Petroleum news

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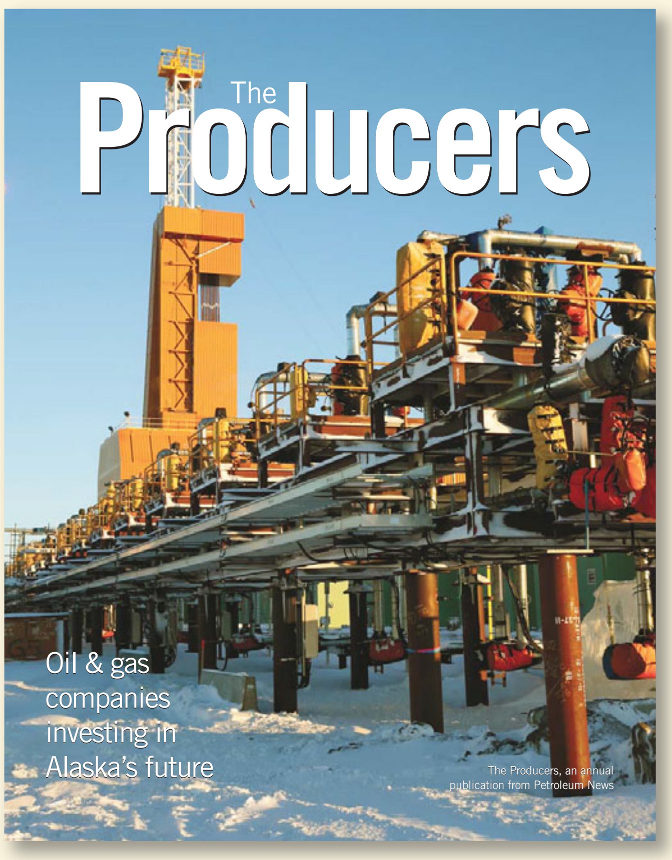
page 10 Kenai LNG 50th anniversary celebrated in Japan (part 2 of 2)

2019 Producers magazine inside



Inside this week's issue is the annual Producers magazine, a look at oil and gas companies investing in Alaska's future.

FTC won't stop BP Alaska sale to Hilcorp; Carl Portman to retire

UNLIKE THE BP-ARCO MERGER that closed in 2000 and was subject to oversight from the Securities and Exchange Commission, which did not allow BP to purchase ARCO's Alaska assets, the proposed Hilcorp Alaska-BP Exploration Alaska deal has been reviewed by the Federal Trade Commission. The agency did not identify any antitrust or anticompetitive issues so will "not prevent" Hilcorp and BP from closing the $5.6 billion sale, Alaska Department of Natural Resources Commissioner Corri Feige told members of the House and Senate Resources committees in a Nov. 12 letter.

The Alaska Department of Law is currently conducting a similar review of the proposed transaction, she said in the

see **INSIDER** *page 18*

Oil Search Alaska files first Pikka plan of development

Oil Search Alaska took another significant step forward in its Pikka oil field development by filing the first plan of development for the North Slope unit with the Alaska Department of Natural Resources' Division of Oil and Gas.

The POD, dated Nov. 1, has a cover letter addressed to both Corri Feige, DNR commissioner, and Rex Rock Sr., president of Arctic Slope Regional Corp. It was signed by Bruce Dingeman, chief operating officer of Oil Search Alaska, who will be taking over as president of the Alaska unit of Oil Search Ltd. from Keiran Wulff, who was recently appointed to the top position of managing director of the ASX-listed parent and will be moving to Sydney in mid-December. To ensure a smooth transition of responsibilities Wulff is maintaining his Alaska responsibilities until then to help oversee the company's entry into front-end engineering and design for the Pikka

see **PIKKA POD** *page 14*

FACILITIES

$25 million for port

Fed grant helps fund petroleum, cement dock, but tariff increases remain

By STEVE SUTHERLIN
Petroleum News

The Port of Alaska has garnered a $25 million grant from the federal "Better Utilizing Investments to Leverage Development (BUILD) Transportation Discretionary Grants program," to build the third and final phase of an upgrade to its petroleum products and cement handling facilities, U.S. Secretary of Transportation Elaine L. Chao said Nov. 12.

The cost of the project is $81 million, based on current engineering projections, said Jim Jager, director of external affairs for the port. The port has yet to see any contractor bids on the project.

Despite a $25 million cash infusion, the port will not reduce initial tariffs under a 10-year, escalating user fee schedule adopted by the Port Commission, he said.

Reductions of the rates would be more likely once the total costs of the project — including financing — are known, Jager said, adding that the port's overall cost estimate has already factored in some degree of success in attracting grants, as well as an anticipation of favorable financing terms.

Users seek a voice

Casey Sullivan, government and public affairs manager for Marathon Petroleum Corp. in Alaska, said the port is moving forward with the entire redo at lightning speed, based on plans drawn

see **PORT OF ALASKA** *page 19*

EXPLORATION & PRODUCTION

Alaska & independents

Mustang partner says North Slope offers clear, level path for small companies

By KAY CASHMAN
Petroleum News

Majid Jourabchi, president of Thyssen Petroleum, and a partner in Mustang, the first oil field that a small independent has taken from discovery to production on the North Slope, thinks Alaska is a good place for investment under the current system.

"As far as an independent on the North Slope, I believe that going forward more and more independents will look into Alaska. Major oil companies will concentrate on new fields while the independents can develop smaller fields that fit their economic capability and appetite," he told Petroleum News Nov. 11.

"The independents and state of Alaska have had

> *"The independents and state of Alaska have had growing pains and all of us are still suffering from the effects of it. Going forward we are not looking for any new programs that favor an independent or a major oil company; we are just looking for a clear and level path." —Majid Jourabchi*

growing pains and all of us are still suffering from the effects of it. Going forward we are not looking for any new programs that favor an independent or a major oil company; we are just looking for a clear

see **ANS APPEAL** *page 15*

FINANCE & ECONOMY

New home, new name

Natural gas power Encana moving headquarters to Denver; relabeling as Ovintiv

By GARY PARK
For Petroleum News

DOUG SUTTLES

JASON KENNEY

It made a formal entry into the Canadian oil patch in 1973 when the Alberta government launched Alberta Energy Co. as a government corporation to offset Arab oil embargos and subsequent price aftershocks.

Now all those deep Alberta and Canadian roots have been severed as AEC's successor company Encana chose Oct. 31 — neither a Trick nor a Treat for most Canadians — to rename itself Ovintiv and later announce its headquarters would be moved from Calgary to Denver.

The word came as no surprise to Gwyn Morgan, AEC's founding chief executive officer, who said the company's center of gravity had been shifting for years, though he conceded "it's the sort of step that all of us hoped wouldn't happen, especially the employees and the guy who founded the company."

Alberta blames Trudeau

Alberta Premier Jason Kenney was less forgiving,

see **ENCANA MOVES** *page 16*

● PIPELINES & DOWNSTREAM

Exxon, BP apply for 5% pipeline transfer

By KRISTEN NELSON

Petroleum News

ExxonMobil Pipeline Co. and BP Transportation (Alaska) Inc. have applied to the Regulatory Commission of Alaska for approval of a transfer of 5% interest in the PTE Pipeline from EMPC to BPTA.

The companies told RCA the proposed transfer is part of the larger transaction in which BP is exiting Alaska through sale of BP Exploration (Alaska) Inc. to Hilcorp Alaska LLC and transfer of BP Pipelines (Alaska) Inc.'s Alaska-related assets, including its entire 100% stock ownership interest in BPTA, to Harvest Alaska LLC.

Transfer of the 5% interest in the PTE Pipeline "is intended to better align ownership percentages of PTEP with the anticipated ownership levels in the Point Thomson Unit upon completion of the BP-Hilcorp Transaction," the companies said, and told RCA that aligning pipeline ownership with unit ownership is in the best interest of the public, as alignment mitigates "the risk of disputes that cost shippers considerable amounts of money to resolve or overcome."

The PTE Pipeline is a 12-inch inside diameter, 22-mile common carrier liquid petroleum transportation line from the central processing facility at Point Thomson to a connection to the Badami Pipeline at the Badami central processing facility, the companies said.

Ownership interests

The companies said BPTA currently owns 32% of PTEP and its ownership would be increased to 37%. ExxonMobil owns the other 68% of the line.

The most recent data from the Alaska Department of Natural Resources' Division of Oil and Gas for Point Thomson unit ownership show ExxonMobil Alaska Production with 61.2%, BP Exploration (Alaska) with 31.9%, ConocoPhillips Alaska with 4.9%, Jade Energy with 1.6% and 16 other owners, each with ownership of less than 1%.

ConocoPhillips Alaska said in May 2017 that it was dropping its working interest ownership in Point Thomson. The company said its interest, about 5%, was being relinquished to the other unit owners per the unit operating agreement. ConocoPhillips was not a partner in the PTE Pipeline.

The PTE Pipeline is a 12-inch inside diameter, 22-mile common carrier liquid petroleum transportation line from the central processing facility at Point Thomson to a connection to the Badami Pipeline at the Badami central processing facility, the companies said. The line has a capacity of some 70,000 barrels per day, with a currently established remaining economic life of 19 years, through 2045, "which could be extended if new or additional oil production is developed in the area that it serves."

The companies said they have also begun a process with the State Pipeline Coordinator Section of the Alaska Department of Natural Resources for approval of the transfer of the EMPC interest in the state's right-of-way lease to BPTA. ●

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● EXPLORATION & PRODUCTION

Division of O&G approves Point Thomson POD

Two-year plan says compression improvements underway; one update completed, more updates in works; goal is 10,000 bpd production

By KRISTEN NELSON
Petroleum News

The Alaska Department of Natural Resources' Division of Oil and Gas has approved the 2020-21 Point Thomson unit plan of development.

In a Nov. 7 approval letter, acting division Director Tom Stokes said while Point Thomson operator ExxonMobil Alaska Production has so far been unsuccessful in consistently producing 10,000 barrels per day of condensate from the field, as described in the 2012 Point Thomson unit settlement agreement, the division "believes EMAP is diligently working to resolve the production reliability issues" and so finds the 2020-21 POD "necessary and advisable to protect the public interest." Stokes also said the division appreciates the company's "continued efforts to consider LNG opportunities and willingness to share information about those efforts."

The 2020-21 POD was submitted Oct. 2 and covers two years: Jan. 1, 2020, through Dec. 31, 2021.

ExxonMobil and BP are the major working interest owners at Point Thomson

Production began in 2016

In its POD ExxonMobil said the company constructed the Point Thomson initial production system from 2012-16 and began production in 2016. The high-pressure gas cycling project utilizes "industry-first reciprocal injection compressors," the company said, with condensate separated from gas and the gas compressed and reinjected into the reservoir. The condensate is transported through the Point Thomson Export Pipeline for delivery to the trans-Alaska oil pipeline. The IPS is designed to cycle 200 million cubic feet of gas per day and deliver up to 10,000 barrels per day of condensate for sale.

The field has three active wells, with gas and condensate produced from the PTU 17 well on West Pad and the PTU-15 and PUT-16 on Central Pad used for gas reinjection. The field also has a class 1 disposal well used for produced water and gray water disposal, the company said.

From Jan. 1, 2018, through July 31, 2019, condensate production averaged 5,200 bpd, a total of 3 million barrels delivered for sale during that period, with maximum monthly average production of 10,700 bpd in December 2018.

From Jan. 1, 2018, through July 31, 2019, condensate production averaged 5,200 bpd, a total of 3 million barrels delivered for sale during that period, with maximum monthly average production of 10,700 bpd in December 2018. Gas production averaged 96 million cubic feet per day for the period, with 93 million reinjected into the reservoir and the remaining used as fuel gas to support unit operations. Maximum monthly average production of 199 million cubic feet per day was in December 2018.

Reliability issue

ExxonMobil said that in the current reporting period the field "experienced issues related to its gas injection equipment, which is based on leading edge technology designed to handle gas reinjection at the high pressures of the Point Thomson reservoir."

It said they were working with the equipment manufacturer "to investigate potential reliability improvements using existing equipment and modifications to improve future performance" and had "designed and procured a modified component" for use in the Point Thomson gas injection systems.

The first of the new components was installed in July, the company said, and remaining equipment has been ordered and is expected to be received and installed during the POD period.

Alaska Oil and Gas Conservation Commission records show an uptick in condensate production, presumably following installation of the new component, with a July average of 4,201 bpd (30 days of production during the month), an August average of 3,345 bpd (21 days of production) and a September average of 5,038 bpd (30 days of production).

These volumes are still down from the year's high of 9,674 bpd on March.

ExxonMobil said it is also upgrading lubrication systems at Point Thomson "and continuing to optimize operations and maintenance practices to further increase reliability and reduce downtime."

"Reliability of production has been an ongoing concern because of reported issues with gas injection equipment," Stokes said in the division's approval letter. He said the 2012 Point Thomson unit settlement agreement "requires the IPS to have an objective of a minimum of 10,000 barrels of condensate per day," and while the average for the reported period was 5,200 bpd, he noted that the company "reports that additional work to improve reliability of gas injection has been completed and more new components will be installed," with design and installation of the first of new components occurring in July.

Major gas sales

A major gas sale was a premise of the 2012 Point Thomson settlement agreement.

In 2018 the Point Thomson Unit Letter Agreement made some modifications.

The 2012 settlement defined an Alaska LNG project as including a gas treatment plant, large diameter pipeline, liquefaction facilities, marine terminal and required transmission pipelines and other facilities to liquefy Alaska

see POINT THOMSON POD page 7

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● EXPLORATION & PRODUCTION

Amaroq applies for Nicolai Creek disposal injection

By KRISTEN NELSON
Petroleum News

Amaroq Resources LLC has applied to the Alaska Oil and Gas Conservation Commission for a disposal injection order for disposal of produced water and other Class II eligible waste fluids from the Nicolai Creek unit in the Tyonek formation in the NCU.

The commission has scheduled a public hearing on the application for Dec. 12 at 10 a.m. at its Anchorage offices at 333 W. 7th Ave.

G. Scott Pfoff, president of Amaroq Resources, applied for the disposal into the NCU 1B well on Oct. 29.

In its application the company said the NCU 1B well is a depleted gas well directionally drilled to state of Alaska lease ADL 17585, an offshore lease in Trading Bay, 100% owned by Amaroq Resources. The well's surface location is onshore on ADL 391471. The NCU 1B was drilled in 2002 as a sidetrack to NCU 1A which was a sidetrack of the original NCU 1.

The NCU 1B was sidetracked at 2,186 feet and 7-inch casing was set from 3,650 feet measured depth back to the surface.

Amaroq said there are no other lease holders within one quarter mile of the surface location of NCU 1B

Tyonek formation

Amaroq said the proposed injection zone is within the Tyonek formation and is present between the measured depths of 2,307 to 2,370 feet as recorded on the logs of the NCU 1B well. Injection is planned for the gross interval from 2,307 feet MD to 2,370 feet MD, with perforations already present at 2,307 to 2,326 feet MD and 2,350 to 2,370 feet MD.

"The lithologies at these depths are primarily sandstones, conglomerates, and siltstones with minor coal beds interbedded with shales above and below the perforated intervals," the company said.

The zone appears to exhibit good properties for fluid injection on the logs, with a reasonable estimate of porosity within the sands of 24-28%, with permeabilities of 50-100 millidarcies based on equivalent sands some 6,769 feet to the north in the NCU 3 well.

"The proposed disposal zone is depleted along with the other gas producing zones in the NCU 1B well," the company said, with cumulative gas production as of September 2019 of 581,539 thousand cubic feet from the NCU 1B well.

Disposal from NCU

Amaroq said the plan is to dispose of produced water from other NCU wells into the NCU 1B. "Additional solids free fluids for disposal could include workover and completion brines from any other future workover operations which are anticipated to contribute less than 1% of the overall volume of fluids to be injected."

> *"There are no known water wells or other borings within ¼ mile of the NCU 1B well that could potentially be a conduit to fresh water for injected Class II wastes," the company said.*

The company said that at this time it "does not intend to dispose of drilling muds or cuttings or other heavily solids laden fluids in the NCU 1B well nor does it intend to take in Class II wastes from other local operators."

Amaroq said it has purchased surface injection facilities from the Aspen 1 disposal well and moved that equipment to NCU. "AOGCC field inspection personnel are familiar with this injection facility," the company said. Maximum anticipated daily injection volume is 364 barrels per day, with average daily volumes estimated to be 100 to 200 bpd.

Amaroq said the zone planned for injection is a depleted gas zone. It's estimated porosity is 25% its permeability is 50-100 millidarcies. "With these formation properties, the injected produced water fluids will leak off rapidly into the reservoir," the company said, and since the fluid will be primarily produced water, its very low viscosity "will contribute to rapid leak off."

NCU 1B

Amaroq said the NCU 1B is on the same pad as the NCU 2, 9 and 6 wells. NCU 2 is shut-in; NCU 9 is a completed gas producer; the NCU 6 was plugged and abandoned in 1980.

The company said it believes that the NCU 6 well is secure due to cementing and "will not be a conduit for Class II wastes to reach freshwater sources."

The NCU 2 well penetrated the proposal disposal zone but it is fault separated in these two wells, while the NCU 9 well is a Beluga formation gas producer and does not penetrate the sands proposed for disposal.

"There are no known water wells or other borings within ¼ mile of the NCU 1B well that could potentially be a conduit to fresh water for injected Class II wastes," the company said. ●

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Congratulations

Congratulations Brooks Range!

Kudos to Brooks Range Petroleum and its partners on the start-up of Mustang, the first oil field that a small independent has taken from discovery to production on Alaska's North Slope.

Brooks Range Petroleum

Bart Armfield

ABR Inc.
Acuren
AES Electric Supply, Inc
Afognak Leasing LLC
Airgas, an Air Liquide company
AK Lofts
Alaska Dreams
Alaska Frac Consulting LLC
Alaska Frontier Constructors (AFC)
Alaska Marine Lines
Alaska Materials
Alaska Railroad
Alaska Rubber & Rigging Supply Inc.
Alaska Steel Co.
Alaska Tent & Tarp
Alaska Textiles
Alaska West Express
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Arctic Controls
ARCTOS Alaska, Division of NORTECH
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Avalon Development
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SALA Remote Medics
Security Aviation
Soloy Helicopters
Sourdough Express
Strategic Action Associates
Summit ESP, A Halliburton Service
Tanks-A-Lot
The Local Pages
TOTE – Totem Ocean Trailer Express
Weona Corp.
Weston Solutions
Wolfpack Land Co.
Worley

● FINANCE & ECONOMY

EIA: US on course for production record

Brent averaged $60 in October, down $3 from September, down $21 from October 2018; forecast to average $60 in 2020, down from $64

By KRISTEN NELSON
Petroleum News

The U.S. Energy Information Administration said in its Short-Term Energy Outlook, released Nov. 13, that Brent crude oil spot prices averaged $60 per barrel in October, down $3 per barrel from September and down $21 per barrel form October 2018.

EIA Administrator Dr. Linda Capuano said "EIA forecasts that the average spot price for Brent crude oil in 2019 will be almost $64 per barrel, a year-over-year decrease of $8 per barrel. In 2020, EIA expects the average crude oil price to continue decreasing, albeit at a slower pace than the change from 2018 to 2019."

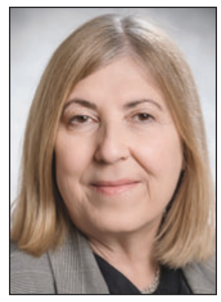
EIA said the projected decline is due to rising global oil inventories, particularly in the first half of 2020.

Annual averages, actual and forecast, as shown on the EIA's website are $54.15 per barrel for Brent in 2017, $71.19 in 2018, an estimated $63.59 this year and $60.10 forecast in 2020.

West Texas Intermediate prices are expected to average $5.50 per barrel below Brent in 2020.

On the plus side, U.S. crude oil production continues to rise.

"The United States remains on course to set new crude oil production records this year and next," Capuano said. "In fact, EIA's November outlook expects that U.S. crude oil production will average more than 13 million barrels per day this month, the most U.S. oil production in one month on record."


LINDA CAPUANO

EIA data show an estimated 12.25 million bpd in U.S. crude production in the third quarter of 2019, projected to rise to 13.01 million bpd in the fourth quarter and to average 13.29 million bpd next year.

EIA said based on preliminary data and model estimates, it is estimating that the U.S. exported 140,000 bpd more crude oil and petroleum products in September than it imported, a growing trend, with exports exceeding imports by 550,000 bpd in October.

Capuano said more exact data for those months will be published later in November.

U.S. net exports expected to average 750,000 bpd in 2020.

Natural gas

"U.S. natural gas production has outpaced U.S. consumption during 2019," Capuano said, "resulting in increasing inventory levels."

Storage injections in the U.S. outpaced the previous five-year average during the 2019 injection season, EIA said, a result of rising gas production.

Annual U.S. dry natural gas production is forecast to average 92.1 billion cubic feet per day this year, EIA said, up 10% from 2018. Production is expected to "grow much less in 2020 because of the lag between changes in price and changes in future drilling activity, with low prices in the third quarter of 2019 reducing natural gas-directed drilling in the first half of 2020." Natural gas production is forecast to average 94.9 bcf per day next year.

LNG exports

Liquefied natural gas exports are expected to average 4.7 bcf per day this year and 6.4 bcf per day in 2020, EIA said.

Capuano said EIA expects LNG exports "to increase to 5.8 billion cubic feet per day by the end of 2019 and 7.9 billion by December 2020."

Gross exports averaged nearly 1.7 bcf per day in January 2017, she said. "Several new U.S. LNG export facilities, along with growing domestic natural gas production, are responsible for the rapid rise of the United States as a leading LNG energy exporter."

EIA said three new liquefaction facilities — Cameron LNG, Freeport LNG and Elba Island LNG — commissioned their first trains in 2019, with natural gas deliveries to LNG projects setting a new record in July, an average of 6 bcf per day, increasing to 6.6 bcf in October, when new trains at Cameron and Freeport began ramping up.

EIA said Cameron LNG exported its first cargo in May, Corpus Christi LNG's newly commissioned Train 2 exported its first cargo in July, followed by Freeport in September. Elba Island expects to ship its first export cargo by the end of the year, and in 2020, Cameron, Freeport and Elba Island expect to place their remaining trains in service, EIA said.

That will bring total U.S. LNG export capacity to 8.9 bcf by the end of 2020.

Capuano said that over the past month global market risks have moderated, as Saudi Arabia's production appears to have recovered from the attacks of Sept. 14. "Some of the demand side risks stemming from concerns over economic growth also seem to be diminishing," she said, "as Americans set a new record for the month of October by consuming nearly 9.4 million barrels of gasoline."

"Crude oil markets traded in a relatively narrow range in October following heightened volatility in September stemming from the attack on Saudi Arabian crude oil processing facilities," EIA said.

It said the return of Saudi Arabian production to pre-attack levels is one indication of diminishing supply and demand side risks, along with receding expectations of lower oil demand related to lower economic growth, which appear to be providing some support for prices slightly above $60 per barrel.

The agency said there is some slower economic activity, such as third-quarter gross domestic product growth in China at the slowest rate since at least 1992, but there are other economic indicators which are up, such as the Manufacturing Purchasing Manager's indexes, which increased in both China and the U.S., along with U.S. economic growth. ●

Contact Kristen Nelson at knelson@petroleumnews.com

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POINT THOMSON POD

North Slope natural gas for export and also providing natural gas for in-state deliveries, and said the project must be one advanced by the state, a state-owned project such as the Alaska Gasline Development Corp., a public corporation and government entity as defined in statute or an entity in which a state-owned entity holds a controlling equity share.

The Sept. 10, 2018, letter agreement suspended "dates, deadlines, terms, conditions, undertakings, commitments, submittals, and obligations," required biennial PODs for Point Thomson which would address "ongoing IPS or other unit exploration, development, and operations, including activities in furtherance of the Alaska LNG Project" as described in the 2012 settlement agreement.

The extension provided in the 2018 letter agreement "shall continue until DNR provides notice to all parties to the Settlement Agreement that either: (1) there is a Final Investment Decision on an Alaska LNG Project; or (2) work on the Alaska LNG is no longer progressing."

If DNR issues a suspension notice — declaring that work on the Alaska LNG project has stopped — the Point Thomson unit working interest owners "will resume work on the suspended portions of the PTU POD." The unit owners would then have 30 months to commit to a Point Thomson unit expansion or sanction a major gas sale.

The 2012 settlement agreement had a deadline at the end of 2019 for sanction of a Point Thomson expansion if a major gas sale wasn't sanctioned by June 2016. There was agreement on an expansion plan in late 2017 — requiring increase of Point Thomson condensate production to 30,000 bpd or moving natural gas to Prudhoe Bay for reinjection.

MGS report

In its POD, ExxonMobil lists steps the unit owners and operator took in 2018 and 2019 to promote and support a potential MGS project, including:

•Confidentiality agreement to allow disclosure of information to AGDC in connection with an Alaska LNG project;

•Sharing with AGDC information related to design and routing of a gas transmission line from Point Thomson to Prudhoe;

•Confidential discussions with AGDC and potential partners on financing and/or investing in MGS project;

•Two Point Thomson owners (BP and ExxonMobil) provided funding, technical support for permitting for Alaska LNG; and

•Unit owners continued evaluation of technical feasibility of potential MGS projects.

"The PTU owners anticipate undertaking appropriate planning and activities to position the Unit for an MGS consistent with AGDC progress on the Alaska LNG project," ExxonMobil said. "These activities will be based on prior work done by the PTU operator to prepare for an MGS," with timing and scope "dependent upon the MGS project milestones and activity."

ExxonMobil said that to date reservoir performance at Point Thomson has been in line with expectations, with "no indications of reduced reservoir connectivity or capacity since production commenced."

A preliminary list of long-range activities required to ensure alignment with an Alaska LNG project include:

•Coordinate design activities, execution of unit well development to "deliver the MGS project design volumes over time."

•Coordinate design activities, execution to "efficiently meet the MGS project design rate and gas specification."

•Progress Point Thomson permitting associated with MGS to achieve MGS startup milestone.

•Progress commercial agreements, well planning, engineering, permitting to support MGS.

ExxonMobil noted that the 2018-19 POD anticipated work activities related to Point Thomson expansion. Consistent with the letter agreement that work was suspended in September 2018. "However, the technical and commercial work streams were brought to a position where they could be quickly resumed in connection with an expansion project," the POD says.

Reservoir management

ExxonMobil said that to date reservoir performance at Point Thomson has been in line with expectations, with "no indications of reduced reservoir connectivity or capacity since production commenced."

Dry gas is reinjected for pressure maintenance, to aid condensate recovery and conserve gas for future development, the company said. "No other EOR efforts are planned through 2021."

The company said the IPS central pad processing facilities have produced production in excess of design rates of 200 million cubic feet of cycled gas and 10,000 bpd of condensate. "The gas injection compressors have demonstrated the ability to operate at maximum design capacity based on facility performance data."

The 2012 settlement agreement provides that after IPS startup, unit "owners shall identify and pursue debottlenecking work to increase the capacity of the installed facilities," the POD says.

The unit operator "reviewed debottlenecking opportunities with the assistance of an independent engineering contractor" during the 2018-19 POD, ExxonMobil said, including a review of operating parameters "such as separator pressures and hydraulic limits, but no significant debottlenecking opportunities were identified to increase capacity beyond those possible with current facilities, wells, and operations."

When fully operational, the company said, "the facility has consistently produced greater than" the 200 million cubic feet per day design rate.●

Contact Kristen Nelson at knelson@petroleumnews.com

EXPLORATION & PRODUCTION

US rig count continues to fall, down by 5

Baker Hughes reports the number of rigs drilling for oil and natural gas in the U.S. continued to fall the week ending Nov. 8, down by five to 817, following a drop of eight the previous week and a steep drop of 21 rigs the week ending Oct. 25.

In its weekly rig count the Houston oilfield services company said the active rig count was down 264 from 1,081 active rigs a year ago.

The company reported that 684 rigs targeted oil (down seven from the previous week; down 202 from a year ago) and 130 targeted natural gas (unchanged from the previous week; down 65 from a year ago). There were three miscellaneous rigs active (up two from the previous week and up by three from a year ago).

The company said 56 of the U.S. holes were directional, 710 were horizontal and 51 were vertical.

Alaska and California were each up by one rig from the previous week.

The rig counts in most states were unchanged from the previous week: Colorado, Louisiana, Ohio, Oklahoma, Pennsylvania, Utah, West Virginia and Wyoming.

North Dakota was down by one rig.

Texas, with the most active rigs at 413, was down by three from the previous week.

New Mexico was down by four.

Baker Hughes shows Alaska with eight rigs active for the week ending Nov. 8, up from six a year ago.

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

International rigs

Baker Hughes released its monthly international rig count for October on Nov. 7.

International rigs averaged 1,130 in October, down one from the September count of 1,131 but up 113 from an October 2018 count of 1,017. The worldwide count, including North America, averaged 2,123 rigs in October, down 18 from 2,141 in September and down 148 from a count of 2,271 in October 2018.

North America, the U.S. and Canada, averaged 993 in October, down 17 from an average of 1,010 in September and down 261 from an October 2018 average of 1,254.

—KRISTEN NELSON

COMMUNITY

ConocoPhillips AK invests in housing

Catholic Social Services said Nov. 13 that ConocoPhillips Alaska provided a $150,000 grant for the Community Housing Project, a partnership between Catholic Social Services, Rural Alaska Community Action Program Inc. (RurAL CAP), Salvation Army and United Way that supports families moving from homelessness to housing.

"Early childhood research has shown that homelessness is the second most traumatic event that can happen to a child, after losing a parent. That trauma has life-long impacts on physical and mental health," said Lisa Aquino, CEO of Catholic Social Services. "ConocoPhillips Alaska's investment will play a large part in eliminating that trauma."

The company's grant will extend rapid rehousing services to families in need. Specifically, it will help quickly move 10 households and more than 30 people to permanent stability by supporting each family's housing, income stability, and social and emotional wellbeing.

"None of these families and individuals want to be homeless. Most of them are working when something unexpected and unfortunate happens to them," said Joe Marushack, president of ConocoPhillips Alaska. "This housing program focuses on getting the family or individual into housing first, so they can turn their energy and attention toward getting back on their feet. Alaska needs more successful programs like this."

For more information visit www.cssalaska.org.

—PETROLEUM NEWS

● NATURAL GAS

Battle of words over AK LNG continues

Location the issue: AGDC responds to request from City of Valdez for environmental data; borough fist-a-cuffs — Kenai vs Mat-Su

By KRISTEN NELSON
Petroleum News

The Federal Energy Regulatory Commission has received more comments in the continuing disagreement over where a liquefaction facility for the Alaska LNG Project should be located.

FERC published a draft environmental impact statement for the Alaska LNG Project in June, with comments due Oct. 3, but continuing to pile up in early November.

The latest: Project sponsor Alaska Gasline Development Corp. has responded to a request from the City of Valdez for environmental impact data on location of the liquefaction facility at Valdez, rather than Nikiski, which is the site AGDC proposed; and the Kenai-Peninsula Borough responded to statements made by the Matanuska-Susitna Borough in response to comments on the DEIS by the U.S. Army Corps of Engineers.

AGDC v Valdez

AGDC responded to FERC on an argument by the City of Valdez (see story in Oct. 13 issue of Petroleum News) that the DEIS did not adequately consider Valdez for the LNG facility.

AGDC said "the DEIS thoroughly analyzes and compares the Nikiski site to several alternatives, including the Port Valdez site at Anderson Bay." While the DEIS found a pipeline to Anderson Bay would be within the trans-Alaska oil pipeline corridor for most of its length and would avoid Cook Inlet crossing impacts, the DEIS also found "that both the site at Anderson Bay and the pipeline required to reach the site would result in numerous environmental impacts," AGDC said.

The DEIS also found "an additional 113 miles of lateral pipelines would need to be constructed to reach in-state markets in Fairbanks and Anchorage, as well as a lateral to the Kenai Peninsula to a yet to be determined delivery point," AGDC told FERC.

The DEIS does contain a comparative analysis, AGDC said, and "concludes that the Anderson Bay site would not provide a significant environmental advantage over the proposed Nikiski site."

Valdez argued that AGDC aggregated data on impacts of the LNG site at Anderson Bay and a 148-mile spur required to reach in-state markets in Anchorage if the pipeline went to Valdez.

AGDC said the Valdez argument is "based on a mischaracterization" of the purpose of analyzing impacts of pipelines connecting Valdez to Fairbanks and Anchorage.

The DEIS "does not even mention the Palmer and Fairbanks spurs specifically," AGDC said, but analyzes "impacts of an 'assumed pipeline lateral' to Fairbanks and Anchorage from each of the alternative sites."

AGDC said a natural gas pipeline capable of delivering gas to the most populous areas of the state is needed to meet the project's objectives, based on AGDC's identification of three areas of the state — Fairbanks, Anchorage/Mat-Su and the Kenai Peninsula — where most of the population resides. Courts have held that agencies "have a duty to consider the applicant's purpose and the objective of the applicant's project," AGDC said. "The DEIS properly relies on AGDC's statement that a purpose and need of the Project is to allow for in-state gas deliveries to the State, which reasonably includes the largest population centers in the state."

AGDC told FERC "the analysis of the Valdez alternative in the DEIS is not incomplete or inadequate" and asks that FERC reject the Valdez criticism of the DEIS comparative analysis, saying "the DEIS properly compares the respective impacts of both the liquefaction site and associated pipelines of each alternative that are needed to meet the Project's objectives."

Kenai Peninsula v Mat-Su

The Kenai Peninsula Borough responded to comments on the DEIS by the Matanuska-Susitna Borough (see story in Oct. 27 issue of Petroleum News), telling FERC that the Mat-Su motion for a supplemental EIS contains "grossly misleading

see AK LNG BATTLE page 15

Congratulations

Happy 50th anniversary for Kenai LNG!

ConocoPhillips

Marathon Petroleum Corporation

Celebrating the 50th anniversary of the Kenai LNG plant's first delivery of liquefied natural gas to Japan and the 50th anniversary of the Kenai Refinery, today both operated by Marathon Petroleum.

ABR Inc.
Acuren
AES Electric Supply, Inc
Afognak Leasing LLC
Airgas, an Air Liquide company
AK Lofts
Alaska Dreams
Alaska Frac Consulting LLC
Alaska Frontier Constructors (AFC)
Alaska Marine Lines
Alaska Materials
Alaska Railroad
Alaska Rubber & Rigging Supply Inc.
Alaska Steel Co.
Alaska Tent & Tarp
Alaska Textiles
Alaska West Express
American Marine
Arctic Controls
ARCTOS Alaska, Division of NORTECH
Armstrong
ASTAC Broadband, LLC
AT&T
Avalon Development
Aviator Hotel
Bombay Deluxe
BrandSafway Services
Brooks Range Supply
Calista Corp.
Carlile Transportation
Chosen Construction
Colville Inc.
Computing Alternatives
CONAM Construction
Cruz Construction
Denali Universal Services (DUS)
Doyon Anvil
Doyon Associated
Doyon Drilling
Doyon, Limited
exp Energy Services
F. R. Bell & Associates, Inc.
Fairweather
Flowline Alaska
Fluor
Frost Engineering Service Co. – NW
Fugro
GMW Fire Protection
Greer Tank & Welding
Guess & Rudd, PC
HDR Engineering, Inc.
ICE Services, Inc.
Inspirations
Judy Patrick Photography
Little Red Services, Inc. (LRS)
Lounsbury & Associates
Lynden Air Cargo
Lynden Air Freight
Lynden Inc.
Lynden International
Lynden Logistics
Lynden Transport
Maritime Helicopters
Nabors Alaska Drilling
Nalco Champion
NANA WorleyParsons
Nature Conservancy, The
NEI Fluid Technology
Nordic Calista
North Slope Telecom
Northern Air Cargo
Northern Solutions
NRC Alaska
Oil Search
Pacific Power Group
PENCO
Petroleum Equipment & Services, Inc.
PRA (Petrotechnical Resources of Alaska)
Price Gregory International
Raven Alaska – Jon Adler
Resource Development Council
SALA Remote Medics
Security Aviation
Soloy Helicopters
Sourdough Express
Strategic Action Associates
Summit ESP, A Halliburton Service
Tanks-A-Lot
The Local Pages
TOTE – Totem Ocean Trailer Express
Udelhoven Oilfield System Services Inc.
Weona Corp.
Weston Solutions
Wolfpack Land Co.
Worley

● HISTORY

Kenai LNG 50th celebrated in Japan

Part 2 of 2: Still in family — Operatorship of Phillips/Marathon plant moved from ConocoPhillips in 2018 to Andeavor, now part of Marathon

By **KAY CASHMAN**
Petroleum News

The 50th anniversary of the Kenai LNG plant in Nikiski was celebrated at Negishi LNG receiving terminal outside Tokyo, Japan, in a Nov. 6 ceremony hosted by Tokyo Electric Power (now JERA Co.), Tokyo Gas Co., Mitsubishi Corp. and ConocoPhillips Asia Pacific.

1 2 SERIES

The Kenai LNG plant in Nikiski, for decades owned by ConocoPhillips predecessor Phillips Petroleum (plant operator, 70%) and Marathon Petroleum predecessor Marathon Oil (30%, operator of the LNG tankers) began exporting liquefied natural gas to Japan in November 1969, with Mitsubishi acting as a buyer's agent and Phillips as the seller. At the time, the Kenai LNG plant complex, which includes a docking and loading terminal, was the only LNG export facility in the United States and the first source of LNG to Japanese markets.

BILL BULLOCK

The dignitaries that led the Nov. 6 event included Toshihiro Sano, chairman of JERA, Takashi Uchida, president of Tokyo Gas, Takehiko Kakiuchi, president and CEO of Mitsubishi, and Bill Bullock, president, Asia Pacific and Middle East, ConocoPhillips.

"Together Japan and ConocoPhillips pioneered the Asia Pacific LNG market, helping drive economic progress throughout the region. This close relationship endures, as we continue our commitment to safely deliver LNG to the country. We look forward to our continued partnership with Japan, which we see as being a strong, long-term market," Bullock said in a press release prior to the ceremony.

Alaska Gov. Michael Dunleavy toured the receiving terminal following the ceremony with executives from Tokyo Gas (see posed group photo in pdf version of this story — security rules prevented photos being taken during the actual tour).

STATE OF ALASKA

Alaska Governor Michael J. Dunleavy pictured here with representatives of ConocoPhillips (Bill Bullock), Mitsubishi, Tokyo Gas, and JERA, the original Alaska LNG project partners involved with the first shipment of Kenai LNG to Japan.

"The state of Alaska will continue to look at innovative and economic means to commercialize our vast quantities of North Slope gas, to provide cheap clean energy for Alaskans, to create jobs and strengthen the economy of not only Alaska, but our economic partners, like Japan," Dunleavy said. "For decades, Alaska and Japanese citizens, businesses, and our governments have formed relationships through cultural, educational, and economic partnerships. I would like to congratulate our economic and energy partners on 50 years of working together and my sincere wish for a continued prosperous relationship between your country and Alaska."

Gas tug of war starts in 1999

Since 1969, a lot has changed in Southcentral Alaska's natural gas industry.

Initially the area was awash in gas from the Cook Inlet basin, on and offshore, with only about 50,000 people representing the local market.

To use the vast amounts of stranded natural gas, Union Oil, predecessor to Chevron, opened the largest fertilizer plant on the U.S. West Coast in 1968 in north Kenai using gas to manufacture and export fertilizer to the Pacific Rim; next in 1969, the Kenai LNG export facility at Nikiski began production and started exporting LNG to Japan, both entities employing hundreds of Alaskans and making significant contributions to the local economy. (The population of Kenai jumped from 321 in 1950 to 3,533 in 1970.)

While Southcentral Alaska was awash in natural gas with more and more oil and gas being discovered in the 1960s, the largest nearby residential market for gas, Anchorage, the state's biggest city, was simultaneously growing,

In 1970, Anchorage's population was 48,081; by 1980 it had more than tripled to 174,431; by 1990 it was 226,338, by 2010 291,826, and in 2019 the number of inhabitants in the municipality of Anchorage had climbed to 291,538, as compared to an estimated 735,720 citizens statewide.

At the same time, the late 1960's discovery of the North Slope's giant Prudhoe Bay oil field had started diverting oil and gas company attention and investment north.

Still, the most active Cook Inlet producers continued to invest in the Cook Inlet basin for several decades — Marathon, ConocoPhillips and Chevron (and its predecessors Union Oil/Unocal).

But after 30 years, Cook Inlet basin natural gas production was noticeably declining and the attitude toward exporting the products made from that gas — LNG and fertilizer — began to shift, with a rift developing between those who wanted the Kenai LNG plant and fertilizer plant to continue production and those that wanted the gas to be kept in Alaska for use by its residents, as evidenced by the following Petroleum News headlines and story excerpts.

• April 28, 1999, Export license extended for Cook Inlet liquefied natural gas: Department of Energy says supplies in Southcentral Alaska should be adequate for projected needs during extension. …

The U.S. Department of Energy … has granted the export license extension requested by Phillips Alaska Natural Gas Corp. and Marathon Oil Co. for exports from the Nikiski liquefied natural gas plant … for a five-year extension of their existing export license for 2004 through 2009. The extension was protested by Enstar Natural Gas Co. … the protestors argued … that approval of the application would cause a shortage of natural gas in Southcentral Alaska during the five-year extension period. ...

• Sept. 28, 2000, Unocal's Cook Inlet gas program replaces production: Company's gas currently goes mainly to Nikiski fertilizer plant; for basin the challenge will be to meet gradual growth in demand and peak winter demands. …

• April 28, 2001, New study says Cook Inlet needs new gas reserves: At issue — what can be discovered and developed in Southcentral, what needs to be imported, to keep area running on natural gas. …

Cook Inlet natural gas reserves have been falling since 1982, because no significant new reserves have been added and the

see **LNG 50TH** page 11

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LNG 50TH

area will need new supplies — or storage facilities — to meet peak demand by the end of the decade. …

• Nov. 17, 2002, Unocal closes Kenai office, eliminates 71 positions in Alaska operations. …

Unocal Alaska, Cook Inlet's dominant oil and gas producer, is scaling back, a move the company says reflects the fact that its business in Cook Inlet is mature, which means declining resources and few …

• March 14, 2004, Cook Inlet natural gas supply goes short: Major industrial gas user Agrium working with exploration companies exploring for gas, might even partner to find more gas. …

The fertilizer plant on the Kenai Peninsula south of Anchorage, Alaska, was built to take advantage of a stranded gas situation, as was the liquefied natural gas plant next door: big gas discoveries. …

• Dec. 19, 2004, Agrium, Unocal settle litigation over gas supplies to Nikiski fertilizer plant: New gas contract runs through end of October, after which plant will close if no new supplies found. …

• Feb. 27, 2005, Good Alaska location goes bad for Agrium: Nikiski fertilizer plant location's advantages are overshadowed by iffy Cook Inlet gas supply, company says. …

In many ways, Alaska's Kenai Peninsula is a wonderful place for Agrium Inc. to have a nitrogen fertilizer plant, except for one glaring and perhaps fatal weakness — there doesn't seem to be enough natural gas. …

• July 17, 2005, Agrium gets gas to keep plant open. …

Agrium said July 14 that it has concluded gas supply contract negotiations with Cook Inlet producers that will allow it to keep its Kenai nitrogen facility open until November 2006. …

• Nov. 20, 2005, Enstar, Marathon strike new gas contract: The new contract should ensure adequate natural gas supplies for Enstar until 2016. …

Southcentral Alaska residents may feel that they're suffering from sticker shock at escalating natural gas prices but they're still paying considerably less than consumers in the Lower 48. …

• May 28, 2006, Steady as she goes: Marathon continues to maintain Cook Inlet gas production; Kasilof to come online; Kenai field gas storage starts up. …

FILE PHOTO

The Kenai LNG plant at Nikiski on Alaska's Kenai Peninsula.

Marathon Oil Corp. is continuing to develop new natural gas production from its existing Cook Inlet fields while also exploring for and developing new gas fields. That was the key message from John Barnes. …

• Oct. 1, 2006, Cook Inlet gas crunch: Crisis or deliverability issue — Southcentral Alaska players debate gas future. …

There may or may not be a crisis in the Cook Inlet natural gas market, but there are uncertainties, especially with so much of Southcentral's energy needs met by natural gas, the …

• Oct. 8, 2006, Southcentral Alaska running out of cheap gas: Utilities already seeing deliverability problems in Cook Inlet; industrial users provide backstop for utility needs in cold weather. … Natural gas powers electric utilities in Southcentral Alaska, provides heat for residential and commercial customers and is the feedstock for Kenai Peninsula industrial plants which make fertilizer and ...

• Jan. 28, 2007, Inlet gas usage sets record: Enstar, Cook Inlet gas producers scrambled to meet peak; new interconnects planned. ...

Cook Inlet uses more natural gas on cold days — and delivering those peak needs is trickier than in the past. Enstar Natural Gas, the Southcentral gas distribution company, set a throughput record Jan. …

• Jan. 28, 2007, Export extension filed: Nikiski plant partners Conoco, Marathon apply to extend LNG license 2 years. …

• Sept. 16, 2007, LNG plant key to stable Cook Inlet market: Supporters say renewing Nikiski facility's federal export license for two years would be good for economy, industry and state. …

• Sept. 30, 2007, Agrium shutting down: Kenai Peninsula nitrogen facility being mothballed until it gets new gas feedstock. …

• Dec. 2, 2007, Scenario 'alarming … downright scary': Kenai Peninsula Borough mayor tells RDC conference attendees Alaska needs energy plan; closing LNG plant not the solution. …

• June 8, 2008, LNG license renewed: Nikiski export terminal gets 2 year extension; DOE says gas supplies adequate. …

• Jan. 18, 2009, Nearing edge of the cliff: How close is Southcentral Alaska to the limits of Cook Inlet gas deliverability?

At a Regulatory Commission of Alaska public meeting on Jan. 10 officials from Alaska Railbelt gas and electricity utilities described how peak demand for natural gas during a recent cold snap had tested …

• Aug. 2, 2009, Rolling blackouts? The day of reckoning may be approaching for CI utility gas deliverability. …

• March 28, 2010, Cook Inlet needs $2.8B: Study assesses investment in new CI wells to maintain adequate Southcentral gas. ...

• April 18, 2010, More time for exports: Kenai LNG owners to ask for another two-year extension to export license….

• Oct. 31, 2010, Utilities have fuel, facilities issues: Southcentral electrics tell chamber natural gas needed, but also major plant, transmission upgrades, total of $13.5 billion by 2025. …

If you thought declining reserves of natural gas in Cook Inlet were the only issue for Southcentral Alaska energy users, you need to hear the area's major electric utilities talk about the monies. …

see **LNG 50TH** *page 12*

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LNG 50TH

• Nov. 14, 2010, Chevron pulls plug: Cook Inlet assets for sale, holding onto North Slope, ANWR leases. …

Chevron said Oct. 12 that it plans to market all Cook Inlet assets owned by Union Oil Company of California and Chevron U.S.A. Inc. …

• March 20, 2011, Keeping all options open: ConocoPhillips plans to preserve Cook Inlet LNG plant for possible future use. …

When ConocoPhillips announced in February that it would close the LNG plant that it operates on Alaska's Kenai Peninsula, the company said that it would begin mothballing the plant after it offloads its last consignment of LNG, probably in April or May. And at an Anchorage Energy Task Force meeting on March 15 Dan Clark, manager of Cook Inlet assets for ConocoPhillips Alaska, said that the company plans to put the plant into a "preserved condition."

• Aug. 4, 2011, Kenai LNG facility to run through August. …

Four additional liquefied natural gas cargoes, one to China and three to Japan, will allow the Kenai LNG plant to remain open through early August. ConocoPhillips said April 19. ...

• July 24, 2011, New inlet player: Houston-based, privately held Hilcorp buying Chevron's Cook Inlet assets. …

The familiar logos long associated with Union Oil Company of California and Chevron will soon be absent from Alaska's Cook Inlet, replaced by a new logo, that of Houston-based Hilcorp Energy. …

• Oct. 16, 2011, Conoco buys Marathon Oil's 30% share of Nikiski LNG plant. …

• March 25, 2012, No respite ahead: PRA now projects Cook Inlet natural gas supply shortfall in 2014 or 2015. …

A new flurry of exploration activity in the Cook Inlet basin in recent years and reports of some possible new gas fields on the horizon would seem to bode well for the future of the utility natural gas, but …

• April 15, 2012, Marathon to exit Alaska: Selling its Cook Inlet assets to Hilcorp to focus on oil resources elsewhere. …

Hilcorp, others improve gas picture

Although there was still not enough natural gas coming from the Cook Inlet basin to meet the needs of all users by 2014, Hilcorp and smaller companies were improving the situation by squeezing more gas out of mature oil and gas fields, as well as exploring for and finding new reserves.

The following excerpts from the story "Gas exports to restart: DOE issues new export license for ConocoPhillips Kenai Peninsula LNG facility" best explains the Cook Inlet gas situation at this point in time:

The U.S. Department of Energy has authorized the renewal of a license for the export of liquefied natural gas from ConocoPhillips' LNG facility at Nikiski on the Kenai Peninsula to countries that do not have free-trade agreements with the Unites States, ConocoPhillips said April 14.

In February the agency issued a similar license for the export of LNG to countries that do have U.S. free-trade agreements.

Both licenses run for a period of two years and, individually or in combination, allow for the export of up to 40 billion cubic feet per day of gas. ...

Given the recent debate about potential shortages of Southcentral utility gas from the Cook Inlet basin, it may appear counter-intuitive to see the authorization of gas exports from the basin. Indeed, in early 2013 ConocoPhillips, citing uncertainty in the local gas market, mothballed the Nikiski LNG plant when a previous export license expired. But with companies such as Hilcorp Alaska and Cook Inlet Energy revitalizing Cook Inlet gas production, and with multiple companies exploring in the basin and bringing new gas fields on line, the gas supply situation has changed dramatically in recent years. The Southcentral Alaska gas and power utilities have now all secured contracts to fully meet their gas supply needs through to the first quarter of 2018. And, with Hilcorp having furnished the bulk of those contracts, other companies have been expressing concern about finding markets for new gas, should gas exploration prove fruitful. ...

ConocoPhillips pauses LNG exports

Two years later in early 2016 ConocoPhillips paused exports from the Kenai LNG plant, although the facility continued to produce some LNG, during the second half of the year sending eight tanker truckloads to Fairbanks Natural Gas LLC facilities.

In November 2016, the company sold its legacy offshore North Cook Inlet gas field and the Tyonek platform to Hilcorp, and put the LNG plant up for sale, just three years shy of its 50th birthday.

In December, ConocoPhillips sold most of the rest of its Cook Inlet fields and related assets in separate transactions to Hilcorp, including (but not restricted to) the North Trading Bay and Nicolai Creek units.

Unsuccessful in finding a buyer for the Kenai LNG plant, ConocoPhillips mothballed it in mid-2017.

In early 2018, ConocoPhillips sold the plant to Andeavor, formerly called Tesoro Corp., and the long-time operator of the nearby Nikiski oil refinery. The sale price was an (unconfirmed) $10 million versus its Kenai Peninsula Borough assessed value of $55 million.

Marathon-Andeavor merge

In 2018, Marathon once again became a big player in the Cook Inlet basin when it merged in a takeover with Andeavor, a deal that closed later that year.

The merger gave Marathon ownership and operatorship of both that the Kenai LNG plant complex, which includes a dock and loading facility, or terminal, and the nearby Kenai oil refinery.

In the April 30, 2018, deal, Marathon agreed to buy rival Andeavor for $23.3 billion, creating the largest independent fuel maker in the United States, with an initial enterprise value greater than $90 billion.

Although Alaska is a minor player in the merged entity's portfolio of refining assets, both the LNG plant and the oil refinery have something deemed important in the Marathon-Andeavor merger presentation — export port access.

On Jan. 31, 2019, Andeavor spokesman Scott LaBelle told Petroleum News in an email, "This acquisition further strengthens our integrated value chain by optimizing our operations in Kenai and providing low-cost fuel for our (oil) refinery to produce the fuels that consumers in Alaska need to keep their lives moving."

The Kenai LNG plant was the last of ConocoPhillips' Cook Inlet assets to be sold, as the company had long been focusing on its North Slope oil fields and exploration prospects.

Exporting LNG has not resumed under Andeavor.

Another look at gas supplies

In response to a commission by Enstar Natural Gas Co., Petrotechnical Resources of Alaska updated its 2012 assessment of Cook Inlet gas demand and supply. (See "PRA Cook Inlet gas forecast indicates more development needed" in May 20, 2018, issue of Petroleum News.)

The revised assessment indicated that at current rates of gas well drilling, gas supplies would start to fall short of demand in 2021.

Of course, none of the production was allocated for the Kenai LNG plant or the fertilizer plant, which currently belongs to Nutrien. (See Petroleum News story, "Nutrien continues to work on re-starting Alaska fertilizer plant" in the June 9 edition.)

Kenai LNG Cool Down Project

Trans-Foreland Pipeline Co., a wholly owned arm of Marathon via the acquisition of Andeavor, formerly Tesoro, by Marathon, filed in April with the Federal Energy Regulatory Commission for authorization to construct, install, own and operate modifications to the Kenai LNG plant, under Section 3 of the Natural Gas Act.

The company applied to make facility modifications to "bring parts of the Kenai LNG plant out of current warm idle status by importing LNG and using the LNG to cool existing LNG storage tanks and associated LNG facilities," as well as minor modifications to prevent environmental and economic waste from boil-off gas.

The work would involve installation of a new 1,000 horsepower electric-driven boil-off-gas booster compressor unit and related equipment with the goal of importing LNG so that the Kenai plant could provide up to 7 million standard cubic feet per day of natural gas to Marathon/Trans-Foreland's affiliated Kenai Refinery.

The modifications are collectively referred to as the "Kenai LNG Cool Down Project."

FERC has set the schedule for environmental review of the project, with the environmental assessment to be released Dec. 13 and the 90-day federal authorization decision deadline March 12, 2020.

Will LNG exports ever again take place from the Kenai LNG plant? It largely depends on gas supply and that is an unknown, although Hilcorp and a couple other companies are exploring for additional reserves.

And there is still talk of bringing North Slope natural gas via a pipeline to Kenai, but that will depend on economics, which has always been an obstacle for natural stranded so far from markets.

Stay tuned. ... ●

Contact Kay Cashman at publisher@petroleumnews.com

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PIKKA POD

project, while also engaging with stakeholders and being involved in budget and planning for 2020 and beyond.

Although the POD describes proposed operations for the North Slope winter off-road season 2019-20, through early production start in 2022 and full-facility production in 2024, the actual term of the plan is one year, from Feb. 1, 2020, through Jan. 21, 2021.

While there were no significant changes in development activities previously made public by Oil Search Alaska and reported by Petroleum News, the document confirmed project details and provided a few updates, such as the company is still working with Kuukpik Corp. regarding access to Kuukpik surface lands for Pikka unit operations. Kuukpik is the Native village corporation for the community of Nuiqsut.

Pikka B and C drilling

An annual report in the POD describes operations conducted under the current and fourth, plan of exploration, or POE, that ends Jan. 31.

Planned activities for the fourth POE were based on the drilling of the Pikka B, Pikka B ST1, Pikka C and Pikka C ST1 wells.

The company completed that drilling, with "data analysis ongoing and expected to be completed" by Jan. 31, the POD said.

Oil Search Alaska, or OSA, built ice roads and two ice pads beginning at the Mustang pad in the Southern Miluveach unit to the Pikka B and Pikka C appraisal well sites.

Pikka B was drilled to a depth of approximately 5,192 feet true vertical depth, and its deviated sidetrack well was drilled to 4,921 feet TVD. A production test was done at the Pikka B ST 1.

The Pikka B wells "helped delineate the southern half of the planned Nanushuk development area and in the subsurface basis of design," the POD said.

OSA drilled the Pikka C well to approximately 4,650 feet TVD, and the Pikka C ST 1 horizontal sidetrack well to 4,118 feet TVD in the central part of the unit. These wells helped "delineate the northern limit extension of the reservoir and in the subsurface basis of design," per the POD.

Coring, logging, AVO analysis

Conventional core was acquired in both wells along with a "full suite of LWD (logging while drilling) and wireline logs, including fluid sampling," the POD said.

Routine and special core analysis, or SCAL, was done on the conventional core from Pikka B, Pikka B ST 1 and Pikka C wells.

"SCAL conducted on the nearby Qugruk 8 well has identified key uncertainties with respect to reservoir quality distribution and water saturation as predicted by capillary pressure experiments," the POD said. "The routine and SCAL work will investigate reservoir quality distribution, water saturation and capillary pressure to reduce uncertainties and narrow the range of outcomes in the Nanushuk reservoir model. In addition to a robust set of routine analyses, a number of SCAL, including relative permeability, capillary pressure, fluid flow velocity and fluid sensitivity analyses were undertaken."

Fluid sampling for the Pikka B and C sidetracks was gathered via LWD MDT (measurement while drilling) and samples collected during the well test.

"Single-phase fluid samples will help address key remaining uncertainties identified in pre-FEED engineering study, including asphaltene precipitation and miscible gas injection," the POD said.

Initial modeling of enhanced oil recovery through miscible gas injection has been "encouraging, but additional testing of single-phase oil samples is needed to confirm the results."

Data acquired in the Pikka B and C wells is being integrated into OSA's reservoir model. Adjustments, the POD said, "will be made to the stratigraphic framework and distribution of reservoir properties within the static model. Fluid analyses and SCAL will be integrated into the dynamic model through refinement of the relative permeability and capillary pressure curves."

Results from recent wells are also being integrated into existing 3D seismic interpretation, the POD said, noting "adjustments will be made to the existing elastic inversion and AVO models as appropriate. The results of geophysical modeling will be used to guide the distribution of reservoir properties with the static reservoir model." (AVO analysis is a technique geophysicists use to determine thickness, porosity, density, velocity, lithology and fluid content of rocks. Successful AVO analysis requires special processing of seismic data and seismic modeling to determine rock properties with a known fluid content.)

OSA continues to advance facility engineering and design and contract negotiations for Pikka unit development, per the POD.

The Pikka B and C wells allowed further appraisal of the giant Nanushuk reservoir for the front-end engineering and design, or FEED, phase of the project, and "inform the subsurface basis of design for planning of development wells and production infrastructure," the POD said.

An Oct. 22 release of OSA's parent company's third quarter financial results said it was on track to enter FEED by the end of this year, as planned.

Key development activities

Based upon work conducted under previous POEs, as well as the drilling of the Pikka B and C wells last winter, the POD said the company is "moving forward with development activities to conduct a major hydrocarbon development in the Pikka unit" that will initially tap two of the stacked plays — the Nanushuk and Alpine reservoirs.

"Subject to satisfactory commercial terms and economic conditions," the key development activities expected to occur in the POD period include:

• Further front-end engineering work that is scheduled for completion in mid-2020, which will help reach a final investment decision by the working interest owners at that time (timing confirmed Oct. 22).

• A civil works program to install gravel roads and pads, as well a bridge over the Miluveach River.

• Procurement of materials with extended delivery schedules.

Future key development activities involve development drilling beginning in early 2021 from an initial development pad, first targeting the Nanushuk reservoir; early production start in 2022 "to acquire additional data in support of reservoir management;" and construction activities for the remaining field infrastructure, such as processing facilities, additional pipelines, etc. that is scheduled to occur in parallel.

And, of course, commissioning of processing facilities and full facility production in 2024.

Civil works over two-years

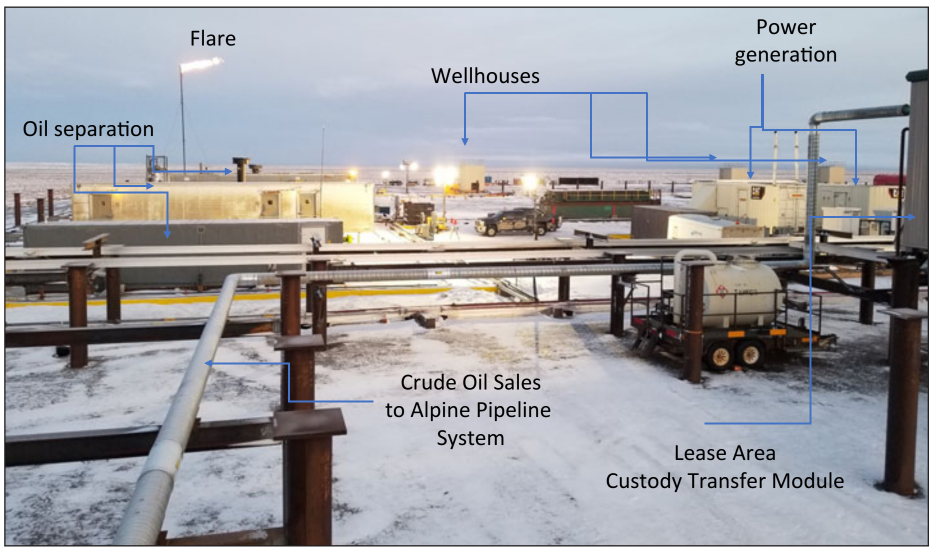
The civil works program, which will be both in the Pikka unit and adjacent to it, is part of a two-year program across winter 2019-20, summer 2020, and winter 2020-21, to establish the necessary civil infrastructure for development. It will involve ice road construction, gravel roads and pads, and bridge and culvert installation.

Gravel will come from the ASRC gravel consolidated mine site and the North Slope Borough gravel mine site F.

Specific winter 2019-20 activities, pending receipt of necessary approvals

see **PIKKA POD** *page 18*

BROOSK RANGE PETROLEUM CORP.



Mustang production facilitiies online.

continued from page 1

ANS APPEAL

and level path."

As Petroleum News previously reported, the Mustang oil field, operated by Brooks Range Petroleum Corp., went online Nov. 2 utilizing an early production facility. The field is in the Southern Miluveach unit, adjacent to the Kuparuk River unit.

BRPC is run by Bart Armfield, who has directed the project from the beginning.

For the first few days Mustang oil was trucked and sold to nearby operator Eni because ConocoPhillips needed to "certify the meters, open the blinds and have a person on location," and BRPC did not have enough storage capacity, Jourabchi said Nov. 6.

Since then the oil has been flowing through Mustang's pipeline to the Alpine pipeline and on to the trans-Alaska pipeline.

The plan is to ramp production up to 6,000 barrels per day and use the revenue to upgrade to a larger scale and permanent 15,000 barrel-per-day production facility, BRPC told Alaska's Division of Oil and Gas in its Sept. 30 filing of Southern Miluveach's seventh annual development plan.

Initial production, BRPC told the division, will be from two existing wells — North Tarn 1A and SMU M-02, with Mustang 1A next. The suspended well "requires drilling lateral extension/possible sidetrack," which will be done in January.

Up to four new wells will be drilled in 2020, with full development involving a total of 10 producer and 11 injectors.

BRPC told the Alaska Oil and Gas Conservation Commission that audited Kuparuk reserves are 21.2 million barrels of 1P (proven oil in place), with a total recovery after waterflood of up to 35%, expected to rise to 40% with tertiary recovery. ●

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PIPELINES & DOWNSTREAM

Pipeline progress and pain

The beat goes on in Canadian pipeline two-step.

Every hint of progress on one front seems to get dealt a setback on another.

The best news lately came from Enbridge, which expects the Canadian portion of Line 3 from Alberta to the U.S. Midwest will be fully operational by Dec. 1 and analysts are hopeful that U.S. regulatory barriers will be removed and open the way for deliveries to reach capacity of 370,000 barrels per day in the second half of 2020.

If that happens there will be some relief for the glut of oil sands bitumen trapped in Western Canada.

Those hopes are tied to a revised environmental impact statements from Minnesota regulators which are due for release by Dec. 9, allowing Enbridge to complete the replacement of an aging system at a cost of at least C$9 billion.

Separately, service has been restored on the existing Keystone pipeline which was shut for a week after an estimated 1.5 million liters of crude leaked from a rupture in North Dakota, one of the largest U.S. onshore spills in the past decade.

Enbridge Chief Executive Officer Al Monaco said his company is "putting more pipe in the ground to enhance overall safety and reliability of the system, giving us more operating flex." He also said Enbridge is on pace to free up an additional 100,000 bpd of pipeline capacity on its lines by the end of 2019 through optimization.

Separately, service has been restored on the existing Keystone pipeline which was shut for a week after an estimated 1.5 million liters of crude leaked from a rupture in North Dakota, one of the largest U.S. onshore spills in the past decade.

Without explaining what happens, operator TC Energy (formerly TransCanada), which is engaged in an endless regulatory and court battle to proceed with its 800,000 bpd Keystone XL link to the Texas refinery region, insisted that the "leak detection systems enabled us to remotely shut down the pipeline."

The company said no concerns have been raised about air quality around the site, or the adjoining area.

But Canadian producers suffered from the fallout, which saw Alberta heavy crude prices get dragged down to about US$34 a barrel compared with about US$56 for West Texas Intermediate.

The U.S. Pipeline and Hazardous Materials Safety Administration has ordered TC Energy to provide an affected portion of the pipeline to testing by an independent laboratory.

—GARY PARK

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AK LNG BATTLE

statements."

Kenai told FERC that the Mat-Su Borough contends that the U.S. Army Corps of Engineers believes the DEIS is "inadequate."

"Nothing could be further from the truth," Kenai said.

While the Corps commented on various aspects of the DEIS, it "did not, however, object to the principal conclusion in the DEIS that the Port MacKenzie site advocated by Mat-Su for the Alaska LNG terminal 'would not provide a significant environmental advantage over the proposed Nikiski site.'"

"Tellingly, USACE has not requested a supplement to the DEIS," Kenai told FERC. "Having observed that the NEPA process, based on the ongoing analysis by the interested agencies, reached a conclusion different from Mat-Su's desired result, Mat-Su seeks to disrupt and delay this proceeding," KPB said.

Kenai also notes that the Port MacKenzie alternative "would allow for only two of the three currently identified gas delivery points within the state," denying benefits of direct gas delivery to the Kenai Peninsula.

As for who gets to decide on the site, Kenai said: "AGDC was created by Alaska statute and delegated the authority to select the site for the Alaska LNG export terminal. AGDC selected Nikiski on the Kenai Peninsula as the preferred sit. Mat-Su is now questioning the decision of the State of Alaska, even when there is no environmentally preferable site." ●

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ENCANA MOVES

saying the shift of Encana's corporate domicile to the U.S. and dropping the tie to Canada in the corporate name is indicative of a "broader decline" of the Canadian energy sector and a deliberate policy of Prime Minister Justin Trudeau's government to phase out the oil sands.

For Kenney it was a blow to his strategy since taking power in April of lowering corporate taxes in hopes of reviving capital investment, battling to get pipelines out of Alberta to new markets.

Alberta Energy Minister Sonya Savage said Trudeau's signal on the importance of oil and gas to the Canadian economy has been "abysmal. It's very difficult for investors to have confidence in Canada. This is a very hostile environment for producers."

Cenovus Energy CEO Alex Pourbaix called the move a "tragedy for Canada. To see a company of that importance to Canada now exit its head office is a tough day."

The only comment from Trudeau's government came from Natural Resources Canada, which said it was "disappointed" with Encana's decision, but promised to "ensure that Canada and Alberta remain competitive and that our energy sector remains a source of good, middle-class jobs."

Just 4 employees in 1975

In 1975 AEC employed just four people, who quietly developed a strategy for the company's next move when it attracted huge public support by selling half its shareholding at C$10 a share to raise C$75 million, leaving the balance under government control.

Over the next 20 years AEC embarked on a rapid expansion path, buying a stake in the Syncrude Canada oil sands consortium, opening a natural gas storage facility that later became AECO, the Alberta trading hub, and started its own steam-powered oil sands project.

Then it moved speedily into the big leagues, merging with PanCanadian Petroleum in a C$23 billion deal to create Encana, while selling its international holdings to pursue its development of unconventional gas resources in North America.

The fact that Encana's share price has tumbled almost 70% in the last two years and that it has no controlling shareholder could make it an attractive target for a prospective buyer.

In 2008, Encana split in half — one company under its existing name to focus on natural gas and one labeled Cenovus to hold most of its parent company's oil assets (conventional and oil sands).

It didn't take long before Encana saw the folly of its ways in unloading oil. A corporate strategy of doubling gas production by 2015 was abandoned as it started to build a portfolio in natural gas liquids.

Suttles hired in 2013

After years of floundering in its search for a path to success, Encana entered a new phase after Chief Executive Officer Randy Eresman ended his eight-year term by hiring Doug Suttles as president and CEO in mid-2013.

By then Encana had faded from its glory days, which briefly saw the company hold the largest market capitalization of any listing on the Toronto Stock Exchange, lead North America in gas production and puts its stamp on the Calgary skyline by erecting The Bow, a 57-storey tower as its headquarters.

Suttles arrived at Encana after a series of senior positions with ExxonMobil and BP (including president of BP Exploration (Alaska) and later as BP's lead executive in the aftermath of the Deepwater Horizon.

He got compensation of C$15.5 million last year, by which stage he had delivered a strong hint of changes to come when he moved his own operations from Calgary to Denver, citing personal reasons.

US shale oil

That came after several moves over the years to boost Encana's presence in U.S. shale oil, including the US$5.5 billion acquisition of Newfield Exploration a year ago to add major operations in Oklahoma — deals that some analysts viewed as over-priced.

Production last year in Canada totaled 209,000 barrels of oil equivalent per day in the Montney and Duvernay plays, and 313,000 boe per day from the Anadarko, Permian, Eagle Ford, Uinta and Williston plays.

Suttles told analysts that setting up shop in Denver will give Encana (Ovintiv) access to a much larger source of investment from U.S. index funds, which have grown in popularity as exchange traded funds.

(Encana was always well understood as a blending of Energy and Canada; the choice of Ovintiv was explained by Encana as standing "for our commitment to deliver unmatched value through continuous innovation" — triggering a "whatever" response from many observers.)

Suttles said the rebrand was driven by the market's perception that the company was primarily a natural gas enterprise, hurting its valuation.

"We're proud of our company's history, but we have meaningfully transformed our business ... and it is important that transformation is recognized."

Foreign buyer more possible

Generally overlooked in the fallout is the prospect that Encana's move to the U.S. will open the door for a foreign buyer to acquire the company without making pledges to the Canadian government about job security or investment to gain federal approval.

The fact that Encana's share price has tumbled almost 70% in the last two years and that it has no controlling shareholder could make it an attractive target for a prospective buyer.

Attorneys say such a bid would not face a review under the Investment Canada Act, ICA, which requires a commitment over three to five years that deals for companies worth more than C$1 billion would generate a "net benefit" to Canada and "significant undertakings (to the federal minister of Innovation, Science and Economic Development)" on how a new owner would operate a Canadian business.

"Once the ICA no longer applies to a transaction, the government certainly loses the ability to get those net benefit undertakings," said Chris Hersh at the law firm of Cassels Brock & Blackwell in Toronto. ●

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INSIDER

letter. And “consistent with its obligation to manage the state’s resources for the maximum benefit of the people,” DNR is also doing “extensive due diligence and review” of the deal.

While it is “early in this process, significant resources within this agency and the Department of Law are currently deployed to ensure this robust oversight,” Feige said.

A partial list of DNR’s ongoing review activities includes: “(1) examining the purchase and sale agreement that effectuates the sale to understand how the obligations to the state are shared amongst the parties, including whether or not the original lessee remains liable for obligations accruing before the transfer; (2) contracting with an independent and highly respected economic consulting firm to rigorously examine Hilcorp’s ability to fulfill its obligations to the state under a set of stressful scenarios; (3) examining the existing financial assurances structure to determine what amendments will be required to properly manage the change in the state’s risk profile due to the sale; (4) conducting a thorough in-house financial analysis of several years of financial information; and (5) identifying and resolving any potential issues associated with the operation of acquired pipelines and infrastructure.”

In addition to DNR, other state agencies have a regulatory oversight role concerning the sale, Feige said, including but not limited to: the Alaska Oil and Gas Conservation Commission on issues regarding bonding and transfer of well ownership; the Department of Environmental Conservation on discharge prevention and contingency plan approvals and certificates of financial responsibility; the Regulatory Commission of Alaska concerning the transfer of common carrier pipeline assets; the Department of Revenue on possible tax implications; and the Department of Fish and Game regarding the possible transfer of permits.

—KAY CASHMAN

RDC’s Carl Portman to retire in June


CARL PORTMAN

THE RESOURCE DEVELOPMENT COUNCIL for Alaska will lose one of its most valuable employees at the end of June, Deputy Director Carl Portman.

Among many other duties, Portman has been responsible for the impressive list of presenters at the association's conference every November.

Set to retire June 30 after what will be 39 years with RDC, Portman said he will be leaving after the association’s annual meeting.

“I still plan to help out RDC on a volunteer basis, working on the conference and other … issues. I would also like to get involved in other organizations, including Food Bank of Alaska. It’s going to be a challenging adjustment, but I’m ready to give it a shot,” he said.

—KAY CASHMAN

AG seeks to intervene in enviro lawsuit re. Hilcorp Cook Inlet seismic

THE ALASKA ATTORNEY GENERAL’S OFFICE filed a motion Nov. 13 to intervene in a lawsuit by Cook Inletkeeper and the Center for Biological Diversity that challenges the decision by the National Oceanic Atmospheric Administration, acting through the National Marine Fisheries Service, to issue incidental take regulations and letters of authorization okaying the unintentional take of marine mammals by Hilcorp Alaska that allow the company to conduct underwater seismic surveys on oil and gas leases in lower Cook Inlet.

Among other things, any delay in the development of the leases causes a “direct negative impact on Alaska’s tax revenues,” the AG’s motion says.

The case, in the U.S. District Court for the District of Alaska, is No. 3:19-cv-00238-SLC.

—KAY CASHMAN

Dunleavy appoints Walsh, Reaves to board

ALASKA GOV. MICHAEL DUNLEAVY recently reappointed Tom Walsh, Anchorage, and appointed Dave Reaves, Wasilla, to Alaska’s Oil and Gas Competitiveness Review Board.

Walsh’s term runs until July 1, 2023, and Reaves until July 1, 2021, according to statement from the administration.

Created in 2013 by Senate Bill 21, the board was designed as a resource for the Alaska Legislature, and is tasked with establishing and maintaining salient data on oil and gas exploration, development and production, as well as providing lawmakers with factual information on the state’s fiscal system, labor pool and regulatory competitiveness,

The board’s first report was delivered to the Legislature in March 2015. It is in the process of updating that report and developing a score card that simplifies where Alaska stands compared to its competition around the world (see story in Oct. 27 issue of Petroleum News).

—KAY CASHMAN

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PIKKA POD

and agreements, are expected to entail:

- Ice road construction (in support of gravel lay activities).
- Mine site deployment and rehabilitation. (Gravel will be placed for the Nanushuk access road; Nanushuk operations pad; Nanushuk process facility pad; ND-B access road and pad; access road and pad for water access to lake 7903; and initial upgrades to the Mustang Road.)
- Bridge installation across the Miluveach River.
- Culvert installation (cross-drainage and fish passage) along relevant sections.

Placement of gravel for a tie-in pad in the vicinity of ConocoPhillips operated Kuparuk central processing facility 2 is also scheduled.

Summer 2020 work activities will likely involve:

- Pipeline road crossing casing installation.
- Rework of gravel paced in the winter.
- Additional Mustang Road upgrades.

Activities over the 2020-21 winter season are anticipated to include;

- Work not finished in winter 2019-20 and construction of other civil infrastructure.
- ND-C access road and pad.
- Access road and pad for the boat ramp.
- Installation of the Kachemach River bridge.

Temporary infrastructure for the 2020 activities will consist of camps at both mine sites, as well as on-ice infrastructure in the development area, the POD said.

Infrastructure elements

Major components of Pikka infrastructure include:

- Nanushuk processing facility to receive produced fluids from the drill sites to convert it to sales quality crude. (The NPF includes power generation for all project facilities.)
- Nanushuk operation pad with the main camp, shops, storage, water and wastewater treatment, and fuel station.
- Three drill sites for the drilling equipment and support facilities for both drilling and completion operations as well as production (e.g. pipeline pigging), routine well testing and process fluid heating.
- Infield pipelines and cables from and to the processing facility and the three drill sites, ND-A, ND-B and ND-C, including multiphase production pipelines, water injection pipelines, gas lift pipelines (HP gas for artificial lift), gas injection pipelines (HP gas for miscible water alternating gas flood oil recovery) and fiber optic and power cables.
- Import and export pipelines and cables from and to the processing facility and any required tie-in pad(s) including an oil export pipeline, a water pipeline, a fuel gas pipeline, a fiber optic cable and a power cable.
- Other civil infrastructure supported by gravel pads with connecting gravel roads.

Future opportunities

Once Pikka production operations are underway, OSA will conduct well, reservoir and facility management activities to optimize economic hydrocarbon recovery. Future development opportunities within the unit will be “appraised and evaluated as they become known/understood through these activities,” the POD said.

OSA has completed appraisal drilling activities “sufficient” for defining the resource targets (and surface locations) for the proposed Pikka development.

The development drilling beginning in 2021 will further delineate the resource distribution within the unit.

A participating area has not yet been established in the unit; but an application to establish a PA will be submitted “prior to commencement of regular production,” the POD said.

Additional exploration and appraisal drilling of high-value targets will be conducted where justified, possibly necessitating the need for more PAs.

—KAY CASHMAN

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PORT OF ALASKA

without significant input from the users of the facility.

"Marathon ... our issue is, we want to make sure that whatever the project is — whether it's repairing and replacing what they have, because it could be there for some long term — or whatever they create new, we are just wanting to ensure that it's effective, that it's safe, and that it's usable."

Sullivan said Marathon has been active in discussions throughout the last year with the design team, the city and the port.

"It's still a process; we're not completely satisfied," he said. "There are still a lot of questions out there about the design, and how it will interact with the existing infrastructure."

"It's not a done deal in our minds," Sullivan said. "We still have a lot of concerns; they're going full speed ahead."

"As a group, the users group had a lot of questions about the financing model; we haven't really seen a full financing package, and we've advocated that they get a full financing package," he said.

The user group does however appreciate the federal assistance.

"We're glad to see a lot of these grants come in," Sullivan said, "We really wish that they would kind of pause until they get their heads wrapped around the rest of it."

"It was fully designed, but without any real input from the stakeholders — the people that are actually going to use the dock," he said. "That is a little bit of the crux of the issue, that we as the user group, and Marathon, to some degree, have had on the design aspect."

"Unfortunately, they lacked the stakeholder buy-in," Sullivan said.

To date "very few" of the stakeholders' comments have been incorporated into the port's plans, he said. "They've taken some comments, and they've not taken some others."

The stakeholders are supportive, but they want to support the right project, Sullivan said. "We want that port to be successful, but we also want to do it in a prudent fashion, both financially and construction wise."

Tariff increase plan

The Port Commission, in its October meeting "approved a tariff increase plan to pay for construction of the remainder of the petroleum cement terminal, PCT-1," Jager said.

Shore side work finished in the summer of 2019, Jager said. It entailed stabilization work, and transitional dredging for the new dock.

"That's all done, and that has been paid for with money that we already had," he said.

The second phase is to be built in 2020.

"We contracted with Pacific Pile and Marine to do that work," Jager said. "We already have money in the bank and a contract let, and we're all set to start construction this spring, of just the trestle and deck — it will not be a usable dock."

In 2021, the goal will be "to put in the mooring dolphins, and all of the fendering, and then all of the infrastructure on top of the deck that makes it useful — things like the pipes, the cement and fuel offloading systems, and equipment," Jager said. "That work is what the tariff increase would pay for. We do not have money for that at this time."

"When they came up with the number for the tariff increase, that assumed that we would get some grants and some

U.S. ARMY CORPS OF ENGINEERS

Port of Alaska, Anchorage

favorable loan packages that would reduce the amount of the total project cost. We don't know exactly which grants or which favorable loan terms we'll get," Jager said the $25 million grant goes a long way toward answering that question.

"At some level, it was already cooked into the plan that the Port Commission has for how we're going to pay for the new docks," he said. "We're not changing anything we're doing; we're still moving forward with the same tariff increases."

Final construction out to bid early 2020

"This winter, probably in January-February — sometime in the first quarter of 2020, we will go out to bid for the construction for that final phase," Jager said. "Once we get the construction bids back, probably in June, we'll open those bids up, and we'll know how much it's going to cost to build that final piece of the dock."

"We will look at that, and we will look at whatever other grants and beneficial loan arrangements we may have gotten, and that's when we'll be able to say, what is the final tariff have to be," he said.

"For right now, we're moving forward with exactly the plan we had, because there's still so many unknowns that we don't know exactly how it's all going to shake out."

Jager said he regretted confusion raised when a consultant's presentation emphasized potential Alaska Industrial Development and Export Authority 50-year term financing as part of the basis for new tariff charges.

"If you look at the graphics he provided, he had what he called the AIDEA scenario, where we got certain beneficial loan terms from AIDEA," Jager said. "We have pursued those further and at this point we think we're not going to get those ... it should have said, 'favorable grant and loan scenario.'"

"Based upon meetings that we had last week, AIDEA's loan terms are more likely to apply to the cargo deck than to the petroleum cement terminal, but we still have some other loan options out there," he said. "We're working on a TIFIA loan that could give us terms that would be very similar to what we were expecting, or what we had factored in as a possible AIDEA scenario."

The Transportation Infrastructure Finance and Innovation Act provides credit assistance for qualified surface transportation projects of regional and national significance, according to the U.S. Department of Transportation.

"We have a couple of other grant proposals out there," Jager said. "You don't know exactly what grants you're going to get, and exactly what beneficial terms; it's a ballpark, pretty good order of magnitude guess."

"But on the other hand, if you go, 'I can't make a decision until I have a certain number,' you're stuck in the headlights; you'll never make any progress," he said. "We've basically made our best guess; we're moving forward, and as the uncertainty disappears, the Port Commission will come back and adjust the tariffs."

"We think we've got conservative numbers that are probably the worst case," he said. "It could very well be better, meaning the ultimate tariffs will be lower."

The tariffs are to be "smoothed" upward over 10 years, but if savings warrant, "we just won't do the final increases

According to the port website, 94% of all refined petroleum products entering Southcentral Alaska enter through the Port of Alaska.

if they're not needed," Jager said.

Jager said the port will continue to pursue grants up to and past the commencement of the project.

"Probably after construction is done, not so much," he said. "There are a number of grants though, that are reimbursable grants ... for instance, FEMA has grants for resiliency — earthquake preparedness."

Fuel terminals 'most at risk'

Constructing an earthquake resistant dock is a priority for the port.

According to the port website, 94% of all refined petroleum products entering Southcentral Alaska enter through the Port of Alaska.

Jager said that at POL-2, the newest existing petroleum, oil and lubricant dock, 20% of the piles under the main deck of the dock failed during the 7.0 earthquake of 2018.

"Now we've gone in and put pile jackets on; we've fixed it, if you will — but the bottom line is, our two fuel terminals are our most at risk terminals," Jager said. "It's critical that we get a resilient dock built so that we're ready for the next earthquake."

The new dock will be robust in that regard.

"PCT will be built to what I'm calling super seismic standards," Jager said.

"In order to build anything you have to hit building codes," he said. "Normal building codes more or less hit what is called a life safety standard; if you're standing on the dock when the big earthquake hits, you will get to shore alive. That's the goal. The dock itself may not survive."

"We're building to super seismic standards that say, not only will the people who are on or in the vicinity of the dock survive, the dock itself will survive and will be more or less fully functional within seven days of the big event."

"You've got to have piles that are a little heftier — a little more robust; your trestle needs to be more robust," Jager said, adding that all the systems need to be extra strong to survive the design earthquake, which is just a bit bigger than the 1964 earthquake was. ●

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