid-connected system of its type in the Americas, Worthington said.

Exportable knowledge

Jeremy Kasper, assistant director of the Alaska Hydrokinetic Energy Research Center in the University of Alaska Fairbanks, told the conference that, with the attractive economics in remote rural areas, Alaska is at the forefront of adopting hydrokinetic technologies, with knowledge gained from implementation of these systems becoming exportable to other parts of the world.

The Hydrokinetic Energy Research Center has, for example, been developing and testing ways of diverting river debris from turbine systems — the diversion of debris away from turbine blades is essential in making river deployment of the technology viable, Kasper said.

Cook Inlet tides

When it comes to the energy inherent in tidal currents, the massive tides of Alaska's Cook Inlet represent a world-class resource. And ORPC Alaska has been working with Homer Electric Association, a local electric utility, on the potential development of an in-current tidal power system at East Foreland, on the west coast of the Kenai Peninsula. But, in the absence of funding incentives that would create a necessary technology incubator environment, Cook Inlet tidal power cannot currently compete on cost with the relatively cheap power already available in the Alaska Railbelt, Worthington said.

"So, while we have this incredible resource, we don't really have the market conditions to attract a large-scale tidal energy development in Cook Inlet at this time," he said.

Worthington later told Petroleum News that ORPC plans to continue the venture at East Foreland with Homer Electric but that, at present, there is no firm timeframe for a demonstration or pilot project. To date, the project has involved, in conjunction with the Alaska Energy Authority and the University of Alaska Anchorage, the measurement and modeling of the East Foreland tidal resource.

ORPC is currently using the East Foreland site as a test location for its in-river turbine technology, Worthington said.

False Pass

ORPC has also turned its attention to the possibility of installing a tidal power system in False Pass, a relatively narrow sea channel between the first of the Aleutian Islands and the western end of the Alaska Peninsula. The local False Pass community currently uses power that costs somewhere in the range 36 to 42 cents per kilowatt hour, and there is a seafood processing facility that could potentially bring a commercial demand that would provide economies of scale, Worthington said.

A group that includes the Aleutian Pribilof Islands Association, the city of False Pass and ORPC is currently assessing the tidal resource and developing a project plan that minimizes financial risk, he said.

Igiugig river turbine

The turbine that ORPC is shipping to Alaska for the in-river test at Igiugig is essentially a prototype system. The plan is to install the turbine device in the Kvichak River and operate it between mid-July and mid-September this year, removing the device before the winter ice sets in, Worthington explained. The Alaska Energy Authority is involved in the project, he said.

The project team wants to demonstrate that a device can be safely and successfully deployed, operated over a reasonable amount of time and then retrieved — success this summer would lead to phase two of the project, a commercial operation, Worthington said.

Yakutat wave power

Bill Staby, founder and CEO of Resolute Marine Energy, a company developing wave energy technology, told the conference about his company's project to develop a wave energy system along the shore at Yakutat. The company's system involves seafloor-mounted hinged flaps that move with the waves. The company has obtained a Federal Energy Regulatory Commission permit for a wave-energy system in a 24-square-mile area along the coast.

Staby said that his company needs to conduct environmental studies in the proposed site, in part to clarify the details of the system design, such as the locations for the placement of the seafloor devices. Current estimates suggest that the system could support 450 kilowatts out of Yakutat's roughly 600- to 700-kilowatt electricity load, Staby said. The company is still refining the economics of the project but currently projects a cost of about 26 cents per kilowatt hour for its power output. That compares with the 50 to 60 cents per kilowatt hour that Yakutat residents currently pay for their electricity — the city entirely depends on diesel power generation, Staby said.

"By September of 2015 we expect to be deploying the first of the wave energy converters," he said. ●

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● ENVIRONMENT & SAFETY

Testing dispersants in ice-cold water

BSEE uses Ohmsett test tank to evaluate the likely effectiveness of oil dispersants in an Arctic offshore oil spill response

By ALAN BAILEY
Petroleum News

The Bureau of Safety and Environmental Enforcement has used its Ohmsett test facility in New Jersey to test the effectiveness of dispersants in dealing with an offshore oil spill in Arctic conditions, according to the spring issue of an Ohmsett newsletter. The idea was to determine whether various dispersants would be suitable for Arctic use, the newsletter said.

Dispersants work in a similar manner to soap, breaking an oil slick into minute oil particles that can disperse through the water column, thus accelerating the rate at which microbes in the water consume and destroy the oil. Although controversial as a consequence of questions over the potential toxicity of the dispersants and of the oil droplets that the dispersants create, dispersants can form part of the arsenal of tools used to combat an oil spill.

But the increased viscosity of oil in cold water may inhibit the action of a dispersant, while the dispersant itself may behave differently in cold conditions from the way in which it acts in relative warmth, the newsletter says.

The Ohmsett facility consists essentially of a large, long water tank, with equipment for creating waves to simulate ocean conditions. Researchers tested four different dispersants by applying each dispersant to an oil slick composed of North Slope crude oil, floating on water in the Ohmsett tank. The tests were carried out in cold winter conditions, augmented by a chiller system, with the water temperature maintained just above the freezing point for salt water, the newsletter says.

Breaking waves

Dispersants require a mixing action, perhaps from waves or the wash of a vessel, to spread the oil droplets through the water. So, the researchers conducted the Ohmsett testing by spraying dispersant onto the slick and exposing the treated slick to breaking waves generated in the test tank. Three identical test runs were carried out for each type of dispersant. In addition, three control runs, in the same conditions but without dispersant, were carried out at the beginning, in the middle and at the end of the test sequence, to provide a baseline against which the effectiveness of the dispersants could be measured.

Samples of oil recovered after each test were analyzed for water content, to cor-

see DISPERSANT TESTING page 14

PIPELINES & DOWNSTREAM

Gasoline production ends at North Pole

Gasoline production has ended at the North Pole Refinery.

Flint Hills Resources spokesman Jeff Cook said May 1 gasoline production ended at 12:01 a.m.

The move is the first step toward a shutdown of the entire refinery, the Fairbanks Daily News-Miner (http://bit.ly/SekCp1) reported.

Flint Hills announced in February that it would close the facility because of the high costs of doing business in Alaska and its ongoing obligations from a chemical spill that has affected local water supplies. The company said 81 of the refinery's 126 jobs would be lost.

Company spokesman Jeff Cook said April 30 that the refinery would shut down its extraction unit at 12:01 a.m. May 1, ending gas production.

The production of jet fuel and heating fuel will end May 24, a week ahead of the refinery's initial shutdown schedule, Cook said. Closure of the plant is months away, however.

The production of jet fuel and heating fuel will end May 24, a week ahead of the refinery's initial shutdown schedule, Cook said. Closure of the plant is months away, however.

To be decommissioned

The plant will be "decommissioned," Cook said, which he compared to winterizing a vacant building.

"The fact that we stop refinery production, that's just the start of the decommissioning process," Cook said.

Mothballing the plant carefully will allow a prospective buyer to resume production more quickly, he said.

The Alaska Legislature approved a tax credit bill in April to assist Alaska refineries. The measure could provide as much as $10 million for investment in plants.

Flint Hills has "nothing firm" to report on the search for a refinery buyer, Cook said.

Flint Hills will continue doing business in Alaska after the refinery closure. It intends to honor supply contracts with customers. The company in February said 35 employees in Fairbanks or North Pole would retain their jobs and 10 more would stay on in Anchorage.

The company will purchase products from other in-state refineries to meet obligations, Cook said.

—ASSOCIATED PRESS

continued from page 5

BC ANSWERING

economic development, increased Gross Domestic Product and a balanced provincial budget for the benefit of future generations.

He said the final fiscal legislation will offer certainty to the industry and indicated the government has made more progress towards a tax regime than he anticipated when he assumed the LNG portfolio less than a year ago.

Coleman also emphasized that the legislation will incorporate skills training and immigration to achieve Clark's goal of "having a workforce in place to build an economy of the future."

The government is especially determined to establish a robust, home-grown training and recruitment process that will enable British Columbia to avoid the worker shortages that have plagued the development of an LNG industry in Australia.

Coleman told a British Columbia TV program that Australia encountered a "significant problem with the whipsawing of the cost of labor," that pushed some budgets 45 percent over their original estimates.

He said some of those same companies are among those considering investment in British Columbia.

"It was not a great experience for the companies that had to go through (the Australian difficulties) and today they're saying, 'We're not making that same mistake.'" ●

Contact Gary Park through publisher@petroleumnews.com

● EXPLORATION & PRODUCTION

ANS April production up 1.7% over March

Largest Slope increase at Kuparuk, up 7%; Cook Inlet crude oil production averages 16,223 bpd in March, down 2% from February

By KRISTEN NELSON
Petroleum News

Alaska North Slope crude oil production averaged 555,987 barrels per day in April, up 1.73 percent from a March average of 546,520 bpd.

The largest month-over-month increase was at the ConocoPhillips Alaska-operated Kuparuk River field, which averaged 149,449 bpd in April, up 6.89 percent (9,639 bpd) from a March average of 139,810 bpd.

Kuparuk volumes include satellite production from Meltwater, Northeast West Sak or NEWS, Tabasco, Tarn and West Sak, as well as from the Eni-operated Nikaitchuq field and the Caelus Energy Alaska-operated Oooguruk field. (Caelus completed its purchase of Oooguruk from Pioneer Natural Resources Alaska in mid-April.)

In March, the most recent month for which data by field is available, Nikaitchuq averaged 19,733 bpd, up 3.4 percent (646 bpd) from a February average of 19,087, and Oooguruk averaged 7,343 bpd, up 19.6 percent (1,202 bpd) from a February average of 6,141 bpd.

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

Prudhoe up slightly

The BP Exploration (Alaska)-operated Prudhoe Bay field averaged 316,002 bpd in April, up 0.8 percent (2,473 bpd) from a March average of 313,529 bpd.

Prudhoe volumes include satellite production from Aurora, Borealis, Midnight Sun, Orion, Polaris, Sag River, Schrader Bluff and Ugnu, as well as production from the BP-operated Milne Point and Northstar fields. BP recently announced plans to sell its interest in Northstar and half of its interest in Milne Point to Hilcorp Alaska, which will operate those fields.

March AOGCC data shows that Milne Point averaged 20,151 bpd, up 6.6 percent (1,251 bpd) from a February average of 18,900 bpd, while Northstar averaged 10,499 bpd, down 0.4 percent (37 bpd) from a February average of 10,536 bpd.

The ConocoPhillips-operated Alpine field averaged 53,857 bpd in April, up 0.5 percent (241 bpd) from a March average of 53,616 bpd. Alpine volumes include satellite production from Fiord, Nanuq and Qannik.

Lisburne, Endicott down

Production from the BP-operated Endicott field averaged 8,327 bpd in April, down 17.5 percent (1,767 bpd) from a March average of 10,094 bpd. Endicott includes production from the Savant Alaska-operated Badami field, which in March averaged 1,051 bpd, down 10.8 percent (127 bpd) from a February average of 1,178 bpd. Hilcorp is also acquiring BP's interest in Endicott and will operate that field.

Production from the BP-operated Lisburne field averaged 28,352 bpd in April, down 3.8 percent (1,119 bpd) from a March average of 29,471 bpd. Lisburne production includes Niakuk, Point McIntyre and Raven.

Cook Inlet production down 2 percent

AOGCC figures show Cook Inlet production for March averaged 16,223 bpd, down 2.1 percent (344 bpd) from a February average of 16,567 bpd.

Hilcorp Alaska is the largest operator in Cook Inlet, with five fields: Beaver Creek, Granite Point, McArthur River, Swanson River and Trading Bay, which collectively produced 12,051 bpd in March.

Beaver Creek, the smallest, averaged 131 bpd in March, down 24.8 percent (43 bpd) from a February average of 175 bpd.

Granite Point averaged 2,687 bpd in March, up 10.4 percent (254 bpd) from a February average of 2,433 bpd.

McArthur River — Cook Inlet's largest — averaged 4,330 bpd in March, down 1.1 percent (49 bpd) from a February average of 4,379 bpd.

Swanson River averaged 2,272 bpd in March, down 5.9 percent (142 bpd) from

see APRIL PRODUCTION page 9

ENVIRONMENT & SAFETY

USCG holds meetings on Arctic ops plan

The U.S. Coast Guard has prepared a draft environmental assessment for planned Arctic operations and will hold public open house meetings beginning May 12.

The draft EA is available for review online at www.uscg.mil/D17 with comments due May 28.

Four public open house meetings are scheduled to discuss the draft EA:

Nome, May 12, 3-7 p.m., University of Alaska Fairbanks Northwest Campus conference room;

Anchorage, May 13, 4:30-7:30 p.m., Hilton Anchorage Hotel, Chart Room;

Kotzebue, May 14, 4:30-7:30 p.m., private dining room, Nullagvik Hotel; and

Barrow, May 16, 4:30-7:30 p.m., Top of the World Hotel, Nanuq Lounge.

—PETROLEUM NEWS

● GOVERNMENT

No funds for wetlands permitting study

Legislature removes budget funding for study into state takeover from federal agencies of primacy for dredge-and-fill permitting

By ALAN BAILEY
Petroleum News

In its final version of the state budget for the 2015 fiscal year, the Alaska Legislature dropped the funding for an evaluation of the possibility of the state taking over from the federal government the primacy for wetlands permitting in Alaska.

"The second year's work is not funded for that program," Ty Keltner, information officer for the Alaska Department of Environmental Conservation, told Petroleum News on May 5. But although the funding has gone, the law passed in 2013 requiring the state to investigate the primacy issue is still in effect, giving state agencies an obligation to continue with the program, Keltner said.

The Department of Environmental Conservation is the lead state agency for the primacy investigation, with the Alaska Department of Natural Resources also involved.

The permitting in question, called "404 permitting" after the section of the Clean Water Act that mandates its use, applies to any activity that involves the dredge and fill of materials into the waters of the United States. Overseen by the U.S. Environmental Protection Agency and administered by the U.S. Army Corps of Engineers, the permitting involves the thorny question of what actually constitutes U.S. waters under federal jurisdiction, a question that plays into state accusations of federal permitting overreach into state interests.

The 404 permitting program came into particular criticism in Alaska following wetland permitting delays for ConocoPhillips' CD-5 oilfield development in the northeastern National Petroleum Reserve-Alaska.

The Clean Water Act allows for the possibility of individual states taking over administration of the 404 permitting program for non-navigable waters, although the Corps of Engineers has said that it would retain administration of tidal waters, navigable waters and adjacent wetlands.

Question of priorities

Andrew Sayers-Fay, deputy director of the Department of Environmental Conservation Division of Water, told Petroleum News on May 5 that his division is still figuring out how to respond to the pulling of the funding. The plan had been to deliver to the Legislature for the next legislative session a cost-benefit analysis report for state primacy, Sayers-Fay said. But now the division must determine the relative priorities of preparing that report and of doing some other work, including the state permitting needed in association with a new Corps of Engineers placer mining general permit, he said.

It is likely that the division will move personnel who have been working on the 404 permitting analysis into a section that already deals with wetlands permits, thus retaining the expertise on the 404 permitting question — there are pending vacancies in the relevant section because of upcoming staff retirements, Sayers-Fay said.

And, rather than dropping the 404-permitting report, it is more a question of when the report will be completed.

"We are planning to continue, but it's obviously going to be much slower given the change in resources," Sayers-Fay said. ●

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APRIL PRODUCTION

a February average of 2,414 bpd.

Trading Bay averaged 2,630 bpd in March, down 7.2 percent (204 bpd) from a February average of 2,834 bpd.

Cook Inlet Energy operates the Redoubt Shoal and West McArthur River fields.

Redoubt Shoal averaged 1,270 bpd in March, up 7.1 percent (85 bpd) from a February average of 1,186 bpd, while West McArthur River averaged 833 bpd in March, down 24.3 percent (268 bpd) from a February average of 1,101 bpd.

ExxonMobil subsidiary XTO operates the Middle Ground Shoal field, which averaged 2,069 bpd in March, up 1.1 percent (23 bpd) from a February average of 2,046 bpd.

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

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● FINANCE & ECONOMY

Economist discusses new production tax

Goldsmith says no $2.1 billion 'giveaway'; based on market conditions, production, MAPA or ACES could result in more state tax

By KRISTEN NELSON
Petroleum News

There was no $2.1 billion "giveaway." Either ACES or MAPA could produce more state revenue depending on market conditions and production levels.

Those were the conclusions economist Scott Goldsmith presented to the Resource Development Council May 1. A 42-page paper explaining his conclusions was posted the same day on the Institute of Social and Economic Research website.


SCOTT GOLDSMITH

Goldsmith, professor emeritus at ISER at the University of Alaska Anchorage, studied changes in oil and gas production tax in Alaska between the old tax, Alaska's Clear and Equitable Share or ACES, and the new tax, the More Alaska Product Act or MAPA, enacted by the Alaska Legislature last year as Senate Bill 21.

The $2.1 billion figure is the difference, Goldsmith said, between the $7.2 billion the Alaska Department of Revenue forecast for 2014 fiscal year oil revenues in fall 2012 and the department's fall 2013 forecast of $5.1 billion.

That difference, Goldsmith told RDC, took everyone by surprise.

Opponents of SB 21 blamed the difference on passage of the tax change.

Goldsmith compared that to concluding that your rooster crowing causes the sunrise, and said he found that only 4 percent of the amount, some $90 million, was due to the shift, effective Jan. 1, from ACES to MAPA, while 96 percent was due to other factors such as updated price forecast and costs.

Majority due to market

More than half of the $2.1 billion difference, $1.29 billion, was due to a revision of market assumptions between the 2012 and 2013 fall forecasts, Goldsmith said.

That includes $304 million in higher lease expenses, 14 percent higher than projected in 2012; $242 million in a lower market price for crude oil, down 4 percent from that projected in 2012; $198 million due to 6 percent fewer barrels than projected; $80 million due to a 15 percent higher cost for transporting the oil; $361 million due to a 16 percent drop in rate of progressivity in ACES, reflecting lower oil prices; and $105 million, 14 percent, in higher credits.

Of the remainder, $320 million was due to a reduction in royalty payments the state received, $140 million to reduction in corporate income tax and $300 million to payment of expiring ACES credits.

The future

Goldsmith said future revenues depend on the price of oil and production costs per barrel. Under current conditions, fiscal year 2015 revenues would likely be $74 million more with ACES, he said. And looking at the last three fiscal years, ACES had an advantage exceeding $1 billion a year.

That advantage disappears in 2014 with price moderation and lease cost increases, Goldsmith said, noting that price is stable and analysts don't see much upward movement, while production costs have risen, more than doubling in the last decade, and are expected to continue to rise.

One notable cost at Prudhoe Bay, the North Slope's largest field, is water handling, Goldsmith said the field now produces more water than oil, and could be called a giant water field with oil as a byproduct, with barrels of water per barrels of oil now at 4 to 1 water to oil.

Manpower costs have also risen, tripling since 2005 to $10 per barrel, Goldsmith said.

Summarizing his results, he said that without enhanced production, future tax revenues could be higher under SB 21 than under ACES if recent price and cost trends continue, and under reasonable future market conditions, with a modest increase in oil investment, more state revenues would be created under SB 21 than under ACES.

The jobs factor

Goldsmith also said that new money coming into the oil patch creates long lasting jobs and increased consumer purchasing power.

While the Legislature spends money trying to create new jobs, he said, new activity in the oil patch creates new jobs at no cost to the state — and each oil industry job generates a lot of other jobs.

On the issue of why the producers favor SB 21, Goldsmith said producers are not in business to minimize taxes, but to maximize profits, and the best way to do that is to expand. Producers may be encouraged through SB 21 to expand, Goldsmith said, and while they may pay more taxes as a result, the pie is bigger. He characterized the difference as between a pie of fixed size and a pie that can expand.

Cook Inlet example

Goldsmith noted that in Cook Inlet, which has had production tax incentives, there has been a dramatic uptick in production, demonstrating that production is sensitive to incentives.

He said he was not suggesting that there would be such a dramatic turnaround in North Slope production, but said while North Slope production has been down in recent years, Cook Inlet has seen increased production.

Goldsmith also said that while companies might pay more tax under SB 21, it provides stability — not fluctuating monthly ACES did; allows the companies upside potential because it lacks ACES' progressivity on price; and because it provides more opportunity for development of marginal fields due to the SB 21 incentive for new oil. ●

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EXPLORATION & PRODUCTION

State taking comments on Paxton expansion

The state is taking comments on Hilcorp Alaska LLC's plans to expand the Paxton pad.

The program would add some 1.25 acres to the production pad at the Ninilchik unit to accommodate appraisal wells and, pending success, potentially additional infrastructure.

Hilcorp plans to drill the 10,000-foot PAX-6 well this year and is permitting the PAX-7, PAX-8 and PAX-9 wells for the near future. If successful, the appraisal wells would be converted to producing wells and the pad augmented with expanded production infrastructure.

The work would begin this summer and continue through May 2019.

The Ninilchik unit sits along the coast of the southern Kenai Peninsula south of Kasilof.

The state is taking comments through May 30.

—ERIC LIDJI

ALTERNATIVE ENERGY

Susitna-Watana project secures some funding

After up-and-down movement on proposed financial-year-2015 funding for the state's Susitna-Watana Hydroelectric Project, the budget that the state Legislature eventually passed includes $20 million for the project, Emily Ford, spokeswoman for the Alaska Energy Authority, told Petroleum News in a May 1 email.

Gov. Sean Parnell's original proposed budget had included just $10 million for the project. Parnell had expressed concern about the impact on the project of delays in obtaining land use permits from the Native corporations that own land at the project site.

In early January Wayne Dyok, the project manager, told the governor that the project needed $110 million in the 2015 financial year to enable the completion of a study plan and the preparation of an application for a Federal Energy Regulatory Commission license for the hydropower system. A shortfall in funding would lead to delays in some fieldwork, Dyok said.

Parnell subsequently increased the proposed funding to $32.7 million, contingent on the land access permits being obtained. And in April the project successfully completed negotiations with the Native corporations, with the permits being duly issued.

But the Legislature did not incorporate Parnell's proposed amendment in the budget, Ford said. Nevertheless, additional funds were added for the Susitna-Watana project, bringing the total funding for financial year 2015 to $20 million, she said.

—ALAN BAILEY

FINANCE & ECONOMY

Oil sands top breakeven list

There's a widely held misunderstanding that the easiest way to make money in the North American oil patch is to acquire property in the Alberta oil sands and start producing.

It's assumed that a leaseholder can either strip the top layer and start mining, or, if the bitumen deposits are buried too deep for open pit operations then the answer lies in drilling wells, injecting steam and melting the bitumen.

But, of all the oil plays in North America, none come close to the breakeven point for new oil sands projects that combine mining and upgrading.

A report by Scotiabank that examined 50 plays said West Texas Intermediate crude prices of US$100 per barrel are needed for a new mining venture to generate a 9 percent after-tax return on investment.

Existing mining and upgrading operations can yield similar returns with oil prices at US$60-$65 per barrel, while Alberta in-situ oil sands projects can reach the breakeven threshold at WTI prices of US$63.50.

For other plays, Scotiabank set breakeven levels of: US$63.50 for Alberta conventional oil; US$57.90 for Lloydminster heavy oil; US$57.67 for the Shaunavon play in southwestern Saskatchewan; US$44.30 for southeastern Saskatchewan's Bakken formation; US$69 for the U.S. Bakken; US$65.41 for the Niobrara; US$81 for the Permian basin; and US$63.57 for the Eagle Ford in Texas.

—GARY PARK

EXPLORATION & PRODUCTION

Shell CFO comments on Alaska commitment

During a media briefing following Shell's announcement of its first quarter 2014 results, Simon Henry, the company's chief financial officer, assured reporters that his company has no plans to withdraw from Alaska, despite some media reports to the contrary.

And, although the company does not plan to drill in the Alaska Arctic offshore in 2014, the company does plan to recommence its drilling operations, perhaps in 2015.

Both Shell and ConocoPhillips, another company planning to drill in the Chukchi, are also waiting to see new safety regulations for offshore drilling in the Arctic that the Bureau of Ocean Energy Management and the Bureau of Safety and Environmental Enforcement have been developing in the wake of the Deepwater Horizon disaster in the Gulf of Mexico.

"We are looking currently at what it will take to be certain of drilling in 2015, and there are still some open question marks, both legal and regulatory systems, that we need to move through," Henry said. Henry was presumably referring to the uncertain legal status of his company's Chukchi Sea leases, following a 9th Circuit Court of Appeals decision to uphold an appeal against the environmental analysis for the 2008 lease sale in which Shell purchased those leases — the Bureau of Ocean Energy Management is currently reworking the analysis following a court order from the federal District Court in Alaska.

Both Shell and ConocoPhillips, another company planning to drill in the Chukchi, are also waiting to see new safety regulations for offshore drilling in the Arctic that the Bureau of Ocean Energy Management and the Bureau of Safety and Environmental Enforcement have been developing in the wake of the Deepwater Horizon disaster in the Gulf of Mexico.

"There are various milestones coming up in both of those processes," Henry said. "We are operationally able to drill next year but are not yet committed to do so, pending legal and regulatory developments."

—ALAN BAILEY

● NATURAL GAS

US uncertainty unsettles LNG industry

By BILL WHITE

Researcher/writer for the Office of the Federal Coordinator

Anxiety is rising in the liquefied natural gas business over the slow rollout of North American LNG export projects. Anxiety about supply. Anxiety about pricing.

The worry was simmering at the big Gastech Conference & Exhibition held March 24-27 in Goyang, South Korea, as LNG buyers and sellers fretted that the world's constrained supply could last beyond the next few years.

"Despite all the rhetoric and hubris that our industry generated, LNG will be shorter for longer than most people are imagining," said Martin Houston, a recently retired chief operating officer of the U.K.'s BG Group, a global LNG supplier.

Where once 10 LNG projects worldwide were predicted to get sanctioned for construction in 2013, just one actually did, he said, Yamal LNG in Russia.

BILL WHITE

"Demand is rising strongly. There are many new markets. ... As an industry, we are failing, year-on-year, to meet the targets we set ourselves," Houston told some 1,200 conference attendees from across the globe.

LNG demand has been flat for two years, constrained because little new supply has come to market.

Growth for the immediate future likely is under control. New plants starting in Papua New Guinea and Algeria in 2014, and in Australia, Indonesia, Malaysia and Louisiana in the following few years should slake demand that's busting in China and India and blossoming in such new LNG consumers as Thailand and the Middle East, as well as up-and-comers like Myanmar and the Philippines. Bernstein Research recently estimated supply will grow by over 30 percent in the next three years, according to Platts news service.

Like many other forecasters, Abujbara estimates about 150 million metric tons of LNG supply — about 20 billion cubic feet of gas a day — will be needed in 2025 beyond what is currently under construction or approved for construction.

Then what.

"We believe that markets are underestimating demand and over-stating supply," Bernstein said in its new report. "While buyers may feel they have the upper hand, the market looks tight to us through 2020."

A couple of years ago, the U.S. and Canadian supply was expected to begin rolling out in force by 2017 or so, right when it would be needed based on demand projections. But U.S. projects are backed up, awaiting government approvals and final investment decisions. And Canadian projects have had trouble locking down customers as buyers wait to see what happens with U.S. projects.

Only one of the 40-plus proposed North America LNG projects (only a handful actually will get built, most say) will have its gas on the market by 2017, the Cheniere Energy project at Sabine Pass, La. Mid-2018 is the best-case scenario for first gas from the next Lower 48 project, and consensus predictions for most Canadian LNG projects now are a chilly "sometime post-2020."

It's not only the delayed volumes from North America that are muddying the marketplace.

Many proposed U.S. projects plan to handle LNG priced in a brand-new way: The U.S. Henry Hub market price for natural gas, plus additional gas to run the plant, plus a liquefaction fee, plus shipping costs.

That's a departure from the Asia standard of discounting LNG slightly below the energy-equivalent crude-oil price. At current prices, Lower 48 LNG would cost Asian buyers far less than oil-indexed LNG. That possible pricing break has the rapt attention of both buyers and sellers, even though Henry Hub pricing history is noted for dramatic highs as well as dramatic lows, presenting a risk to LNG buyers.

Houston, the former BG executive, characterized the Asian buyers' state of mind this way: Indecision, inertia and indexation anxiety.

Industry in flux

The prospect of North America LNG exports has cast an aura that "something is coming" that could alter the industry's status quo, said another speaker at the conference, Peter Thompson of London-based consultancy Gas Strategies.

It's what a business school professor would call a "disruptive innovation" — the big new idea that upsets the old modes of commerce.

Thompson's firm surveyed financiers, project developers, traders and buyers this winter in London, Houston and Singapore. No one is sure what might happen, or how fast.

That's a problem for an industry in which it takes many years to authorize and build a new project, Thompson said. It's also making the people who finance LNG projects edgy by adding another level of risk that they're not quite sure how to mitigate, he said.

Thompson called North America LNG the century's third great wave of expansion, after Qatar's massive build of export plants in the first decade and Australia's great expansion under way today.

North America is providing new ways of playing in the LNG business, he said. Buyers are finding easy entrée as upstream investors in gas fields. They are negotiating contracts that will add pricing diversity to their global gas purchases. And maybe just as important, many U.S. cargos could have "destination flexibility," freeing the buyer to divert the LNG to any port that's needier or higher-priced, a break from the tradition of a seller locking its buyer into long-term commitments

see LNG UNCERTAINTY page 17

● EXPLORATION & PRODUCTION

CIE eyes possible Sabre well partners

Anchorage-based company closes deal for rig to drill prospect near West McArthur River oil field; Sword well produces 600 bopd

By WESLEY LOY
For Petroleum News

Cook Inlet Energy LLC says "several potential joint venture partners" have expressed interest in its planned Sabre well.

The Sabre prospect is near the company's producing West McArthur River oil field on the inlet's west side.

Anchorage-based Cook Inlet Energy is a subsidiary of Miller Energy Resources Inc., a publicly traded Tennessee company.

On May 5, the company exercised an option to buy a rig to drill the Sabre prospect, a filing with the U.S. Securities and Exchange Commission said.

The purchase price was $3.25 million. The seller was Baker Process Inc., a subsidiary of oilfield services giant Baker Hughes.

The plan now is to retrofit the rig to meet the requirements for drilling Sabre, an April 29 operational update said.

Rig drilled geothermal well

The rig is a National 1320 model that formerly belonged to Naknek Electric Association, a small rural cooperative in the Bristol Bay region of Southwest Alaska. The co-op used the rig to drill a failed geothermal well. Subsequently, as part of its bankruptcy case, the co-op sold the rig to Baker in 2012.

The rig improvements are planned to take place over a four-month period in Cook Inlet Energy's Nikiski yard.

"The estimated total acquisition and building cost for the new rig is expected to be $10 million," the April 29 update said. "The company expects that the rig will pay for itself within 16 months of activity, making the purchase more attractive than a lease of the same unit."

The newly acquired rig will be called rig 36, the company said.

Sword produces

Cook Inlet Energy in 2013 drilled a precursor to Sabre called the Sword No. 1.

The company hired Patterson-UTI Drilling Co.'s rig 191 to drill Sword, which reached a final measured depth of 18,475 feet.

The Sword well penetrates three zones, but has produced solely from the Hemlock zone with a recent flow rate of about 600 barrels of oil per day, the company said.

"The two additional zones are expected to add significantly to the Hemlock production," the update said.

A second zone in the Sword well, the Tyonek G, recently tested at about 290 bopd with a 6 percent water cut, the company said. The zone subsequently was isolated pending a test of the third and final zone. ●

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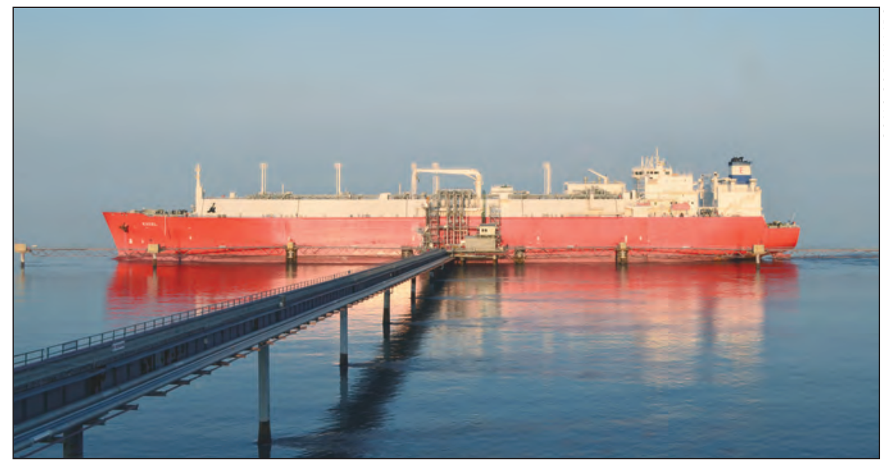
NATURAL GAS


CONOCOPHILLIPS

LNG vessel Excel at ConocoPhillips LNG facility in Kenai

LNG carrier arrives at Nikiski facility

The first LNG vessel to pick up a cargo of liquefied natural gas from ConocoPhillips' LNG facility on Alaska's Kenai Peninsula since the re-opening of the facility has arrived at the dock in Nikiski, ConocoPhillips spokeswoman Amy Burnett told Petroleum News in a May 5 email. The vessel, called the Excel, will carry the first of six cargoes to be exported from Nikiski to Japan this year, Burnett said.

In 2013 ConocoPhillips mothballed the facility because of uncertainties over gas supplies from the Cook Inlet basin. However, a resurgence of the Cook Inlet gas industry has encouraged the company to restart the plant. On April 14 the U.S. Department of Energy issued a new export license, giving permission for the export of up to 40 billion cubic feet of gas per year through the plant to non-free-

see **LNG VESSEL** page 14

ENVIRONMENT & SAFETY

Ninth ice camera planned for Cook Inlet

The Cook Inlet Regional Citizens Advisory Council is planning another expansion of its ice camera network.

The Kenai-based, congressionally mandated organization promotes safe oil tanker and other industry operations in Cook Inlet.

The council has a network of eight high-resolution digital cameras mounted around the inlet in locations where drifting winter ice floes pose a serious hazard for vessels.

Two of these cameras were installed in 2013 on Cook Inlet Energy's Osprey offshore platform and Hilcorp's Granite Point platform.

Now the council is making plans to install its ninth camera, working with partners including the city of Kenai.

"This camera will be on city property and aimed at the mouth of the Kenai River to monitor freshwater ice forming there that poses a greater risk to mariners because of its density," the council said in its April newsletter. "When this freshwater ice is transported on a flood tide it can move as far north as the Nikiski docks, creating dangerous conditions for vessels during and after mooring."

The National Oceanic and Atmospheric Administration has access to live streaming from the cameras, helping agency analysts better evaluate ice conditions in the upper and middle inlet.

"We can compare what we are seeing on the web cameras with what we are seeing on satellite imagery to make more informed decisions regarding sea ice thickness and sea ice concentration," NOAA's National Weather Service said in the council's 2013 annual report. "In addition, the sea ice web cameras are essential for our sea ice analysis on days when we have no recent visual satellite imagery of the inlet due to cloud cover."

—WESLEY LOY

FINANCE & ECONOMY

BP's sale to Hilcorp pegged at $1.25B

When the sale of certain BP North Slope assets to Hilcorp Alaska was announced April 22, financial details were not disclosed.

But in an April 29 first quarter analysts' call, BP executives said the sale brought in $1.25 billion.

Brian Gilvary, BP's chief financial officer, said the sale was part of a plan announced to October to divest a further $10 billion in assets by the end of 2015. In 2013 BP completed a $38 billion divestment program.

"So far we have signed deals worth over $3 billion against this commitment," he said, referring to the $10 billion. "This includes the recently announced sale of a package of assets in the Alaskan North Slope for $1.25 billion."

Bob Dudley, BP's group chief executive, noted that in addition to the $1.25 billion, the sale included "a development carry for the Liberty field of up to $250 million"; that would bring the total to $1.5 billion.

Echoing statements BP made at the time the sale to Hilcorp was announced, Dudley said: "This deal will concentrate our operating footprint and we expect it to drive higher activity into the basin. This enables us to focus more intensely on maximizing production from Prudhoe Bay, North America's largest oil field, as well as progressing the Alaska LNG opportunity."

Assets acquired by Hilcorp in the sale, which is subject to state and federal regulatory approvals is expected to close at the end of the year, include all of BP's interests in the Endicott and Northstar oil fields and a 50 percent interest in Liberty and Milne Point. BP's interests in oil and gas pipelines associated with those fields are also included.

—KRISTEN NELSON

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DISPERSANT TESTING

rect for the effects of emulsification and for the natural water content of the oil, the newsletter says. And during the tests a laser and flourometer system measured the nature of the dispersed oil droplets. These instruments enabled the quantification of the performance of each dispersant, showing how much oil was diluted into the water and the sizes of the oil droplets that the dispersants created, the article says. Droplets more than a certain size will tend to resurface to form a new slick, rather than remaining suspended in the water, the newsletter says.

The newsletter article does not describe the results of the testing but says the results will provide oil spill response organizations and government regulators with information for making decisions on dispersant use. ●

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LNG VESSEL

trade-agreement countries such as Japan.

Although there have been concerns in recent years about the adequacy of gas supplies from the Cook Inlet basin for Southcentral gas and power utilities, the utilities have now secured supplies through to the first quarter of 2018. And, with companies exploring for gas and developing new gas fields expressing concern about finding markets for new gas discoveries, the LNG facility can presumably provide a commercial outlet for gas production. In addition, the operation of the facility can enable gas producers to keep gas wells operating during the summer, when utility gas demand is low, thus improving the efficiency of well production. And in the winter, during periods of peak gas demand, the LNG facility can act as a backstop for utility gas delivery, with gas otherwise designated for LNG production used to bolster the utility supplies.

—ALAN BAILEY

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KAWASAKI Q&A

governor during a very long election year.

Petroleum News: If the line doesn't run through the borough, then the property tax issue is off the table for you isn't it?

Kawasaki: The other issue with property taxes has to deal with impact aid and properties that are going to be used for oil and gas in the future. That was one of the issues that was never taken off the table other than a letter of intent and the governor's executive order in how that might be treated and that folks would be involved and engaged. I would have liked to see it in the enabling legislation. That's what legislators are supposed to do, write the confines of the law rather than leave it open for interpretation.

Petroleum News: You weren't around for the Stranded Gas Act discussions during the Murkowski administration. Your term started just after that. In talking with your colleagues, do you see that same kind of contract coming back?

Kawasaki: I really do. The HOA and the MOU (memorandum of understanding) were done behind closed doors. This bill SB 138 was essentially a bill to legitimize the HOA and the MOU, which were done behind closed doors. It's the backward way to do things in my mind. I have the same fears as the legislators who were here during SGDA. I share those concerns that we're going to have a contract for a stamp up or stamp down. That's not really the way I think the process is meant to be.

Petroleum News: Don't you think it's difficult to have negotiations such as this in public? That's not exactly a standard practice.

Kawasaki: I think there is a certain thing to be said about negotiations in public. It tells the business community and industry what we would like to see in a pipeline. Though the AGIA process didn't produce a particularly viable option with gas prices faltering and falling, the process I don't think could be construed as negative. What we had was this is what the administration, this is what the Legislature and this is what the state of Alaska want in a gas line: bid for it. I kind of liked that kind of approach versus this one, which is done behind closed doors.

Petroleum News: Getting back to HB 4, which you again approved, then the issue of a board member from Texas rather than Alaska arose. This concerned you. Do you really see this as a problem with just one of five being from out of state?

Kawasaki: I see that as a pretty significant problem for a board of directors from the state, for the state advocating for the state of Alaska and its residents and have a person that isn't from the state of Alaska on it while holding a distinct policy making role. On top of that a couple of folks on the board who said it was really great to have this kind of expertise on the board and it lends credence to board discussion and that they will listen to his judgment. That scares me even more that a member who is not from Alaska and doesn't have roots in Alaska will be making huge policy decisions on everything from gas off take to in-state pricing to eminent domain. And I really believe if the person were a value to AGDC (Alaska Gasline Development Corp.), then they can contract with that person as an advisor. For that person to become a policy maker gives me real concern.

> *"The real threat and real problem in a bill like this, is you are going to advance this bill to a point where it gets so far down the line it will be difficult for any legislator to say no this is not the contract we want to see go forward."* **—Rep. Scott Kawasaki, D-Fairbanks**

Petroleum News: Several backers point to Exxon's advancing Point Thomson as a strong sign Exxon is serious. What were your impressions during your visit there last fall?

Kawasaki: I'm a little bit upset that it had to come to the point where litigation was necessary to really get some movement up in Point Thomson. From the state's point of view, we've always known it's an incredible asset. I think it's an incredible asset and I think Exxon knew it and has known it all along. It took a governor like Gov. Palin, a fairly aggressive governor, to push it and push it to a point where if it's not going to be developed like you promised for 30 years, we'll take you to court. I think it's a testament to the tremendous resources we have here. It's a bigger story to get those fields developed and get those folks to develop what they've got.

Petroleum News: He's only one out vote of five with the other board members being from Alaska. So he's one-fifth of a total decision. Don't you think Alaska's voice is strong enough?

Kawasaki: Sure he's one out of five, but there were several members of the board, of AGDC, who testified that they listen to him when he talks because he's got all that experience. Being on that policy board, in my mind, means he has a disproportionate amount of say in the way policy works. I don't think it should be that way. I think he should be hired as a consultant to the board with pay, but I don't think he should be involved in the policy-making provisions of AGDC.

Petroleum News: Along these same lines, there is the new makeup of the SARB (State Assessment Review Board). That does potentially affect your constituents?

Kawasaki: Well we haven't seen the new board make a ruling yet. There is a lot of discomfort to have a board like that. It gives me concern and pause for concern that the folks who were on the board previously like Marty McGee as a state assessor had experience as an assessor is not on the board. This is a shift away from local property tax payers and a shift toward the pipeline owners. That's sort of a red flag. I haven't seen any votes yet, but it's certainly a cause for pause. You might have protections from the Supreme Court ruling, but the state assessors are policy-making review board.

Petroleum News: Closer to you and your constituents, Flint Hills is shutting down. What are your concerns?

Kawasaki: I don't think the governor or this administration has been very engaged in the refining industry in the state of Alaska. We've heard from Flint Hills and heard them say refining particularly is not doing that well. We saw the oil spike in 2008 take down refining margins. I think the administration should have seen this coming. The administration should have done a lot more to prevent this happening either with the quality bank provisions or with the royalty oil contracts that will help us maintain refinery capacity in the state of Alaska. Again, I think the administration should have seen this coming and done a lot more to prevent what's happening either with the quality bank provisions or working with the royalty contract to help us maintain our refining capacity in the state of Alaska. I don't think they did either of that in this case. The sulfolane is probably one issue, but the refiners here in Fairbanks, PetroStar for instance, have complained that they had issues with refinery capacity. Again, the administration could have done a lot more to prevent it. I spoke with the person from Flint Hills and right now it will not resume operations as things are now. So the next step is what's next? A new buyer? A different royalty contract? A combination of those needs to happen in order to make that refinery profitable and work into the future. It's going to take stakeholders like the administrations and DNR to really get engaged in the process or it might never come back.

Petroleum News: There's a pretty contentious ballot issue — the SB 21 oil tax repeal. Do you honestly believe there is a chance to get this repealed?

Kawasaki: We knew that we were going to get outspent. There is no way we can raise that kind of capital against an industry with a vested interest in this issue like the majors. The public is getting engaged. The public is learning a lot. It was very easy to get more than enough signatures for the petition. As more and more people see the production hasn't increased to the level they feel satisfied and isn't projected to increase, so we will get a lot of those votes. I still think it's a huge uphill battle, though.

Petroleum News: Do you have any closing thoughts?

Kawasaki: This state is still an untapped resource. But I think we need to have a lot more independent and smaller players. This administration has focused on the big players and less on the smaller players who can really turn the dial on oil and gas production in Alaska. Hilcorp's entry into the North Slope foray is going to be a positive. I hope other players like those start to play. Not just in Prudhoe Bay and places where we know there is gas but all across the state. Doyon, for instance, continues its drilling in the Interior. That's a real positive. That's just 35 or 40 miles away from Fairbanks. It might not be the volumes of a Prudhoe Bay find, but the fact that there is that kind of activity going on, I think it shows we are a state with an untapped resource that folks are ready to get out there and develop. We as a state need to take a larger view that incorporates not just majors but newer developers and Native corporations doing their own work. ●

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Petroleum news

Oil Patch Bits

Fugro hires Khadjinova as new Alaska manager

Fugro Pelagos said that Rada Khadjinova has been hired as its Alaska division manager. In this role, she serves as the focal point for all Fugro activities in the state, coordinating with other Fugro companies to deliver clients a complete range of survey, geotechnical, and subsea services.


RADA KHADJINOVA

Khadjinova is a certified project management professional with 23 years of experience, the last seven of which have been in the area of engineering and environmental project management. She also holds graduate certification in environmental regulation and permitting from the University of Alaska Anchorage and a master's degree in international relations from Troy State University.

Originally from Russia, Khadjinova has lived and worked in Anchorage since 1993. She currently serves on the board of directors for the Pacific Rim Institute and as a commissioner on the Anchorage Sister Cities Commission.

"Rada's long and diverse experience in Alaska will allow Fugro to better serve our customers in this unique and challenging region," said David Millar, president of Fugro Pelagos. "There is no doubt that our oil and gas, infrastructure development, government, and academic customers will benefit from Rada's proven ability to deliver on high-latitude projects. We are extremely pleased to have Rada join the Fugro team."

NSTI celebrates excellence in safety milestone

North Slope Telecom Inc. recently achieved two significant safety milestones: 1 million hours with no lost time injuries and five years with no recordable injuries. These milestones are especially impressive considering they were accomplished while climbing and erecting communications towers in extreme environments such as the North Slope of Alaska or building communications shelters on remote mountaintops only accessible by helicopter.

NSTI's proven risk management protocols and procedures used to control the hazards encountered ensure continued success. A constant focus on employee safety and on responsibility towards the environment is a key element of all NSTI operations.

"Our employees work hard and take safety seriously. These accomplishments are a direct result of that. It makes me proud to have all of them as members of our team," said Dave Smith, vice president North Slope Telecom Inc.

North Slope Telecom Inc. is a contracting and consulting firm specialized in the design, construction, and maintenance of telecommunications systems. NSTI's capabilities include system design and integration of local and wide area networks via satellite, terrestrial microwave, VHF/UHF radio, fiber optics and copper.

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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CONOCO EARNINGS

both Alaska and the oil industry benefited," Vic Fischer, a constitutional delegate and a primary sponsor of a measure to repeal the law, said in a statement. "The state was able to put away $17 billion in savings. Now three of the richest companies in the world are reaping handsome profits from Alaskans' oil, while we wonder which essential services will have to be cut next."

The question of whether to keep or repeal the current system will go before voters in a referendum on the primary ballot this August, near the release of second quarter earnings.

Profits up, taxes down

ConocoPhillips saw increased profits in Alaska in the first quarter.

The $598 million in adjusted earnings came on $930 million in income from continuing operations before income taxes. In the first quarter of 2013, the company reported $543 million in adjusted earnings on $842 million in revenue. In the fourth quarter of last year, the company reported $555 million in adjusted earnings on $860 million in revenue.

By comparison, ConocoPhillips reported adjusted earnings of $446 million from the Lower 48 and $356 from Canada during the first quarter of the year. Companywide, ConocoPhillips reported more than $2.2 billion in consolidated adjusted earnings.

ConocoPhillips paid $876 million in state and federal obligations during the first quarter, with $570 million going to state production, property and income taxes and state royalties, according to the company. The remainder went to the federal government.

The company reported a tax rate of 51.6 percent for Alaska during the first quarter, down from 61.6 percent in the first quarter of 2013 and 56.2 percent in the fourth quarter of 2013. Considering only income taxes, ConocoPhillips reported a 35.6 percent effective tax rate in the first quarter, roughly even year-over-year and quarter-over-quarter.

By comparison, ConocoPhillips reported an effective income tax rate of 66.9 percent for Europe, 37.5 percent for the Lower 48 and Latin America, 30.9 percent for the Asia Pacific and Middle East, 23.7 percent for Canada and 42.8 percent for its entire portfolio.

ConocoPhillips only details its total tax rate — income and non-income — for Alaska.

Higher spending

The increased profits come amid increased spending.

ConocoPhillips reportedly spent $415 million on capital expenditures in Alaska during the first quarter of the year, considerably higher than the $262 million spent during the first quarter of last year and the $304 million spent during the fourth quarter of last year.

By comparison, ConocoPhillips spent much more in other regions: $1.3 billion in the Lower 48 and Latin America, $848 million in the Asia Pacific and Middle East, $622 million in Canada and $613 million in Europe. The Alaska spending constituted nearly 11 percent of the total $3.9 billion capital program for the company during the first quarter.

The Alaska spending went toward adding two rigs to its existing four-rig fleet and drilling two exploration wells in the National Petroleum Reserve-Alaska. The company said it is still evaluating the results of those wells: Rendezvous No. 3 and Flat Top No. 1.

The company is also planning a new drill site at the Kuparuk River unit, a new development in the NPR-A Greater Mooses Tooth unit and a renewed push for heavy oil production. ConocoPhillips said it hired some 1,700 new workers in the first quarter.

The company said it is still aiming for a late 2015 start-up of the CD-5 Alpine satellite.

Asked during a recent quarterly earnings call whether Alaska could become an area of growth for ConocoPhillips over the near term, Executive Vice President of Exploration and Production Matt Fox said, "Depending on how things play out as we put these development plans together, there's a possibility that we could see growth in Alaska, but even just stabilizing production on an asset of that size and that maturity would be a pretty good accomplishment and I think that's achievable over the long run."

ConocoPhillips spent $132 million on depreciation, depletion and amortization expenses in Alaska during the first quarter, down slight year-over-year and quarter over quarter.

Production down

The higher profits mask declining production.

All told, ConocoPhillips produced 200,000 barrels of oil equivalent per day from Alaska during the first quarter, out of nearly 1.6 million boe per day for the company as a whole.

ConocoPhillips produced 175,000 barrels of oil per day in Alaska in the first quarter, down nearly 4 percent quarter-over-quarter and nearly 8 percent year-over-year.

By comparison, Lower 48 oil production was 171,000 bpd during the first quarter, up 8.2 percent quarter-over-quarter and 15.5 percent year-over-year. With the rise in unconventional oil production from the Eagle Ford shale and Bakken formation, the Lower 48 is becoming increasingly oil prone for ConocoPhillips after years of being primarily a gas-producing region for the company. At the current rate, Lower 48 oil production will likely pass Alaska oil production during the second quarter of the year.

ConocoPhillips believes its currently slate of programs could add more than 40,000 barrels of oil equivalent per day of new oil production from Alaska by 2018.

ConocoPhillips produced 16,000 bpd of natural gas liquids in Alaska during the first quarter of the year, even quarter-over-quarter and down 11 percent year-over-year.

$106.39 per barrel

The company reported earning an average liquids price of $106.39 per barrel from Alaska during the quarter, up $2.35 quarter-over-quarter and down $4.40 year-over-year.

ConocoPhillips produced 55 million cubic feet of natural gas per day in Alaska during the first quarter, up 21 percent quarter-over-quarter and mostly even year-over-year. The Alaska natural gas market often fluctuates depending on the status of the aging liquefied natural gas export terminal on the Kenai Peninsula. The facility sat idle for much of last year.

The company plans to deliver six LNG shipments this year. Each would contain some 2.75 billion cubic feet, of which some 60 percent is expected to be from third parties, according to ConocoPhillips, reflecting the rise of smaller Cook Inlet producers.

By comparison, ConocoPhillips produced nearly 1.5 bcf of natural gas per day from the Lower 48 and 707 mmcf per day from Canada during the first quarter.

ConocoPhillips reported an average price of $5.22 per thousand cubic feet for its Alaska natural gas during the first quarter, up from $3.74 per mcf during the fourth quarter of last year and $5.20 per mcf during the first quarter of last year, reflecting exports.

ConocoPhillips reported an average price of $5.08 per mcf from the Lower 48 and $5.81 per mcf from Canada during the fourth quarter, suggesting a narrow premium for Alaska. ●

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LNG UNCERTAINTY

to take deliveries only to specified locations.

The key U.S. projects — the ones most likely to proceed — are a different business structure, too, Thompson said.

A traditional LNG project involves development of gas fields, pipelines, a liquefaction plant, storage tanks, a shipping terminal and tankers, as well as regasification terminals to receive the LNG — a coordinated value chain developed in unison.

But for many U.S. export projects, much of this value chain exists already. The project's core undertaking is just the liquefaction plant, a much smaller investment, and, in part because it's smaller, one that allows newer kinds of companies into the business than the government and international oil companies that have dominated the business. The LNG plant merely would provide a service to the resource owner — processing, storing and shipping the gas; it would never take ownership of the gas, avoiding the risks of commodity prices.

All of this challenges the norms underpinning existing projects and existing marketers, and how they do business, Thompson said. According to his survey results, the industry is in flux: There's no consensus on what might happen.

Ten Alaska-sized projects needed

Sheng-Chung Lin, chairman of CPC Corp., Taiwan's state-owned LNG importer, summed up the buyer and seller mindsets these days.

Buyers: I need affordable and reasonable prices. I see possibly lots of supply coming, particularly from a new pricing venue. That will pressure prices down.

Sellers: I need profitability with steady production for a long time. More demand is coming. Price should reflect spiraling costs. The market will be tight if no final investment decisions to build new LNG projects occur or uncertainty persists.

Andrew Walker, vice president for global LNG at BG Group, like many other speakers, blamed the schism on the U.S. slow move to LNG "creating a divergence in buyer and seller views."

However, Alaa Abujbara, chief operating officer for commercial and shipping at Qatargas, the world's biggest LNG producer, warned gas buyers about counting too strongly on North American LNG to meet their demand needs.

Like many other forecasters, Abujbara estimates about 150 million metric tons of LNG supply — about 20 billion cubic feet of gas a day — will be needed in 2025 beyond what is currently under construction or approved for construction. That's about 10 projects the size of the proposed Alaska LNG plant, which is in a preliminary, pre-construction phase of development.

"The 150 million metric tons of LNG are going to be very challenging to bring on stream, and people need to start thinking about it as early as possible," Abujbara said. U.S. projects have regulatory uncertainty and many have unproven liquefaction companies behind them. Canada would be a new, unproven exporter and its projects face cost pressures, he said.

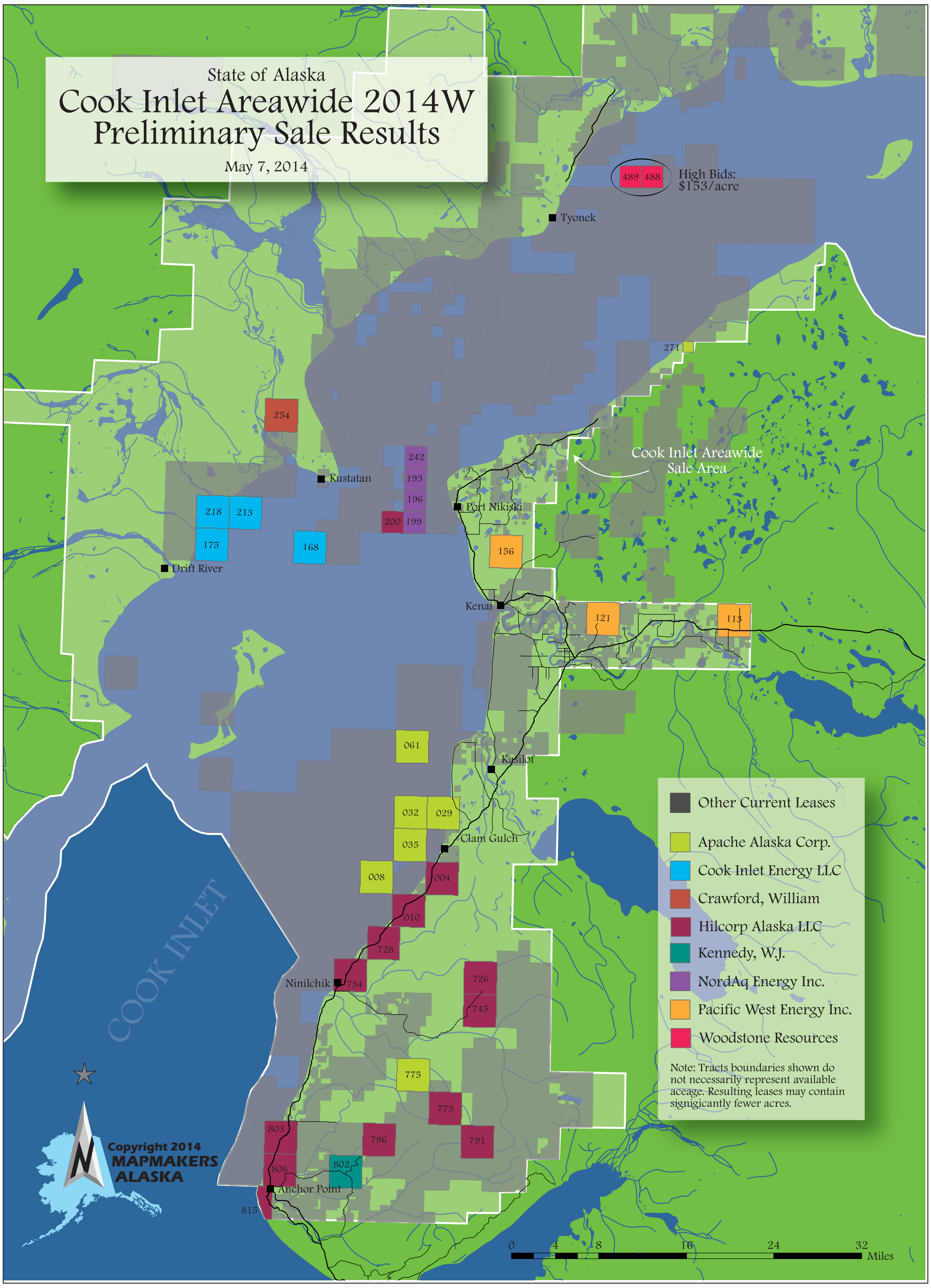
Hamad Rashid Al Mohannadi, chief executive of RasGas Co., the other major Qatari LNG maker, also cautioned buyers.

U.S. prices remain attractive only if Henry Hub prices remain low and oil prices remain high, and project costs don't go haywire, he said.

Houston, the former BG Group executive, made a similar point. He noted that the short-lived spike in U.S. gas prices during a February cold snap — averaging over $7 for a week — should remind buyers that marrying into the U.S. market exposes them to possible extreme price volatility. The embodiment of that volatility in this winter's price spikes, he said, is prolonging the stall that's keeping new projects from moving ahead.

At $7 per million Btu for the feed gas, Lower 48 LNG would lose much of its allure in Asia, costing around $14 delivered to Japan, about the same as oil-indexed LNG prices when crude oil costs about $100 a barrel. ●

Editor's note: This is a reprint from the Office of the Federal Coordinator, Alaska Natural Gas Transportation Projects, online at www.arcticgas.gov/us-export-uncertainty-unsettles-global-lng-industry



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LEASE SALE

through 10.

The state has been holding Cook Inlet areawide sales since 1999, when the minimum bid per acre was $5. The minimum bid went to $10 an acre for Cook Inlet in 2006 and to $25 an acre in 2012.

In recent Cook Inlet sales the state sold 545,050 acres in 2011, 128,300 acres in 2012 and 100,322 acres in 2013, bringing in almost $11 million in the 2011 sale, $4.6 million in the 2012 sale and $3.1 million in the 2013 sale.

Apache, Hilcorp account for some $3M

Apache Alaska was the top bidder in the Cook Inlet sale with apparent high bids totaling almost $2 million, taking 30,103 acres for $1,918,256, an average of $63.72 per acre.

Lisa Parker, Apache's Alaska government relations manager, told Petroleum News after the sale that the company was filling in around areas where it has acreage and is shooting seismic. Five of the seven tracts on which Apache was apparent high bidder are offshore, west and northwest of the Ninilchik unit adjacent to a large block of existing Apache leases. One small tract is on the northwestern shore of the Kenai Peninsula, adjacent to a more northerly block of Apache leases and the seventh lease is onshore on the southern Kenai Peninsula, southeast of the Ninilchik unit.

Apache is in the exploration phase and has no current Cook Inlet production.

Hilcorp Alaska, which has consolidated acquisitions from Union Oil/Chevron and Marathon into a dominant production position in the inlet, also appeared to be filling in around its existing lease position, taking 13 tracts for $1.16 million, an average of $34.95 per acre.

Hilcorp took an offshore tract west of Nikiski, seven tracts along the shoreline — four south of Clam Gulch east of the Ninilchik unit and three along the shoreline from Anchor Point north. The company

see **LEASE SALE** *page 19*

E&P

State closes off-road travel on North Slope

The Alaska Department of Natural Resources, or DNR, has closed all areas of state land north of the Brooks Range for off-road travel, thus closing this winter's tundra-travel season. Temperatures have been above freezing during the day in both the foothills and coastal areas, and snow deterioration has been observed across the region, the agency said in a May 5 announcement.

All off-road travel currently in progress must be completed by 4 p.m. on May 8, the agency said. However, the agency said that it may approve travel extensions on a case-by-case basis, if snow remains adequate for off-road travel in some areas. Extensions require prior approval from the Division of Mining, Land and Water, DNR said.

Summer tundra travel for permit holders with approved off-road travel vehicles may be allowed, starting on July 15, DNR said.

Last year winter tundra travel continued until May 17 for the upper foothills and western coastal areas, with the remaining areas closing on May 20.

—ALAN BAILEY

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LEASE SALE

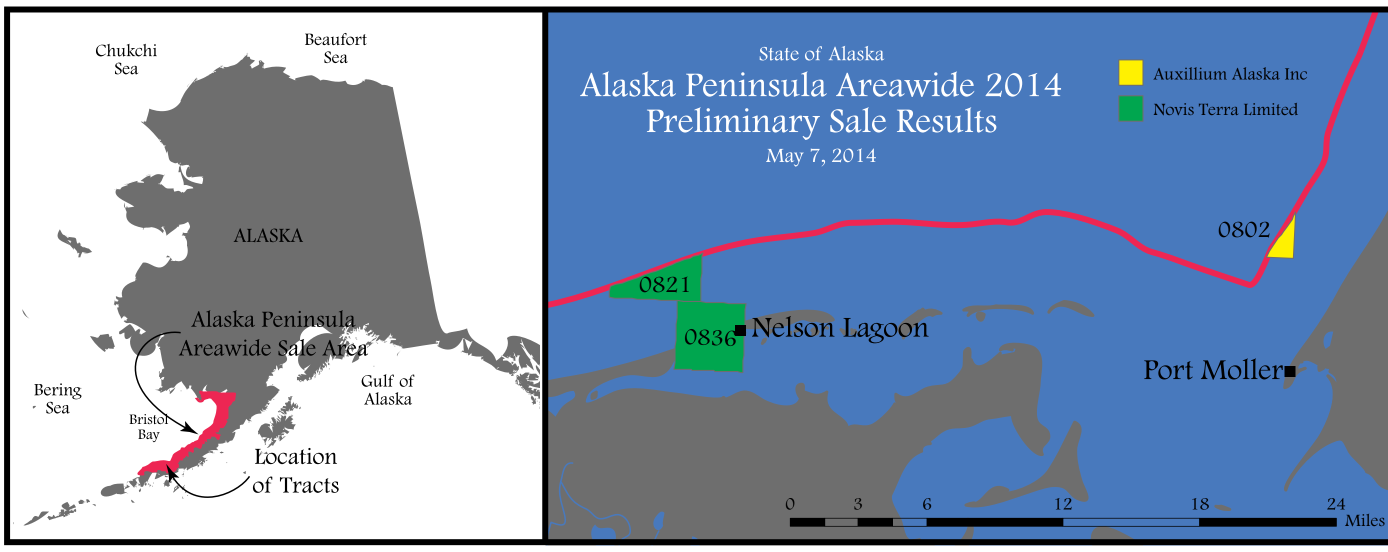
also took five onshore tracts on the southern Kenai Peninsula, two west of existing Hilcorp acreage on the eastern edge of the sale area, one near Hilcorp's Nikolaevsk unit and two farther northeast, north of the North Fork unit.

Cook Inlet Energy, Nordaq

Cook Inlet Energy LLC, also a Cook Inlet producer, took four tracts for $763,315.20, bidding an average of $33.13 an acre. Three of the Cook Inlet Energy tracts are on the east side, near where Bachatna Creek enters the inlet; the fourth is on the southwestern edge of the company's offshore Redoubt Shoal unit.

Nordaq Energy, a Cook Inlet explorer which doesn't yet have production, took four tracts offshore East Foreland, paying $314,470 for 10,240 acres, an average of $30.71 per acre.

Woodstone Resources of Houston took 5,120 acres for $783,360, paying the highest per-acre price in the sale, $153. Woodstone already has almost 27,000 acres of state leases — one Cook Inlet tract, the remainder on the North Slope — but has no production. The tracts Woodstone took in this sale are adjacent to the ConocoPhillips Alaska-operated North Cook Inlet unit.



MAPMAKERS ALASKA

Others taking acreage in the sale included China-based Pacific West Energy, which took three tracts, two onshore east of Kenai and one farther north east of Nikiski, a total of 2,600 acres for $26,380, an average of $27.48 per acre.

W.J. Kennedy took a 5,760-acre tract for $237,715.20, $41.27 per acre in the vicinity of the Cook Inlet Energy-operated North Fork gas field on the southern Kenai Peninsula and William Crawford took a 100-acre tract for $25 an acre, a total of $2,500, at West Foreland.

None of those three bidders has existing acreage.

Alaska Peninsula sale

The bidders in the Alaska Peninsula sale, which brought in $51,400 for 10,280 acres, were Auxillium Alaska out of New York City and Novus Terra Ltd. out of China. Each bid the $5 minimum per acre, Auxillium for one 880-acre tract, and Novus Terra for two tracts totaling 9,400 acres, for a total of $4,400 for Auxillium and $47,000 for Novus Terra. Neither of the companies holds any existing Alaska oil and gas lease acreage.

The Novus Terra tracts are in and north of Nelson Lagoon; the Auxillium tract is north of Port Moller.

Prior to this sale there were no active leases on the Alaska Peninsula. The Alaska Peninsula leases have a 10-year term with rental rates of $1 an acre in year one, $1.50 an acre in year two, $2 in year three, $2.50 in year four and $3 an acre in years five through 10. ●

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

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LNG REALITY

take a large chunk out of profit margins and thus government revenues."

Adding to those doubts, there is the likely revival of nuclear power generation in Japan and South Korea, tough competition from other LNG-exporting countries and the likelihood that Asian importers will form a "buyers club" to rein in LNG prices.

Lower revenues

Lee predicted that these and other developments could lower British Columbia's C$100 billion target to a low as C$12 billion and as high as C$48 billion.

The report also challenged the British Columbia government's lofty goal of C$45 billion a year from the special LNG income tax announced in this year's provincial budget, suggesting it is more likely to plummet to C$200 million to C$600 million.

Lee also said one of the big unknowns could be the cost of dealing with greenhouse gas emissions that would be emitted from an LNG industry, especially if an international treaty to curb carbon emissions is ratified.

He said the decision by Shell Canada and its partners to formally incorporate their LNG Canada joint venture is welcome news, even though a final investment t decision on the C$12 billion project is far from certain.

Companies 'looking long and hard'

Lee said the four companies are "still looking long and hard at whether their investment will deliver appropriate returns."

LNG Canada Chief Executive Officer Andy Calitz said the new corporate pact is an important milestone because it creates an operating entity to hire prospective suppliers and contractors.

He noted that the Asian partners had the option to quit the venture, but instead chose to stick with supporting LNG exports from British Columbia.

"They all very clearly, very demonstrably, very specifically stayed with project," he said.

Calitz said that of every 100 shipments by LNG Canada, 15 would go to Korea Gas, 15 to Mitsubishi, 20 to PetroChina and 59 to Shell.

He said that allowing for front-end engineering, environmental assessment and consultations with First Nations and assuming corporate sanctioning within 24 months, construction should start no later than early 2016, allowing first shipments by late 2020, about two years behind the Pacific NorthWest LNG project.

British Columbia Premier Christy Clark, determined to keep her foot to the gas pedal, is leading a provincial delegation to Malaysia, Singapore and Hong Kong on her latest effort to sell the virtues of doing LNG business with British Columbia.

—GARY PARK

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BC targets LNG tax ruling

The British Columbia government has set Nov. 30 as its deadline to finalize all provincial LNG costs, including taxes, along with the costs of meeting environmental standards and the terms of First Nations compensation.

Premier Christy Clark made the pledge May 5 in Kuala Lumpur with Chief Executive Officer Shamsul Azhar Abbas of Malaysia's Petronas, operator of the Pacific NorthWest LNG project.

In return, Petronas said it would continue working toward a final investment decision, targeting a development agreement by Nov. 30 which could see Petronas lead the field of 15 British Columbia LNG proposals out of the starting gates.

State-owned Petronas is one of several proponents that have raised concerns about the entire costs contained in the government's tentative fiscal regime. It asked for clarity by mid-2014.

Natural Gas Development Minister Rich Coleman has said the government needs more time to consult with proponents before rolling out the relevant legislation.

Both the government and Petronas agreed to assign officials by June 30 to spend the next five months crafting the development pact.

"Securing this commitment from Petronas shows our strategy for attracting investment to B.C. is working," Clark said in a statement. "Our goal is to be the most competitive jurisdiction in the world for LNG."

The two parties said that signing the letter of intent is proof of their determination to secure "mutual interests" to make Pacific NorthWest a reality.

—GARY PARK

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ELF TUSSLE

marginal or small oil fields from being shut-in prematurely due to an excessive rate of taxation.

Department of Revenue officials began to question the ELF tax break for the six satellites. They concluded the satellites and Prudhoe, where most of the oil from all the fields was processed, were "economically interdependent."

On Jan. 12, 2005, the Department of Revenue issued a decision informing the oil companies that the satellites and Prudhoe would be combined, or aggregated, for ELF calculation purposes.

The effect was a major tax increase.

Companies appeal

The decision didn't sit well with oil companies, who lost administrative appeals and now are appealing in the Superior Court.

The companies include Chevron, ConocoPhillips, ExxonMobil and Forest Oil. Although BP, which operates the Prudhoe Bay field, also was affected by the department's decision, it elected not to join the appeal.

On Oct. 13, 2012, an administrative law judge, Christopher Kennedy, ruled in the Department of Revenue's favor.

A state legal brief filed recently in Superior Court argues the Department of Revenue correctly used its "statutory and regulatory discretion" to aggregate the oil fields.

The questions now before the court, the brief says, are whether the Department of Revenue was required to adopt a regulation for its aggregation decision — Kennedy said no — and whether the oil company taxpayers were denied due process.

The case covers only a limited tax period, from Feb. 1, 2005, to March 31, 2006. That's because the ELF statute was repealed effective April 1, 2006, as part of state tax reform.

Nevertheless, the production tax revenue at stake is huge, in the hundreds of millions of dollars, according to a state litigation summary provided to legislators.

Superior Court Judge Sen Tan is presiding over the case. ●

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FURIE OPERATING ALASKA

The platform support frame for Furie Operating Alaska's Kitchen Lights unit A platform.

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FURIE PLATFORM

from Kitchen Light will start in the third quarter of 2014.

Discovered 2011

The company first discovered natural gas in the Kitchen Lights unit in 2011, when drilling the Kitchen Light unit No.1 well using the Spartan 151 jack-up rig. The company has since drilled two additional Kitchen Lights wells and has started a fourth. Although the company has indicated the discovery of a significant gas field, the actual size of the find is unclear. A statement of discovery filed with the Alaska Department of Natural Resources for the Kitchen Lights unit No. 3 well said 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 company first discovered natural gas in the Kitchen Lights unit in 2011, when drilling the Kitchen Light unit No.1 well using the Spartan 151 jack-up rig.

According to Furie's Kitchen Lights plan of operation the offshore platform is of monopod design, with a single 18-foot-diameter caisson that will support a production deck about 62 feet above mean sea level. Facilities on the platform will include a helideck and crew accommodation. The Spartan jack-up rig will be cantilevered over the side of the platform for the drilling of development wells.

Subsea pipelines

The twin gas pipelines from the platform to the shore will be 10 inches in diameter and for much of their length will run parallel to an existing subsea pipeline system, the Cook Inlet Gas Gathering System. The pipelines will pass under a coastal bluff, to emerge onshore at the surface in the grounds of the processing facility. The processing facility, on a 10-acre site, will remove water, gas condensate and sand from the raw gas delivered from the platform, thus enabling the delivery to market of sales-quality gas.

Furie has not indicated who will purchase the Kitchen Lights gas. Although there have been concerns in recent years about the availability of sufficient Cook Inlet gas for Southcentral Alaska power and gas utilities, the utilities now have sufficient gas under contract to maintain supplies through the first quarter of 2018. ConocoPhillips has recently announced the restart of its liquefied natural gas plant at Nikiski, for the export of gas from Alaska. And Agrium is considering the reopening of its mothballed natural-gas-fed fertilizer plant at Nikiski.

—ALAN BAILEY

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