Petroleum news

page 2 US crude to average 10.7 million bpd this year, 11.3 million in 2019

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AOGCC working bonding, wants ability to go after prior owners

CATHY FOERSTER

HOLLIS FRENCH

It's kind of like musical chairs, with the state left standing if a company goes bankrupt leaving oil or gas wells that need to be plugged and abandoned, something which companies normally do in the course of managing a field.

The Alaska Oil and Gas Conservation Commission has been fighting the federal government over the issue for years — because the commission has authority over wells drilled decades ago in what is now the National Petroleum Reserve-

see **AOGCC BONDING** page 8

AIDEA OKs budget for Mustang Road, credit line for ongoing costs

During its March 1 meeting the board of the Alaska Industrial Development and Export Authority approved a resolution, setting a budget for Mustang Road LLC, the operator of the gravel road and pad for the Mustang oil field that is being developed on the North Slope. The board also approved a line of credit of up to $300,000 from an AIDEA revolving fund, to cover continuing costs being incurred by Mustang Road. This latest board decision follows a decision on June 19 last year, authorizing AIDEA to acquire a 100 percent ownership interest in Mustang Road, and the subsequent acquisition of the company in December.

A joint venture operated by Brooks Range Petroleum Corp. is developing the Mustang field in the Southern Miluveach unit, immediately west of the Kuparuk River field. There have been

see **MUSTANG ROAD** page 11

Alberta rolls bitumen dice

Faced with losing an estimated C$9 billion in royalties over the next five years unless the pipeline bottlenecks are solved, the Alberta government is ready to take a gamble.

Premier Rachel Notley said her government would provide C$800 million in loan guarantees and C$200 million in direct grants to private-sector firms who are willing to embark on partial upgrading of raw oil sands bitumen, reducing the thickness of the molasses-like substance to improve its flow through pipelines.

"Make no mistake, there is a role for us in incenting and fostering energy innovation and diversification," she said. "We don't need to sit on the sideline and watch places like (the U.S. Gulf Coast refineries) eat our lunch."

Currently, 10 companies are working in upgrading tech-

see **BITUMEN DICE** page 11

RCA extends approval deadline for Hilcorp Cook Inlet pipeline work

The Regulatory Commission of Alaska has extended the deadline for decisions on applications by Hilcorp Alaska subsidiaries relating to the company's project to enable oil to be shipped west to east by pipeline under Cook Inlet. The deadline has been extended from March 8 to July 20. The commission says that it needs more time to consider and rule on issues raised by the applications. It is not clear what impact the delay may have on the project timeline.

Hilcorp subsidiaries filed three applications with the commission in September. One was a request to grant Kenai Beluga Pipeline LLC a certificate for the carriage of oil west to east through one of the existing twin Cook Inlet Gas Gathering System pipelines under the inlet. A second was a

see **DEADLINE EXTENDED** page 11

PIPELINES & DOWNSTREAM

Future possibility

Hilcorp plans Tyonek oil pipeline in parallel with new subsea gas line

By ALAN BAILEY

Petroleum News

Harvest Alaska, the pipeline subsidiary of Hilcorp Alaska, plans to lay a subsea oil pipeline under Cook Inlet from the Tyonek gas production platform to Ladd Landing on the west side of the inlet, with an eye to the possibility of future oil development from the platform. The company plans to lay the oil line in conjunction with the laying of a subsea gas pipeline, planned as part of Hilcorp's Cross Inlet Pipeline project, a project to enable the shipment of oil west to east by pipeline under the inlet.

"We do believe there is opportunity for future development of oil from the Tyonek platform," Hilcorp spokeswoman Lori Nelson told Petroleum News in a March 2 email. "There are no near-term drilling plans, but the installation is being done in concert with the Cross Inlet Pipeline project to cre-

ARCO discovered an oil pool, originally call the Sunfish accumulation, under the North Cook gas field when drilling the Sunfish and North Foreland exploration wells from jack-up rigs in the early 1990s.

see **SUBSEA LINE** page 12

PIPELINES & DOWNSTREAM

Gold rush to black gold

Hyder eyed as port to take Alberta bitumen to Asia; discussions have only started

By GARY PARK

For Petroleum News

Alaska may now hold the key to moving bitumen from the Alberta oil sands to Asia through a C$17 billion project being promoted by First Nations leaders.

Eagle Spirit Energy believes it can sidestep a campaign to ban oil tanker traffic from leaving the British Columbia coast by delivering 1 million barrels per day by pipeline to a tanker port at Hyder, an old Alaska gold-rush town, rather than the original plans to build a terminal at Grassy Point about 15 miles south of Hyder in British Columbia.

"It's a complete answer to any tanker ban," said Calvin Helin, Eagle Spirit president and chairperson, who said more than 30 First Nations in Alberta and British Columbia are lined up to become equity partners in the scheme which has financial backing from Vancouver's Aquilini Group.

Major Canadian oil sands producers including Suncor Energy, Cenovus Energy and MEG Energy want the venture to proceed, while investment broker AltaCorp Capital is poised to organize financing.

He said construction of a terminal would cost about C$1 billion, while an additional C$500 million would be spent on spill prevention measures, including tugboats, barges and training.

see **HYDER PORT** page 12

NATURAL GAS

Working with FERC

Officials say AGDC is working to understand agency's new info request

By KRISTEN NELSON

Petroleum News

Alaska Gasline Development Corp. officials told the Senate Resources Committee Feb. 28 that they will be responding to the Federal Energy Regulatory Commission's request for additional information and will also be meeting with FERC staff to make sure they understand the extent of some of what the agency is requesting.

Frank Richards, AGDC senior vice president project management, and Lieza Wilcox, vice president commercial and economics, responded to questions from senators on the FERC request and on progress on the Alaska LNG project.

AGDC responded to FERC's Feb. 15 request for additional environmental data March 7, a tabulated response which Richards said in a cover letter included either a response or the date upon which AGDC anticipates filing the information.

Richards told the committee that after AGDC filed its application for the Alaska LNG project with FERC in April 2017, the agency responded over the summer with 801 questions, questions which AGDC answered over the fall and finalized in January.

Those are key questions the state has to resolve, Wilcox said: how to attract investors into the project early on and will there be the ability to invest as the project moves forward.

see **AGDC RESPONSE** page 9

● FINANCE & ECONOMY

US crude to average 10.7 million bpd

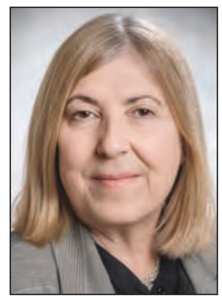
This year's production average would be highest on record, topping 9.6 million bpd in 1970; EIA forecasts 11.3 million bpd in 2019

By KRISTEN NELSON
Petroleum News

U.S. crude oil production is, as projected, at record levels and forecast to go even higher, the U.S. Energy Administration said March 6 in its Short-Term Energy Outlook.

"EIA estimates that U.S. crude oil production averaged 10.3 million barrels per day in February, up by 230,000 from the January level, which included some well freeze-offs in the Permian and Bakken," Dr. Linda Capuano, EIA administrator, said in a statement accompanying the outlook. She said EIA is reporting that for 2017, total U.S. crude oil production averaged 9.3 million barrels per day, "ending the year with production at 9.9 million in December."

"EIA projects that U.S. crude oil production will average 10.7 million barrels per day in 2018, which would mark the highest annual average U.S. crude oil production level, surpassing the previous record of 9.6 million barrels per day set in 1970. EIA forecasts that 2019 crude oil production will average 11.3 million barrels per day," Capuano said.



LINDA CAPUANO

For 2018, "the forecast expects production to continue hitting new monthly highs — barring any significant energy disruptions. By the end of 2018, the short-term outlook is forecasting a new record average of 10.7 million barrels per day in U.S. crude oil production, and we continue to expect production to average above 11 million barrels per day in 2019," Capuano said.

Brent down from January

EIA said North Sea Brent crude oil spot prices averaged $65 per barrel in February, down $4 per barrel from January, the first month-over-month drop since last June.

"EIA's forecast expects prices to decline gradually, averaging $60 per barrel in the second half of the year," Capuano said, with the annual average Brent price expected to remain near $62 per barrel this year and next, "which is lower than prices in recent weeks but is higher than the average in 2017 by less than $8 per barrel."

Brent averaged $54 per barrel in 2017, the agency said.

EIA expects West Texas Intermediate crude oil prices to average $4 per barrel lower than Brent this year and next.

Natural gas production increasing

EIA said U.S. dry natural gas production is estimated to have averaged 73.6 billion cubic feet per day last year and is forecasting that level will rise to an average of 81.7

see **EIA OUTLOOK** page 3

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● NATURAL GAS

Fairbanks LNG storage project moves ahead

Next major step in the Interior Energy Project is underway; LNG supply expansion on hold until purchase of Pentex by IGU completes

By **ALAN BAILEY**

Petroleum News

The construction of a new 5.25 million gallon liquefied natural gas storage facility in Fairbanks began in December and is moving ahead, with an anticipated completion date in the fall of 2019, Dan Britton, president and CEO of Pentex Natural Gas Co, told the board of the Alaska Industrial Development and Export Authority on March 1.

Excavation of the storage tank site has been completed, and much of the subsurface structure, including an insulation layer that will lie under the concrete tank foundation, has been installed, Britton said.

The storage tank construction comes as part of the Interior Energy Project, a project to bring increased supplies of natural gas to Fairbanks and its surrounds. The idea is to make energy in Fairbanks more affordable, while also encouraging the use of natural gas as a means of helping to improve air quality in the city during the winter.

Utility consolidation

Currently LNG for delivery to Fairbanks is manufactured at Pentex's Titan plant near Point MacKenzie on Cook Inlet and shipped by road trailer to Fairbanks. Fairbanks Natural Gas, a Pentex subsidiary, stores and gasifies the LNG for the distribution of gas to customers in central Fairbanks. Interior Gas Utility, a utility owned by the Fairbanks North Star Borough, does not currently have a gas supply. IGU has agreed to purchase Pentex, with the sale scheduled to complete by the end of May. Following completion of the sale, IGU will operate as a single, integrated utility for the whole of the Fairbanks region. Completion of the sale is, in part, contingent on Regulatory Commission of Alaska approval of the utility merger.

The idea is that IGU will expand the LNG supply for Fairbanks. The IEP has negotiated a flexible gas supply agreement with Hilcorp Alaska that will enable a ramp up of the supplies, as necessary. Pentex has acquired some new, large LNG trailers in support of the ramp up.

Gene Therriault, AIEDA's IEP team leader, told the AIDEA board that moving ahead with the expansion of the LNG supply is currently on hold, pending completion of the Pentex purchase by IGU. The expectation is that the combined utility will issue a request for proposal for an increased LNG supply through the expansion of the Titan plant or from some other source, Therriault said.

Distribution system build out

In 2015, as part of an earlier phase of the IEP, both FNG and IGU started to build out their gas distribution pipeline networks in Fairbanks, in anticipation of an expanded gas supply for the city. And, regardless of any LNG plant expansion, the implementation of the new LNG storage facility, now under construction, would provide the capacity to connect new consumers through the expanded distribution system. The greatly expanded LNG storage capacity would enable IGU to warehouse gas produced in the summer for use in the winter. In addition, the new facility would provide more of a backstop of reserve gas to assure continuity of supplies for more consumers.

A critical factor in the economics of the IEP is the number of Fairbanks businesses and residents that end up using natural gas to heat their buildings — the higher the number of consumers, the lower the unit cost of the gas.

There is also a strong incentive to move ahead with construction of the new storage facility — if the facility is operational and in use by Jan. 1, 2020, it will qualify for a state tax credit.

LNG storage tank

Britton told the AIDEA board that Pentex had awarded the contract for the construction of the storage facility to Preload Cryogenics from the Boston area. Preload has subcontracted various components of the work, with much of the work being conducted by Alaska-based contractors. Although the original concept for the tank had involved a single tank wall, the tank being constructed is of a double-walled design, a design that provides a higher level of security, should the tank develop a leak. Britton told the board that Preload Cryogenics had quoted the double-wall design at a comparable price to a single-wall model.

see **FAIRBANKS LNG** *page 4*

continued from page 2

EIA OUTLOOK

bcf per day this year — a new record. That would be 8.1 bcf per day higher than 2017 level, EIA said, "and the highest annual average growth on record."

The agency also expects natural gas production to increase in 2019, with forecast growth of 1 bcf per day.

The Henry Hub spot oil price averaged $2.66 per million British thermal units in February, down $1.03 from January. EIA said it expects natural gas prices to moderate in the coming months based on a forecast of record natural gas production levels.

Henry Hub spot prices are expected to average $2.72 per million Btu in March and $2.99 for all of 2018, rising to an average of $3.07 in 2019.

Market issues

EIA said that although crude oil prices declined in February after seven consecutive months of increases, "most fundamental crude oil supply and demand indicators suggest global petroleum inventories are declining."

Commercial petroleum inventories in Organization for Economic Cooperation and Development countries declined to 2.83 billion barrels in February, down 211 million barrels from February 2017 and the largest annual decrease in inventories since 2003, the agency said. Inventories are 40 million barrels higher than the five-year average for February, "the narrowest difference to five-year average levels since November 2014, suggesting an increasingly balanced market."

EIA said North Sea Brent crude oil spot prices averaged $65 per barrel in February, down $4 per barrel from January, the first month-over-month drop since last June.

The Brent-WTI spread was the lowest in more than six months, closing at $3.03 per barrel March 1. "Several factors specific to the crude oil market in the U.S. midcontinent could be contributing to a narrowing spread," EIA said, including a continued decrease in crude oil stocks in Cushing, Oklahoma, with reports that the Keystone, which flows into Cushing, continued to operate below nameplate capacity. EIA also cited an all-time high for crude refinery inputs in Petroleum Administration for Defense District 2 and higher export demand, with weekly exports more than 2 million bpd for the week ending Feb. 16, the second highest since it began publishing weekly export data in 2016.

EIA said the Louisiana Offshore Oil Port, the largest crude oil import facility in the U.S., recently began to test loading crude oil for export and further infrastructure developments along the U.S. Gulf Coast could allow more crude exports. ●

Contact Kristen Nelson at knelson@petroleumnews.com

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FAIRBANKS LNG

"That's a really big improvement for our security and safety," Britton said.

Construction of a 100-foot diameter LNG storage facility in Interior Alaska involves some particular challenges. The inner tank will be fabricated from 9 percent nickel plate, to prevent the steel becoming brittle when in contact with the LNG. The outer tank will be constructed from concrete. And a combination of insulation and flat-loop evaporators will maintain the ground under the foundation at an appropriate temperature, thus ensuring the stability of the foundation.

Need to increase gas demand

A critical factor in the economics of the IEP is the number of Fairbanks businesses and residents that end up using natural gas to heat their buildings — the higher the number of consumers, the lower the unit cost of the gas. Britton said that since there is now a timeline for starting the gas supply expansion, it is now possible to better communicate with potential customers about their future options. Therriault said that there is a plan to hire a conversion specialist in Fairbanks, to spearhead efforts to encourage people to use natural gas.

Therriault also commented that the Alaska Energy Authority is helping municipalities with the implementation of Property Assessed Clean Energy, or PACE, arrangements that can bring low cost financing to businesses wishing to convert to natural gas use. In addition, the state Legislature is considering legislation to enable on-bill financing, a convenient means for consumers to pay gas conversion costs. Another option being monitored involves obtaining some funding for conversion assistance through an Environmental Protection Agency plan for addressing air quality non-attainment.

Financing for the IEP comes from a $57.5 million state capital appropriation, $125 million in SETS loans from the Sustainable Energy Transmission and Supply Development Fund, and $150 million in AIDEA bonding. The state Senate has passed a bill extending the deadline for issuing bonds for the project until June 30, 2023 — the House is considering an identical bill. ●

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● ENVIRONMENT & SAFETY

Washington state groups push carbon-pricing voter initiative

By PHUONG LE
Associated Press

One day after a carbon tax bill stalled in the Washington Legislature, a coalition of environmental, community and labor groups on March 2 filed a proposed citizens' initiative that would put a price on carbon emissions.

Saying voters, communities and businesses want strong action to reduce greenhouse gas emissions, initiative sponsors want to ask voters in November to charge large emitters such as power plants and refineries.

They'll first need to collect nearly 260,000 valid voters' signatures by July 6 to certify the measure for the November ballot.

Aiko Schaefer, who directs Front and Centered, one of the initiative backers, said the measure would hold corporate polluters accountable while investing in solutions that protect health, water and forests.

The proposal would charge $15 per metric ton of carbon content of fossil fuels and electricity sold or used in the state starting in 2020. It would increase by $2 a year in 2021 until the state meets its carbon emissions reduction goal for 2035.

Backers say money raised would be spent on strategies that reduce greenhouse gas emissions, including projects for renewable energy, forests and other natural resources.

Other sponsors include the Washington State Labor Council, The Nature Conservancy, Washington Conservation Voters, Washington Environmental Council, Puget Sound Sage, Climate Solutions, Got Green and OneAmerica.

"I believe the average citizen in well aware of the climate crisis that we're facing" and they want action, said Fawn Sharp, president of the Quinault Indian Nation.

She said 29 tribes with the Affiliated Tribes of Northwest Indians also back the proposal.

The coalition backing the measure includes some groups that opposed a 2016 carbon tax ballot measure. Washington voters defeated that measure by a 59 to 41 vote. Opponents criticize a carbon tax, saying it will raise gasoline and electricity prices for families, workers and employers and puts businesses in the state at a competitive disadvantage to those not subject to the tax.

The moves come a day after Gov. Jay Inslee and Sen. Reuven Carlyle, the prime sponsor of a carbon tax bill, said they didn't have enough votes to pass that measure out of the state Senate. That measure initially would have charged $20 per metric ton but was later amended to $12 per ton. Inslee and Carlyle are Democrats.

The bill cleared key policy and fiscal committees — advancing further than previous measures — but didn't have the votes needed to bring it to a floor vote.

Kyle Murphy, executive director of Carbon Washington, which brought I-732 to the ballot, said support for climate change is really strong and "we're pleased to see an initiative finally moving forward."

Jeff Johnson, president of the Washington State Labor Council, said "this initiative has a price mechanism but also take the majority of the fees collected and invests it in driving carbon pollution down."

He said the coalition has about 1,000 volunteers who are ready to collect signatures. They'll also use paid signature gatherers.

"The cost of not doing anything is much higher than the cost of doing something about it," said Johnson. ●

● EXPLORATION & PRODUCTION

Hearing scheduled for Lookout pool rules

Conoco plans water alternating enriched gas injection for enhanced oil recovery at NPR-A Greater Moose's Tooth accumulation

By KRISTEN NELSON
Petroleum News

ConocoPhillips Alaska has applied to the Alaska Oil and Gas Conservation Commission for pool rules and an area injection order for the company's Lookout oil pool in the Greater Moose's Tooth unit in the National Petroleum Reserve-Alaska. AOGCC has scheduled a hearing on the application for 10 a.m. April 3 at its Anchorage offices.

Greater Moose's Tooth is west of the Colville River unit and Lookout production will go to the Alpine central facility at that unit for processing.

The company said it is also applying for modification of the Colville River unit gas offtake order to allow gas from the unit to be provided to Lookout and for modification of allowable enhanced recovery fluid rules for several Colville River unit pools to allow injection of Lookout produced water.

Lookout is one of the discoveries announced in 2001 by ConocoPhillips Alaska predecessor Phillips Alaska, discoveries made after NPR-A was reopened to exploration in 1999. The company said in May 2001 that discoveries were made at five wells and a sidetrack drilled over the previous two winters — Spark 1 and Spark 1A, Moose's Tooth C, Lookout 1, Rendezvous A and Rendezvous 2, while a sixth well, targeting a different interval, was a dry hole. The wells were believed to have encountered three separate hydrocarbon accumulations, the company said.

The Lookout oil pool will be the first production from the Greater Moose's Tooth unit, where a $1 billion development is underway to complete the pad at Greater Moose's Tooth and other infrastructure. First production is expected late this year, with GMT1 production expected to be 25,000 to 30,000 barrels per day.

Lookout oil pool

ConocoPhillips told the commission that the area covered by the Lookout oil pool was first assessed in 2001 and 2002 at the Lookout 1, Lookout 2 and Mitre 1 wells, with the Lookout wells both encountering hydrocarbons while the Mitre 1 was outside the reservoir limit.

The proposed Lookout oil pool contains Alpine C and Alpine D intervals, with the base of the pool defined by the Upper Jurassic Unconformity defined in the Lookout 1 well at 8,000 feet measured depth and 7,930 feet true vertical depth. The Alpine C and Alpine D intervals are from measured depths of 7,833 feet to 8,000 feet, and true vertical depths of 7,763 feet to 7,930 feet.

ConocoPhillips said the Lookout oil pool "is an oil accumulation formed by a stratigraphic trap of the shallow marine, Upper Jurassic Alpine C sandstone," overlying the Kingak shale and underlying the Miluveach formation.

"A long-term interference test between Lookout 1 and Lookout 2 confirms reservoir connectivity over the majority of the reservoir," the company said, with local compartmentalization possible in the southern portion.

Unit formed in 2008

The Greater Mooses Tooth unit was formed in 2008 and a 2015 record of decision for a supplemental environmental impact statement covered the project to develop the Lookout oil pool, with the project to develop Lookout known as the Greater Moose's Tooth 1 project sanctioned in 2015.

> *The company said Lookout production is expected to be fully compatible with that from Colville River unit pools because Lookout and the Alpine oil pool "share a similar geologic history with the same oil charge source (Lower Kingak) and rock deposition source (Alpine A and B)."*

The company noted that GMT1 is the first development wholly within NPR-A.

The drill site is some 8 miles southwest of the CD5 drill site, with a permanent road connecting the two drill sites. There are four new pipelines for produced crude, water injection, miscible injection and gas lift. Nine horizontal wells, four producers and five injectors, are planned, with an injection program of water alternating with enriched gas injection to optimize recovery.

ConocoPhillips said Lookout is similar to the Alpine oil pool, "except Lookout does not have Alpine A sand present, does not include Kuparuk sands, has a lighter (higher API) oil and an associated higher solution gas-to-oil ratio," and from an operational standpoint will be treated similar to Colville River unit oil pools.

Properties

ConocoPhillips said the API gravity at Lookout is 42.5.

Estimated original oil in place at Lookout is based on well data from the Lookout 1 and 2 wells, on seismic and on an interference test. Pre-development estimates of OOIP range from 70-150 million barrels, with a low estimate of 70 million barrels, a medium of 80 million barrels and a high of 150 million barrels. "Additional reservoir data from the planned development wells will enhance the understanding of sand distribution and may result in an update to the OOIP estimates," the company said.

Development

Lookout will be developed with horizontal production and injection wells. Pilot holes are planned to provide additional reservoir data and assist in well placement.

ConocoPhillips said pressure support at Lookout will be maintained with water and gas injection and an enriched water alternating gas flood will be initiated early in the waterflood to improve ultimate recovery.

"Due to the expected reservoir throughput, the production wells are planned as unstimulated horizontal producers," with two wells planned to have multilateral completions in the thicker section of the reservoir. The company said historical success of secondary and tertiary recovery mechanisms in the Alpine C sands at the Colville River unit "provides an analog for the expected performance" at Lookout. Because of the rock properties and waterflood mobility at Lookout, the expectation for ultimate recovery from enriched water alternating gas flood is expected to be in the range of 50-65 percent of original oil in place, the company said.

Primary recovery alone is expected to yield a 20 percent recovery, with remaining ultimate recovery from secondary and tertiary mechanisms with enriched water alternating gas injection, with an expected enhanced oil recovery of 12 percent and the remaining recovery "from pressure maintenance with waterflood support and depends on maintenance of voidage replacement."

MT6 drill site

Lookout will be developed from the new MT6 drill site, connected to the Alpine central facility for production processing and delivery of dry gas, enriched gas, water and electricity, ConocoPhillips said.

The company said MT6 will be a "not normally manned" drill site but said operators would be present every day except in extreme weather or other circumstances.

"The MT6 design requires minimal operator presence for operations. Monitoring of critical well and facility information, and routine operations, are

see **POOL RULES** page 6

NATURAL GAS

CINGSA reports on 2017 facility usage

Cook Inlet Natural Gas Storage Alaska LLC, known as CINGSA, has filed with Alaska's Division of Oil and Gas the company's 2018 plan of development, which includes a summary of usage of its storage facility in 2017. Various companies, including gas and power utilities, use the facility, located south of the city of Kenai, to hold gas for later use, in particular to warehouse summer produced gas for use in the winter when gas demand is high. The facility, which stores the gas in the Sterling C sands of a depleted section of the Cannery Loop gas field, plays a particularly critical role in the depths of the winter, when gas production from the Cook Inlet basin struggles to keep pace with utility gas demand.

According to CINGSA's new plan, gas injection into the facility in 2017 was minimal, at 63 million cubic feet, in January and peaked at 1,115 million cubic feet in August. Injection rates were relatively high from May through August. Withdrawals peaked at 1,641 million cubic feet in January and remained above 1,000 million cubic feet through March.

According to CINGSA's new plan, gas injection into the facility in 2017 was minimal, at 63 million cubic feet, in January and peaked at 1,115 million cubic feet in August. Injection rates were relatively high from May through August. Withdrawals peaked at 1,641 million cubic feet in January and remained above 1,000 million cubic feet through March.

The facility has a maximum storage capacity of 18 billion cubic feet, including 7 billion cubic feet of working gas, used to maintain adequate pressure in the storage reservoir. Total gas stored in the facility ranged from a minimum 11.7 billion cubic feet in April, following winter gas withdrawals, to a maximum of 15.5 billion cubic feet in September, in preparation, presumably, for winter.

The plan says that fluctuations in commercial power caused a few upsets to operations at the facility: CINGSA has now installed a gas fired generator at the facility for emergency use.

CINGSA told the division that it does not anticipate any changes in the operation of the storage facility in 2018. The company is contemplating an expansion of the facility and towards the end of 2017 conducted an open season, soliciting interest in increased storage capacity. CINGSA says that it received four responses to the open season and will be meeting with interested parties in the first quarter of 2018, to discuss potential expansion plans, if any, for 2019 or beyond.

—ALAN BAILEY

NATURAL GAS

Alaska LNG plant would use Kenai's water

An 800-mile natural gas pipeline will use water from the city of Kenai if the Alaska Gasline Development Corporation builds its proposed liquefaction plant and export terminal in Nikiski, the Peninsula Clarion reported Monday.

The previous plan for the LNG project was to supply the plant with water from wells in Nikiski, but that had to be changed after test wells underperformed or exceeded government standards for contamination.

The previous plan for the LNG project was to supply the plant with water from wells in Nikiski, but that had to be changed after test wells underperformed or exceeded government standards for contamination.

Jesse Carlstrom, the corporation's communications manager, said the terminal and plant would need about 150 gallons per minute of fresh water to operate. Carlstrom said that would be less water consumption than the existing industrial facilities in the plant area.

Kenai Public Works Director Sean Wedemeyer said the city's water system supplies about an average of 1 million gallons of water per day.

He said the additional demand would require upgrades to Kenai's water system, although he didn't know exactly what kind of upgrades or how much they would cost.

The corporation plans to release a feasibility study this spring of using Kenai's water system to supply the plant.

Carlstrom said the corporation plans to shoulder at least some of the cost.

—ASSOCIATED PRESS

EXPLORATION & PRODUCTION

US drilling rig count increases to 981

The number of rigs drilling for oil and natural gas in the U.S. increased by three the week ending March 2 to 981.

That exceeds the 756 rigs that were active this time a year ago.

Houston oilfield services company Baker Hughes reported that 800 rigs drilled for oil (up one from the previous week) and 181 for gas (up two).

Among major oil- and gas-producing states, Oklahoma increased by three rigs, Alaska and Pennsylvania each gained two rigs and New Mexico and Texas each increased by one.

Colorado decreased by three rigs, North Dakota lost two rigs and Louisiana lost one.

Arkansas, California, Ohio, Utah, West Virginia and Wyoming were unchanged.

The U.S. rig count peaked at 4,530 in 1981. It bottomed out in May of 2016 at 404.

—ASSOCIATED PRESS

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POOL RULES

accomplished remotely from the ACF control room."

Crude oil from Lookout will move to CD5 in a 20-inch cross-country flowline where it will be commingled with CD5 production and flow on to the Alpine central facility.

Crude oil from Lookout will move to CD5 in a 20-inch cross-country flowline where it will be commingled with CD5 production and flow on to the Alpine central facility. Water injection arrives via a new 14-inch flowline which connects both MT6 and CD5 to the Alpine central facility; enriched gas injection arrives via a 6-inch flowline connecting MT6 to the existing CD5 flowline.

The company said Lookout production is expected to be fully compatible with that from Colville River unit pools because Lookout and the Alpine oil pool "share a similar geologic history with the same oil charge source (Lower Kingak) and rock deposition source (Alpine A and B)." ●

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FINANCE & ECONOMY

IEA report points to buoyant oil demand

Says that more investment will be needed to ensure adequate supplies after 2020; US expected to be prime player in oil production

By ALAN BAILEY
Petroleum News

Predominantly because of strong economic growth in Asia, global oil demand will increase by some 6.9 million barrels per day to 104.7 million bpd by 2023, according to the International Energy Authority's Oil 2008 report, the agency's latest five-year forecast for global oil markets.

The report says that, although current supply growth can keep up with supply needs through 2020, more investment will be needed to support production after that year — the world has yet to recover from a major drop in investment in 2015-16. Oil production in the United States will, thanks to the shale oil revolution, support a significant proportion of the demand growth — there is currently little increase in spending in the upstream oil industry outside the United States, IEA says.

"The United States is set to put its stamp on global markets for the next five years," said Dr. Fatih Birol, IEA executive director. "But as we've highlighted repeatedly, the weak global investment picture remains a source of concern. More investment will be needed to make up for declining oil fields — the world needs to replace thee million barrels per day of declines each year, the equivalent of the North Sea, while also meeting robust demand growth."

Excess stock disappearing

Currently the excess in global oil stocks that has characterized the last few years has almost disappeared, resulting in a recovery in the oil price, the report says. The oil price rally, in turn, has fueled a new wave of production growth in the United States. This growth, coupled with production growth in Brazil, Canada and Norway, can meet demand through 2020, the IEA report says.

At the same time, the International Monetary Fund has predicted a global economic growth rate of 3.9 percent in 2018 and 2019, leveling to about 3.7 to 3.8 percent per year in 2020 to 2023. Developed countries show strong growth, with tax cuts in the United States likely to drive annual growth of 2.7 percent in 2018 and 2.5 percent in 2019 before slowing in response to eventual fiscal adjustments. Growth in Europe and Japan remain strong.

But growth will likely be particularly strong in China and India, averaging out somewhere between 6.3 and 6.5 percent per year.

Strong economies will require more oil, particularly as feedstock for the petrochemical industry. Hence the projected growth in oil demand between now and 2023. The IEA expects China and India to continue to account for nearly 50 percent of global oil demand. However, the rate of demand growth in China is likely to slow, as the Chinese economy becomes more consumer oriented, the IEA report says.

Changing demand mix

In China, government recognition of the need to tackle poor air quality in cities is driving stringent fuel efficiency and emissions regulations. Sales of electric vehicles are rising and there is increasing use of natural gas as a transportation fuel, especially for trucks and buses.

On the other hand, global economic growth is lifting more people into middle class lifestyles, a trend that is creating a rapid rise in demand for consumer goods and services. That, in turn, fuels an increasing demand for chemicals derived from oil and gas, for the manufacture of a wide variety of products that support more affluent lifestyles. Ethane and naphtha, two chemical feedstocks, account for about one quarter of the IEA's projected growth in oil demand by 2023.

Slow investment recovery

Meanwhile investment in new oil production has barely recovered from the sharp drop in investment that resulted from the fall in the oil price in 2014, the IEA report says. While investment was flat in 2017, early data for 2018 suggest only a slow rise. A concern is that investment is particularly focused on tight light oil production in the United States. The consequence of sluggish investment may be the squeezing out by 2023 of spare global production capacity, with the resulting possibility of increased oil price volatility, the IEA report says.

New investment will be the key to replacing production lost as existing oil fields decline, and to driving up production to meet growing demand. But the past three years have seen declining production in China and Mexico. Venezuela, with the world's largest oil reserves, has seen production fall by more than half since former President Chavez came to power, with that decline expected to accelerate. Mexico, on the other hand, is instituting reforms that could see its production return to growth by 2023, the IEA report says.

U.S. role in production growth

With relatively slow production growth from the Organization of the Petroleum Exporting Countries, production from the United States will likely support oil demand growth through 2020. At some 3.7 million bpd, U.S. output growth, in particular light tight oil, will likely account for more than half of global production growth by 2023, and could go higher if oil prices rise above projected levels, the IEA report says. However, production of conventional non-OPEC oil will likely decline slightly between now and 2023, with growth coming from tight oil, oil sands and natural gas liquids, the IEA report suggests.

Demand for crude oil in Asia, in particular, will provide oil export opportunities for the United States, and export volumes from the U.S. have already increased sharply. The IEA expects current bottlenecks in shipping oil by pipeline from Canada and the Permian basin to ease, as new pipeline projects come to fruition. And U.S. crude export facilities are being upgraded.

However, although the U.S. shale oil industry can respond quickly to rising prices, OPEC countries will account for a major share of the oil supply, with spare production capacity in Saudi Arabia being particularly important in stabilizing world oil markets, the IEA report says.

Changing oil mix

Curiously, the emergence of tight light oil is driving a change in the crude oil mix, the IEA report says. Whereas a few years ago the assumption was that the oil mix would gradually trend towards an increasing proportion of heavier oil grades, the advent of light, tight oil development is pushing an increased proportion of light oil in the mix, with heavier oil production also growing, while the middle grades constitute a decreasing proportion of the overall production.

The IEA report also says that there is significant uncertainty associated with major changes to marine fuel specifications that the International Maritime Organization is mandating. The new regulations will drive a switch from high sulfur fuel oil to marine gasoil, or to a new very low sulfur oil, but it is not clear how successful the maritime and refining industries will be in implementing the changes. The changes will impact the mix of oil fuel products but will not significantly change the total demand for oil products, the report says.

Growing refinery capacity

Although the IEA report projects increasing global oil demand, the report also suggests that refining demand will slow, as electric vehicles and natural-gas fueled vehicles replace vehicles powered by liquid fuels, particularly in China, and as oil products from natural gas fractionation substitute for refined products. However, global refining capacity is growing — the IEA expects excess refining capacity to put pressure on refining margins. The Middle East will likely see the biggest growth in refining capacity, with China and other Asian countries also seeing strong growth, the IEA report says. ●

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AOGCC BONDING

Alaska, where wells were left unplugged and unabandoned. The Bureau of Land Management, the NPR-A landlord, has done some work, but some of that was unsatisfactory and there still remain two to three dozen wells in NPR-A needing to be plugged and abandoned.

AOGCC Commissioner Cathy Foerster has been battling with BLM over the issue for years and hasn't been shy about sharing the problem with the Alaska Legislature, which has also put pressure on the federal government to clean up in NPR-A. Lisa Murkowski, the state's senior U.S. senator, got some money for cleanup work, but it isn't enough to cover all that needs to be done.

The commission requires bonding for companies wanting to drill in the state, to ensure that wells are properly plugged and abandoned, but to date, Foerster and Commission Chair Hollis French told the House and Senate Resources committees March 5 in separate hearings, the commission has only required minimum bonding of $100,000 for a single well or $200,000 for all a company's wells in the state.

Last year the commission began working on its bonding requirements and brought the issue to the Legislature's attention. AOGCC held a workshop with operators on bonding and has required all companies in the state to provide estimates of their costs to plug and abandon.

Costs vary widely

The cost varies widely, French told House Resources, based on whether it is a North Slope or Cook Inlet well, whether the well is reachable by the road system, is onshore or offshore. He said the commission's best estimate to plug and abandon on the west side of Cook Inlet, off the road system, is about $600,000 per well.

Foerster told Senate Resources that the commission has started to require operators to come in, once a year, and report on the number of wells they have which are idle, identify wells with no future utility and those with issues — and agree to which wells the company will plug and abandon. That, she said, will be a slow process because every rig devoted to P&A isn't doing something that generates revenue — for the operator and for the state.

So, how big a problem is it and what is the solution?

When Aurora Gas went bankrupt, with 19 west side Cook Inlet wells, only six wells were purchased out of bankruptcy. Of those not purchased, 10 were on Cook Inlet Region Inc. land. If the operator doesn't P&A the wells, then that becomes the responsibility of the landowner. In CIRI's case, however, when the original operator sold its CIRI leases to Aurora Gas, CIRI insisted that the original operator retain the responsibility to P&A the wells, should Aurora Gas fail to do so. CIRI has pursued that obligation and the work will be done.

As for the other three wells, those are on state land, making the Alaska Department of Natural Resources, as the landowner, responsible to P&A. Eventually, Foerster told legislators, DNR will be coming to you for the money to do that.

The numbers problem

The state is now potentially on the hook to P&A three wells.

But the real problem, French and Foerster told legislators, is that more than 5,000 wells have been drilled in the state, and as large companies tend to sell out of mature provinces to smaller companies, the state faces the problem of that P&A requirement falling on the shoulders of companies which don't have the deep pockets of the major North Slope producers.

AOGCC is working on raising its bonding amounts, and French and Foerster told legislators the commission has the statutory authority to do that — the $100,000 and $200,000 it now imposes in bonding are set in law as minimums, not maximums.

Foerster said the commission can set the bonding higher but noted that bonding isn't free. The more financially secure a company is, she said, the cheaper it is for them to get a bond — and the less worried the commission is about the company. BP can get a bond for pennies on the dollar, she said; for an independent, the cost would be high and might be prohibitive.

Prior operator laws

There is something the commission can't do on its own, and is asking legislators to consider: Two states, California and Kansas, have written into statute the ability of the state to go back to a previous operator if the current operator fails to P&A. California used this recently, Forester said, with an offshore platform Exxon had sold to another operator. When that operator went bankrupt, the state was able to go back to Exxon under the state's "prior operator" law, because Exxon was operating the platform when the law went into effect.

That would require a statutory change, and House Resources Co-Chair Geran Tarr, D-Anchorage, said the committee was interested in working on that.

Foerster told Senate Resources the Legislature has another option — set up an idle well fund, charge companies $100 per idle well in year one, $500 per well in year two, $1,000 in year three, etc. Eventually, she said, companies would start to look pretty hard at whether idle wells have utility. A fund would accumulate which could be used to P&A wells, and operators would be encouraged to identify wells without future utility and do the P&A work.

Sometimes wells do have future utility.

Foerster said many wells which had been idle on the North Slope were brought back into production when coiled tubing technology became available. Had all those well been P&A'd when production stopped initially, she said, both the companies and the state would have been out a lot of oil.

—KRISTEN NELSON

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AGDC RESPONSE

Then in February, he said, came another request.

Richards said AGDC has been pressing FERC to publish its National Environmental Policy Act schedule, and also pressing the agency to leverage work AGDC has done for the Alaska Stand Alone Pipeline project, for which the U.S. Army Corps of Engineers is the lead agency.

The new questions

Of the data requests in FERC's Feb. 15 letter, Richards told the committee there were three levels of information. Some, he said, were refinements on information AGDC has provided. The second level, he said, requires some new information AGDC would have to compile. And the third is a request for detailed data, similar to an alternative analysis, for a Port MacKenzie liquefaction plant site and for a portion of a pipeline route to Valdez.

He said AGDC's response to FERC would provide a schedule on the first two categories and said AGDC would follow up with a face-to-face meeting with FERC staff to get clarification on what will be required for the third category.

In response to a question from Sen. Cathy Giessel, R-Anchorage, chair of Senate Resources, Richards said AGDC does have access to site selection analysis done in the past, citing 2012 work done by Southcentral LNG Project, a predecessor to Alaska LNG. At that time the project team made the determination that Port MacKenzie was unsuitable because it was a working port with a goal through its master plan for import and export capabilities, he said. The team in 2012 felt, Richards said, that you couldn't have a working dock face co-located with an LNG plant.

He said he thinks FERC wants to make sure that the same analysis was followed for Port MacKenzie as was followed for Nikiski and other sites.

Asked by Sen. Bert Stedman, R-Sitka, about potential delays in the project which could come from the alternatives' analysis, Richards said there would be work required. On the line to Valdez, FERC has asked that AGDC look at a small segment of that route where it intersects with two wild and scenic rivers, which will require looking at land-use issues around a small segment of the route. That might take several months, he said.

On the Port MacKenzie request, Richards said AGDC needs to find out how much information FERC will require.

see **AGDC REPONSE** *page 10*

Petroleum news — Oil Patch Bits

PND announces new hires in its Anchorage office

PND Engineers Inc. said Feb. 27 that Ian Brown, PLS, and Kendra Spencer have joined its Anchorage office.

IAN BROWN

KENDRA SPENCER

Brown was hired as a senior land surveyor and will be heading up the survey department. He holds a Bachelor of Science in Geomatics, with a survey emphasis, from the University of Alaska Anchorage and has six years of surveying experience, and brings expertise in right of way, drone mapping and photogrammetry. His surveying experience includes topographical design, differential leveling, as-built and hydrographic survey. He has experience conducting surveys for Alaska Division of Lands and the Federal Aviation Administration. Primarily Brown's past project experience has involved survey work for oil and gas companies, as well as rural road and bridge work for the Kenai Peninsula Borough and the Enstar gas line in Homer, making him comfortable working in remote industrial settings.

Spencer was brought on as an accounting technician for the firm. She has 10 years of Alaska accounting experience, including seven years with Era Helicopters where she handled all accounting functions for Alaska, and two-and-a-half years with Ravn Alaska as the administrative assistant for the maintenance department. Spencer is familiar with Troo, Trax, Citrix, QuickBooks, Oracle, TFBO, ADP, Empower and ShoreTel Communicator software. She will assist the accounting department with accounts payable, accounts receivable, payroll, invoices, and project accounting activities.

The AES to hold its fifth annual conference in April

The Arctic Encounter Symposium said Feb. 28 that April 2018 marks the fifth consecutive year it will have brought together government policymakers, senior industry officials, scientists, researchers, indigenous leaders and other experts to discuss the challenges and opportunities facing America's emerging Arctic.

The theme of AES 2018 is The Future of Arctic Security: Energy, Environment, International, Economic. As the largest annual Arctic policy conference in the United States, AES provides key insights into the most pressing issues facing the region through panel discussions, speeches, information sessions and networking opportunities.

Speakers at this year's conference include Deputy Secretary Elaine Duke of the Department of Homeland Security; U.S. Sen. Lisa Murkowski of Alaska, chairman of the Senate Energy and Natural Resources Committee; Congressman Rick Larsen, 2nd Congressional District of Washington; Congresswoman Pramila Jayapal, 7th Congressional District of Washington state; Ted Scambos of the National Snow and Ice Data Center; and Commodore Angus Topshee, Deputy Director of NORAD-USNORTHCOM. Also attending will be representatives from Arctic nations as well as diplomats, scientists, business leaders, reporters, researchers, tribal leaders and other stakeholders.

The 2018 AES will be held at the Bell Harbor International Conference Center in Seattle, Washington. The full agenda for the April 19-20 symposium will soon be made available on the AES website. For more information and a full list of speakers visit www.arcticencounter.com.

Editor's note: Some of these items 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 September.

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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AGDC RESPONSE

If they want on-site field work, borings and bathymetric data, what will have to be done in the summer. He said AGDC had met with the Matanuska-Susitna Borough Feb. 27 on this issue, which the borough had raised with FERC. The borough also made a late request to become an intervenor in the project. FERC granted that intervenor status, Richards said, and also the borough's request for alternatives analysis.

Richards said that when AGDC met with the borough it offered to provide AGDC access to information the borough has compiled.

Litigation issue

Sen. Natasha von Imhof, R-Anchorage, noted FERC's Feb. 15 statement that AGDC had been refusing to provide some information. Richards said some of what FERC has requested wouldn't normally, under NEPA, be developed at this stage. He said AGDC has identified that it will do these studies, but FERC is saying they want them now. FERC has said that the previous partners agreed to provide them at the time of filing.

Richards said AGDC will develop plans for those and talk to FERC about a minimal standard for what they would expect now. We don't have everything fleshed out, he said.

Von Imhof asked why FERC was asking for these items now, and whether in fast tracking the application AGDC has missed important hurdles.

Richards said AGDC's FERC attorney has said the agency is now getting litigated on almost every decision they make and wants to make sure they have information that will form the basis of a legally defensible document.

He said his understanding of the agreement the previous project management had with FERC staff is that it was a commitment to provide outlines of plans that would come in later and what those plans would include.

FERC wants to make sure those plans will meet their standards, Richards said, and that AGDC will follow through and provide the information needed.

Receipt authority

Both von Imhof and Stedman asked Richards about AGDC's request for receipt authority — the ability to accept funds for the project from third parties.

Wilcox said the commercial focus of the project has been on marketing the project, making potential customers aware that it exists. We've done the marketing, she said, have identified interested parties and are working on agreements with those parties.

AGDC is now starting to look for money, and to the extent we can accept money from outside sources it would help equity investors decide whether they'll be willing to invest, she said.

Those investors will also be asking whether they'll be able to invest just in FEED, front-end engineering and design, or if they will be able to invest in the project later — and whether further decisions from the Legislature will be required for that investment to take place.

Those are key questions the state has to resolve, Wilcox said: how to attract investors into the project early on and will there be the ability to invest as the project moves forward.

She said there are a number of approvals the Legislature would have to make, such as whether the state's royalty-in-kind natural gas will be committed to the project. Without RIK gas the project won't work, she said. There are other issues on which the state must decide, Wilcox said, including a number of upstream issues.

AGDC doesn't want unlimited receipt authority so it can just walk away. But, she said, to be able to make definitive agreements the project will need to know what it's able to offer in terms. She said AGDC anticipates active engagement with the Legislature to flesh it out so we know what we can offer equity partners that would be coming into the project.

The Chinese issue

Stedman noted that legislators heard from a consultant recently about the synergy created in the project if some Chinese companies came forward, noting that China has both an interest in retiring coal plants to clean up its air and in supplying modules for the project. He asked if discussions included things such as module construction.

Richards said working with China wasn't just an opportunity to commercialize gas, but also for China to produce materials and equipment for the project and how that might reduce project costs.

The previous joint venture under ExxonMobil leadership looked at China as one of the places where plants could be modularized and costs reduced. China is producing large modules now, Richards said, and meeting standards set by large international oil companies.

Fluor looked at sourcing as a way to reduce project costs and identified potential savings of some $1.4 billion, he said.

China can produce modules and steel plate that can be rolled into pipe, although the concern now is with potential tariffs. U.S. plants can't produce the grade of steel needed for the project's pipe, Richards said, adding that AGDC has engaged with the Trump administration on this issue.

There are U.S. pipe mills that can roll 42-inch pipe, he said, and AGDC is working with them to make sure they can meet project standards.

Right of way

Stedman asked if there were any sections of the right of way AGDC didn't have access to.

Richards said that under legislative direction the state gave AGDC right-of-way leases across state land at no cost.

The federal right of way is tied up in the EIS. Once a record of decision is issued, the Bureau of Land Management will grant the federal right of way.

That leaves about 40 miles, Richards said, 38 miles of which south of Denali are controlled by a large Native corporation, Ahtna. Richards said AGDC has met with Ahtna and will be negotiating that right of way with them.

There are also some private parcels on the Kenai Peninsula before you get to the LNG plant site.

Then there is the 400 acres acquired by Alaska LNG LLC — the producer parties to the project — to which AGDC is not a party. When AGDC was one of the partners in Alaska LNG the plan was for the producer partners, through Alaska LNG LLC, to acquire that acreage and for AGDC to become a partner in the LLC later.

Richards said AGDC is required to have control of that land before FERC will issue its authorization and said AGDC in discussions and negotiations with the LLC to acquire rights to that land. ●

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BITUMEN DICE

nologies, but more investment is needed to commercialize the ventures.

If successful, partial upgrading would increase the value of bitumen by increasing the number of refineries that can process Alberta's heavier crude and generate fewer greenhouse gas emissions per barrel than full upgrading.

It could save producers billions of dollars a year by reducing the C$13.3 billion they spend for diluent to blend with bitumen, allowing it to flow through pipelines, and free up space on constrained pipelines by as much as 30 percent.

The government estimated that a C$1 billion investment would leverage up to C$5 billion in private sector investment.

But the idea comes with risks after billions of dollars of public money was flushed down the drain on four failed upgrader projects, although Notley said investments will be independently evaluated.

If bitumen can be partially upgraded in Alberta and give a boost to exports, producers should be able to narrow the gap between the price they receive and the price elsewhere.

A spokeswoman for Alberta's United Conservative Party doubted whether offering small loan guarantees and grants would slow the flight of investment out of Alberta, adding her party is concerned about "gambling with taxpayer dollars in trying to micromanage our economy."

—GARY PARK

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DEADLINE EXTENDED

request for a certificate, allowing Cook Inlet Pipe Line Co. to transport gas around the Tyonek gas pipeline system under the more northerly part of the inlet. And a third was a request for approval for Cook Inlet Pipeline Co.'s plan to extend and modify the existing pipeline system, to accommodate the new oil and gas transportation arrangements.

The idea is that oil will be shipped west to east through the CIGGS line, while an existing gas line from the Kenai Peninsula to the offshore Tyonek gas platform will connect to a new Tyonek subsea gas line to the west side of the inlet. The capacity of the new gas line will replace the CIGGS gas carrying capacity lost when one of the CIGGS lines converts to the carriage of oil.

Hilcorp subsidiaries filed three applications with the commission in September.

Hilcorp has planned the business and regulatory arrangements for the modified pipeline system, so that the cost of the pipeline project can be recovered through oil transportation rates, without impacting the rates for the carriage of gas across the inlet.

—ALAN BAILEY

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MUSTANG ROAD

significant delays in the development project, as a result of technical difficulties with development drilling followed by funding challenges during a period of low oil prices. The road and pad for the field have already been constructed, as have many of the modules for the field facilities. Brooks Range has recently said that it anticipates development proceeding this year, with first oil in the first quarter of 2019.

The design concept for the field anticipates the field facilities becoming the fulcrum for other developments in the immediate neighborhood — the production facilities will connect with the nearby Alpine oil pipeline.

AIDEA, as part of its role to encourage industrial development in Alaska, has been providing assistance with the financing of the road, pad and processing facilities for the Mustang field. The agency acts a source of financing at attractive rates, ultimately earning a return for the state from the agency's investments.

AIDEA funding assistance

In 2012 AIDEA lent $20 million for the construction of the road and pad by acquiring an 80 percent stake in Mustang Road. The agency anticipated making an 8 percent return on its investment. Then, in 2014, AIDEA opted to partner with CES Oil Services Pte. Ltd. to form Mustang Operations Center 1 LLC, for the construction of the Mustang processing facility. AIDEA committed up to $50 million to the $200 million to $225 million project, with a 10 percent annual dividend being part of the deal. This deal also involved MOC 1 obtaining a working interest in the Mustang field.

In June 2017 the AIDEA board approved an additional $2.5 million from an AIDEA revolving fund as bridging finance for MOC 1. The board also approved the acquisition by AIDEA of 100 percent of MOC 1, although that ownership change has not yet happened.

Under the terms of an agreement between AIDEA and Brooks Range for the use by Brooks Range of the Mustang road and pad, Brooks Ranges must pay Mustang Road, now fully owned by AIDEA, a usage fee of $50,000 per quarter, once the Alaska Department of Natural Resources has approved the easement, or the easement goes into effect, for the road and pad.

Budget for Mustang Road

As part of its March 1 resolution, the AIDEA board approved a budget for Mustang Road, for the period up to June 30, 2018. That budget encompasses costs such as property taxes, lease fees and administrative expenses. But the company has no current revenue source or operating capital, and income from Brooks Range usage fees is contingent on the timing of DNR approval of the easement acquisition. The board has, therefore, approved the line of credit of up $300,000, an amount of money that should more than cover an anticipated funding shortfall of less than $200,000.

John Springsteen, AIDEA CEO and executive director, told the board in a March 1 memorandum that continuing AIDEA support for the Mustang project is consistent with AIDEA's mission and supports the state's interest in independent oil development on the North Slope. Ultimately, AIDEA expects to earn revenue from Mustang Road, once the Mustang field goes into operation.

—ALAN BAILEY

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HYDER PORT

First Nations opposition

But two major alliances of First Nations — Yinka Dene Alliance and Coastal First Nations — have voiced their opposition to the project.

"Literally no First Nation on the coast is in favor of Eagle Spirit," said Art Sterritt, executive director of Coastal First Nations. "It's a bit misleading for Eagle Spirit to hold a press conference in Calgary and announce things have changed in British Columbia because they haven't."

A spokesperson for the Yinka Dene said her group's six member nations are flatly opposed to "oil transportation through our lands and waters."

In response, Helin said Eagle Spirit has secured agreements with First Nations along 80 percent of his company's proposed route.

He said the business case will eventually win over opponents, claiming partners will receive compensation "of a completely different order" from what was offered by Enbridge for its Northern Gateway plan to ship bitumen to Kitimat.

Helin said leading petroleum economists have been consulted, but their findings are contained in non-disclosure agreements that could remain sealed for months or years to come.

Sterritt said Eagle Spirit has yet to offer acceptable terms. "They got through a few more doors than Enbridge, but never got any more support than Enbridge," he said.

Agreement with Roanan

Walter Moa, president and CEO of Roanan, a Vancouver-based private company that has owned property in Hyder for 40 years, said his company has signed an agreement to work with Eagle Spirit.

He said Hyder is an ideal location for a tanker port because of its deep waters.

Moa hold the Financial Post that Roanan holds port, townsite and mineral claims in the area of the town, adding: "Alaska is in general very supportive of resource development."

Helin said discussions with the Alaska government and others impacted by the proposal have just started.

He said construction of a terminal would cost about C$1 billion, while an additional C$500 million would be spent on spill prevention measures, including tugboats, barges and training.

Transport Canada sessions

Transport Canada has held 75 sessions to discuss a moratorium proposed by the Canadian government that would effectively ban the establishment of an oil tanker port in Canadian territory on the northern British Columbia coast.

Eagle Spirit has started a C$1 million fund-raising campaign to pay for a legal challenge of the proposed ban, while urging the government to start a "new process whereby the interests of all affected, especially indigenous and other communities in the region, are considered concurrently with a robust industry and national economic assessment, which recognizes the importance of ensuring Canada's world-leading environmentally and socially responsible oil and gas industry can reach the growing demand of global markets."

Helin said First Nations are completely opposed to a government policy being made by foreigners, such as American-financed environmental non-government organizations, "when it impacts their ability to help out their own people."

He said those communities "are sick and tired of being dependent on the government and want to be able to move forward with non-transfer payment funding."

The project would "deliver more benefits in terms of employment, business opportunities and revenues and cannot be duplicated from government programs they are seeking to escape," Helin said. ●

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SUBSEA LINE

ate efficiencies."

Tyonek W 8 line

The planned 8-inch oil pipeline, designated the Tyonek W 8 pipeline, is described in an application that Harvest has submitted to the National Marine Fisheries Service for an incidental harassment authorization for subsea pipeline laying in conjunction with the Cross Inlet Pipeline project. Harvest will need an approved IHA in case of minor disturbance to marine mammals in the inlet during the pipe laying operations. Cook Inlet beluga whales, which are listed as endangered under the Endangered Species Act, are found in the region of the planned work.

But the planned oil line is not part of the Cross Inlet Pipeline project — under that project Hilcorp will ship oil west to east under the inlet using one of the twin Cook Inlet Gas Gathering System pipelines that currently runs under the inlet. The new subsea gas pipeline from the Tyonek platform to Ladd Landing will carry gas under the inlet, to replace the gas carrying capacity that will be lost when one of the CIGGS lines is converted from the carriage of gas to the carriage of oil. An existing gas line runs between the Tyonek platform and Nikiski, on the west side of the inlet.

Capped for future use

The planned Tyonek W 8 oil line will remain unused, unless there is an oil development from the Tyonek platform — the IHA application says that, once laid, the pipeline would be capped for future use. There is a known oil pool under the North Cook Inlet gas field that the Tyonek platform serves. The laying of the oil line at the same time as the gas line will presumably save significant pipe laying cost relative to laying the oil line separately.

Laying of the Tyonek oil and gas pipelines will involve welding pipeline segments onshore at Ladd Landing and using a pull barge to pull the pipelines, in parallel, across the inlet to the Tyonek platform. The pipelines will be buried in the tidal transition zone and lie on the seafloor along the remainder of the pipeline route. Harvest plans to conduct the laying of the pipelines between April and mid-September of this year.

A known oil accumulation

ARCO discovered an oil pool, originally call the Sunfish accumulation, under the North Cook gas field when drilling the Sunfish and North Foreland exploration wells from jack-up rigs in the early 1990s. The prospect lies in a major geologic anticline called the Northern Lights anticline.

In 1998 Phillips Petroleum, which by then owned the leases for the North Cook Inlet field, conducted some appraisal drilling into the oil accumulation, which was then known as Tyonek Deep. The company applied for a right of way for an oil pipeline from the Tyonek platform to the west side of the inlet. But by early 1999 the company said that it had put a potential Tyonek Deep development on hold, waiting for oil prices to improve, to render the project viable. At that time the company said that it had tested two wells in the oil pool, had run completion tubing in a third well, and that the wells were ready for production.

The Phillips Alaska operations manager said that the company was evaluating the reservoir and that the development was not viable at that time. The development never happened.

In 2001 Conoco Inc. and Phillips Petroleum merged to form ConocoPhillips. ConocoPhillips continued as operator of the North Cook Inlet field.

Development considered

In 2003 and 2004 Prodigy Alaska considered the possibility of an oil development at Tyonek Deep. The company said that, of 17 wells that had been drilled into Tyonek Deep by that time, 15 were deemed productive and eight tested at initial rates of up to 3,600 barrels of oil per day, per zone. Prodigy said that improved technology and higher oil prices since the 1990s could make the prospect viable. But, again, the development did not take place.

In 2014 Buccaneer Alaska Operating LLC proposed a Tyonek Deep development. At that time ConocoPhillips had farmed out the deep oil rights at North Cook Inlet. However, although Buccaneer initiated the permitting of a four-well drilling program, the development did not proceed.

In 2016 ConocoPhillips sold its 100 percent interest in the North Cook Inlet leases, including the Tyonek Deep section, to Hilcorp Alaska. It now appears that Hilcorp is eying the possibility of a Tyonek Deep development. ●

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