Petroleum news

page 3 Q&A: Hawker — education hope for SB21; equity needs to be good

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Mineral consultant bails out, lawyers jump into mix at B.C. gold project

While money is undeniably tight across the mineral exploration sector, a number of juniors mounted multimillion-dollar exploration programs on promising metals projects across Alaska, including a US$2.5 million program at Constantine Metal Resources' Palmer volcanogenic massive sulfide project near Haines.

CONSTANTINE METAL RESOURCES LTD.

A special supplement to Petroleum News
WEEK OF November 24, 2013 Petroleum

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

TransCanada wants LNG role

RUSS GIRLING

TransCanada is "more optimistic" than it has been for a long time that Alaska is close to announcing an LNG export project in which the Calgary-based company is aiming to secure a "strong role" in the construction and operation of a pipeline, Chief Executive Officer Russ Girling said Nov. 19.

He said discussions over the last 12 to 18 months have achieved "alignment" between the Alaska gas producers (ExxonMobil, ConocoPhillips and BP), TransCanada and the state on an LNG venture that could see an LNG announcement

see **LNG ROLE** *page 18*

Conoco moving ahead at CD-5; Kuparuk gets another drilling rig

JUDY PATRICK

TROND-ERIK JOHANSEN

ConocoPhillips Alaska President Trond-Erik Johansen told the Resource Development Council's annual conference in Anchorage Nov. 20 that work on the new Colville River unit drill site, CD-5, is on schedule and on budget.

CD-5, which will develop the Alpine West satellite, was an investment decision made before the passage of Senate Bill 21, he said. That production oil tax change, passed last spring, is being challenged by voter initiative.

Johansen said under the previous tax regime, ACES, Alaska's

see **CD-5 PROGRESS** *page 12*

NATURAL GAS

CINGSA is ready

Southcentral utilities have stored sufficient natural gas to meet winter needs

By ALAN BAILEY
Petroleum News

As temperatures drop and residents of Southcentral Alaska start to dust off their ski gear for the winter season, the Cook Inlet Natural Gas Storage Alaska facility, or CINGSA, on the Kenai Peninsula is brim full of gas, ready to ensure that winter gas supplies in the region can meet winter gas demand, keeping buildings heated and the lights on.

The storage facility's three initial users — Enstar Natural Gas Co, Chugach Electric Association and Municipal Light & Power — have all confirmed to Petroleum News that they have succeeded in meeting their storage targets for the

The winter of 2012-13 was the first winter in which the utilities faced a shortfall in gas deliverability.

winter and that they have sufficient gas, both under contract and in storage, to meet their anticipated winter needs.

Homer Electric Association, whose contract with CINGSA activated Nov. 1 in support of the utility's plan to start its own gas-fired power generation in 2014, began injecting its gas into the facility on Nov. 6 and anticipates having its contracted volume of gas in storage by the end of

see **CINGSA READY** *page 20*

NATURAL GAS

Viable gas line seen

Alaska consultant says fiscal incentives, state ownership could boost project

By WESLEY LOY
For Petroleum News

A proposed Alaska liquefied natural gas export project could be economically feasible with "changes to the project's cost structure and the state's fiscal framework."

That's the view of Black & Veatch, a Kansas-based global engineering, consulting and construction company the state hired to study the project.

The consultant's 188-page report, released Nov. 18, also says partial state ownership of the project could help it along.

The study comes amid yet another surge of

Alaska can help with incentives such as royalty relief or tax breaks, but estimated future market prices for gas dwarf all other variable in the project's economics, Black & Veatch says.

hope for building a second trans-Alaska pipeline to develop the rich but stranded reserves of natural gas on the North Slope. Alaska's frustrated dreams of such a pipeline are as old as the existing 800-mile crude oil line, which has been operating since

see **VIABLE GAS LINE** *page 17*

GOVERNMENT

Troubled times in Canada

Ontario, Quebec governments schedule own pipeline probes of safety, benefits

By GARY PARK
For Petroleum News

Obstacles piling up in front of Canada's petroleum industry and its government allies are accumulating so rapidly that hopes of exporting oil sands bitumen and LNG risk being stonewalled.

Ontario and Quebec, by far Canada's most populous and industrialized provinces, have decided to step around Canada's Constitution and conduct their own reviews of two pipeline proposals — TransCanada's Energy East and Enbridge's Line 9 reversal and Line 9B expansion.

Both projects are trapped in the whirlpool created by the successful stalling tactics used by opponents of TransCanada's Keystone XL, Enbridge's Northern Gateway and Kinder Morgan's Trans Mountain expansion.

"In terms of greenhouse gas emissions, we can either decide that we want to get to 'yes' (on LNG approvals) or are we going to throw up barriers ... that will ensure we don't have a natural gas industry in British Columbia."
—British Columbia Premier Christy Clark

The campaign against resource development has extended to demonstrators invading the front lawn of British Columbia Premier Christy Clark's Vancouver home, where they erected a fake rig to protest the province's use of hydraulic fracturing to extract the gas needed as feedstock for LNG, and frightened her 12-year-old son in the process.

see **TROUBLED TIMES** *page 13*

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

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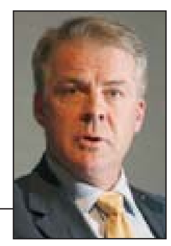

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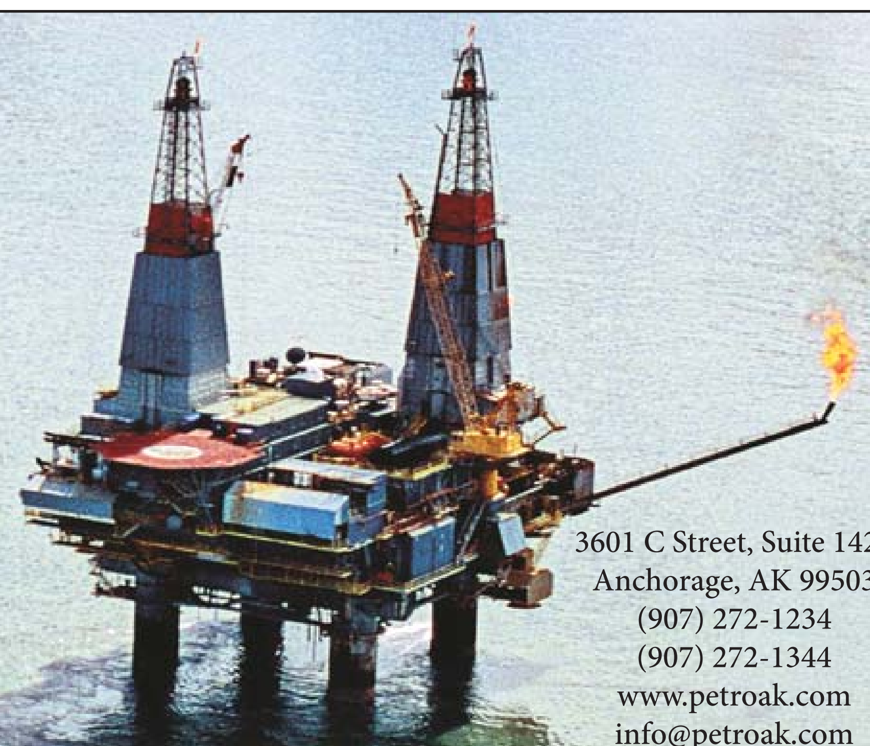

● GOVERNMENT

Hawker sees hope for SB21 with education

Anchorage Republican says AGDC better way to move forward than AGIA; equity share nothing new — but has to be good deal for state

By **STEVE QUINN**
For Petroleum News

Rep. Mike Hawker has been a member of the House for 12 years, long enough to see three tax regime changes, including this year's Senate Bill 21, a failed gas line contract proposal and another gas line plan that is slowly eroding thanks to market changes, the Alaska Gasline Inducement Act.

Still, Hawker, an Anchorage Republican, has also watched and helped shepherd what he believes is progress in advancing the state's economic mission — and Constitutional obligation — maximizing the state's resources.

Three years ago, he and House Speaker Mike Chenault backed the Cook Inlet Recovery Act, which provides the legal framework and incentives for natural gas storage facilities while adjusting tax credits to encourage Cook Inlet exploration.

This year the Legislature approved an in-state gas line bill known as House Bill 4, which empowers the Alaska Gasline Development Corp. to ensure natural gas commercialization to state communities. Time will tell how effective it is, but Hawker remains supremely confident AGDC, already with a board and chairman in place, will be instrumental in advancing North Slope gas commercialization.

Hawker, a member of the House Resources Committee and chairman of the Legislative Council, recently returned from Point Thomson, where operator ExxonMobil is carrying out its share of an out-of-court settlement with the state that ended a longstanding battle over field development.

Hawker sat down with Petroleum News to discuss these interim developments as lawmakers start preparing for a Juneau return.

Petroleum News: You recently took a trip to Point Thomson, long considered crucial toward advancing a pipeline and shipping North Slope gas south. What were your takeaways?

Hawker: Having spent a great deal of my professional career working in the Arctic and having been at Prudhoe since the early days of pipeline production and seen the development for Prudhoe to Kuparuk and then to Alpine, it's been very fascinating to me to see the increasing commitment to environmental protection, to safety and to low impact drilling that Point Thomson presents.

Petroleum News: With that in mind, two U.S. senators recently announced how they want to permanently close off ANWR for oil exploration and production because of concerns of environmental protection and safety. What's your response to that?

Hawker: That's nothing new. Those senators have had a historic animosity toward Alaska, a bent for radical environmentalism in shutting down Alaska's ability to develop our resources. No surprise. It's the reason we've been fighting to open ANWR since 1981 and it's the reason we need to keep fighting today. We not only are fighting to move forward. We are constantly fighting a rearguard action to prevent the Outside forces from moving us backwards.


REP. MIKE HAWKER

Petroleum News: So why do you believe ANWR is still worth fighting for?

Hawker: there has been only one exploratory well in the 1002 Area of ANWR. That was the KIC 1 well back in 1981, I believe. That's a very tight well still. No one really knows the resource potential under ANWR. It seems to me foolish, that we as a state or as a nation are not able to identify whether or not there are resources in the ANWR area that can be developed in an environmentally responsible way. Those fighting the development in ANWR are doing it with a bury your head in the sand approach rather than let's determine all the facts, get all the information and determine what's the best route approach.

Petroleum News: Circling back to Point Thomson, what do you believe the progress you've seen means for future resource development whether it's oil or natural gas?

Hawker: What we see at Point Thomson is a very expensive development, a development that clearly is not going to be economically viable with the production of the oil that it currently is focused on. It's a statement by Exxon, in implementing the Point Thomson settlement agreement, to be ultimately preparing to make Point Thomson gas available for monetization.

Petroleum News: You've been in office long enough to see the back and forth between the state and Point Thomson and the settlement that came last year. Is there a sense of relief to see the development finally moving forward?

Hawker: Relief is the wrong word. It's certainly gratifying to see positive movement in developing the known resource. What's it been — since 1976 that Point Thomson was identified? That we've moved forward both in the technical ability to monetize that high-pressure resource and that we've moved into an era where it is both economically possible and that we are truly looking at a coming era where there will in fact be a North Slope gas pipeline to get that gas to market. So relief is the wrong word, but it certainly is gratifying to be in public office at a time when this long-sought development is coming to fruition.

Petroleum News: DNR just released a report suggesting the state take an equity stake in an LNG pipeline project that would cover between 20 to 30 percent.

Q AND A

Hawker: That premise is nothing new by any means. It was an integral part of the proposal brought forth under the Stranded Gas Development Act and most recently under HB4, which gave AGDC the ability to participate in the equity ownership of a project that goes forward. HB4 didn't mandate that AGDC do it, but it certainly gave it the authority to participate in the ownership of a project. I personally think that is a very viable proposal for us to consider as a Legislature. But the devil is in the details. We need to make sure we are getting a good deal for our investment, not just making the investment so we get a project.

Petroleum News: You noted how HB4 gives you the flexibility to do this. Are the features of HB4 emerging and showing their value?

Hawker: Without question. I'm hearing from stakeholders throughout the community. They are continually amazed how the elements of HB4 are truly giving the state empowerment it needs to participate in a project. I've even heard people in the industry use the word prescient in forethought in anticipation of what the state will require.

Petroleum News: Are you pleased with the progress with the in-state line? You've got your board in place and even a chairman voted upon. Can that be considered meaningful progress?

Hawker: I'm very pleased with the continued development of AGDC and I'm extremely pleased with the governor's appointments to the board. As we state with our HB4 legislation, one of our fundamental concepts was to insulate AGDC from political influence as much as humanly possible in this state, to let it operate like a business venture making sensible business decisions. To do that, you have to have a properly organized management structure. That's why we established the board structure as it was. The governor's implementation of that board structure with extremely competent people is a huge affirmation of his support for AGDC, for HB4 and for our efforts to make certain that any gas development in this state begins with getting Alaska's gas to Alaska's citizens.

Petroleum News: Is there anything else to highlight regarding the in-state line and HB4 since the session ended?

see **HAWKER Q&A** page 19

● NATURAL GAS

Asian LNG joint venture quickens pace

Aurora LNG JV, headed by Nexen, signs deal with BC government for terminal north of Prince Rupert; 3 others still in discussions

By GARY PARK
For Petroleum News

Nexen, a division of China National Offshore Oil Corp., heads an Asian consortium that is jostling for a place in the lineup of British Columbia LNG proponents.

The joint venture, named Aurora LNG, has signed a land deal with the British Columbia government to locate a terminal at Grassy Point, 18 miles north of Prince Rupert.

The deal requires Aurora to pay an immediate C$12 million to the province and another C$12 million in 2014 for exclusive rights to 1,500 acres at the northern end of Grassy Point and 393 acres of foreshore.

Nexen controls 60 percent of the project, with Japan's INPEX Corp. and JGC Corp. each holding 20 percent.

Beyond announcing that the partnership will now embark on a site viability review, a comprehensive environmental impact assessment and stakeholder consultation, Nexen Chief Executive Officer Kevin Reinhart gave no indication at a news conference of a timetable for a final investment decision, an operational startup or a filing for an export permit. Neither Aurora nor the government disclosed the potential scope of the project.

The decisions depend on "acceptable cost estimates, fiscal terms and obtaining acceptably priced sales agreements," CNOOC said.

But Aurora has edged ahead of three other partnerships that submitted eligible expressions of interest in Grassy Point sites — Woodside Petroleum, which operates six of the seven LNG processing trains in Australia; a partnership of Imperial Oil and ExxonMobil; and South Korea's SK E&S, a multi-utility player in northeast Asia's gas and electricity business.

The government said discussions will continue with the other three proponents for a parcel alongside the Aurora land.

A spokesman for Imperial said his partnership is "continuing to assess potential sites" in an area to the south at the deepwater port of Kitimat, where Chevron and Royal Dutch Shell have selected sites for their Kitimat LNG and LNG Canada projects.

Reinhardt said Aurora will "do everything we can to responsibly and economically advance the development of an LNG facility and export terminal."

Government officials said they will work with First Nations in the Grassy Point area to ensure lasting economic benefits from an LNG project.

CNOOC Chief Executive Officer Li Fanrong said LNG exports are the "most attractive option for maximizing the value of our Canadian shale gas business," acquired in last year's takeover of Nexen to gain ownership of shale gas deposits in the Horn River, Cordova and Liard basins of northeastern British Columbia.●

Contact Gary Park through publisher@petroleumnews.com

CORRECTION

Correction to ExxonMobil story

Dale Pittman was incorrectly identified as ExxonMobil Production Co.'s Alaska production manager on page 56 of The Producers magazine, released Nov. 17 by Petroleum News.

Pittman was replaced earlier this year by Karen Hagedorn.

His photo in a side box in the article, "Exxon at work at Point Thomson," is being replaced in the online pdf of the magazine with a photo of Hagedorn

Our apologies.

KAREN HAGEDORN

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● EXPLORATION & PRODUCTION

First operator class sees hands on

Point Thomson production modules being built in Korea; pier, landing strip, mine in place; pipeline work to be finished this winter

By KRISTEN NELSON
Petroleum News

ExxonMobil Production Co. is working both facilities and personnel for its Point Thomson development.

The company's Alaska production manager, Karen Hagedorn, and its Point Thomson construction manager, Bryan Johnson, briefed the Anchorage Chamber of Commerce Nov. 18 on progress to date and upcoming work, essentially an update on briefings ExxonMobil has given earlier (see story in Sept. 22 issue of Petroleum News).

Hagedorn stressed the significance of the new infrastructure ExxonMobil is putting in place on the eastern side of the North Slope, describing it as "opening up a new portion of the North Slope."

It's something that's happened before, she said, with one investment in a development facilitating the one after that.

In addition to some 65 contractors and hundreds of workers involved in the construction phase — more than 500 people on site last winter and more than 600 this winter — Hagedorn said that as production manager, she is "actively developing the organization that will be operating Point Thomson for the long term."

The first class of 11 trainee operators — all Alaskans — have been in classroom training for about six months in Anchorage, she said. And because Point Thomson is a high-pressure gas field, with important safety and process training required, the trainees have started on-the-job training out of a high-pressure gas facility in Mobile Bay, Alabama.

With the airstrip commissioned workers can now fly direct to Point Thomson, Johnson said. Prior to that, they had to fly into Deadhorse and go out to Point Thomson by helicopter.

Johnson detailed companies working on the project, and laid out upcoming work.

This winter, he said, the company will complete the pipeline to Badami, as well as gathering lines; build three more bridges — one was completed last year; complete existing pad work; and build the west pad.

Work completed last winter and summer included opening the gravel mine and gravel placement; placement of 2,200 vertical support members for the pipeline; putting a permanent pier in place for barge deliveries; completion of the camp; and commissioning of the airstrip.

With the airstrip commissioned workers can now fly direct to Point Thomson, Johnson said. Prior to that, they had to fly into Deadhorse and go out to Point Thomson by helicopter.

He said completion of the pier makes way for delivery of production modules under construction at Hyundai Heavy Industries in Korea. They will arrive in the summer of 2015. A drilling rig will be moved back out to Point Thomson in early 2015.

With facilities complete, first production of condensates from the field into the trans-Alaska oil pipeline is planned for early 2016. ●

Contact Kristen Nelson at knelson@petroleumnews.com

GOVERNMENT

Texas A&M center to manage institute

The Bureau of Safety and Environmental Enforcement, or BSEE, announced Nov. 7 that it has selected the Texas A&M Engineering Experiment Station's Mary Kay O'Connor Process Safety Center to manage the Ocean Energy Safety Institute. The Engineering Experimental Station is partnering with Texas A&M University, the University of Texas and the University of Houston in this task, BSEE said.

"I look forward to working closely with our partners at the institute on finding ways to improve safety offshore," said BSEE Director Brian Salerno. "The institute will develop a program of research, technical assistance, and education that serves as a center of expertise in offshore oil and gas exploration, development, and production technology, including frontier areas, such as high temperature/high pressure reservoirs, deepwater, and Arctic exploration and development."

"The three partner universities represent a unique combination of capabilities and resources needed to address the needs for the institute," said Dr. M. Sam Mannan, chemical engineering professor in the Engineering Experiment Station. "We applaud BSEE for supporting this major undertaking of national importance that will impact ocean energy safety for the nation and world for years to come."

Services to BSEE

BSEE had announced in May that it was going to establish the safety institute as an independent body for research and shared learning for offshore energy exploration and development. The institute stems from a recommendation by the Ocean Energy Safety Advisory Committee, a federal advisory group.

The safety institute will provide services to BSEE, including technical assistance with emerging technologies; the development and maintenance of an equipment failure monitoring system; and training for federal employees on state-of-the-art technologies, BSEE said. The institute will also promote collaboration among federal agencies, industry, standards organizations, academia and the National Academy of Sciences, while also holding forums for the dissemination of information and best practices, the agency said.

—ALAN BAILEY

● ENVIRONMENT & SAFETY

ARRT proposes new dispersant procedures

Revised plan for oil spill response would include an area around Alaska coast where use of dispersants would be pre-authorized

By ALAN BAILEY
Petroleum News

The Alaska Regional Response Team, or ARRT, the advisory board to the U.S. Coast Guard oil spill response on-scene commander, is proposing changes to guidelines for the use of oil dispersants in the event of an oil spill offshore Alaska. The most significant component of the changes, which would bring the Alaska plan into line with the national oil spill contingency plan, is the inclusion of a zone offshore southern Alaska, the Alaska Peninsula and the Aleutian Islands where the use of dispersants would be pre-approved.

The U.S. Coast Guard is conducting a series of public outreach meetings and meetings with Alaska tribal government representatives, to explain the proposals and gather comments. The proposed plan changes must go through a 90-day public review period, ending Feb. 14, after which the ARRT will take into consideration the comments it receives before publishing a final version of the plan.

The potential for the use of dispersants in response to an Alaska offshore oil spill is a subject that has caused controversy in the state, with some people claiming that dispersant use would cause irreparable environmental damage while others say that dispersants can prevent the oiling of shorelines and other environmental impacts.

Dispersants accelerate the rate of bacterial decomposition of oil by breaking the oil into tiny droplets and distributing the droplets through the water column, rather like the action of dish soap on greasy plates.

Needed in toolkit

Lt. Veronica Colbath, external affairs officer for the U.S. Coast Guard, told Petroleum News Nov.18 that the preferred method of dealing with an oil slick after an oil spill is the mechanical recovery of oil from the water but that dispersants provide another tool that might have to be used if necessary.

However, the Alaska Intertribal Council ... has issued a statement claiming that the proposed procedure undermines required consultations with tribal governments by allowing dispersant use during a spill response without the agreement of tribal authorities.

"It's important to have every tool available and dispersants is one of those tools," Colbath said.

Mark Everett, the Coast Guard co-chair for the ARRT, told Petroleum News that the revised guidelines address concerns about the possibility of an oil tanker accident, especially in the Cook Inlet and Prince William Sound regions or on the international sea route that passes close to the Aleutians. Under federal regulations the inclusion of a dispersant pre-authorization zone in the Alaska contingency plan will mandate industry to maintain a stock of dispersant and dispersant application equipment, at the ready in case of a tanker accident. At present industry does maintain a stock of dispersants in Alaska but does so on a voluntary basis, Everett said.

Currently, if an offshore oil spill occurs in Alaska waters, the federal on-scene commander for the spill response makes a decision on whether to use dispersants, following a request for dispersant use by the entity that is responsible for the spill. But state authorities and the Environmental Protection Agency must concur with the on-scene commander's decision and must also conduct consultations with the National Marine Fisheries Service and the U.S. Fish and Wildlife Service before a final decision is made, Everett explained.

Decision must be reviewed

If an oil spill were to occur in the proposed dispersant pre-authorization zone, the federal on-scene commander's decision would still have to be reviewed by the state and the Environmental Protection Agency, but a pre-approved decision process would improve the efficiency with which a decision could be finalized, Everett said. And a requirement to conduct testing of dispersant use before full-scale dispersant application would continue to be part of the regulations, he said.

Additionally, under the proposed new guidelines, stakeholders in the Alaska oil spill contingency plan will have 24 months after approval of the revised plan in which to identify any areas within the dispersant pre-approval zone where dispersants use should be avoided.

Everett also emphasized that, apart for the process for reviewing the proposed plan changes, Alaska residents can express views or concerns about any element of spill response planning through participation in Alaska subarea contingency planning committees. And the proposed new guidelines encourage the greater involvement of multiple stakeholders in the decision making process during a spill response, Everett said.

Tribal involvement

Review of the proposed new guidelines includes consultation with Alaska tribal governments and the guidelines would require the involvement of federally recognized tribes in the dispersant decision-making process during a spill response. However, the Alaska Intertribal Council, an organization that advocates for Alaska tribal governments, has issued a statement claiming that the proposed procedure undermines required consultations with tribal governments by allowing dispersant use during a spill response without the agreement of tribal authorities. ●

Contact Alan Bailey at abailey@petroleumnews.com

INTERNATIONAL

Russians building largest nuclear icebreaker

Construction has started in a St. Petersburg shipyard of what will be the world's largest and most powerful nuclear-powered icebreaker, according to a report in the Barents Observer. The new Russian vessel, 173 meters in length and to be constructed at a cost of about 1.1 billion euros, will be powered by two nuclear reactors and will be ready for operations in 2017, the Barents Observer said.

During a ceremony on Nov.5 celebrating the start of construction of the vessel, Vyacheslav Ruksha, the general director of Atomflot, the Russian Federation's nuclear power corporation, said that the new icebreaker would be capable of keeping Russia's Northern Sea Route open to shipping year round, according to a report on Atomflot's website. Russia has been promoting its Northern Sea Route, the route that traverses the edge of the Arctic Ocean around the country's northern coast, as a means whereby commercial shipping can cut the transit time between Europe and East Asia.

Russia has announced a tender for the construction of two more icebreakers of the same type, the Barents Observer said.

—ALAN BAILEY

● PIPELINES & DOWNSTREAM

FERC investigating Quality Bank

The federal regulator will examine the valuation of Resid, but is dismissing the complaint by Flint Hills that launched the matter

By ERIC LIDJI
For Petroleum News

Federal regulators are investigating whether the Quality Bank formula accurately measures the value of a heavy distillate extracted from the trans-Alaska oil pipeline.

The Federal Energy Regulatory Commission recently dismissed a complaint that Flint Hills Resources LLC made over the formula used to value the various products shipped on the pipeline, but said the refiner raised issues worth examining in greater detail.

Flint Hills believes the formula undervalues Resid, or the residual product that is left behind after all the lighter petroleum products have been distilled from crude oil.

The complaint missed the statute of limitations to file a complaint, according to FERC, but the federal watchdog said the proceedings so far have raised enough questions to justify an independent investigation into how the Quality Bank formula values Resid.

FERC Administrative Law Judge H. Peter Young will hear testimony starting in February 2014 and issue an initial decision on the matter in early May, according to the agency.

Flint Hills also brought the matter before state regulators, but the Regulatory Commission of Alaska is waiting until Jan. 15, 2014, to decide whether it will hear the case.

All mixed up

The Quality Bank has been in dispute "almost from its very inception," as FERC put it.

The fund addresses a basic problem on the North Slope. The stream of crude oil moving though the trans-Alaska oil pipeline contains a mixture of supplies from many producers. Each stream can differ in value depending on the quality of the crude oil and the nature of a pipeline makes it unfeasible — if not impossible — to separate shipments.

Without a mechanism to address this imbalance, a company shipping a barrel of low-quality crude would take a barrel of average-quality crude at the end of the pipeline.

So now, when a company ships crude oil valued below the pipeline average, it pays into the "quality bank" to compensate companies shipping supplies valued above the average.

The Quality Bank formula sets the rates, but setting a formula is tricky.

Initially based on gravity

A 1984 methodology used the gravity of oil supplies to determine compensation, but in 1989 some shippers challenged this methodology. They said the increase in natural gas liquids being shipped through the pipeline upended the usefulness of gravity as a measurement tool. A 1993 ruling used distillation to determine the methodology. The methodology broke the production stream into seven products, each valued separately.

A lawsuit over the past decade challenged this ruling, particularly in regard to Resid.

The current methodology assumes Resid will be used for coking, where it is broken into a lighter fuel and asphalt. The value of those two products determines the value of Resid.

Since 2009, the published price of ANS crude has been higher than the Quality Bank value of the finished products extracted from the stream, according to Flint Hills.

The situation is odd, given that a finished product should be more valuable than its raw materials. Flint Hills blamed this discrepancy on the way the Quality Bank formula values Resid, and proposed a new formula that would increase the value of this product.

Continuous litigation

The complaint drew limited support.

ConocoPhillips said the proposed change would allow any company to challenge the Quality Bank formula any time it believed that world economic conditions had changed the value of a product, which could bring back the decades of continuous litigation.

Tesoro Alaska and Anadarko Petroleum Corp. offered similar comments, saying the formula allows for the regular changes and corrections in the markets for each product.

Exxon asked FERC to reject the complaint on technical grounds, saying Flint Hills failed to file the complaint within the time allowed for by various laws governing the pipeline.

Flint Hills interpreted the statute of limitations differently, a position shared by PetroStar.

While quibbling with Exxon on the details, FERC ultimately dismissed the Flint Hills complaint because of the statue of limitations, but will consider the matter independently. ●

Contact Eric Lidji at ericlidji@mac.com

EXPLORATION & PRODUCTION

CGG Land proposing 3 seismic shoots

The state is taking comments on three 3-D seismic programs that CGG Land Inc. is proposing to acquire this coming winter on the eastern and central North Slope.

The proposed West Canning 3-D seismic program would cover some 280 square miles of state-owned acreage between the Point Thomson and Badami units.

The region is home to the proposed Brooks Range Petroleum Corp. Telemark unit, as well as the proposed East Mikkelsen prospect at the eastern end of the Badami unit.

The proposed Great Bear & Niksik 3-D seismic programs would cover some 280 square miles of state-owned acreage just south of Deadhorse and the Prudhoe Bay unit.

The proposed Great Bear & Niksik 3-D seismic programs would cover some 280 square miles of state-owned acreage just south of Deadhorse and the Prudhoe Bay unit.

CGG Land is permitting those two programs together, but describes them in permitting documents as separate efforts. The Great Bear program overlaps the Dalton Highway and the trans-Alaska oil pipeline, and the Niksik program borders it along its western edge.

The region is home to a source rock exploration program led by Great Bear Petroleum LLC. The company has commissioned two previous seismic campaigns over its acreage, and drilled the Alcor No. 1 and Merak No. 1 wells in late 2012, but recently said it would acquired a third seismic campaign before unveiling a development plan in late 2014.

CGG plans to conduct the programs using "tracked vibrators supported by tracked cable trucks." The vibrator lines would run east to west, spaced some 550 feet apart with vibrator points every 50 feet along each line. The vibrators have a frequency between 4 and 100 hertz, used between eight to 12 seconds for each "sweep," according to CGG.

All three programs would run through the end of May 2014.

The Division of Oil and Gas is taking comments on the plans through Dec. 16.

—ERIC LIDJI

GOVERNMENT

Alberta takes larger marketing role

The Alberta Petroleum Marketing Commission is destined for a more proactive investment role if the provincial legislature agrees to seek out new opportunities for the government's royalty crude and bitumen along with allowing the agency to participate in oil and natural gas projects.

Under the Building New Petroleum Markets Act, which is targeted for adoption in early December, the way would be opened for the APMC to grow its mandate beyond the 100,000 barrels per day of bitumen it is ready to provide to kick start TransCanada's Energy East project, designed to move 1.1 million bpd of oil sands and light crudes to refineries on Ontario, Quebec and New Brunswick.

Energy Minister Ken Hughes said in a statement that "reaching new energy markets by supporting and encouraging the development of infrastructure is critical to get the best value for our energy resources."

Currently the APMC markets 70,000 bpd of conventional crude and 300,000 bpd of bitumen — which could grow to 400,000 bpd in 2015 — that the Alberta government accumulates in lieu of cash royalties from producers.

As well, 37,500 bpd of the so-called Bitumen Royalty in Kind, BRIK, barrels have been committed to cover 25 percent of the feedstock needed to launch an upgrader by North West Upgrading, with Canadian Natural Resources as a partner.

Energy Minister Ken Hughes said in a statement that "reaching new energy markets by supporting and encouraging the development of infrastructure is critical to get the best value for our energy resources."

He said the government will look at projects that "need strategic support from the province to enable them to happen."

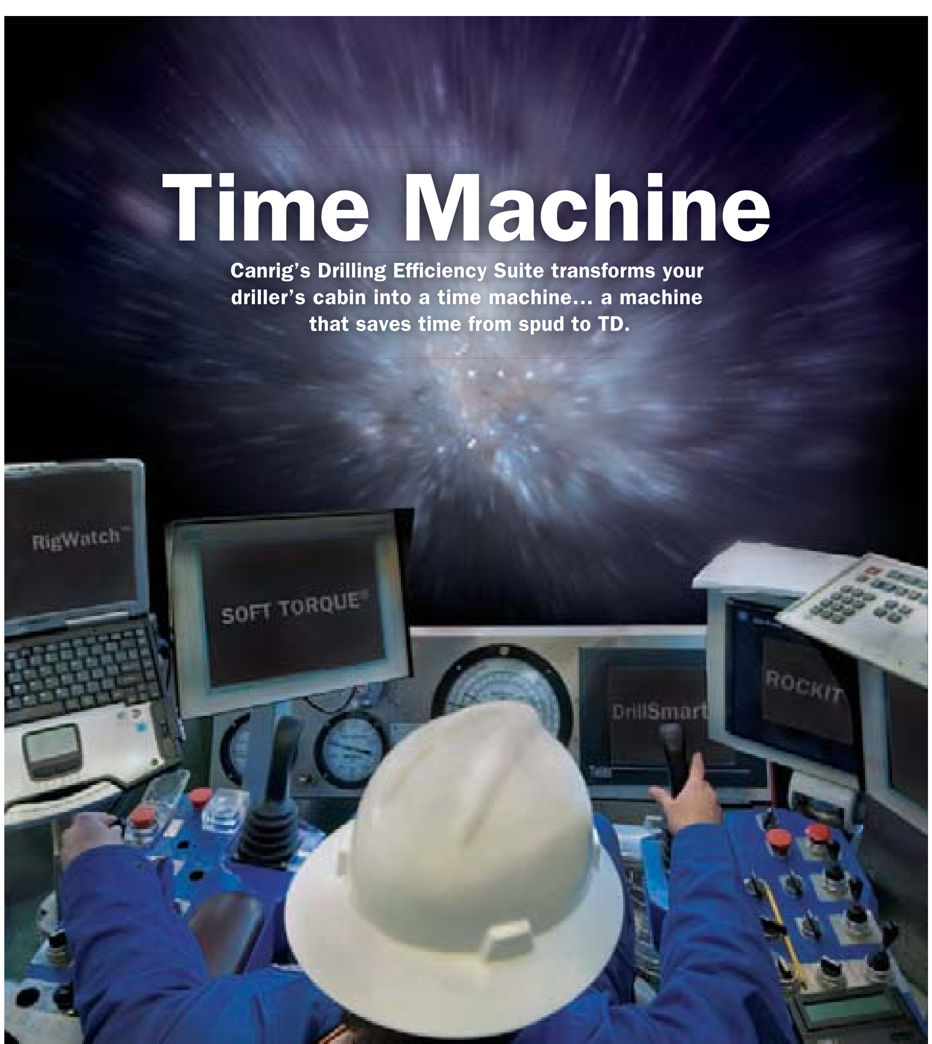
A spokesman for Hughes said the legislation is designed to give the Alberta government a chance to provide a stronger strategic direction to the APMC and give the agency a chance to "look at potential opportunities rather than waiting for them to come to us."

He said the government realizes that there is more it could do to access new markets, including initiatives it learns about on trade missions, and wants the ability to "push the APMC to look at some other options."

Alex Pourbaix, TransCanada's president of energy and oil pipelines, welcomed the prospect of cooperation between government and industry to support infrastructure projects such as Energy East.

"Working together will ensure these vital resources move to market in a safe and reliable way," he said.

—GARY PARK



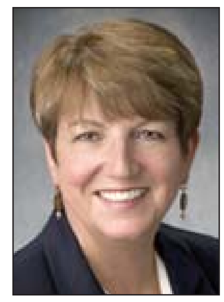
● GOVERNMENT

Newfoundland reaches for Hibernia stake

Province interested in Canadian government share, but premier says price must be right; minister hints government open to talks

By GARY PARK
For Petroleum News

The Newfoundland government is eager to become a larger equity partner in its offshore by acquiring the Canadian government's 8.5 percent share of Hibernia — but only "if the price is right," said Premier Kathy Dunderdale.


KATHY DUNDERDALE

The two governments have tap danced around each other for many years over a possible transfer of ownership, although the topic has gone quiet since 2011 when word leaked out that the price tag was C$1 billion for a field that it estimated to contain 407 million barrels of proved and probable reserves, with the most recent production averaging almost 1250,000 barrels per day.

Hibernia led Newfoundland's offshore production in 1997, followed by Terra Nova and White Rose. Hebron is now on track to join the club, delivering its first oil in late 2017 or early 2018.

Nalcor Energy, an arm of the Newfoundland government, has a 4.5 percent interest in Hebron and 10 percent of the Hibernia South extension project.

Murphy eying exit?

The other shareholders in the main Hibernia field are ExxonMobil 33.125 percent, Chevron Resources 26.875 percent, Suncor Energy 20 percent, Murphy Oil 6.5 percent and Statoil Canada 5 percent. There has been persistent speculation that Murphy is eying the exit door.

Canada's Finance Minister Jim Flaherty dropped the latest hint in mid-February that his government is open to talks over its stake, but stopped short of

see HIBERNIA STAKE page 10

ENVIRONMENT & SAFETY

Eyak plans Cordova spill response facility

The Native Village of Eyak has applied to the U.S. Army Corps of Engineers to construct a new facility at Shepard Point in Cordova for the support of oil spill response activities. According to information provided with the permit application the facility's dock will be able to accommodate oil spill response and other vessels with deeper drafts than any existing facilities in the area. The facility will provide an equipment and material staging area contiguous with the dock.

The facility would improve existing oil spill response capabilities at Cordova which has an airport with the longest runway in the Prince William Sound region but lacks a deepwater port, the application says. The new facility, connected to the airport by road, would be capable of providing access to deep-draft oil spill response vessels in any tide — current spill response plans envisage Cordova airport receiving 20 percent of out-of-region equipment mobilized for a response in the region, but with that equipment having to be delivered to the response site using fishing vessels, the application says.

The application says a consent decree associated with the civil settlement for the Exxon Valdez oil spill had included an agreement and some funding for the facility, but the facility has not yet been constructed.

Building the facility would involve the construction of a 600-foot-long deepwater port at Shepard Point and a 4.5-mile road connecting Shepard Point to the Cordova road system, the application says. The dock would be of traditional design, supported on pilings and connected to land by a trestle. No dredging would be required to achieve the necessary water depth.

—ALAN BAILEY

● FINANCE & ECONOMY

IEA stresses growing energy demand

Report predicts shift in demand to Asia & Middle East, highlights Brazil as oil producer, stresses energy pricing and efficiency

By ALAN BAILEY
Petroleum News

In the 2013 edition of its World Energy Outlook report the International Energy Agency, or IEA, sees global energy demand growing by one-third between now and 2035, but with Asia and the Middle East taking center stage for demand growth while demand remains static in the developed countries of the Organization for Economic Cooperation and Development. The report predicts that India and Southeast Asia will take over the lead from China in driving energy demand growth in the 2020s, while the Middle East will become the world's second largest consumer of natural gas and third largest oil consumer by 2030.

"Major changes are emerging in the energy world in response to shifts in economic growth, efforts at de-carbonization and technological breakthroughs," said IEA Executive Director Maria van der Hoeven when announcing the publication of the new report on Nov. 12. "We have the tools to deal with such profound market change. Those that anticipate global energy developments successfully can derive an advantage, while those that do not risk taking poor policy and investment decisions."

The report singles out Brazil as of particular interest. This country is anticipated to maintain one of the world's least carbon-intensive energy sectors while increasing its energy use by 80 percent and becoming a top oil producer during the next couple of decades or so, the report says.

And estimates of ultimately recoverable oil resources continue to increase, offsetting estimated production decline rates of about 6 percent per year for conventional oil fields that have passed their peak, the report says.

Key to success

But the ready availability of affordable energy will prove critical to economic success and industrial competitiveness in the years to come for many countries. At present, natural gas trades in the United States at one-third of the import price for Europe and one-fifth of that for Japan, with Japanese or European industrial consumers paying twice as much for electricity as their counterparts in the United States, and Chinese industry also paying almost double the U.S. prices, the report says.

The United States should see an increase in its share of global exports of energy-intensive goods in the coming years while Europe and Japan should see their shares decline, the report says.

The report highlights the importance of energy efficiency as a means of addressing high energy prices but says that it is likely that as much as two-thirds of the potential economic gains from energy efficiency will remain untapped by 2035, unless market barriers such as the use of fossil fuel subsidies can be overcome.

Global gas market

An accelerating move towards a more global market in natural gas could reduce the current differentials in gas prices between different regions of the world. The export of liquefied natural gas from the United States coupled with market reforms in the Asia-Pacific region could trigger a loosening of the rigidity of gas supply contracts and their linkage to high oil prices, the report says.

At the same time, efforts to address climate change will not diminish. A projected rise of 20 percent in energy-related carbon emissions by 2035 is expected to cause an average global temperature rise of 3.6 C, a rise that is much larger than the internationally agreed target of 2 C, the report says. And the report predicts a continuing increase in the level of subsidies for renewable energy sources.

New technologies

Although the Middle East is set to remain central to world oil supplies, new technologies such as shale oil development and the development of oil fields in very deep water are making available new oil resources previously viewed as technically or economically inaccessible. And estimates of ultimately recoverable oil resources continue to increase, offsetting estimated production decline rates of about 6 percent per year for conventional oil fields that have passed their peak, the report says. The use of oil is becoming increasingly focused in just the transportation and petrochemical sectors, the report says.

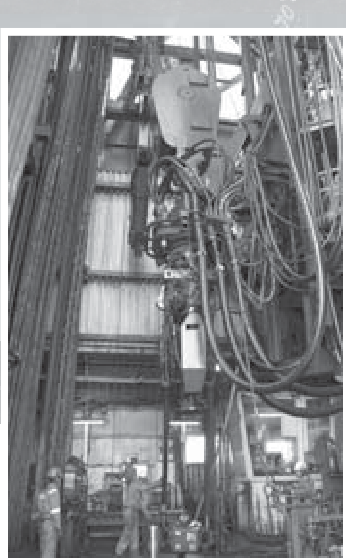
But oil refining is facing worldwide turbulence as oil demand in developed countries declines while demand in Asia and the Middle East rises, and as the composition of oil feed stocks for refineries changes. In countries where oil consumption drops, refinery capacity will be under used, with some refineries potentially closing, making way for new refining capacity in new centers of demand.

The use of biofuels will probably triple by 2035, eventually meeting 8 percent of the demand for road transportation fuel, the report says.

Increasing electricity demand

The report says that worldwide electricity demand is likely to increase by more than two-thirds by 2035 and that the use of fossil fuels will probably continue to dominate electricity generation. However, the share of renewable energy sources in power generation will probably increase from 20 percent in 2011 to 31 percent in 2035, overtaking natural gas as a source of energy and approaching coal, which will likely remain the dominant fuel for use in power stations. However, the future demand for coal is somewhat uncertain, mainly because of the varying stringency of different environmental policies, the report says. Nuclear power's share of the electricity generation energy mix will probably remain fairly static, the report says. ●

Contact Alan Bailey at abailey@petroleumnews.com



● NATURAL GAS

Producers no strangers to LNG projects

Major Alaska North Slope companies — BP, ConocoPhillips, ExxonMobil — have substantial liquefied natural gas investments worldwide

By BILL WHITE
Researcher/writer for the Office of the Federal Coordinator

The big three North Slope oil and gas producers working toward a multibillion-dollar Alaska liquefied natural gas export project have substantial LNG investments across the globe. In some cases these investments go back decades.

1 / 2 SERIES

Taken together, ExxonMobil, BP and ConocoPhillips own stakes in LNG production plants in the Middle East, Southeast Asia, Australia, Africa, the Caribbean and North America.

In addition, ExxonMobil owns an interest in two of the dozen or so plants under construction worldwide, while ConocoPhillips has a piece of a third project.

Each company also is in the LNG importing business — investors in terminals where liquid methane can be received, stored, warmed back into a vapor then routed into the gas pipeline grid. ExxonMobil in Texas, the United Kingdom and Italy; ConocoPhillips in Texas; and BP in China — the only Western oil company with such an investment in China.

ConocoPhillips has a third LNG enterprise the other two companies lack in their portfolios: It owns one of the muscular liquefaction technologies that superchills methane to minus 260 degrees, compressing the gas into a liquid that's more cost-effective to ship long distances. ConocoPhillips debuted its technology at its Nikiski, Alaska, LNG plant in 1969, and the process is running at five other plants from Point Fortin, Trinidad, to Darwin, Australia. Four LNG plants under construction worldwide will use it as well.

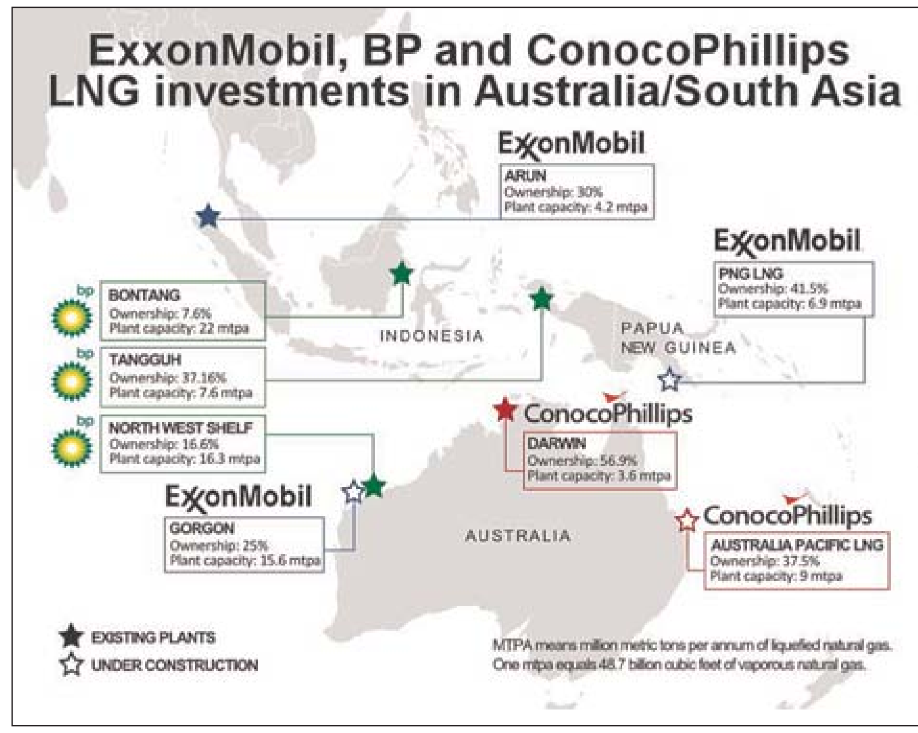

BILL WHITE

Though a hot energy commodity these days, LNG is a side dish on the menu of activities these three petroleum companies are engaged in worldwide.

In the companies' annual reports, the LNG financials are too small within their global operations to earn a dedicated line on the corporate income statements. However, in the text, LNG merits mention as drawing investment capital as well as one of the many possible growth areas in the companies' portfolios.

LNG production is a business dominated by major multinational petroleum companies like these three Alaska operators, and by national oil companies in such countries as Qatar, Indonesia, Malaysia, Nigeria and Algeria.

Among the multinationals, Shell is an even bigger global LNG player than the three Alaska North Slope operators. Shell makes LNG in Brunei, Malaysia, Australia, Russia, Qatar, Oman and Nigeria, with Trinidad and Tobago as well as Peru coming soon when Shell closes its purchase of Spanish oil company Repsol's interest in the plants there.



OFFICE OF THE FEDERAL COORDINATOR

Other major international oil and gas companies with substantial investments in LNG plants include Chevron (United States), Total (France), Eni (Italy), Statoil (Norway) and INPEX (Japan).

The qualities needed to shine in the LNG industry are the very same traits that oil wildcatters need to grow into global petroleum producers:

•The patient endurance of a long-distance runner.

•Access to bales of money, through both strong cash flow and stellar creditworthiness.

•A risk-taking DNA.

Tackling LNG investments can entail vast scales of time, cost and risk.

On time, Joseph C. Geagea, president of Chevron Gas and Midstream, put it this way at a Tokyo LNG conference in September 2013: On average, a project takes 18 years from gas discovery to the first LNG shipment setting sail for market.

On cost, a typical project will cost billions of dollars, even tens of billions, not counting the expense of building out the production fields that will feed natural gas to the plant. LNG developments are among the most costly capital projects a

see **NO STRANGERS** *page 11*

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HIBERNIA STAKE

saying when a deal might be done and at what cost.

Dunderdale told reporters a purchase "would be expensive, but you can imagine the return on investment would be very significant as well."

In 2009 Flaherty made the chances of a deal sound remote, noting that Canadian taxpayers through a costly series of grants and loans had "incurred significant costs to develop the Hibernia project and assumed significant risks."

"In this context, the federal government will manage this investment in order to maximize its value to all Canadians and in accordance with best commercial practices," he said.

During the 2011 federal election, Dunderdale asked the leaders of Canada's three major political parties if they would consider a sale, but she conceded "we just weren't able to bridge the gap so negotiations fell apart."

But interest has been revived since word that Hebron is proceeding, along with satellite extensions to the Hibernia and White Rose fields. ●

Contact Gary Park through publisher@petroleumnews.com

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NO STRANGERS

petroleum company will undertake. And lately, particularly for the eight projects under construction in Australia and Papua New Guinea, the price tag has been soaring.

The cost of building an LNG plant doubled from the early 2000s to today, said consultants PFC Energy during an Alaska seminar in August 2013. The cost of developing gas fields to support the liquefaction plants also has jumped, PFC Energy said.

On risk, where to start. Here's a sample:

•Risks of lengthy development — including years before any positive cash flow as well as potential political, regulatory and litigation snags.

•Risks of a long construction period — including cost overruns, weather delays, labor problems and, again, litigation. What if the timing gets mismatched for different components of the development, such as the gas fields are ready but the LNG plant isn't, or tankers launch from the shipyard before the LNG plant is done?

•Technology risks — glitch-prone equipment that delays startup, hampers production or causes contracted deliveries to be missed.

•Price risks — the LNG is pegged to a price index that doesn't support the cost of production, or markets change during the multiyear development and construction.

Let's look at the global LNG investments of ExxonMobil, BP and ConocoPhillips, the three companies considering the Alaska LNG project with their partner, Canadian pipeline firm TransCanada, which has no liquefaction investments.

Their early concept envisions a $45 billion to $65 billion project that includes a gas treatment plant on Alaska's North Slope, a roughly 800-mile pipeline, and a liquefaction plant with LNG storage and a two-berth tanker terminal at Nikiski in Southcentral Alaska.

The export plant would have the capacity to make 15 million to 18 million metric tons of LNG annually, the equivalent of 2 billion to 2.4 billion cubic feet a day of gas.

This would be massive undertaking for the three producers.

ExxonMobil and BP are part owners of larger LNG plants, although those plants scaled up over time. ExxonMobil is investing in a similar-sized project called Gorgon under construction in Australia right now. ConocoPhillips, the smallest of the three, has no other LNG projects in its portfolio on the same scale as Alaska LNG.

In all, the three companies own stakes in more than 40 percent of the LNG production trains operating worldwide today — a typical LNG plant features several LNG trains running side by side, each liquefying methane independent of each other.

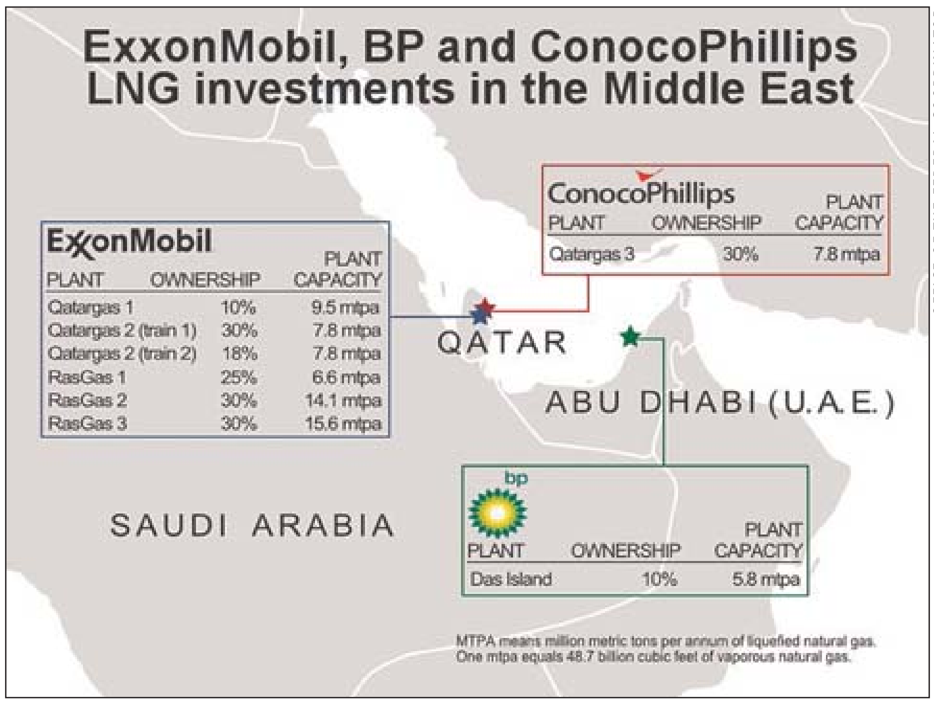
Because almost all of those investments involve minority interests in the trains, the companies' actual share of today's global LNG plant nameplate capacity totals about 13 percent.

In the 1980s and 1990s, Qatar's leaders decided the Mideast nation's ownership of the spectacular North Field — the world's largest dry-gas field — would become a cornerstone of their 21st century economy.

LNG exports became the means, and ExxonMobil became the biggest outside investor propelling Qatar's leap to the top among the world's LNG makers. It owns a share in 12 of Qatar's 14 LNG trains.

Qatar's first LNG trains cranked up in the late 1990s.

Its 2003 production of about 14 million metric tons per year — about 2 billion



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cubic feet a day when warmed back into a vapor — already ranked Qatar as the fourth-largest LNG exporter in the world, behind Malaysia, Indonesia and Algeria.

By 2011, Qatar could produce 77 mtpa, more than three times No. 2 Malaysia's output.

Exxon's entrée into Qatar and some of its other LNG ventures came via Mobil Oil. Exxon and Mobil, two massive products of the U.S. Supreme Court breakup of Standard Oil 100 years ago, merged in 1999.

Mobil was an investor in Qatar's first LNG plants: A 10 percent stake in Qatargas 1's three trains and a 25 percent share of Rasgas 1's two trains.

The investments continued after the Mobil and Exxon merger. The company has stakes in seven of the nine LNG trains Qatar commissioned since, all from 2004 through 2011. National oil company Qatar Petroleum is majority owner in each train.

ExxonMobil also has partnered with Qatar Petroleum in three LNG terminals built to import Qatari LNG. One is South Hook in Wales. A second is Adriatic LNG in Italy. The third is Golden Pass in Texas.

ExxonMobil's only LNG plant outside of Qatar is a 30 percent interest in two trains at Indonesia's Arun plant. Arun opened in 1978. But it is slated to stop exporting in 2014 to become an LNG import terminal for Indonesia's growing economy.

Arun also came from the Mobil side or the company, a result of a Mobil gas discovery in 1971.

ExxonMobil is invested in two LNG plants under construction:

•It is a 41.5 percent investor and operator of PNG LNG in Papua New Guinea. The $19 billion 6.9 mtpa plant — about 920 million cubic feet a day — is expected to start up in 2014.

ExxonMobil

LNG plants

Name	Stake	Plant size	Year first opened
Indonesia			
Arun	30%	4.2 mtpa*	1978
Qatar			
Qatargas 1	10%	9.5 mtpa	1997
Rasgas 1	25%	6.6 mtpa	1999
Rasgas 2	30%	14.1 mtpa	2004
Rasgas 3	30%	15.6 mtpa	2009
Qatargas 2, train 1	30%	7.8 mtpa	2009
Qatargas 2, train 2	18%	7.8 mtpa	2009

Plants under construction

Name	Stake	Plant size	Startup
Papua New Guinea			
PNG LNG	41.5%	6.9 mtpa	2014
Australia			
Gorgon	25%	15.6 mtpa	2015

Possible future projects

Australia	Scarborough
Texas	Golden Pass
Russia	Sakhalin 1
Alaska	Alaska LNG
Canada	British Columbia

* million metric tons per annum

Source: Office of the Federal Coordinator research

•It is a 25 percent investor in the Australia's Gorgon project, led by Chevron. The $52 billion, 15.6 mtpa project — about 2.1 billion cubic feet a day — is expected to begin producing in 2015.

Both of those ventures were Mobil plays before the 1999 merger. ●

Part 2 of this story will appear in the Dec. 1 issue of Petroleum News.

Editor's note: This is a reprint from the Office of the Federal Coordinator, Alaska Natural Gas Transportation Projects, online at www.arcticgas.gov/north-slope-producers-no-strangers-lng-projects.

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CD-5 PROGRESS

Clear and Equitable Share, marginal government take in Alaska, including royalties, at $100-a-barrel oil, was 79 percent, compared to Texas at 53 percent and North Dakota at 57 percent.

ConocoPhillips has said the ACES Alaska tax rate was too high, Johansen said, and at that rate investment goes elsewhere. The passage of SB 21 last year, removing progressivity, was a "huge improvement," he said.

And while the SB 21 tax change has been called a giveaway, looked at competitively it's still 10-15 percent higher than Texas and North Dakota, both of which have growing production rates, while Alaska's production continues to decline, Johansen said.

He described the relationship between Alaska and the oil industry as symbiotic: for industry to be successful, the state needs to be successful; for the state to be successful, industry needs to be successful.

CONOCOPHILLIPS ALASKA

Pipe for pilings for the CD-5 Nigliq Channel bridge staged in Anchorage over the summer.

Stepping west

CD-5 will be the farthest west production on the North Slope, extending Colville River unit operations across the Nigliq Channel.

Both CD-5 and Mooses Tooth are in the National Petroleum Reserve-Alaska, but CD-5 sits on Native land, so Mooses Tooth will be the first production from federal lands in NPR-A.

CD-5 development was a must for development farther west at Mooses Tooth, Johansen said.

The importance of CD-5 for Mooses Tooth is that it takes infrastructure across the Nigliq Channel of the Colville River, he said, essential for development farther west.

Johansen earlier in his remarks said health, safety, environment and sustainability are the basis of investment decisions for oil companies.

A bridge across the Nigliq Channel was an essential element of CD-5 development for health, safety and environmental reasons. The drill site will produce for 30 years, Johansen said, and if something goes wrong, if there is an injury or a spill, ConocoPhillips needs to be able to respond quickly in an emergency. The bridge provides that emergency response ability.

Gravel roads farther west into NPR-A are necessary for the same reason, Johansen said, adding that ConocoPhillips is having those discussions now with federal agencies.

CD-5

Johansen reviewed the status of the CD-5 development.

Long lead materials have been procured and fabrication of bridges is on schedule.

Planned activity for the winter season includes ice road building November through January and bridge construction January through April, which is also the timeframe for gravel installation.

Module and pipeline fabrication is also planned for the winter season.

First oil from CD-5 will be in late 2015. Production will peak at 16,000 barrels of oil per day, gross, and the estimated cost is about $1 billion.

Johansen said passage of SB 21 increases the likelihood of more projects moving ahead. He noted a rig was added at the Kuparuk River field, which ConocoPhillips operates, in late May, and has already resulted in 1,600 bpd of new production.

An additional rig is coming to Kuparuk in January, with that rig drilling mainly new capital wells, he said.

Planning is under way for Kuparuk Drill Site 25, development of a late 1980s ARCO Alaska discovery, appraised by ConocoPhillips in 2012 with the Shark Tooth No. 1 well. Johansen said approval for that $600 million project, with peak production estimated at 8,000 bpd and first oil in 2015, will be sought in late 2014.

Approval will also be sought in late 2014 for the Greater Mooses Tooth No. 1 NPR-A development, estimated to cost $900 million and with production, expected to begin in late 2017, to peak at 30,000 bpd.

Mooses Tooth is one of two ConocoPhillips-operated units in NPR-A; Bear Tooth lies farther west.

—KRISTEN NELSON

Contact Kristen Nelson at knelson@petroleumnews.com

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TROUBLED TIMES

Paying no heeded to the prospect that Energy East and Line 9 could replace about 700,000 barrels per day of foreign crude from the Middle East and South Africa to fuel their refineries and attract new investment and new jobs to an ailing refining and petrochemical sector, Ontario and Quebec have opted to appease environmentalists by holdings hearings and conducting probes that are in the realm of Canada's National Energy Board, NEB.

Ontario, Quebec hearings

The Ontario government ordered its energy board will hold public hearings into TransCanada's proposed Energy East project, just hours before the Quebec government named a parliamentary commission to investigate Enbridge's planned Line 9 reversal to deliver domestic crude to refineries in the Montreal and Quebec City regions. They gave no indication of setting deadlines on the reviews.

The NEB is expected to make its final recommendations on Line 9 early next year, while TransCanada has said it should file its Energy East application with the NEB in 2014.

Both provinces conceded that the Canadian government, through the NEB, has jurisdiction over the approval of pipelines that cross provincial borders, but hinted that they are taking a "me-too" lead from British Columbia's success in extracting concessions from Alberta in return for supporting Enbridge's 525,000 bpd Northern Gateway pipeline from the Alberta oil sands to a Pacific Coast terminal for export to Asia and California.

More detail, conditions

Ontario Energy Minister Bob Chiarelli told reporters his province wants more detail on pipeline safety and greenhouse gas emissions related to the 1.1 million bpd Energy East pipeline, as well as ensuring First Nations get consulted and the province obtains jobs and economic benefits.

Quebec Environment Minister Yves-Francois Blanchet told reporters his government will develop a set of conditions it would expect the federal government to impose on a Line 9 approval.

He said that despite Ottawa's role it "can't disregard" the views of the Quebec legislative assembly, especially regarding measures to protect the environment.

Yet the two provinces, without explaining why, effectively passed up their opportunity in late October to make oral presentations before the NEB hearing on the Line 9 application to carry 300,000 bpd of Western Canadian crude to Ontario and Quebec refineries.

Benefit arguments ignored

They have also ignored observations by Al Monaco and Steve Williams, chief executive officers of Enbridge and TransCanada, respectively, that six refineries have closed in Quebec over recent years, and have made the case that the existing Suncor refinery in Montreal and the Valero plant near Quebec City, which account for 20 percent of Canada's refining capacity, could be more profitable if their proposals go ahead.

Williams told a Calgary business audience earlier in November that Energy East would improve the profitability of the 137,000 bpd Montreal refinery and secure a "long-term future" for the facility.

He said the Canadian Energy Research Institute has estimated Quebec stands to gain C$14 billion in investment and taxes from new oil sands development over 25 years, including the possible addition of a coker at the Suncor refinery.

Michel Leblanc, chief executive officer of the Montreal Board of Trade, said public support for the pipelines requires clear assurances of investment in Quebec's refining industries, which, he insisted requires assurances that Quebec will mostly be a transit route for Energy East to deliver crude to Saint John, New Brunswick, for export.

Lines in ground as far as Montreal

What mystifies supporters of Energy East and Line 9 is that both pipelines are already in the ground as far as Montreal.

Energy East involves the conversion by TransCanada of an underutilized natural gas line and Line 9 proposed the reversal of a line that ships imported crude from Montreal to a refinery hub in Sarnia, Ontario.

Taking a conciliatory stance, Alex Pourbaix, TransCanada's president of energy and oil pipelines, said his company "welcomed the chance to get the facts out about the benefits (of Energy East). The process (Chiarelli) outlined, gives us another opportunity to do that."

Alberta Energy Minister Ken Hughes warned against any thought of imposing additional pipelines tolls on the interprovincial shipment of goods if that would reduce the competitiveness of the oil sands and hurt manufacturers in Ontario and Quebec.

But Hughes told said the chance to examine the impact of the pipelines "can only help people understand the importance of energy in their lives."

Opposition to LNG

On the LNG front, a coalition of environmental groups has filed court action against British Columbia's Oil and Gas Commission and gas producer Encana over the use of water from lakes and rivers in fracking for shale gas.

A petition claims the province's energy regulator has been granting repeated short-term water permits in violation of a provincial water act, limiting approvals to two-year terms.

The coalition estimates that the commission has allowed up to 2 million liters a year of fresh water to be drawn from lakes, rivers and streams to be mixed with chemicals and sand for injection to the gas deposits.

Encana declined to comment and the commission said it takes its responsibility for water allocation "very seriously and all applications go through a thorough review process" to ensure water levels are maintained.

The agency has reported that 20.4 million cubic meters of water was approved for withdrawal for various purposes in 2012 and 7 million cubic meters went to fracking.

The British Columbia government has also been accused of sitting on a report commissioned by its climate-change secretariat that measures greenhouse gas emissions associated with developing LNG.

Clark said Nov. 12 she will not let the climate-change agenda set by her predecessor, Gordon Campbell, stand in the way of LNG development.

"In terms of greenhouse gas emissions, we can either decide that we want to get to 'yes' (on LNG approvals) or are we going to throw up barriers ... that will ensure we don't have a natural gas industry in British Columbia," she told reporters.

She argued British Columbia would "do the world a favor" by helping countries such as China switch from coal-fired power generation to cleaner LNG. ●

Contact Gary Park through publisher@petroleumnews.com

● GOVERNMENT

California releases draft fracking rules

ASSOCIATED PRESS

Oil companies would have to test groundwater and notify landowners before they do fracking or other well stimulation techniques under draft rules released by the State of California.

The proposed regulations, considered by state officials to be the most stringent in the country, were announced Nov. 15 in response to a law that Gov. Jerry Brown signed in September.

Companies would also be required to disclose the chemicals used and acquire permits before they start hydraulic fracturing, or fracking. The rules go into effect in 2015, but there will be emergency regulations that companies would have to comply with beginning in January.

Fracking involves pumping huge amounts of water, sand and chemicals into deep rock formations to release oil or natural gas. Other well stimulation techniques use acid to break apart oil-rich formations. While the state oversees oil wells, there have not been specific rules for fracking, which has been going on for decades in California.

Some environmentalists contend the proposed rules don't go far enough and want a fracking ban until regulators can study whether there are risks to public health.

"We want a timeout," said Kathryn Phillips, state director of the Sierra Club told the Los Angeles Times (http://lat.ms/I798O5) in Nov. 16's editions.

"At best, these regulations can be described as a mixed bag," she said. "At worst, they provide another example of an agency's continued deference to a regulated entity, even at the expense of public health and the environment."

Other environmentalists said some oversight is better than none.

Fracking supporters said the rules provide a framework to explore the Monterey Shale, a vast formation that extends from California's Central Valley farmlands to offshore and could ultimately comprise two-thirds of the nation's shale oil reserves.

"These regulations are extensive but strike the right balance," Catherine Reheis-Boyd, president of the Western States Petroleum Association, told the Times.

Under the draft rules, state environmental officials will team with air quality regulators and regional water boards to track potential problems after a job. Wells would also be monitored before and after fracking and some of the chemicals used to stimulate wells would be posted online.

State officials will hold a 60-day public comment period with hearings scheduled in several cities around the same time. ●

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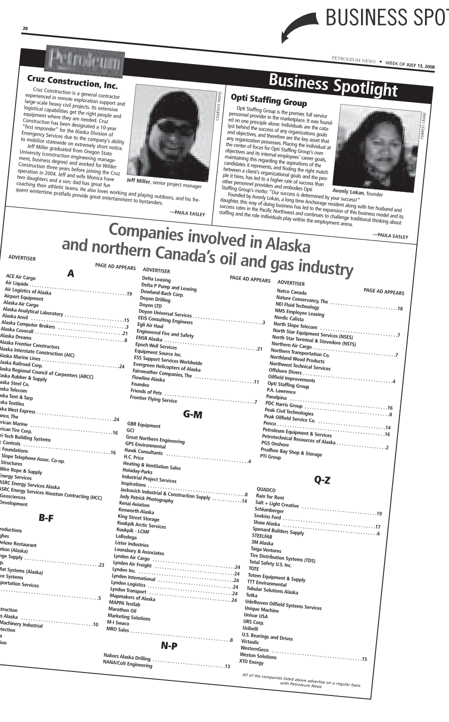

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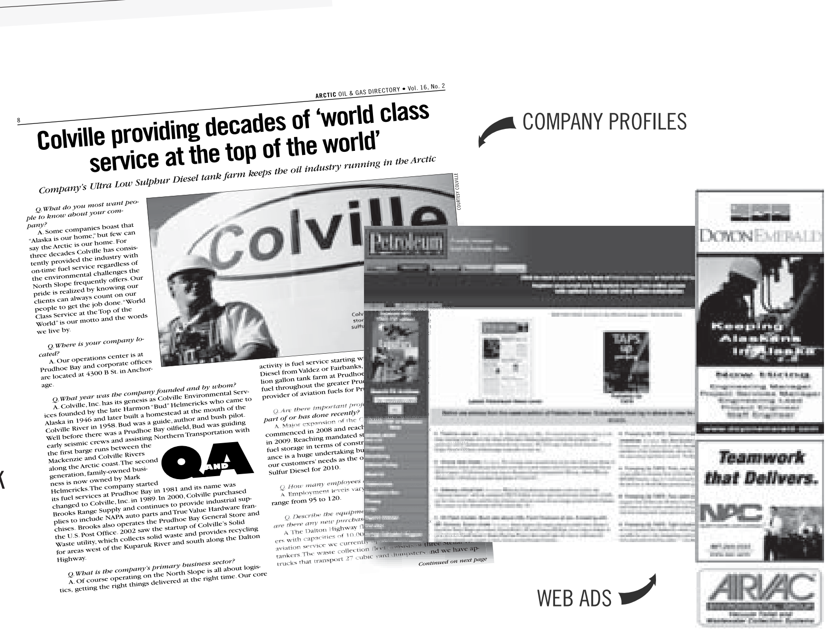

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Petroleum news

Oil Patch Bits

Crowley awarded more CSA awards than any other firm

During the 10th-annual Chamber of Shipping of America awards ceremony held in Washington, D.C., Crowley Maritime Corp. was awarded 100 Certificates of Environmental Achievement for 2013 — more than any other company in the running. The certificates were awarded to Crowley-owned and operated vessels for having worked at least two consecutive years without an environmental incident. Additionally, Crowley was also presented with a membership award in recognition of five years of support to the CSA.

COURTESY CROWLEY

Back row, left to right: Jeff Hoffman; Mike Golonka; Admiral Joseph A. Servidio, USCG; Ralph F. Elroy; and Fred Siefert. Front row, left to right: Nicole Mull, Vince Mull, and Ruth Siefert.

The Environmental Achievement awards are open to all owners and operators of vessels that work on oceans or inland waterways. This year, nearly 1,431 vessels from 76 companies, including Crowley, were recognized. In total, the honored vessels accumulated 10,282 years of safe operations, with a vessel average of 6.9 years. Two hundred and eighty of the vessels have logged more than 10 years each of environmental excellence.

Combined, Crowley's vessels achieved a total of 1,066 years of service without incident. Fifty-three of Crowley's vessels have gone without incident for 10 or more consecutive years, including the following: Saturn, 44 years; Kuparuk River, 43 years; Kavik River, 38 years; Pt. Oliktok and Stalwart, each with 31 years.

Accepting the awards on behalf of Crowley were Mike Golonka, vice president, ship management; Jeff Hoffman, chief engineer, National Glory; Vince Mull, chief engineer, Achievement/650-8; Ralph Elroy, captain, Cape Decision; and Jeff Siefert, chief engineer, Charleston Express. Crowley has been honored with Environmental Achievement Awards each year since at least 2005.

ASRC Energy Services promotes Omnik

SUEGE OMNIK

ASRC Energy Services recently promoted Suege Omnik, PE, to process engineering supervisor for the company's engineering and professional services division. Omnik will manage the process engineering department as well as providing her technical expertise in the construction of new well testing units that are employed by the AES well testing group.

see **OIL PATCH BITS** *page 20*

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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VIABLE GAS LINE

1977.

The facts behind the lack of a gas line are well known: Such a project would be hugely expensive and risky. And gas simply isn't the valuable commodity that crude oil is.

The current project on the drawing board would see construction of a pipeline to carry gas south to tidewater, perhaps in Cook Inlet, where it would be superchilled into a liquid form for transport in special tankers to Asia.

The project would involve BP, ConocoPhillips and ExxonMobil, which are the North Slope's major oil producers, along with perhaps the pipeline company TransCanada.

Such an LNG export project has been considered in the past, only to be written off as uneconomic.

The oil companies are considering the idea again, apparently at the prodding of Alaska Gov. Sean Parnell.

Nothing much new

The Black & Veatch study would appear to offer little in the way of truly new information, when compared to the many past studies and analyses on the idea of an Alaska gas pipeline.

It begins by rehashing many obvious and well-known facts.

The project would be enormously expensive, probably around $45 billion. It would consist of three major components, each of which would be a megaproject in its own right: a plant on the North Slope to treat the raw gas out of the ground ($10 billion), the pipeline itself ($12 billion), and the liquefaction plant on the south end ($23 billion).

Other governments and companies around the world also are pursuing LNG projects to try to capture a piece of the growing gas market, and Alaska's project will have to compete with these.

Alaska can help with incentives such as royalty relief or tax breaks, but estimated future market prices for gas dwarf all other variable in the project's economics, Black & Veatch says.

Finally, the firm says partial state ownership "can offer benefits to all parties involved in the project."

The notion of state ownership also is not a new concept. It was considered strongly during the administration of former Gov. Frank Murkowski. It was dropped during the abbreviated term of his successor, Sarah Palin. Now, it appears it could come alive again under Parnell.

'Big decisions'

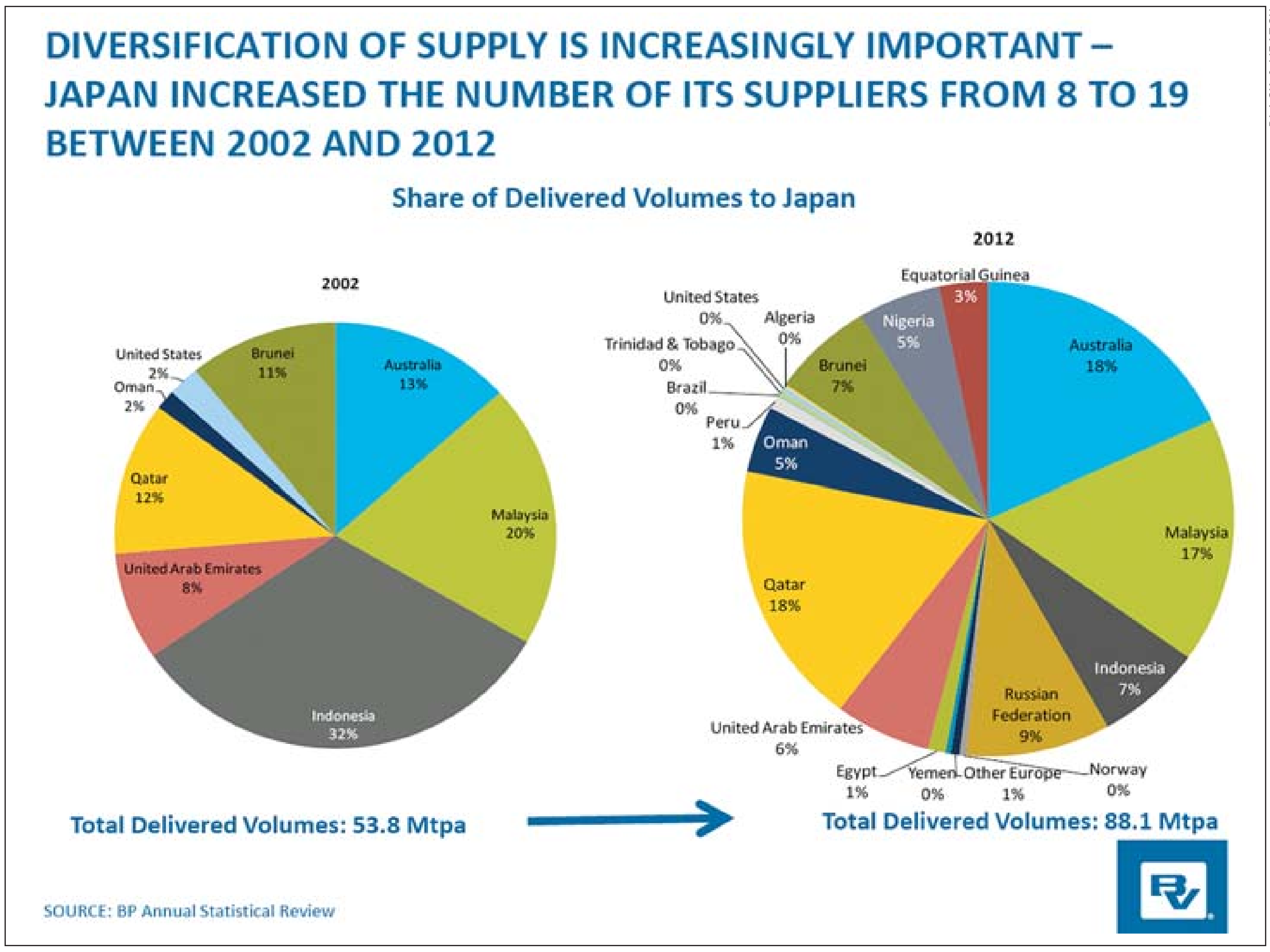
The Black & Veatch report looks at other LNG projects around the world, including some that involve a measure of government ownership. The study examines the various ways governments take their share of the value from gas developments, and finds that under current state and federal law, government take in Alaska would be relatively high at 70 to 85 percent.

The major readership for the Black & Veatch study is likely to include state legislators, who might be called upon to adjust the state's fiscal terms should an actual project materialize.

Elizabeth Bluemink, a spokeswoman for the Alaska Department of Natural Resources, told Petroleum News the study cost $424,064.

"The goal of the study is to inform near-term decisions about the fiscal aspects of an LNG project in Alaska — big decisions that involve our royalties,

see **VIABLE GAS LINE** *page 18*



BLACK & VEATCH

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VIABLE GAS LINE

taxes, or even a potential equity stake in the project," said Joe Balash, Alaska's natural resources commissioner. "This information will help us deliver on our constitutional obligations to maximize the benefits of developing Alaska's North Slope natural gas resources."

The study focuses in particular on that share of the North Slope gas that, upon production from state acreage, would belong to the state as a royalty. Generally, the royalty is 12.5 percent, and could be marketed either by the state itself or by the oil companies. Over the years, the state has taken both approaches with its royalty crude oil.

The royalty gas could be a valuable tool to encourage, after decades of waiting, construction of the gas pipeline, which the state covets as an economic development blockbuster.

But the state also doesn't want to squander the royalty, which could happen if the project isn't structured correctly.

One way to avoid this is to better "align" the state's interests with those of the oil companies, the Black & Veatch study says.

"We have some work to do, but the good news in this report is that we don't have to sacrifice our royalty revenue in the future to get a project going," Balash said.

An ownership stake?

The report examines some alternatives for the state to take an equity interest in the LNG project.

It looks at LNG projects in Norway, Yemen, Angola and Russia, and notes that state participation usually is through NOCs, or national oil companies.

Alaska could obtain an equity interest in the LNG project in exchange for royalty and tax breaks, Black & Veatch says. In some cases, governments have chosen to reduce or even zero out their royalties to improve the economics of an LNG project.

State ownership would provide some of that important alignment of interests, the study says. State ownership also could lower the upfront capital cost to the producer companies.

The question, however, is what sort of state ownership would be ideal?

The state conceivably could take a piece of the project, such as 100 percent ownership of the pipeline component, Black & Veatch says. The producers would pay a tariff to the state for transportation on the line.

Alternatively, the state could take a percentage share of the overall project.

The study finds that a 15 percent stake would not provide positive economics for the state, but 35 percent would under most scenarios.

An equity investment, however, would create serious risk exposure for the state, Black & Veatch says.

If the project saw cost overruns, the state would be responsible for its pro rata share of the increases. As an equity owner, the state would assume risk associated with force majeure, where an unexpected and disruptive event prevents the pipeline from operating and fulfilling contracts.

Also, the state would have "no control over upstream operations and volumes produced" by the oil companies, the study says.

The Black & Veatch report is available online at http://1.usa.gov/17Qd8JR. ●

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The study finds that a 15 percent stake would not provide positive economics for the state, but 35 percent would under most scenarios.

How should Alaska market royalty gas?

Consulting firm Black & Veatch, in a new study done for the state of Alaska, examines an important question regarding how the state should handle its royalty natural gas.

The royalty is the state's share of gas that companies produce from leased state land.

Should the state ever see construction of a megaproject to develop its vast North Slope gas reserves, a major decision for the state will be how to sell its gas.

The state would have two choices: It could take the gas physically, or in kind, and market the molecules itself. Or it could take the gas in value — that is, allow the major producer companies including BP, ConocoPhillips and ExxonMobil to sell the state's gas along with their own volumes.

The Black & Veatch study suggests that taking the gas in value would be smarter than taking it in kind.

And why is that?

For one thing, to sell gas on its own, the state would need to set up a marketing organization at great cost, Black & Veatch says.

Such an organization would require 30 to 40 employees at salaries of $150,000 to $200,000 per year, the study says.

The state would lack experience in gas trading, and would face challenges in competing with the North Slope producers who have well-established liquefied natural gas, or LNG, marketing expertise and global portfolios, the Black & Veatch study says.

The state would need to make firm capacity commitments along the LNG supply chain, which could total up to $1 billion a year, the study says.

Conceivably, the state could realize "negative royalties" if the LNG price drops too low.

Bottom line, taking the royalty gas in kind could lead the state to lose up to 60 percent of its royalty value relative to the royalty-in-value approach, the Black & Veatch study says.

In any event, deciding how to monetize its royalty gas is a problem Alaska would love to have. The North Slope reserves have been stranded for decades as the state's politicians have tried without success to compel the oil companies to lay a costly pipeline to develop the gas.

—WESLEY LOY

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LNG ROLE

in "coming months."

While acknowledging the producers have always wanted to control some equity portion of a related pipeline, Girling told a webcast from Toronto that TransCanada would "hope to land a position" similar to what it has in place for delivering natural gas to two liquefaction terminals on the British Columbia coast.

He said that would involve "being a large component of the gas delivery system and potentially part of the upstream as well."

Girling said the Alaska producers have "always said that at some point in time, never telling us exactly what that point is" the 7-8 billion cubic feet per day of Alaska gas that is currently being reinjected should be moved to market.

Changes in the Lower 48 gas market show that is no longer a "logical market over the next couple of decades, but there is an opportunity to move it to LNG markets."

He said the discussions with the producers, the state and TransCanada have reached the conclusion that LNG exports "make some sense and that Kenai is the most logical place" for a terminal.

Girling said the progress also covers the fiscal terms under which the gas would be produced.

—GARY PARK

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HAWKER Q&A

Hawker: I am not privy to any information that is not already public. All I can do is observe and watch the public record as we've all seen it. I just think they are moving everything in the right direction forward. We've seen them actively engaged with the producers on the project that was started under AGIA that was certainly fraught with peril and challenge. I have all the confidence in the world that the AGDC effort, which will always make certain that Alaskans get first access to Alaskans' gas, is finding a very compatible place along with the producers as they look towards a larger monetization for its economic advantage.

Petroleum News: What problems do you see right now with AGIA, whether it's something that is continuing or something that has emerged?

Hawker: It's the same problems today that existed the day it was passed. I certainly did not vote to grant TransCanada the exclusive license. It's the same inventory of issues that arise when government thinks it can pick a winner in a marketplace where they have no idea where that marketplace is going to be or what that market is going to look like. The AGIA premise was based on the pipeline going to the Lower 48. That has proven to be noneconomic. The AGIA pipeline has a series of must-haves incorporated into it that cumulatively remain a challenge to industry's ability to work under that environment. AGIA has proven to be a failure in accomplishing its desired outcome. We've got producers; we've got an administration; and we've got AGDC that see we need now to revisit that whole issue. We will start to see forthcoming changes proposed to AGIA that remove the government-imposed constraints that stand in the way of gas pipeline development in this state. We stand on the greatest opportunity that we have in my 12 years in the Legislature.

Petroleum News: Do you see that happening in the next legislative session?

Hawker: I would like to see the issues brought forward in the next legislative session that are necessary to take the next major advancement in developing a gas pipeline. I think those are dealing with the economics, our state's approach to taxation of gas and the need to revisit the artificial constraints imposed by AGIA. I very much would like to see those addressed by next session. It's my firm belief that the response to those issues be initiated by the administration based on all of the information they know that the Legislature is not privy to.

Petroleum News: Would you introduce any legislation toward that?

Hawker: I am very happy to sponsor any legislation that the administration would like to talk to us about that would aid in the development of Alaska's North Slope natural gas, specifically legislation that would allow us to get that gas into the hands of Alaskans.

Petroleum News: Should TransCanada be removed from this process as former Gov. Frank Murkowski has said publicly, either in appearances or in published op-eds?

Hawker: That is part of the business decision the administration, the producers and AGDC will have to make. This is where we need to get politics out of the process and let business decisions be made by partners making the decisions.

Petroleum News: Did you attend the LNG symposium several months ago that LB&A sponsored? If so what were your takeaways?

Hawker: I was out of town and didn't spend as much time there as I would have liked. I can make the anecdotal comment on how the program materials were very comprehensive. They were very well presented and by very competent presenters, of course. It gave the Legislature a very strong grounding and understanding of how LNG markets work, which is much different than the gas markets of a single pipeline delivering gas to a hub like somewhere such as Alberta. A true understanding of the value chain from wellhead to consumer that is necessary for an LNG gas pipeline project, was very important and defined very well for the Legislature.

It was something two years ago, when I was head of LB&A, we discussed the need for the seminar. I was happy to see Anna (Fairclough, Eagle River senator), the current chair, follow through with that and bring forward the seminar on the difference between the big pipeline to a hub and a market specific LNG value chain. It was needed. The Legislature, for 10 years, has been focusing only on the fundamentals of a large pipe to a massive hub. LNG being so substantially different in the value chain, this necessitated a vector in our learning process.

Petroleum News: On to oil taxes. SB21 has two lingering issues since the session ended in April. The first is the upcoming referendum next August that seeks to repeal SB21. The second is the issue of providing a clear and concise definition of new oil for tax credit. Let's start with the referendum. What are your thoughts on it?

Hawker: The referendum is unfortunately a sad distraction. SB21 was a good and well thought out piece of legislation. Unfortunately a referendum by its very nature becomes a popularity contest that is not based on the merits but is based on bumper sticker rhetoric. I am certainly hoping the public of Alaska sees through the bumper sticker rhetoric and sees the importance of restoring our international competitiveness in our oil and gas taxation.

Petroleum News: How do you work through the popularity contest or anything that you might deem populous rhetoric?

Hawker: I have, over 12 years in legislative office, come to respect the wisdom of the Alaska voter. I truly believe with the presentation of adequate facts and telling the whole story of the tax bill and the consequences on restoring Alaska's international competitiveness, the additional investment already occurring, and its importance in the development of a North Slope natural gas pipeline, the public will stand behind the SB21 legislation.

Petroleum News: Do you think it could have a chilling effect on investment between now and next August as some have said?

Hawker: I continue to see, as I speak to the industry, oil field support services industry and the regulatory agencies themselves, a continued uptick in investment by our producers. They are committed to making these investments today and moving forward. However, the continuance is all very dependent on us maintaining an economic environment. I personally believe there is absolutely zero chance of a North Slope gas pipeline moving forward if we lose the tax provisions in SB21 and the further refinements to address gas taxation that are necessary to develop that project. We all knew we would have to address gas taxation separately and it was addressed in SB21. Without SB21 and a further evolution of that tax system to encompass a project supporting a gas tax regime, there is no project.

Petroleum News: On to defining new oil. It wasn't just SB21 critics who have concerns. Some concern came from the industry as well during the public hearings. What do you see happening?

Hawker: I think that line is a bit blurry. It could be an area where SB21 could be improved. Of course, it could be handled next session. But it's cleaning up and defining a blurry line. It's not rewriting the tax structure itself.

Petroleum News: One of the other items the Legislature has focused on during the interim is the Arctic. I know that you're not on that committee, but you've been in office as long as just about anyone on the Arctic policy commission. Do you have any thoughts?

Hawker: I think Bob Herron and Lesil McGuire are doing incredibly good work with the Arctic Policy Commission bringing issues to national prominence and national attention as well as communicating those efforts and their concerns within the state of Alaska within the global Arctic community. The Alaska Legislature really has recognized this need to be a player, to be a participant. We have actually stepped up and we have established ourselves as having a very strong voice on these issues.

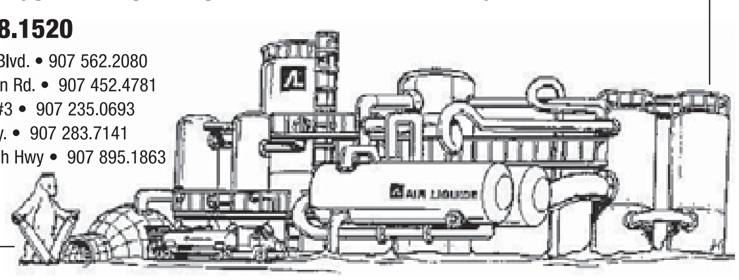
Petroleum News: Given DNR's recent report and how the oil tax issue has been resolved for now, do you see yourself moving any resource development legislation in the upcoming second year of the legislative session, or has the heavy-hitting stuff already been cleared this year?

Hawker: I am always open to moving legislation that is appropriate that advances Alaska's economic interest. At the moment I don't have anything nearly as profound as the Cook Inlet Recovery Act or HB4 in my, well just call it my kit as the British would say. But we are certainly open for anything that's identified as appropriate for my office to move forward. I think this coming session, we will have initiatives by the administration which will build on what we've done in the past years, hopefully moving forward specifically toward getting that Alaska North Slope natural gas pipeline truly out of the discussion stage and through the next development gate into a pre-feed condition. ●

Contact Steve Quinn at squinnwrite@gmail.com

COOK INLET NATURAL GAS STORAGE ALASKA

Wellheads in the Cook Inlet Natural Gas Storage Alaska facility on the Kenai Peninsula. The facilities reservoir was filled with gas for use in the winter and has already starting bolstering utility gas deliveries.



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CINGSA READY

November, Homer Electric Public Relations Coordinator Joe Gallagher told Petroleum News in a Nov. 18 email.

High pressure

The process of storing summer gas in CINGSA for winter use may actually have been a little too successful. On Nov. 13 Colleen Starring, president of CINGSA, sent a letter to the Regulatory Commission of Alaska informing the commissioners that during a pre-winter shut in of the facility between Oct. 28 and Nov. 4 CINGSA had determined that the facility's reservoir pressure exceeded its permitted level. Apparently CINGSA had notified the Alaska Oil and Gas Conservation Commission of the discrepancy. AOGCC has told CINGSA to use one of its wells for pressure monitoring and not to inject any further gas into the reservoir until the pressure has dropped to a level at or below 1,700 pounds per square inch, Starring's letter says.

By contrast, at this time last year CINGSA had not fully met its storage goals for base gas, the gas used to maintain reservoir pressure, with the company saying that it had lost out to some of the demand for gas exported as liquefied natural gas to Japan from the Kenai Peninsula. Ultimately, relatively mild weather at times during the winter resulted in some periods when further gas could be injected into the CINGSA reservoir: The utilities successfully negotiated the winter without any gas shortages.

Plenty of gas

This year with the liquefied natural gas facility mothballed, there has been plenty of gas available from Cook Inlet gas fields during the summer, when utility gas demand is quite low.

Moira Smith, vice president and general counsel of Enstar Natural Gas Co., told Petroleum News on Nov. 15, that Enstar had easily been able to obtain all of the summer gas that it had planned to store.

"We did not have a difficult time at all getting the gas," Smith said. "All of our firm gas suppliers performed as expected and we were within five percentage points of our storage plan all of the injection season."

Although the utilities enjoyed a plentiful supply of gas during the summer, their contracted winter supplies from declining Cook Inlet gas fields are no longer sufficient to deliver gas rapidly enough to meet high needs during cold winter weather, when buildings need high levels of heating and power demand also increases. The utilities still have enough gas under contract to meet total annual demand and, were that demand to be constant year round, would be able to use gas directly from the gas fields. But, given the huge spike in demand during the winter, the utilities must store summer gas in CINGSA for winter use.

Withdrawals started

Smith said that Enstar had already started withdrawing gas from CINGSA in response to cold weather in early November.

"We've been withdrawing pretty significant amounts over the past couple of days," Smith said. She said that a few days earlier, with Enstar's customers burning gas at a rate of 140 million cubic feet per day, the utility had been pulling about 30 million cubic feet per day from storage. But this gas withdrawal was consistent with Enstar's plan for CINGSA usage and the utility anticipates having enough gas to see it through the winter, she said.

At the end of the summer and fall injection period Enstar had stored 6.4 billion cubic feet of gas in CINGSA, a volume representing about one fifth of Enstar's total demand for the year, Smith said.

"So we're very comfortable with having that balance in there," she said.

Winter injections

It is possible that, as last year, Enstar will add to its stored gas through further gas injections during periods of warm winter weather. But, given that excess stored gas remaining at the end of the winter represents a cost to Enstar's customers, judging exactly how much gas to keep in storage is a tricky question, John Sims, Enstar's director of business development, explained.

"So there's an interesting accounting balance that goes on as well. That can be challenging at times," Sims said.

Started spring 2012

CINGSA first went into operation in the spring of 2012, following an approximately one-year, fast-track construction project which ensured the facility's ability to store gas during the summer of 2012 for use in the following winter. The winter of 2012-13 was the first winter in which the utilities faced a shortfall in gas deliverability. The storage facility, located to the immediate south of the city of Kenai, uses a depleted sand reservoir in the Cannery Loop gas field. ●

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OIL PATCH BITS

Omnik graduated from Massachusetts Institute of Technology in 2006 with a B.S. in Chemical Engineering. From 2004 to 2006, Omnik interned at AES and began working full time for the company as a process engineer after graduating from college. She is a member of both the American Institute of Chemical Engineers and the Society of Women Engineers.

Editor's note: All of these news items — some in expanded form — will appear in the next Arctic Oil & Gas Directory, a full color magazine that serves as a marketing tool for Petroleum News' contracted advertisers. The next edition will be released in March.