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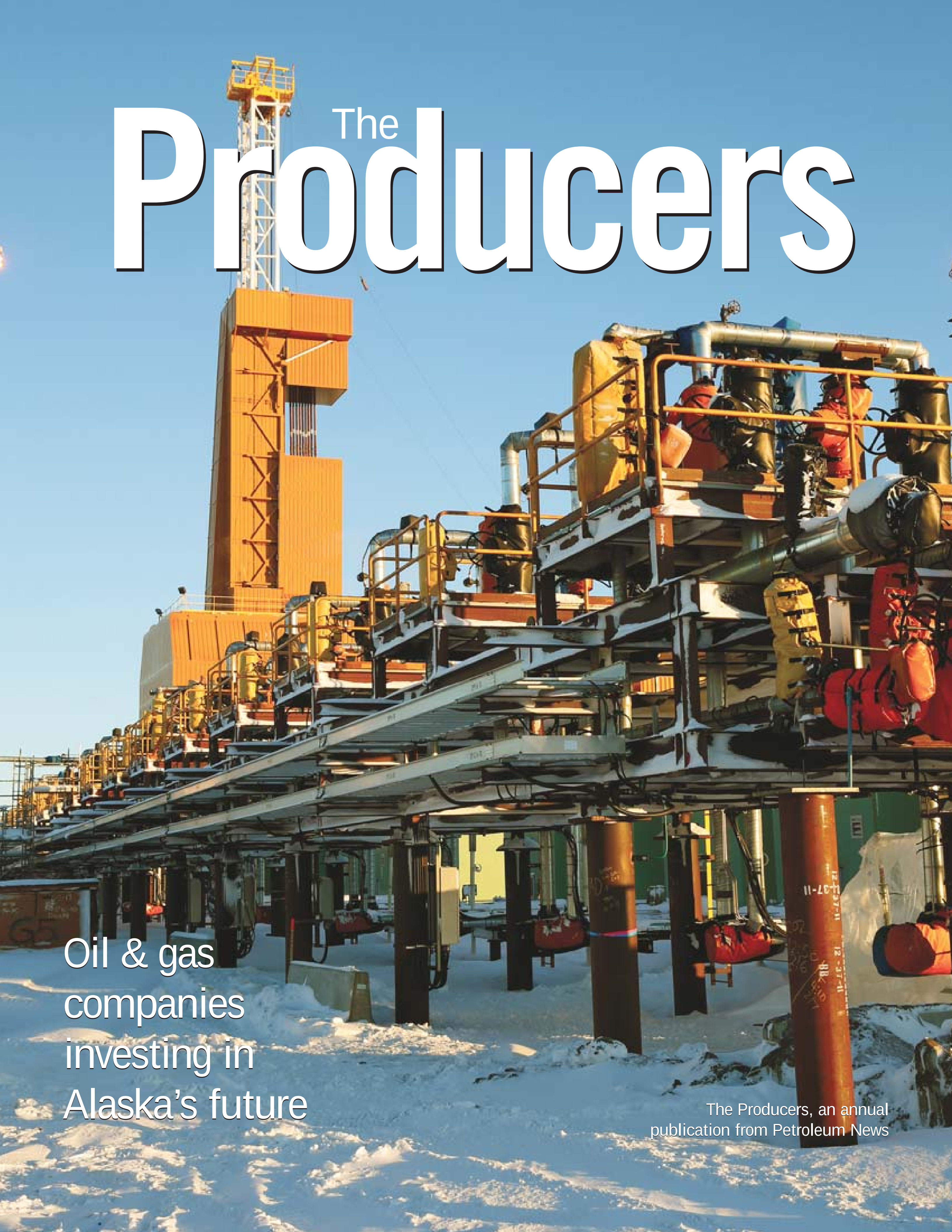

Oil & gas companies investing in Alaska's future

The Producers, an annual publication from Petroleum News


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Future of Alaska oil and gas production looks solid

Oil prices are acceptable, Alaska has a governor who understands the importance of the oil industry to the state's economy and a Department of Natural Resources commissioner who is working to attract investment and get discoveries online more quickly. Plus, Alaska has a huge new North Slope oil play that has taken the province from maturity back to adolescence. Companies are preparing to produce the mostly untapped formation, which could boost Alaska's current output, while explorers across the Slope are searching for other missed pools of oil. To the south companies are exploring new areas and developing innovative technology that is revitalizing the Cook Inlet basin and increasing its output.

All in all, the future of Alaska's oil and gas production looks promising. On the North Slope players such as ConocoPhillips, Oil Search, Hilcorp. Glacier, Brooks Range, Eni, Hilcorp, Jade, 88 Energy and Pantheon are either actively exploring and/or developing new sources of oil, while BP and Hilcorp are employing technology to squeeze every drop out of mature fields.

And soon Hilcorp will be taking over all or part of the operatorship of the Prudhoe Bay unit, hopefully doing what the technically savvy company has done elsewhere in the country and Alaska, and that is increase production. Not that BP hasn't done an excellent job of sustaining output in a field 31 years beyond its plateau, but like other majors BP is hampered by something privately owned Hilcorp is not — layers of management.

As Hilcorp has grown from a small independent to one of the country's largest, it has cleverly kept its management levels low, enabling employees with ideas for improvement easy access to decisionmakers and allowing it to dedicate more capital to field investment versus salaries.

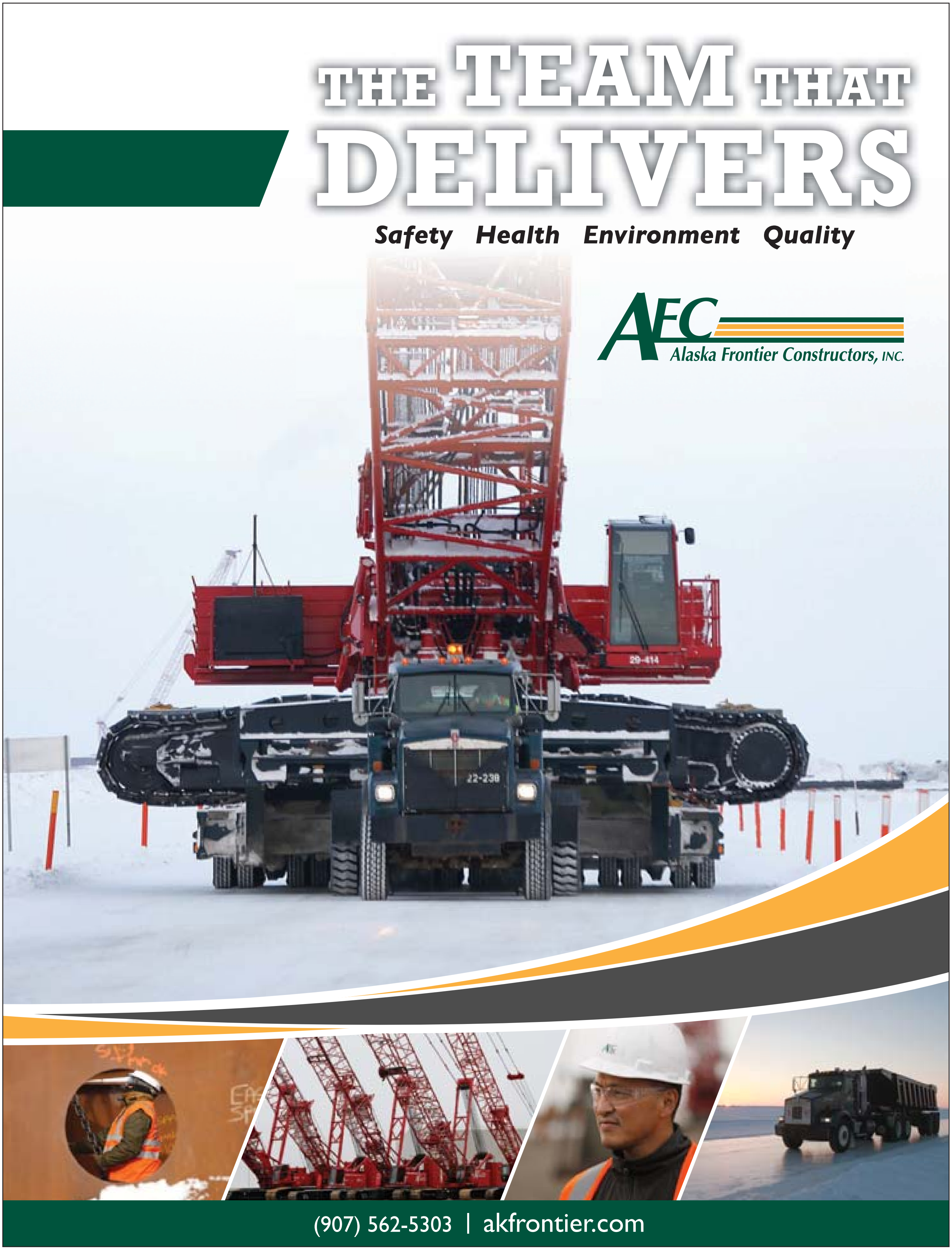
Special kudos to Bill Armstrong who has brought in several larger company partners, which led to an exploration and development renaissance on the North Slope with the discovery of the prolific Nanushuk formation; a renaissance led today by Oil Search.

In the Cook Inlet basin, Hilcorp is the most aggressive explorer and BlueCrest the most innovative with technology, while Amaroq, Glacier and Furie work to maintain and increase production.

Not to forget ExxonMobil, which continues to work the challenges of producing condensate from the high-pressure Point Thomson unit, as well as champion the sale of the unit's 8 trillion cubic feet of natural gas for a future export project.

All in all, Alaska production into the future looks solid.

—Kay Cashman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The Producers

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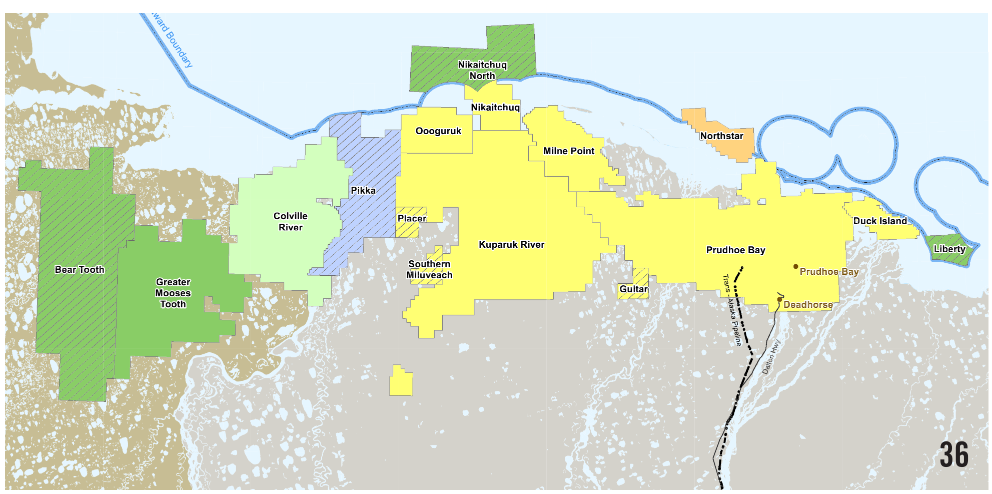

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On the cover: Doyon 25 drilling for ConocoPhillips on the North Slope in early 2019.

Photo by Judy Patrick, courtesy of ConocoPhillips

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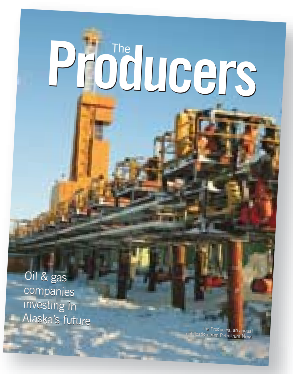

AIX Energy focused on deliverability

Company says depending on compression evaluation might tie 1-4 well to production system

By KAY CASHMAN
Petroleum News

In its fifth plan of development/operations for the Kenai Loop gas field AIX Energy LLC said it will focus on "aligning gas sales with field deliverability" for the period May 7, 2019, through May 6, 2020. The plan was submitted both to the Alaska Department of Natural Resources' Division of Oil and gas and to the leaseholder, Cook Inlet Region Inc.

AIX took over the Kenai Loop field in late 2014 after its developer, Buccaneer Energy, went bankrupt. The four wells at the field were all drilled by Buccaneer between 2011 and 2013. Two wells, Kenai Loop 1-1 and Kenai Loop 1-3, are active producers, AIX said; Kenai Loop 1-2 is temporarily suspended and may be used as a disposal well in the future; and Kenai Loop 1-4 is a shut-in producer, not tied into the field's production system.

The onshore Cook Inlet area field has a single producing lease on CIRI acreage. (In 2017 the company decommissioned Pad 2 and ended a surface lease with the Alaska Mental Health Trust.)

The Kenai Loop gas field facilities include "industry standard compression, dehydration, heating, testing and metering equipment," AIX said.

The company said cumulative production from the field, through the end of April 2019, was 20.8 billion cubic feet of gas, 7,933 barrels of water and 2,508 barrels of condensate.

Production peaked at some 11 million cubic feet per day in 2016 and averaged less than 6 million cubic feet per day this year, according to figures provided by the company.

AIX said in its new plan, filed in May 2019, that it purchased and installed a natural gas fired compressor in the winter of 2018, under the fourth POD.

The company said startup of the compressor occurred in February with the Kenai Loop 1-3 well on compression. The Kenai Loop 1-1 well will be put on compression when required.

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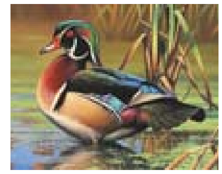

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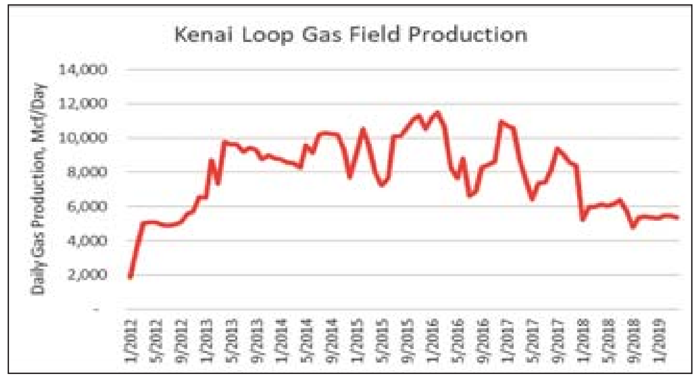


AIX ENERGY *continued from page 9*

As reported by Petroleum News in the fall of 2017, AIX has a gas supply agreement with Enstar Natural Gas Co. which calls for a firm supply of 1.37 bcf of gas between July 1, 2018, and March 31, 2019; 1.464 bcf between April 1, 2019, and March 31, 2020; and a range of 1.095 bcf to 1.825 bcf between April 1, 2020, and March 31, 2021. The daily average was 5 million cubic feet of gas in the first year of the contract, 4 million cubic feet per day in the second year and between 3 million and 5 million cubic feet per day in the third year.

AIX said that in its fourth POD it obtained static reservoir pressure on the two producing wells, Kenai Loop 1-1 and Kenai Loop 1-3, and "updated the material balance estimates of gas in place and reserves."

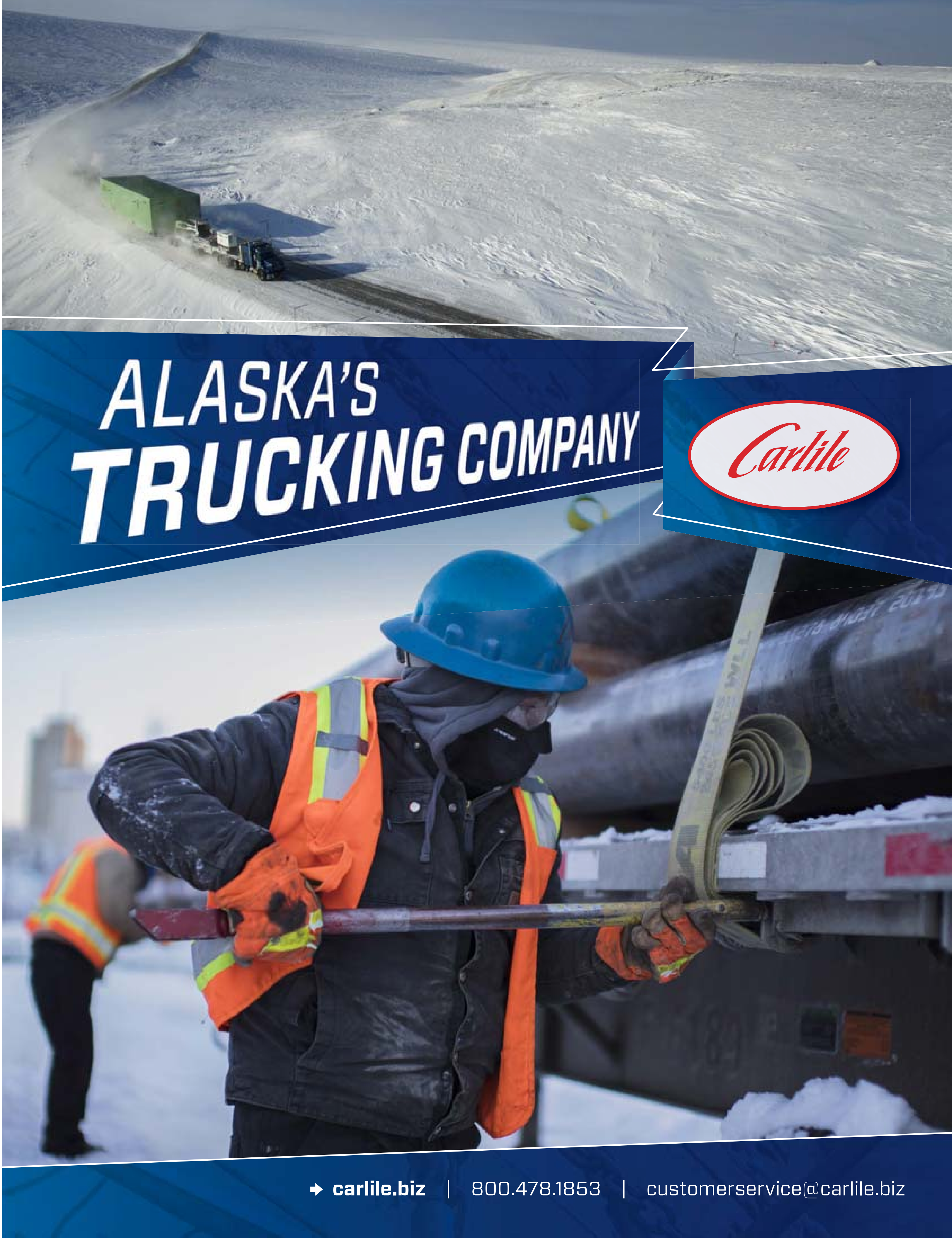
A year-end 2018 reserves report was provided to Enstar under the company's gas sales agreement, AIX said.

For the fifth POD the company said it plans well work and compression, and said that as part of its compression evaluation it will look at the cost and benefit of tying the Kenai Loop 1-4 well to the production system to provide increased deliverability and redundancy to meet its firm gas sales obligations and possibly increase ultimate recovery. It will also evaluate recompleting wells to provide additional deliverability.

The Kenai Loop 1-4 well, drilled in October 2013, tested at 2.5 million cubic feet per day but later proved to be producing from the same reservoir as the Kenai Loop 1-1 well, so the 1-4 well has been used to monitor reservoir pressure.

AIX said that to date it has not identified any drilling opportunities within the producing lease. ●

Contact Kay Cashman at publisher@petroleumnews.com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A coiled tubing operation in progress in the Nicolai Creek No. 10 well

COURTESY LYLE SAVAGE

Amaroq doubles Nicolai Creek output

Well work pays dividends in performance; firm focus on water and sand disposal as wells age

By ALAN BAILEY
For Petroleum News

Thanks to remedial and upgrade work involving the Nicolai Creek No. 10 well, gas production from the Nicolai Creek field onshore the west side of Cook Inlet has recently doubled, Scott Pfoff, president of Amaroq Resources, the field operator, told Petroleum News on Aug. 30, 2019.

SCOTT PFOFF

"We've gone from about 250,000 cubic feet (per day) to 500,000 cubic feet (per day)," Pfoff said.

However, as the field continues to age, there are challenges resulting from long term production declines. In particular, the field's gas compressors were designed to handle larger volumes than are now being produced. And the wells tend sometimes to load up with excess water, Pfoff said.

Acquired in 2018

Amaroq acquired the field in January 2018 as part of the fallout from the bankruptcy of Aurora Gas, the previous field operator — Aurora Gas had operated five onshore gas fields on the west side of the inlet. At the time of its Nicolai Creek purchase Amaroq had been called Aurora Exploration, a completely separate company from Aurora Gas. Given the name confusion, in 2018, after the Nicolai Creek acquisition, Pfoff changed the name of his company to Amaroq Resources.

Alaska oil and gas investor Paul Craig has a one-third interest in the company through Craig's company, Trading Bay Oil & Gas LLC.

Since its acquisition of the Nicolai Creek field, Amaroq has pursued a program of field maintenance and well workovers, rather than drilling new development wells. That strategy continues, with the company focusing on achieving good performance from the field's existing wells, Pfoff said.

The field has six gas wells, four of which are currently pro-

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> *"Right now, the way I see it, I can increase production quite a bit at Nicolai Creek and not have any trouble selling the gas at a good price." —Scott Pfoff*

ducing gas. Two of the wells, the No. 2 and No. 3, have been shut in for some time because of mechanical issues — both wells probably require drilling rig remediation and Amaroq has no near-term plans for dealing with them.

In 2018 Amaroq conducted a slickline operation on the No. 9 well, boosting production from that well by 50%. And a coiled tubing workover of the No. 11 well in the third quarter of that year increased that well's performance by around 85%.

The No. 10 well

The focus in 2019 has been the No. 10 well. Remedial work on this well during the first quarter of the year resulted in excessive water production. Consequently, Amaroq had to shut the well in until summer 2019, when it was able to stabilize production at significantly higher levels than previously.

"We increased our water storage capabilities and did some additional upgrades to surface facilities," Pfoff said.

One issue involved fine sand passing through screens designed for sand capture, a problem that necessitated improvements to the sand handling capabilities of the surface facilities, he said.

There is also some parted tubing downhole in the No. 10 well. But fixing this would require the use of a drilling rig. So Amaroq has been conducting the workover operations and surface facility improvements ahead of a decision on whether a rig operation would be economically justified. It is possible to continue operating the well as is, albeit at a production rate lower than would be possible if the tubing is fixed, Pfoff said.

Sand and water production

As the field matures, the disposal of produced sand and water has become an issue. Currently the sand and water are stored at the surface. However, disposal of these waste materials is needed.

Amaroq plans to convert one of the Nicolai Creek wells to a water disposal well. The company has been talking with AOGCC about this, with a view to filing a permit application for water injection.

"As a result of those discussions we're going to perform injectivity tests on the well we want to convert, and then we'll incorporate those results in our application," Pfoff said.

Further development?

Amaroq has no plans for exploration outside the Nicolai Creek field, Pfoff said. However, there is potential to extend the existing field.

The company is also interested in developing further oil and gas pools at deeper levels below the field, in the Nicolai Creek unit. Currently, rights to those deeper prospects belong to Apache Alaska Corp., which acquired 3D seismic over the acreage in early 2012.

In the 45th plan of development filed with the Alaska Department of Natural Resources' Division of Oil and Gas, which runs

continued on next page

AMAROQ *continued from page 13*

from Dec. 29, 2018 through Dec. 28, 2019, Amaroq has acknowledged the potential to drill an additional production well, the Nicolai Creek No. 12, targeting deeper sands in the Beluga and Upper Tyonek formations to the north of the current production area.

Aurora Gas had conducted an evaluation of this potential well. However, Amaroq does not want to tackle it until the company has dealt with achieving good performance from the field's existing wells, Pfoff said.

In addition to continuing gas production at Nicolai Creek, Amaroq has also considered the possibility of converting part of the field into a gas storage facility, with the capability of holding between 2.5 billion and 3 billion cubic feet of gas. An engineering study conducted several years ago confirmed that possibility. But, in the absence of any recent interest from potential gas storage customers, Amaroq has no current plans to proceed with the storage option.

"It's not the kind of project we can go out and do on spec," Pfoff said.

AOGCC bonding

One challenge that has emerged for Amaroq is a new Alaska Oil and Gas Conservation Commission retroactive bonding policy to increase the levels of surety bonding required for the plugging and abandonment of defunct oil and gas wells.

While AOGCC has been concerned that traditional bonding levels fall short of the realistic cost of adequately plugging a well, increased bonding levels increase field operation costs and

COURTESY LYLE SAVAGE

The compressor facility in Amaroq Resources' Nicolai Creek gas field.

hence impact the economics of a field: Small operators such as Amaroq have argued that, if the state sets bond levels that are too high, the state will lose some oil and gas production when some fields are forced to close as a consequence.

On the other hand, if an operator fails to plug and abandon a well, the cost of the plugging operations will default to the landowner, often the state of Alaska.

In late 2017 Amaroq's purchase of Nicolai Creek was delayed after AOGCC ruled that it required $7 million in surety bonding for the field's wells. The purchase ultimately went ahead after the commission reduced the bonding requirement to $200,000. For many years the minimum bonding requirement in Alaska had been not less than $100,000 for a single well and not less than $200,000 for blanket coverage of all an operator's wells in the state. However, AOGCC had only required bonding at these minimum levels, except in situations where there had been regulatory violations.

After lengthy hearings, in May 2019 the commission increased the minimum statewide bonding level to $400,000 per well for one to 10 wells, with minimum bonding levels running to millions of dollars for larger numbers of wells.

Pfoff said that the bonding levels as now stipulated render the Nicolai Creek field uneconomic. Although the increased bonding was required by Aug. 16, 2019, Amaroq had meanwhile filed a motion for reconsideration of the revised regulations, Pfoff said. Elevating the bond amount for Amaroq remains on hold until the motion has been considered, he said.

A healthy market

At the same time, although Pfoff is concerned about lack of competition, given the few gas producers in Cook Inlet, he sees the Cook Inlet gas market as relatively healthy.

"Right now, the way I see it, I can increase production quite a bit at Nicolai Creek and not have any trouble selling the gas at a good price," he said.

Using the current wells and well completions the field probably has a remaining four to five-year life, Pfoff said. But, with much upside possible, if successfully developed field life could extend considerably, he said.

Pfoff expressed satisfaction with the progress that his company has made in saving the field from closure. ●

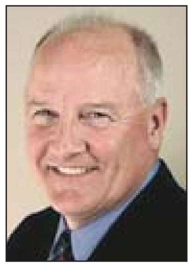
Contact Alan Bailey at abailey@petroleumnews.com

Trident fishbone well on horizon

BlueCrest's new triple fishbone design for Cosmo will equal reservoir contact of 21-27 individual wells

By STEVE SUTHERLIN
Petroleum News

J. BENJAMIN JOHNSON



JOHN M. MARTINECK

BlueCrest Alaska has developed a new "trident fishbone" well design, the latest innovation the company has devised for efficient and economic development of its Cosmopolitan oil project offshore Cook Inlet.

Oil was discovered at Cosmopolitan by Pennzoil Oil Co. in 1967. Other companies have tried to make the project work over the years. BlueCrest knew of the challenges going in, but challenge had created an opportunity for a persistent independent operator to innovate a path to financial viability.

The trident fishbone design is built on the company's success with its single fishbone wells, which have markedly improved the economics of Cosmopolitan.

The trident concept is the latest breakthrough to arise from a long trial and error process. That process has yielded several successful solutions, not only to the challenges inherent in the location of the reservoir — 3 miles out and 1.5 miles down from an onshore drill pad — but to other development challenges that cropped up along the way.

Three tines of the trident

As is implied by the name, the trident configuration involves the drilling of three fishbone wells into the reservoir from a single wellbore originating at the shore-based pad.

"The fishbone wells achieve significantly more reservoir contact and penetration than conventional wells, but we haven't calculated the incremental ultimate recovery; it is substantial," J. Benjamin Johnson, BlueCrest Energy CEO and president told Petroleum News.

"Each fishbone well contacts the same amount of reservoir rock as seven-nine individual horizontal wells, and each trident well should recover the same ultimate reserves as three fishbone wells since the reservoir contact is the same," Johnson said, adding, "so, each trident well provides the same amount of reservoir contact as 21-27 individual wells."

The trident fishbone allows more penetrations into the reservoir in less time, bringing new oil production online sooner, BlueCrest said in a recent presentation. "This saves substantial time and cost associated with drilling the long-reach wells from the onshore drilling location to the offshore reservoir for each fishbone."

Under the original fishbone concept, one long horizontal "mainbore" runs along the bottom of the oil zone, from which multiple full diameter wellbores are drilled upward to penetrate individual productive oil sands.

The finished well structure resembles a fishbone, with multiple "ribs" that flow down into the mainbore.

It will take approximately four months to drill each trident fishbone well from spud to production, Johnson said.

"Each trident well saves five months to drill the wells that would reach the same reservoir penetration with just the fishbone wells," Johnson said. "Overall, it cuts the total drilling time down by more than two years."

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Fishbone wells boost efficiency

The old school method of opening up all the productive sand members of a traditional onshore development would be to drill

continued on next page

BLUECREST *continued from page 15*

scores of wellbores, each penetrating all of the layers. But BlueCrest must drill so far to reach the reservoir, making scores of wells impractical and uneconomic.

With its powerful purpose commissioned directional drilling rig, BlueCrest has accurately steered paths of wells throughout the reservoirs, while setting new Cook Inlet records for long-distance drilling at Cosmopolitan.

Drilling costs have decreased over time, the company said.

BlueCrest said the Cosmopolitan reservoir rock is "highly consolidated, providing a strong capability of wellbores to remain open after the holes have been drilled through the rock."

In addition to steering wellbores in any direction desired, BlueCrest was able to sidetrack wells to create new well paths branching off from an existing well.

After considering all these factors, the company conceived of, and was able to execute, the fishbone approach.

As it looks forward to drilling its first trident fishbone well toward the end of 2019, BlueCrest has enjoyed a year over year production increase at Cosmopolitan.

BlueCrest's Hansen field, the Cosmopolitan project, averaged 1,371 barrels per day in July 2018, up 58.5% from a July 2018 average of 865 bpd, according to data reported by the Alaska Oil and Gas Conservation Commission.

BlueCrest had two wells in production in June 2018 and five wells in production in June 2019.

Conventional field, unconventional location

The total combined thickness of the Cosmopolitan oil sands is more than 1,000 feet.

Like many oil fields, Cosmopolitan oil is deposited between the grains of sand in underground geological layers stacked on top of each other. The Hanson field's individual oil-filled sand layers are separated by thin horizontal layers of silt or shale that create barriers preventing the oil from moving vertically between the oil-filled sands.

BlueCrest estimates that in an old onshore basin such as West Texas, a conventional development of Cosmopolitan's type and size of oil deposit would require more than 100 individual wells.

But Cosmopolitan's conventional field is in an unconventional location, which has prodded the company to innovate.

Many modern wells on Alaska's North Slope and in other basins are initially drilled downward from a surface location, then turning horizontally to pass through the reservoir, opening paths for oil to flow from sands contacted by the wellbores, BlueCrest said. Hydraulic fracturing is commonly employed to create limited paths for the oil to flow from other nearby sands into the horizontal wellbores.

But BlueCrest, over the past three years, has focused on developing a drilling and completion process that would optimally open up the multiple layers of Cosmopolitan sands to production.

BlueCrest tried hydraulic fracturing in two of its initial Cosmopolitan wells, but the cost was high and the fractures were inefficient at creating vertical flow paths between the stacked layers.

The fishbone ribs in the company's first fishbone well penetrate the reservoir at a 110 degree angle, spaced 800 feet apart — 15 acre spacing. Each rib penetrates the entire production interval, from the Hemlock to the Starichkof. Oil flows downward into the main bore; no hydraulic fracturing is employed.

Fifth plan of development

BlueCrest's fifth plan of development, or POD, covers the 2019 calendar year.

The company drilled the first fishbone, the H-12 well, in 2018, under its fourth plan of development covering the 2018 calendar year. The H-12 consists of a wellbore with a long horizontal tail with seven vertical laterals rising into the producing formation.

Based on evaluation of the H-12, BlueCrest re-drilled the H-16 well, with eight laterals.

In 2019, a new eight lateral fishbone well, the H-4, was drilled some 3,200 feet south of existing Cosmopolitan wells. It was brought into production in March 2019.

The H-4 tested the southern extent of the reservoir, BlueCrest told the state.

After evaluating results of the H-16a (the re-drill) and H-4 fishbone wells, BlueCrest said in the POD, it "will decide the best possible location for a possible second well in the 2019 drilling program."

The company filed permits for and got spacing exceptions for its first Trident well, the H-13 on Feb. 22, 2019, stepping out to the northwest. It will be drilled in fourth quarter 2019.

As it looks forward to drilling its first trident fishbone well toward the end of 2019, BlueCrest has enjoyed a year over year production increase at Cosmopolitan.

Tapping a separate gas field

BlueCrest is making plans to tap into the Cosmopolitan unit's 5,000-foot-thick natural gas dome above the Hansen field oil accumulation.

"We are seriously studying it right now," Johnson told Petroleum News in a May 2019 interview that included BlueCrest Alaska Operating LLC President John M. Martineck.

"This gas field is not related to the oil; it is a separate field lying directly above the oil but not connected to it," Johnson said.

The natural gas in the dome is too shallow to be accessed from onshore drilling.

"We discovered the gas field in 2013," Johnson said, the year BlueCrest and its former partner Buccaneer Energy drilled the Cosmopolitan 1 vertical well with the Endeavour jack-up rig. (BlueCrest bought out Buccaneer in 2014 and took over as operator.)

"We logged it, cored it and flow tested it," Johnson said. "In addition, we have very high resolution 3D seismic and we can see each one of the major zones, see the structure. We can see any faults and there are none in the field except for the fault at the north of the field and at the south end of the field."

Martineck said the company has "confirmed the 3D seismic with all the wells we've drilled. We can see the gas sands are continuous. We know it is a large field … and with no water."

The Ninilchik gas field to the north is very similar to BlueCrest's gas field: "We'd be producing from the same horizon, the Tyonek," Johnson said, noting "most other inlet gas fields are produced from the shallower Beluga and Sterling formations."

A pair of the Tyonek sands tested at Cosmopolitan 1 flowed at 7.2 million and 7.3 million cubic feet per day with no water, Buccaneer said at the time.

The conventional development scenario in Cook Inlet has been offshore platforms, but BlueCrest is considering development using a jack-up rig and subsea completions.

"We are still looking at putting in a single platform but modern technology is leading us to look at subsea completions," Martineck said. "It would be a very clean, very simple system ... and this particular location in Alaska would be very well suited" to it.

The gas would be transported by a "3-mile pipeline from the wells to our surface location," Johnson said. "We're already set up for gas in our facility. We'd have to make some changes to our onshore facility, but they'd be minor."

The trident fishbone design is built on the company's success with its single fishbone wells, which have markedly improved the economics of Cosmopolitan.

Pool rules request

BlueCrest submitted an initial field and pool rules application to AOGCC Aug. 2 for the Hansen oil pool at its Cosmopolitan field.

An important aspect of pool rules is oil well spacing, proposed as Rule 3, allowing for no well spacing restrictions within the oil pool, accommodating horizontal, multilateral and fishbone style wells, with the exception that no well can be completed within 500 feet of the exterior boundary of the unit unless ownership is the same on both sides of the unit boundary.

In its proposed rules BlueCrest notes that "fishbone multilateral wells will be completed barefoot with no liners or screens in the reservoir section."

The company said its multilateral fishbone well design has spacing between the individual fishbones, laterals, in a single well and laterals in adjacent wells of some 800 feet, which would require seven or more spacing exceptions per fishbone. To produce remaining reserves under current well spacing rules would be an unnecessary administrative burden on BlueCrest and AOGCC, the company said.

BlueCrest said the proposed pool rules would eliminate intra-pool spacing rules and allow it "to target smaller, undrained portions of the pool that cannot be reached/contacted by wells conforming to current statewide spacing restrictions. Elimination of all spacing requirements inside the pool will help to maximize recovery from otherwise bypassed pay, while allowing for continued production from established development wells."

"The Hemlock/Starichkof reservoir is compartmentalized and highly stratified," the company said, with very limited communication between wells. ●

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BP: Still drilling at Prudhoe Bay after 42 years

Despite sale of Alaska business, major is setting the stage for another 40 years of production

By STEVE SUTHERLIN
Petroleum News


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COMPANY WEBSITE: www.bp.com

In 2019, the giant Prudhoe Bay oil field entered its 42nd year online, but operator BP Exploration Alaska said there is still an important role for development drilling, despite the reality that the field is 31 years beyond its production plateau.

In its annual progress report for the initial participating area, or IPA, of the core Prudhoe Bay field, which covered the 2018 calendar year and in BP's plan of development for work from July 1, 2019, through June 30, 2020, in the IPA, BP said that for the Prudhoe Bay owners the "key priority is on efficient production of the existing wells and facilities."

Prudhoe Bay is well developed, with more than 1,400 wells at the field, yet development drilling "will continue at a pace consistent with the business environment and the ability to identify viable targets informed by ongoing surveillance, supplemented by new seismic data being acquired in the first half of 2019."

The Prudhoe Bay unit, formed in 1977 is operated by BP.

As of September 2019, the Prudhoe Bay unit contained 12 participating areas, 254,235 acres and has an average lease ownership of 26.36% BP, 36.4% ExxonMobil Alaska Production, 36.08% ConocoPhillips Alaska and 1.16% Chevron U.S.A.

Thirteen billion-plus

When Prudhoe Bay went into production in 1977, the initial estimated ultimate recovery was 9.6 billion barrels of oil. To date, however, it has generated 13.599 billion barrels through August 2019.

That number, per BP spokeswoman Megan Baldino, came from the following sources: Prudhoe Bay's IPA 12.596 billion; Prudhoe satellites 0.221 billion (Aurora, Borealis, Midnight Sun, Orion, Polaris); and the Greater Point McIntyre area 0.782 billion (Lisburne, Point McIntyre, Niakuk, Raven, North Prudhoe Bay State and West Beach).

The Prudhoe Bay unit produced an average of 270,000 barrels of oil per day in 2018, accounting for more than half Alaska's total oil production. This number includes natural gas liquids from the central gas facility shipped to the trans-Alaska oil pipeline.

During the 12 months of operations under the 2019 plan of development, or POD, for the IPA, BP is doing more of the kind of work that has sustained production in the Prudhoe Bay area long past its originally anticipated lifespan.

Apart from that, the year is anything but routine for the company and its 1, 600 employees.

Sale to Hilcorp

After 60 years in the state, on Aug. 27, 2019, BP announced it had signed an agreement to sell its entire business in Alaska for $5.6 billion to Hilcorp Alaska, an affiliate of Houston-based Hilcorp Energy, the largest private oil and gas producer in the U.S.

The transaction includes BP's interest in the Prudhoe Bay unit and its related infrastructure and pipelines, its 49% interest in the Trans Alaska Pipeline System, 50% interest in Milne Point, 32% interest in the Point Thomson unit, 50% interest in the Liberty project, 40% interest in Alyeska Pipeline Service Co., 32% interest in the

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Point Thomson export pipeline, 50% interest in the Milne Point pipeline, 25% interest in the Prince William Sound Oil Spill Response Corp. and its interest in exploration leases in the 1002 area of the Arctic National Wildlife Refuge.

The sale does not include the $7.1 million BP Energy Center in Anchorage, a 13,500 square foot building that nonprofits and education groups can use free of charge. BP funded its construction and operation and will be donating it as a legacy to (as of Sept. 27, 2019) an unnamed entity.

The sale also did not include BP Exploration Alaska's headquarters in Anchorage. The 15-floor, 324,000 square foot, Class A office building belongs to Oak Street Real Estate Capital based in Chicago.

The sale to Hilcorp is scheduled to close in 2020.

Well work planned for 2019

Production in 2019 from the core Prudhoe IPA "will largely be driven through continuing improvements in operating efficiency, optimizing base production and wellwork," BP said.

Rotary penetrations are expected to be about equal to 2018, between five and seven.

Coil penetrations will see an increase, from 10 in 2018 to 15-23 in 2019, and rig workovers are expected to increase from two in 2018 to from two to eight in 2019.

BP said wellwork activity "remained at a high level in 2018 with 360 rate adding jobs done and about 900 total jobs performed."

"The coil and rotary rigs were brought back in service in December (2018)," BP said, with future drilling opportunities to "be identified by ongoing surveillance and utilizing the new seismic being acquired and processed in 2019-2020."

Flow station 2 was a focus, with eight wells drilled.

Obsolescence management

BP's 2019 controls management program addresses aging control systems "by installing vendor supported systems," improving life cycle cost and minimizing the impact on production during implementation.

BP said FS3 EMC was replaced by Control Logix in 2018, while Emerson Technologies was identified as a strategic supplier.

"The 2019 plan includes developing technology solutions and an implementation plan for remaining facilities," BP said.

Pilot testing will continue in 2019 on the operator workbench, a mobile device for field workers to collect and input data without returning to a computer station.

BP is also expanding use of unmanned aircraft for monitoring.

Major gas sales

As the Prudhoe Bay unit operator, BP has executed a confidentiality agreement with the Alaska Gasline Development Corp. to allow disclosure of information for the Alaska LNG project.

"To date, the PBU operator has not received formal requests for information from AGDC, FERC, or any other agency, any other unit operator, or any third party regarding the AGDC-led AKLNG project," BP said in its annual progress report for the initial participating area of the field covering the 2018 calendar year and its plan of development for work from July 1, 2019, through June 30, 2020. The company also said it anticipates responding to requests as they arise.

On Aug. 28, one day after the sale of BP's Alaska business to Hilcorp was announced, BP spokeswoman Megan Baldino told Petroleum News in an email that, "the FERC process continues, and BP is honoring its commitment to AGDC and XOM pursuant to the MOU signed in 2019, including payment of up to $10 million."

Broadband seismic program

BP is setting the stage to comb the Greater Prudhoe Bay area for smaller oil pools to target with advanced drilling techniques over the next decade or so.

The key to the effort is a massive 3D seismic survey the company describes as "high density broadband seismic," acquired in the first half of 2019. The 455-square-mile seismic shoot covers most of the Greater Prudhoe Bay area.

"That's the largest that we've ever done at Prudhoe Bay and we're using state-of-the-art technology, so we'll have the best image that we've ever had," Janet Weiss, president of BP Exploration Alaska said on Jan. 18, 2019.

The new data — when combined with North Prudhoe seismic BP acquired in 2015 — will "provide a single continuous seismic image" across the unit, allowing for more efficient drilling. The company said this technology "enables denser and larger datasets to be acquired when compared to legacy methods."

As the Prudhoe Bay field matures, the use of modern technology has become critical to extending field life and to maintaining the field's economic viability, Fabian Wirnkar, BP vice president for reservoir development, said Oct. 5, 2018.

Locating and exploiting the remaining small pockets of oil in the field requires state-of-the-art technology in the form of data acquisition, storage and analysis, and in the form of sophisticated drilling techniques.

Modern seismic surveying, produces crisp images of faults and other subsurface features, enabling the location of features where additional oil may be found. Multilateral wells, drilled out from single wells connecting to the surface, can thread though those remaining pockets of oil. At the same time, the seismic imaging can enable, for example, the precise injection of water into areas where it can be most effectively used.

STEVE SUTHERLIN

BP Exploration Alaska's headquarters in Anchorage was not part of the deal with Hilcorp. The 15-floor, 324,000 square foot, Class A office building belongs to Oak Street Real Estate Capital based in Chicago.

Put River formation recovery

In addition to infield exploration for untapped pockets of oil using 3D seismic, BP has been looking to tap known but difficult to produce reserves in Prudhoe's IPA, by creating production techniques based on data analysis and advanced technology.

In 2018, the Alaska Oil and Gas Conservation Commission approved commingled downhole production for wells completed in both the Prudhoe oil pool and the Put River oil pool which overlies the main reservoir. The ruling allowed production of some 6.9 mil-

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lion barrels of oil in place in the IPA's Put River formation, which would otherwise be stranded.

Put River consists of three lobes — Central, Southern and Western — with a fourth lobe, the Northern, in hydraulic communication with the Prudhoe oil pool. The Southern lobe of Put River has had production since 1999 with an active waterflood.

The Central lobe contains an estimated 1.1 million to 2.7 million barrels of oil in place and the Western lobe about 69.6 billion to 104.4 billion cubic feet in place with a condensate yield of approximately 40 barrels per million cubic feet, and a condensate in place value of between 2.8 million and 4.2 million barrels of oil.

AOGCC said several wells penetrating the Prudhoe and Put River oil pools are candidates for downhole commingling, which "should allow for increased flowrates and flow velocity in the tubing and reduce the potential for the hydrate deposition that is problematic in production from wells completed solely in the (Put River pool). Since standalone production of the Central and Western lobes is not viable due to hydrate deposition those reserves are essentially trapped. Commingling … will allow these resources to be recovered."

Another 40 years

Keeping the Prudhoe Bay unit operating for another 40 years will be critical to future generations of Alaskans, Janet Weiss, president of BP Alaska, told the Resource Development Council's annual conference on Nov. 14, 2018. New technologies will improve operational efficiency and produce more oil out of the field's reservoir rocks, Weiss said.

Sustaining Prudhoe Bay through the next four decades will take the type of grit and innovation that has enabled the stemming of production decline over the past three years, she said.

In 2018, BP reduced operational costs at Prudhoe Bay by 6%, thus adding years to the expected life of the field, she said.

Weiss introduced BP specialists to elaborate on the company's activities.

Unmanned aircraft

Randy Sulte, BP program execution manager, said unmanned aircraft can carry out inspection operations more efficiently and safely. For example, following flooding and subsequent road damage on the North Slope last spring, it was possible to use a drone to obtain high quality images for appraising the situation. Previously it would have been necessary to do an overflight in an aircraft, an operation that would not have been immediately possible because of low clouds.

Unmanned aircraft can eliminate personnel safety risks in operations such as inspecting flares. BP is also testing the use of unmanned aircraft to monitor for methane leaks.

Virtual reality remote access

Holly Willman, BP Prudhoe Bay East Area operations support team leader, demonstrated technology in which a 3D virtual reality headset is used to remotely move around in facilities on the North Slope. This technology enables a facilities engineer to make measurement of pipework in a facility without having to leave BP's Anchorage office.

New computer applications

Dakota Chastain and Bridger Vance, commercial analysts in BP's finance department, said new computer applications allow people to interact with financial data in new ways, providing rapid insights into what is happening from a commercial perspective. The commercial team is developing mobile apps that can simplify and speed up people's access to the data. The idea is to save money, and to be able to work faster and smarter to extend the life of the Prudhoe Bay assets, they said.

BP is deploying a new computer system, the Apex system, to improve operational efficiencies in global oil field operations. In Alaska the system helps the company streamline fluids routing around the Prudhoe Bay field infrastructure, Amy Adkinson, BP systems optimization engineer told Petroleum News.

Maximizing field production requires planning and use of production and injection wells, to best access oil remaining in the field reservoir, and the optimum use of water injection, gas injection and enhanced oil recovery techniques to maintain reservoir pressures.

The routing of fluids

There is an additional aspect of operational efficiency involving the routing of fluids from the wells through the complex of pipework and production facilities that enable oil to be separated and transported to the trans-Alaska pipeline for export from the North Slope, while also recycling produced water and gas back through the field.

The pipelines and facilities have operating limitations but work at optimum efficiency if fully used. At the same time, if some component of the infrastructure is maxed out, that may delay bringing wells online, which impacts the potential to maximize field production.

Prudhoe Bay is particularly complex, with hundreds of wells, multiple gathering centers and flow stations, and a field pipeline network that can enable choices over how to route fluids through various facilities for maximum efficiency. In addition, as the field matures, it produces much more gas and water than oil, making management of fluids particularly important. The idea is to route fluids in a manner that supports the appropriate mix of well and facility usage, keeping the best wells in operation, Adkinson explained.

Faster processing

Although BP has modeling systems for managing the fluid flow, these systems are slow to use. The new Apex system, which is being tuned to the complexities of the Prudhoe Bay field, is much faster. Essentially, engineers can simulate different operational scenarios, evaluate the results and decide on an optimum course of action.

"Apex can unlock that efficiency, so that we can ask a question of our system, model it and have an answer in a matter of a day, versus a week," Adkinson said.

Field operators can move from static modeling of the fluid flows, to more dynamic modeling, assessing how the fluid flows will evolve over time.

The system models fluid flows from the interfaces between wells and the reservoir through to first stage fluid separation. The system is hooked into the production models for individual wells, enabling well production to be simulated, feeding fluid production data into the surface infrastructure simulation. Currently the focus is on gas flows to the central gas processing facility, and how to deal with produced water.

"We've got a team of engineers that are working on (the system) … trying to find all of the useful ways we can use it … to leverage what we already have," Adkinson said.

For example, if there is a plan to bring on new production in one part of the field, it is possible to use the system to simulate the impact of this on field operations as a whole. Due to facility and pipeline constraints the new production might force production to be backed out somewhere else in the field.

Rapid evaluations

Once Apex is fully operational, a reservoir engineer will be able to quickly evaluate the impact of planned well work on surface systems, more accurately assessing the impact on overall production at the field.

The system can also evaluate the impact on production of reconfiguring surface infrastructure.

Apex represents the next step in optimizing Prudhoe Bay operations, using technology to find things that are not intuitively evident, and to test the impact of changes before putting them into effect, Adkinson said. ●

Contact Steve Sutherlin at ssutherlin@petroleumnews.com

BP leaving loss to community

BP's plan to pull out of Alaska could leave a big hole for nonprofits and other programs that benefited from the oil giant's donations and its employee volunteers.

Its footprint has extended beyond the North Slope, its philanthropy including support for student scholarship and teacher honors, summer engineering programs, community cleanups and other initiatives. Employees were encouraged to volunteer and serve on boards.

The BP Energy Center offered free daytime meeting space to nonprofits and community groups, said Tamera Lienhart, director of community affairs for BP Alaska.

STEVE SUTHERLIN

Building elevations of the BP Energy Center were designed to frame and showcase the wooded setting.

Cassandra Stalzer, a vice president with United Way of Anchorage, said Alaska — with its small population — has a "pretty thin philanthropic layer," with few foundations of size that broadly support "the general good" or social service projects, and not a lot of wealthy people who have taken leading philanthropic roles.

"So, BP has been, for many years, one of the most significant players in philanthropy as a whole for the state," she said.

Since 1998, Stalzer said BP and its employees have provided $22 million to her organization for community programs.

Often nonprofits are seen as "nice-to-have extras," but they provide important services, such as housing and mental health programs, she said.

"This could be a quality of life moment for us where we need to figure out what it is that we really value and stand for," she said. United Way continues to press ahead and hopes people take this as an opportunity to get involved, she said.

Laurie Wolf, president and CEO of The Foraker Group, which helps build up nonprofits, said BP's long history and breadth of giving has been notable.

BP reported donating more than $3 million to Alaska community organizations in 2017, with its employees supporting hundreds of education and community groups and youth teams. Baldino said the 2018 figure was $4 million.

Lisa Parady, executive director of the Alaska Association of Secondary School Principals, said BP for years has been generous in providing student scholarships through a partnership with her organization.

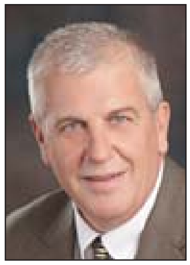
BP has supported programs "that have a significant impact on the lives of our students," she said.

—The Associated Press contributed to this article

Mustang almost there!

Brooks Range Petroleum first small independent to go from discovery to production on North Slope

By KAY CASHMAN
Petroleum News



BART ARMFIELD

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With approvals and permits in place, the first small independent to take an oil field from discovery to production on the North Slope will be delivering oil to the trans-Alaska pipeline sometime in fourth quarter 2019.

In a Sept. 30, 2019, filing of its seventh annual plan of development with the Alaska Department of Natural Resources' Division of Oil and Gas, operator Brooks Range Petroleum Corp. said the holdup from anticipated first quarter startup for the Mustang project in the Southern Miluveach unit was in part tied to the early production facility, or EPF, being delayed, which in turn impacted some drilling.

That said, functional check out of the EPF has begun, BRPC said in its proposed plan of development, or POD.

First oil from existing wells

BRPC drilled the Mustang discovery well, North Tarn 1A, in January 2012, and confirmed it at the Mustang 1 in February 2012.

Mustang is the first development in the Southern Miluveach unit, which is adjacent to the southwest edge of the Kuparuk River unit and sits in the increasingly crowded "billion-dollar fairway" — ARCO Alaska's description of the land between the Kuparuk River unit and the Colville River unit, both now operated by ARCO's successor, ConocoPhillips.

BRPC had originally planned to start the field using a permanent 15,000 barrel of oil per day production facilities. However, that plan was based on a $120 oil price in 2014.

Following the subsequent oil price crash, the company had to put the project into "warm standby" mode before coming up with the plan to install the modestly priced temporary production facility.

The idea was to start production at relatively low rates and then,

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BROOKS RANGE *continued from page 25*

as production ramped up to about 6,000 barrels, use the revenue to upgrade the production facilities to a larger scale.

Planned initial production will be from two existing wells — North Tarn 1A and SMU M-02. Mustang 1A will be next but the suspended well "requires drilling lateral extension/possible sidetrack," which will occur in January 2019, BRPC said.

Up to four new wells will be drilled in 2020 — one scheduled per quarter, the company said.

Full development plans

Longer range proposed development activities remained much the same as originally planned, involving the following:

- Central processing facilities with a capacity to handle 15,000 barrels of oil, 15 million standard cubic feet gas and 7,500 barrels of water per day.
- Drill site facilities.
- Non-process infrastructure including buildings and equipment.
- Up to 10 production wells and 11 injection wells.

Kuparuk sands

As far as plans for the exploration or delineation of any land in the Southern Miluveach unit not included in a participating area, BRPC said it continues to review all potential targets within the unit, including but not limited to the Kuparuk C and A sands, which the company has said are part of the Kuparuk oil pool that is a continuation of the Cretaceous age Kuparuk sands from the Kuparuk River unit.

Planned initial production will be from two existing wells — North Tarn 1A and SMU M-02. Mustang 1A will be next but the suspended well "requires drilling lateral extension/possible sidetrack," which will occur in January, BRPC said.

The Kuparuk A sand consists of a relatively fine-grained shallow marine sandstone overlain by the coarser grained Kuparuk C sands. The Kuparuk A, with its fine grain size, is generally less permeable than the Kuparuk C. Both sands have porosities of around 22%.

The oil trap is formed by a major geologic structure called the Colville anticline. Oil is sealed in the Kuparuk sands by the overlying Kalubik shale, an extensive thick shale found in the region. Another impervious shale, the Miluveach, underlies the sands.

In a 2019 filing with the Alaska Oil and Gas Conservation Commission, Lawrence Vendl, BRPC's exploration and subsurface development manager, said the Kuparuk oil pool within the Southern Miluveach unit lies between minus 5,800 feet true vertical depth subsea and minus 6,400 feet TVDSS.

More development specifics

Some of the details of BRPC's proposed operations for the first year and beyond were:

- Studies for the tie-in of the seawater cross country pipeline to the Alpine seawater pipeline.
- Completion of the initial gas compression and water injection

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BROOKS RANGE *continued from page 26*

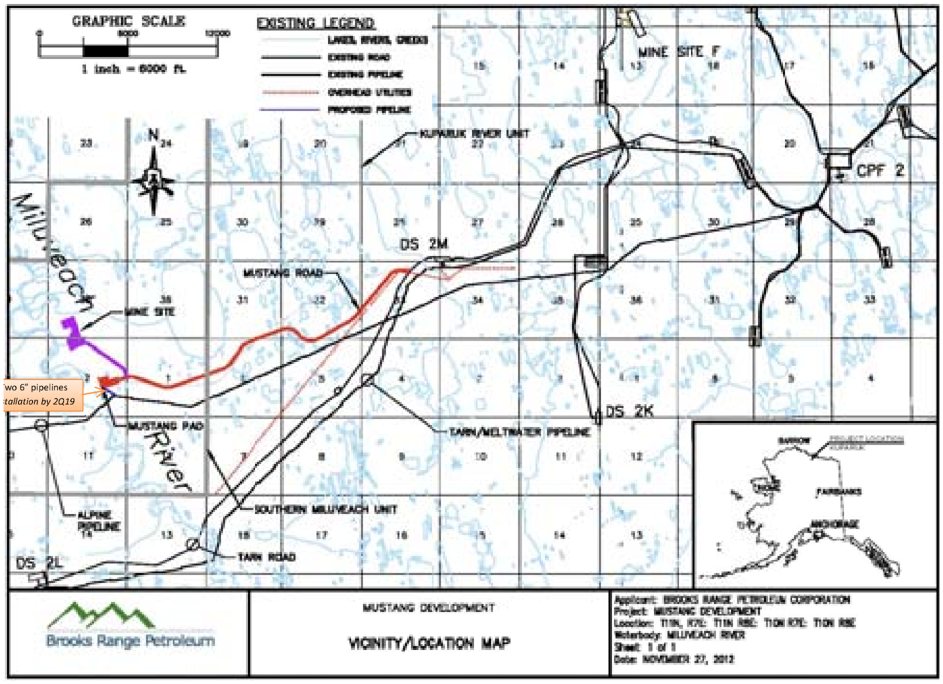
capabilities of the EPF that might continue into 2020.

• Planning activities focused on bringing the modules built for the Mustang operations center, or MOC, to the North Slope during 2020, transporting and integrating MOC 1 in first quarter 2021.

• Planning for integration and substitution of temporary EPF with the permanent MOC process modules.

• In addition to the four wells drilled in 2020, toward the end of that year and through third quarter 2021 six producer and seven injector wells will be drilled.

The surface location of the Mustang facilities, drill pads, roads, docks, causeways, material sites, base camps, waste disposal sites, water supplies, airstrips. etc. were also provided in the POD.



In addition to the four wells drilled in 2020, toward the end of that year and through third quarter 2021 six producer and seven injector wells will be drilled.

Water and gas injection

In June 2019, the Alaska Oil and Gas Conservation Commission approved an application from BRPC to inject fluids at Mustang for pressure maintenance and enhanced recovery of hydrocarbons from the Kuparuk River oil pool within the Southern Miluveach unit.

Waterflood is planned first, followed eventually by lean or miscible gas flood.

Water will be produced water from the field and seawater from the ConocoPhillips seawater pipeline, with gas to be sourced from Mustang processing facilities.

The commission said the anticipated peak daily injection rate for individual wells would be 6,000 barrels of water and 6 million standard cubic feet of gas.

Water and water-alternating-gas injection into the Kuparuk River oil pool in the Southern Miluveach unit, AOGCC said, "will provide a substantial EOR benefit over primary recovery alone" and maximize ultimate recovery, as well as prevent waste.

Vendl told the commission that audited Kuparuk reserves are 21.2 million barrels of 1P (proven oil in place).

Presentation materials at an AOGCC hearing showed 2P at 32.8 million barrels 2P (probable) and 3P at 38.3 million barrels (possible) and showed primary recovery as estimated at 10-15% of original oil in place with waterflood adding 10-25%, for a total recovery after waterflood of up to 35%.

Vendl cited an average estimated recovery rate of 30% with waterflood, expected to rise to 40% with tertiary recovery.

Lease ownership

On the southwest edge of the Kuparuk River unit, Southern Miluveach unit working interest owners as of September 2019 were Caracol Petroleum LLC, with approximately a 36% interest; TP North Slope Development LLC, 22.5%; Mustang Operations Center 1 LLC, 20%; Brooks Range Petroleum Corp., 10%; Nabors Drilling Technologies USA Inc., 6%; AVCG LLC, 4%; Mustang Road LLC, 1%.

Alaska-based Caracol is owned by a Singapore investment company.

The leases in the unit are ADL 390680, 2,560 acres; ADL 390681, 2,560 acres; ADL 90690, 640 acres; ADL 390691, 2,560 acres; and ADL 390692, 640 acres.

AIDEA support

The Alaska Industrial Development and Export Authority has been providing financing assistance for the Mustang project.

Bart Armfield, president and CEO of BRPC, commented on the value of the agency's assistance, in particular the construction of the field's gravel pad and the gravel access road to the pad.

With gravel infrastructure a key to accessing relatively undeveloped areas of the North Slope, several companies have been able to make use of the Mustang gravel infrastructure. For example, he said, Oil Search has been using the Mustang road for access to its work sites in connection with the neighboring Pikka development. And the Nanushuk access road will follow the existing Mustang road for 4.7 miles, although the exact length could vary slightly due to wider curves and other topographical features, Oil Search has said.

Vendl told the commission that audited Kuparuk reserves U are 21.2 million barrels of 1P (proven oil in place). … Vendl cited an average estimated recovery rate of 30% with waterflood, expected to rise to 40% with tertiary recovery.

Workforce peak 90

Armfield is proud that his company is close to bringing Mustang into production.

The workforce at the site has peaked at about 90 people. Overall, 59 Alaska companies have been involved in the Mustang project, he said.

"We will be the first small, independent to go from actual discovery to production on the North Slope of Alaska," Armfield said in April 2019. ●

Contact Kay Cashman at publisher@petroleumnews.com

North Slope's major producer

ConocoPhillips operates multiple state, federal units, also has major ownership at Prudhoe Bay

By KRISTEN NELSON
Petroleum News

JOE MARUSHACK

ConocoPhillips Alaska is the largest oil producer on Alaska's North Slope, operates state and federal units and has a major ownership interest in the Prudhoe Bay field, as well as lease positions, 75% of which, the company says, remains to be explored. Producing units operated by the company include the Colville River unit and the Kuparuk River unit on state land and the Mooses Tooth unit in the National Petroleum Reserve-Alaska. ConocoPhillips is in the process of developing a second NPR-A unit, Bear Tooth, which is the site of its large Willow discovery.

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Kuparuk River unit

ConocoPhillips Alaska is the majority working interest owner, 92.4%, and operator at the Kuparuk River unit, the second largest field on the North Slope.

The most recent change at the field was the Aug. 14, 2019, state approval of the 12th expansion of the unit, adding some 21,513 acres in 11 leases north and west of existing KRU drill site 3S, adjacent to the northeastern edge of the unit and the southern boundary of the Oooguruk unit. These leases, the Nuna prospect, were previously part of Oooguruk when that unit was owned by Caelus Natural Resources Alaska, which contracted the 11 leases out of Oooguruk before it sold its interest in the unit to Eni earlier in 2019.

In its expansion approval the Alaska Department of Natural Resources' Division of Oil and Gas reviewed drilling in the expansion area and said Pioneer Natural Resources Alaska drilled the Nuna

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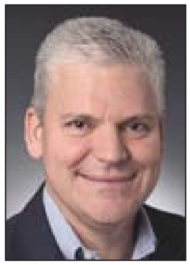
No. 1PB1 and Nuna No. 1 exploration wells to further delineate the Torok reservoir within the Oooguruk unit. ConocoPhillips has drilled Torok reservoir wells in the KRU adjacent to the expansion area, the state said.

The division said ConocoPhillips applied to expand the KRU to include Nuna "based primarily on the tested, but undeveloped, resource within the Torok formation beyond the current unit boundaries of the KRU," said even with existing information, development of the expansion area "is not without risk" and cited as a primary risk to further development if there is a lack of connectivity of "thin-bedded reservoir sands at the inter-well spacing between producer and offset injectors."



MICHAEL HATFIELD

The state said ConocoPhillips has undertaken a systematic approach to evaluating the Torok in the area since 2013, and "currently has two Torok horizontal producer and injector well pairs online in the KRU" and continues to evaluate connectivity and water injection pressure support.

A plan of exploration for the expansion area said ConocoPhillips and the other KRU working interest owners plan to explore and appraise the Nuna expansion area "in connection with further appraisal of the Torok FM within the currently existing boundaries of the KRU."

In a transcript of ConocoPhillips' July 30, 2019, second quarter earnings call, ConocoPhillips' Executive VP and COO Matt Fox referred to Nuna as a high value bolt on to the company's Alaska assets and said the transaction was expected to close in the third quarter. In response to a question at the earnings call on where Nuna fit into the company's development pipeline, Michael Hatfield, ConocoPhillips' president of Alaska, Canada and Europe, described Nuna as a very low cost of supply, in the low $30s, and said it was $100 million for 100 million barrels.

Hatfield said Nuna would be developed from existing pads at Kuparuk and Nuna, gravel and a road are in place and remaining Nuna facilities could be built in a single ice road season.

Appraisal will be over the next couple of years with a target of first oil in 2022, he said, adding that existing drilling and completion technology will be used and the Nuna development will be incorporated as part of the company's Kuparuk program.

Kuparuk field POD

The division approved the 2019 Kuparuk River unit plan of development, or POD, on July 2, 2019. The POD, submitted in early May, covers the Kuparuk, Meltwater, Tabasco, Tarn and West Sak participating areas.

ConocoPhillips is the majority working interest owner at Kuparuk, at more than 92%. It formerly had a 55.3% ownership, but then it acquired BP's 39.2% interest in Kuparuk (and a 38% interest in the Kuparuk Transportation Co.) in July 2018 in a swap for assets in the United Kingdom. Prices were not disclosed but ConocoPhillips said in announcing the closing in December 2018: "Excluding customary adjustments, the transaction prices were cash neutral to both companies."

Other WIOs at Kuparuk are Chevron at 4.95% and ExxonMobil at 2.7%.

ConocoPhillips said its 2019 POD described the status of the field as of the end of 2018.

The Kuparuk field is developed from 45 drill sites, some of which are shared with satellite fields.

Kuparuk had 833 active wells in 2018, 455 producers and 378 injectors, and had an average production rate in 2018 of 80,000 barrels per day of crude oil and 57,000 bpd of water, with an average water injection rate of 69,000 bpd.

Production for the entire unit, including all the participating areas as well as the main Kuparuk field, averaged 106,337 bpd for the 12 months ending July 31, 2019, the most recent data available from the Alaska Oil and Gas Conservation Commission when this issue of Producers was compiled. That compares to 111,142 bpd for the calendar year ending July 31, 2018, 106,800 bpd for the calendar year ending July 31, 2017, and 104,025 bpd for the calendar year ending July 31, 2016.

ConocoPhillips said 11 coiled tubing drilling wells were drilled in 2018, generating peak incremental oil of 3,300 bpd. Six West Sak wells were drilled in 2018.

The well workover program for the Kuparuk PA was scaled down to four wells due to lower well attrition and successful non-rig wellwork activity added some 11,500 bpd in 2018.

ConocoPhillips said five grassroots rotary wells are planned for 2019 in the Kuparuk PA, and some 20 CTD wells.

No additional drill sites are planned.

Natural gas liquids began to come in from Prudhoe Bay again in September 2018, and the increased NGL availability to be blended with gas for miscible injection allowed for an expanded enhanced oil recovery program. "The tertiary flood at Kuparuk is managed continuously by prioritizing immature, efficient patterns," ConocoPhillips said.

"Gas handling limits with the gas lift compressors will continue to constrain production from the Greater Kuparuk Area," the company said, with greater impacts in the summer. "Gas capacity debottlenecking continues to be studied as part of the facility management plan," with emphasis on smaller project with high added value.

Water handling is often a constraint on oil production, more so since 2006 when produced water and seawater injection streams at Central Processing Facility 2 were segregated to reduce high corrosion rates in the water injection system. Upgraded blades began to be phased in in 2014, allowing increase in speed for water injection.

Gas lift is the most common artificial lift method for Kuparuk producers, the company said, but with water cut increasing to as high as 95% in some wells, "many wells cannot lift from the bottom due to the gas lift system pressure constraints," a situation which miscible water alternating gas and immiscible water alternating gas has mitigated to a large extent with the returned miscible injectant and lean gas.

"Studies are ongoing to improve the artificial lift system, as well as evaluate the lift benefits from large scale lean gas injection," the

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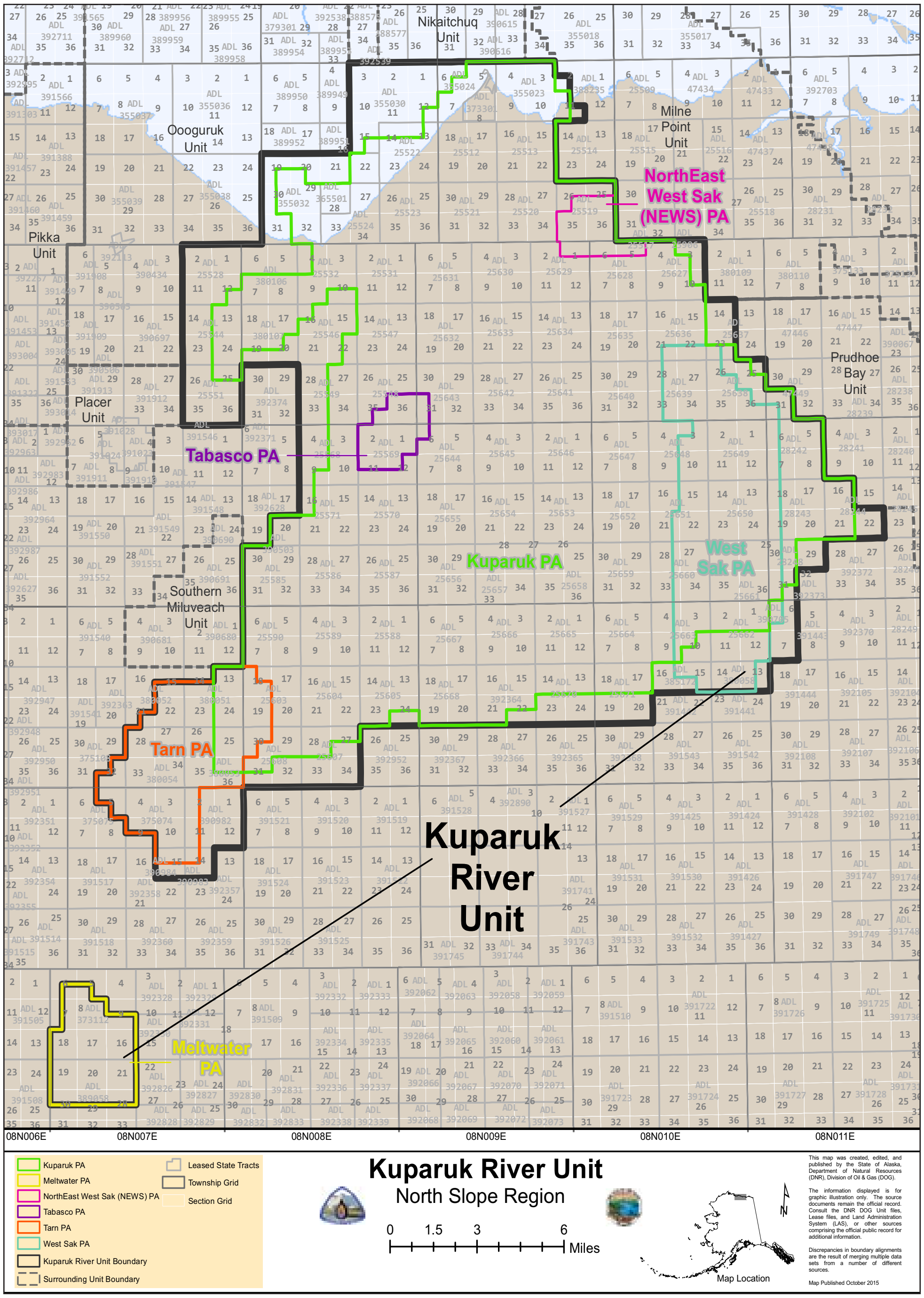
COURTESY CONOCOPHILLIPS

ConocoPhillips has an extended reach drilling rig, the Doyon 26, coming in late in 2019 which will begin drilling Fiord West in the second quarter of 2020, undoubtedly adding new records to those the company has already set — the top 10 longest wells in Alaska are at CD5.



CONOCO *continued from page 31*

company said.

Electronic equipment is becoming obsolete at the field as new equipment is introduced and old equipment is no longer supported, so process control systems continue to be upgraded and automated. Fire and gas systems at the CPFs and seawater treatment plant have been upgraded and drill site upgrades are ongoing, ConocoPhillips said.

Large capital expenditures may be required due to obsolescence of turbines driving water injection pumps and generation equipment and transmission lines, substations and other electrical equipment are approaching expected end of life.

"Much of the operations support infrastructure will be assessed for upgrade or replacement to target another 25 years of production from the KPA and the KPU satellite fields," the company said.

Exploration and appraisal

ConocoPhillips said the overlying Cretaceous Brookian Moraine at Kuparuk is being tested for productivity and waterflood, with a two well pilot producer and injector drilled in 2018 to provide performance data in addition to the original 2015 pilot wells, and two follow up pairs planned for early 2020. Coupled with results from special core analyses, this data will guide future plans for Moraine, the company said.

In addition to the Nuna prospect, acquired after the 2019 POD was filed, ConocoPhillips also has 17,920 acres adjacent to KRU drill site 2S, awarded to the company in December 2017, which includes the Cairn opportunity. The company said Kuparuk working interest owners "are currently evaluating the acreage to understand the potential risks associated with further development."


RYAN LANCE

In a presentation on the company's 2018 earnings in early 2019, Ryan Lance, chairman and CEO, said the company had drilled two wells in December 2018 from existing gravel pads, testing the Cairn prospect from drill site 2S in the southwest corner of the Kuparuk unit.

The 2S pad, the first new drill site at the unit in 12 years, was built following drilling of the Shark Tooth No. 1 in early 2012. That well appraised an accumulation ARCO discovered, but never developed, in the southwest corner of the unit in the late 1980s with the KRU 21-10-08 well. The Shark Tooth was drilled from an ice pad some 4 miles from drill site 2K. Developing Shark Tooth from any of the existing drill sites in the area would have pushed the limits of drilling technology, the company said at the time.

The company also said it brought the 1H-Ugnu-401 well back online in April of 2019. The well had been shut in due to problems with the electric submersible pump. ConocoPhillips said it "continues to work through ESP troubleshooting in an effort to determine if higher oil production rates can be sustained."

Meltwater PA

The Meltwater participating area, or PA, is physically separate from the rest of the Kuparuk River field, a small area south of the

"Much of the operations support infrastructure will be assessed for upgrade or replacement to target another 25 years of production from the KPA and the KPU satellite fields." —ConocoPhillips

Tarn PA developed from the 2P drill site with 16 active wells in 2018, 10 producers and six injectors. In 2018 Meltwater's average production rate was 700 bpd and its average water production was 40 bpd.

NGL imports resumed in September 2018 and Meltwater was returned to miscible injection flood in November. ConocoPhillips said MI was expected to last until the summer of 2019 "at which point the injection line will be fully converted to water injection, which is the service expected for the remainder of the field life."

Meltwater injection was shut in from September through November 2018 while the 8 inch injection line was being replaced to covert the field from gas to water injection.

ConocoPhillips said the produced oil line from the 2P drill site "has a low average velocity and is monitored closely via several physical locations," with the injection line a potential backup should the produced oil line be taken out of surface.

Further drilling opportunities are being analyzed and could include coiled tubing drilling sidetracks or producer to injector conversions.

Following conversion to water injection at 2P, "it is anticipated that the producers will be switched to jet pump when the wells

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CONOCO *continued from page 33*

are unable to lift without aid."

Tabasco, Tarn

The Tabasco satellite field is within the boundaries of the Kuparuk River unit, on the west central side. In 2018, ConocoPhillips said, Tabasco had seven active wells, five producers and two injectors, and oil production averaged 1,200 bpd, water production 10,900 bpd and average water injection 11,400 bpd.

The major recovery mechanism at Tabasco is waterflood.

The Tarn participating area is at the southwest corner of Kuparuk. In 2018 Tarn had 65 active wells at two drill sites, 2L and 2N, 39 producers and 26 injectors. Average 2018 production at Tarn was 6,900 bpd of oil and 19,900 bpd of water with average water injection of 27,800 bpd.

Tarn oil is prone to paraffin deposition so hydraulic jet pumps were the primary method of artificial lift, with production increases of some 10% from use of hydraulic jet pumps.

"Recent Tarn wells were planned with gas lift for artificial lift, and current jet pump wells are being considered for conversion to gas lift as well design allows," with only four remaining wells on jet pump at the end of 2018.

Ten wells have been converted to miscible water alternating gas injection service.

In 2017 and 2018, the company said, there were "reservoir characterization efforts" in the Tarn area, including development of a thin-bed petrophysical model, re-mapping the field and the beginning of work on a reservoir model to "enable the evaluation of the field's remaining development potential. This analysis will continue in 2019."

Appraisal will be over the next couple of years with a target of first oil in 2022, Hatfield said, adding that existing drilling and completion technology will be used and the Nuna development will be incorporated as part of the company's Kuparuk program.

West Sak, NEWS

West Sak is developed from eight drill sites and had 123 active wells in 2018, 56 producers and 67 injectors. The West Sak PA and North East West Sak PA, NEWS, had combined production averaging 22,700 bpd in 2018, with 14,700 bpd of water and an average water injection rate of 36,100 bpd.

The 1H NEWS development project was completed in 2017 and 2018, ConocoPhillips said, including expansion of the existing 1H drill site to accommodate new wells. Waterflooding continues for pressure maintenance and enhanced oil recovery at the West Sak oil pool, with produced water the primary source of injection fluid for the core area in 2018 and seawater injection beginning at 1H in May 2018.

The company said injection and production at West Sak "is challenged by matrix bypass events … or highly conductive conduits between an injector and a producer," which short circuit the waterflood "resulting in poor pattern sweep without remediation." Six remediation treatments were attempted in 2018, but three failed before the end of the year. "A review of these failures is underway as well as an evaluation of alternative treatment methodologies."

The Alaska Oil and Gas Conservation Commission has approved viscosity reducing water alternating gas injection for West Sak. "Early results of VRWAG suggest positive benefits and pattern-level surveillance efforts continue," ConocoPhillips said.

Well completions and artificial lift continue to evolve at West Sak, the company said.

The focus at West Sak in 2019 will be delivery of the 3R drilling program, with expansion of that drill site to add nine new wells, including formation the North West Sak PA, incorporating 2017 3R development wells.

Over the next five years, viscous opportunities beyond 3R will include drilling from existing drill sites and may include new drill sites to access new drilling targets.

There has been one dedicated 4D seismic shoot over 60 square miles including most of the West Sak core area, with the time period between the two surveys from 2005 to 2011.

"The 4D processing applied to these two surveys demonstrated reservoir changes and fault compartmentalization in and around the existing developments. These results are being incorporated into surveillance activities and development planning.

"The West Sak reservoirs appear to be conducive to 4D technology," the company said. "Efforts are underway to understand the potential areas and timing for additional application and acquisition."

ConocoPhillips said the eastern NEWS oil pool is being evaluated for development opportunities with the evaluation "heavily dependent on the results seen from other viscous development opportunities the company is currently exploring."

ConocoPhillips said the overlying Cretaceous Brookian Moraine at Kuparuk is being tested for productivity and waterflood … (with) two follow up pairs (of wells) planned for early 2020.

The division approved the 2019 POD in early July; it has since been amended, most recently, Aug. 27, 2019, to add four new wells at the 3R drill site.

Colville River unit

There are four working interest owners at the Colville River unit who collectively hold less than 1%; then there is operator ConocoPhillips Alaska, which since it bought out Anadarko Petroleum Corp.'s 22% unoperated interest in the western North Slope in 2018, an interest which included 22% at Colville, has held a Colville WIO of more than 99%. ConocoPhillips also now holds 100% in the two federal units in NPR-A, Bear Tooth and Greater Mooses Tooth.

In the 21st status update to the Colville River unit agreement, submitted to the division, Arctic Slope Regional Corp. and the U.S. Department of the Interior's Bureau of Land Management March 15, 2019, ConocoPhillips reported on the status of the unit as of Jan. 1, 2019, and on plans for development for 2019 and the first quarter of 2020, with 14 wells planned for the CRU in that period.

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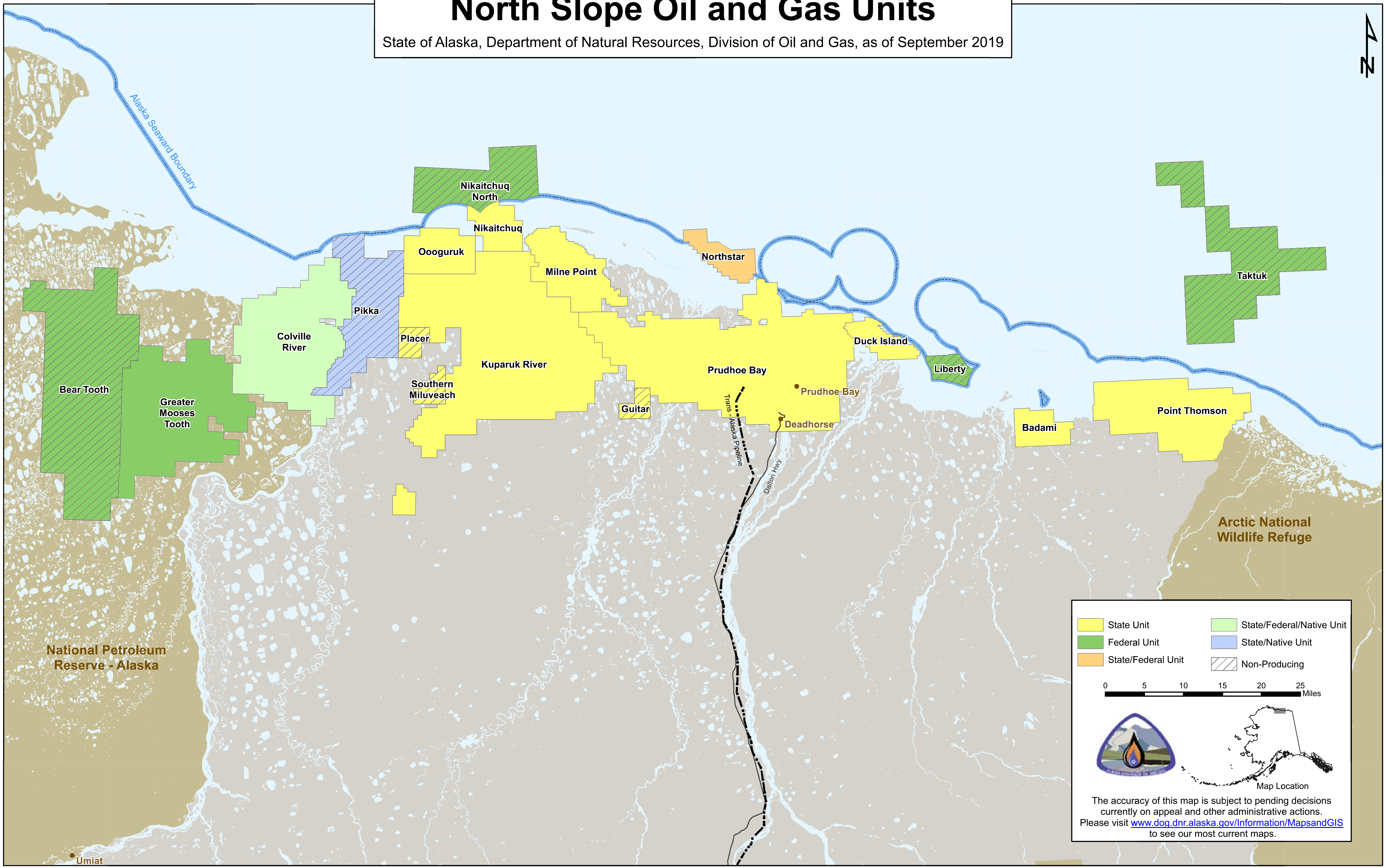
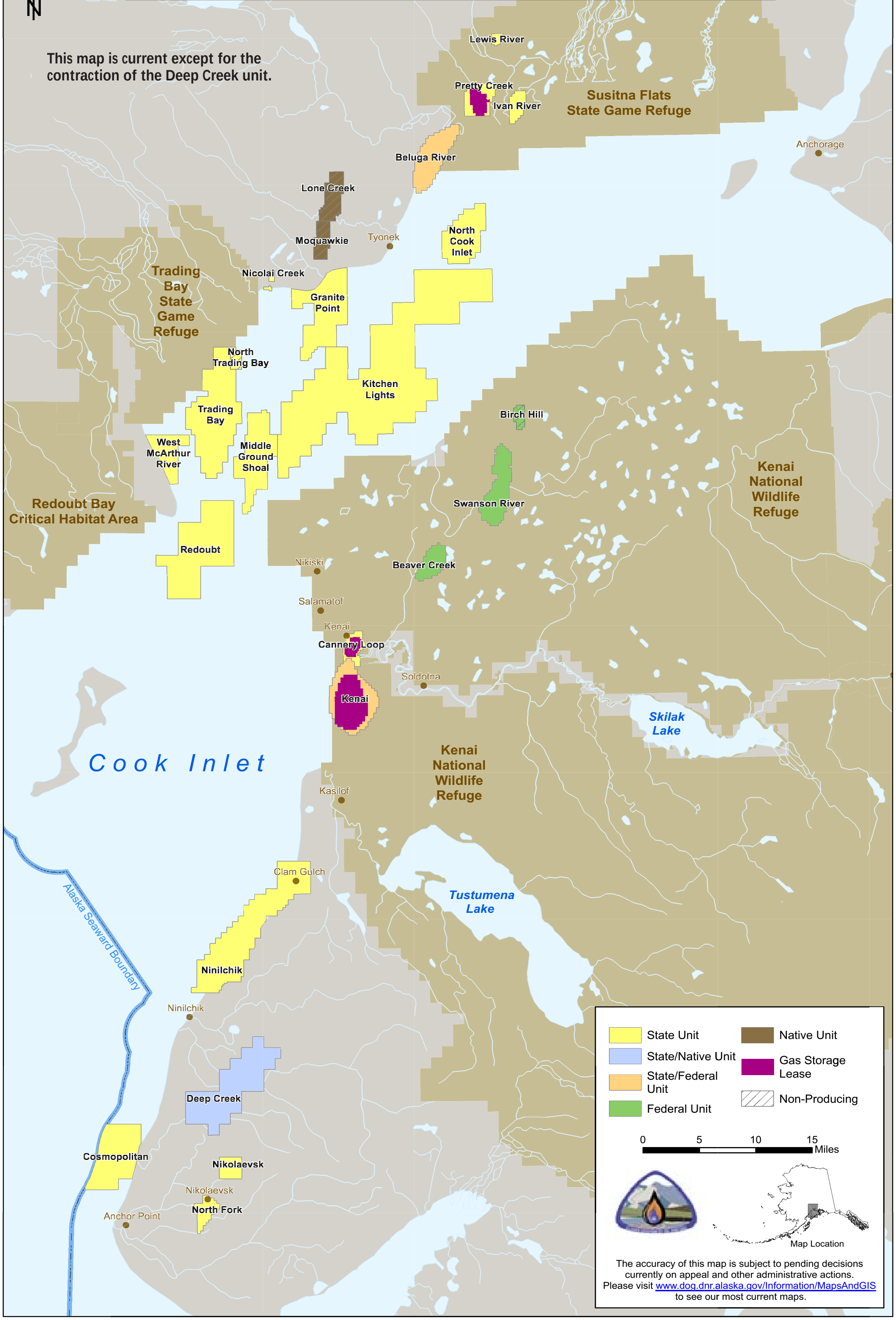
North Slope Oil and Gas Units

State of Alaska, Department of Natural Resources, Division of Oil and Gas, as of September 2019



Cook Inlet Oil and Gas Units

State of Alaska, Department of Natural Resources, Division of Oil and Gas, as of July 2019



The accuracy of this map is subject to pending decisions currently on appeal and other administrative actions. Please visit www.dog.dnr.alaska.gov/Information/MapsAndGIS to see our most current maps.

CONOCO *continued from page 35*

There are six participating areas, four oil pools and eight reservoir areas in the CRU, the company said, with an application to form the new Fiord West Kuparuk PA submitted Dec. 21, 2018.

There are satellite oil pools at three drill sites — Qannik at CD2, Fiord at CD34 and Nanuq at CD4, with separate PA agreements.

"All CRU oil pools are developed primarily with horizontal well technology," ConocoPhillips said. The Qannik and Nanuq PAs are primarily waterflooded, while Alpine, Fiord Nechelik, Fiord Kuparuk and Nanuq Kuparuk employ MWAG, gas-alternating waterflood using either miscible gas or sub-miscible enriched gas.

Alpine PA

In 2018, 152 wells had been drilled at the Alpine PA (78 producers, 72 injectors, two disposal wells). Average 2018 oil production at the Alpine PA was 37,100 barrels per day, with 32,400 bpd of water and an average water injection rate of 80,800 bpd.

Initial drilling planned from CD1 and CD2 was completed by November 2005, with peripheral opportunities pursued since then.

In 2006 development of the Alpine A and C sands began from CD4; CD5 was completed in 2015 with production startup in late October 2015.

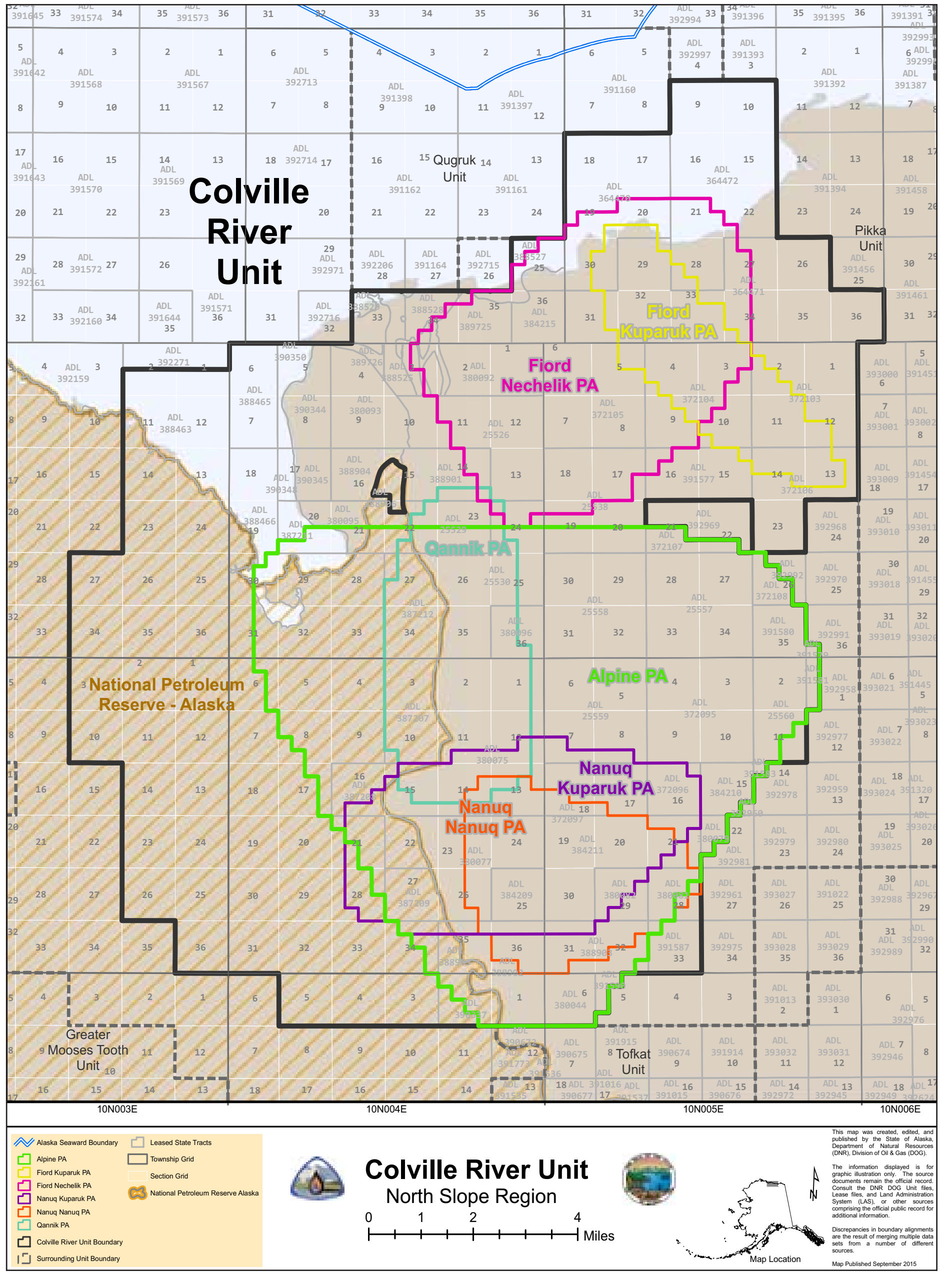
Five Alpine rotary producers and three injectors were planned beginning in the first quarter of 2019 and continuing through the first quarter of 2020. Development during the period will also include coiled tubing drilling targets.

"In early 2020 the heel space between injectors CD5-23 and CD5-25 will be reduced via CTD laterals drilled into the gap between the wells," the company said. There are other opportunities for CTD in 2020.

"Development of the Alpine reservoir continues to focus on the expansion of the existing MWAG flood and the use of line-drive horizontal well patterns."

The company said performance from the Nanuq Kuparuk PA, which started in 2006, continues to exceed expectations, with current production of some 13,000 barrels per day of oil and 6,000 bpd of water.

ConocoPhillips reviewed the CD5 drilling program and noted that two wells, CD5-313 and CD5-314X account for most of current production from Nanuq Kuparuk.



"Drilling results from each CD5 well supported the next westward target," the company said. "With CD5-316, results suggest another target exists to the west, but the location will need a drilling rig larger than Doyon 19 to access its potential," so no additional Nanuq Kuparuk wells are planned for 2019, although a potential infill/CTD sidetrack could be drilled in 2019 or the first quarter of 2020 "as rig optimization/utilization dictates."

The CD5 wells have been setting onshore drilling records since 2016, ConocoPhillips Alaska's VP of external affairs and transportation, Scott Jepsen, told the Alaska Support Industry Alliance Sept. 12, 2019, with the onshore North American record for the longest combined footage for a well and laterals, 47,828 feet, set in July 2019 at the CD5-98 well, which also set an Alaska record, at 32,468 feet, for the longest single well.

The CD5-25, drilled in May 2018, has the record for the longest lateral onshore North American well at 21,748 feet.

Overall, the 10 longest well in Alaska have been drilled at CD5.

Fiord PAs

Fiord Kuparuk production averaged 400 bpd of oil in 2018 and 3,900 bpd of water, with average water injection of 6,400 bpd. Fiord Nechelik PA oil production averaged 5,500 bpd of oil in 2018 and

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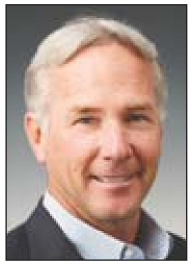
CONOCO *continued from page 39*

11,000 bpd of water, with average water injection of 16,800 bpd.

At Fiord, 23 wells, 13 producers and 10 injectors, have been completed in the Fiord Nechelik PA, with no new rotary wells planned for that PA in 2019 through the first quarter of 2020. There are three producer and two injector CTD sidetrack opportunities which could be drilled.

There were six active wells in the Fiord Kuparuk PA in 2018, three producers and three injectors. "The Fiord Kuparuk wells produce at high water cut making them non-competitive with other wells in the field," the company said, with the wells brought online as water handling capacity allows. No additional Fiord Kuparuk wells are planned through the first quarter of 2020, although one well is being evaluated as a rig workover completion.


SCOTT JEPSEN

First quarter 2019 development plans at Fiord West included a Fiord West Kuparuk reservoir slant pilot hole well near where the extended reach drilling rig will be drilling extended reach laterals, ConocoPhillips said. This well is intended to evaluate static subsurface properties and production to assist detailed ERD well planning and execution.

The company said in its 2019 plan that the well would be included in the Fiord West Kuparuk PA — that new PA was approved May 30, 2019. It includes some 12,015 acres, is jointly managed by the state, ASRC and BLM and includes state, joint state-ASRC and BLM leases.

The PA is about a mile west of the Fiord Nechelik PA — an area with seven exploration wells, six of which encountered the Lower Cretaceous Kuparuk River formation.

In its approval of the PA ASRC said ConocoPhillips plans to drill seven wells in the Fiord West Kuparuk PA with production from the first well expected in the second quarter of 2019 and the other six wells to be drilled by the ERD rig due onsite in the second quarter 2020.

The ERD rig, which will be Doyon 26, will arrive on the North Slope in the fourth quarter of 2019 from Nisku, Canada, in 267 truckloads, Jepsen said. Drilling from a 14-acre pad, it will allow the company to develop 154 square miles of reservoir, compared to 55 square miles which could be developed without the ERD rig. He said Fiord West was a known accumulation, but development was problematic because the area is along the coast in wetlands. The CD2 pad has been extended with a little more gravel for the development.

Nanuq, Qannik

2018 oil production from the Nanuq pool averaged 1,200 bpd, with 100 bpd of water and average water injection of 1,500 bpd.

ConocoPhillips said the Nanuq pool has been developed primarily from CD4 and includes wells in the Nanuq PA, with six producers and four injectors active in the pool.

One CTD sidetrack is planned in 2019-quarter one of 2020; rotary drilling will be considered.

Qannik production averaged 1,600 bpd of oil in 2018 and 300 bpd of water, with average water injection of 1,900 bpd.

The Qannik pool has been developed from CD2 and includes nine wells, six outboard producers and three inboard water injectors with waterflood supplemented with a natural gas cap expansion from the east.

One producer-injector pair is planned for 2019-quarter one 2020 drilling; other drilling will be considered.

Alpine facilities

ConocoPhillips said there were no major process expansions planned for the Alpine Central Facility in 2019 but noted that in 2018 engineering studies were performed to evaluate current water, oil and gas systems limitations at the ACF and analyze options to maximize facility capacity.

In 2018 the Alpine Gas Expansion project was kicked off with the objective of debottlenecking ACF gas handling facility by upgrading the C1 turbine-compressor package and addressing other facility gas handling bottlenecks resulting from increasing gas throughput.

No CD1, CD3 or CD4 expansions are planned for 2019. The first expansion at CD5 was installed in 2017, adding 12 well slots, with engineering design studies completed for a second CD5 expansion in 2018. That expansion will add 10 well slots in 2019.

Expansion engineering, design studies and permitting of the CD2X expansion to support the Fiord West development were completed in 2018, with gravel haul for the 5.3 acre pad expansion completed in the 2018 winter ice road season.

Drill site facility expansion of 21 well slots will be installed in 2019, ready for startup in the first quarter of 2020. Three existing well slots will be available for the ERD rig and three additional slots will be added to the CD2 Qannik well row, with a total of 27 well slots available for ERD drilling in the first quarter of 2020 with future expansion capacity for an additional 11 well slots.

Greater Mooses Tooth

Greater Mooses Tooth in the National Petroleum Reserve-Alaska is ConocoPhillips Alaska's newest unit development, and the first unit on federal land in NPR-A.

The first pad, GMT1, is in production; the second pad, GMT2, is under construction.

In its CRU plan ConocoPhillips Alaska said GMT1 development began in late March 2018 with initial development drilling activities completed in mid-February 2019. The drilling rig was then moved back to CD5. Production at GMT1, the Lookout oil pool, started in October 2018 and is being processed through the Alpine Central Facilities.

GMT1 has an 11.8-acre drilling pad and the company said when production began in October 2018 that the pad will initially have nine wells with capacity for as many as 33. Peak gross production was estimated at 25,000 to 30,000 bpd and the gross cost was estimated at $725 million, including construction and drilling.

Alaska Oil and Gas Conservation Commission records show four development wells, five service wells and two wells listed as unknown drilled at GMT1. As of July 2019, the most recent data available from AOGCC, three wells were on production, and the field was averaging 11,335 barrels per day. However, 86.7% of that volume came from one well, MT6-05, 12.2% from a second well, MT6-03 and just 1.1% from the third well, MT6-06.

In the company's July 30, 2019, earnings call, Matt Fox, ConocoPhillips executive VP and chief operating officer, said the company was getting lower than expected performance in two areas

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CONOCO *continued from page 40*

nationwide, one of which was at GMT1, where one of four production wells was performing below expectations.

In response to an analyst's question, Michael Hatfield, ConocoPhillips president of Alaska, Canada and Europe, said with only four producers at GMT1, underperformance by a single producer "ends up significantly impacting the overall development." He said no remediation is planned, but learnings from GMT1 are being applied to the company's GMT2 plans, although he said GMT2 was a different reservoir.

ConocoPhillips began planning satellites after it brought the Alpine field online in 2000, the satellites being accumulations worth developing but not large enough to justify standalone processing facilities. The 2003 Alpine Satellite Development Plan proposed five satellites: Fiord, Nanuq, Lookout, Spark and Alpine West, with hints of as many as 10 additional accumulations within 30 miles of Alpine.

Fiord was developed from CD3 in 2006, Nanuq from CD4 in 2006 and Qannik from an expanded CD2 pad in 2008. Alpine West was developed from CD5 in 2015.

The other satellites ConocoPhillips listed were the Lookout satellite at a CD6 pad and the Spark satellite at a CD7 pad — both of those in NPR-A. Around that time ConocoPhillips described Lookout as "marginally economic," but said the economics would be improved by the bridge across the Nigliq Channel which was part of the CD5 development. In a 2009 revised application for CD5, ConocoPhillips changed the names of CD6 and CD7 to GMT1 and GMT2, distinguishing Greater Mooses Tooth from Alpine. Spark No. 1, Spark No. 1A, Moose's Tooth C, Lookout No. 1, Rendezvous A and Rendezvous No. 2 were the NPR-A discoveries ConocoPhillips predecessor Phillips Alaska announced in 2001.

GMT2

Jepsen gave the Alliance a GMT2 update in his Sept. 12, 2019, presentation. The gravel pad and 8-mile road are scheduled for 2019, and Jepsen said that gravel was being reworked for the project. 2019 will also see preparation for pipeline installation, which begins in 2020 and is completed in 2021, with drilling beginning that year at GMT2 with first oil planned for late in the year.

A joint record of decision for GMT2 was issued in October 2018 by BLM and the U.S. Army Corps of Engineers, following a final supplementary environmental impact statement in September 2018.

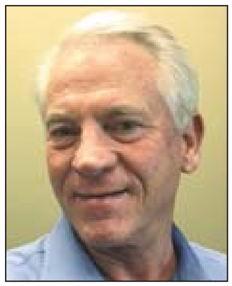
ConocoPhillips is estimating peak production of 35,000 to 40,000 barrels of oil per day from up to 48 wells and a gross capex for the project of some $1 billion. ●

Contact Kristen Nelson at knelson@petroleumnews.com

Eni restarts Nikaitchuq drilling program

Two development wells completed, others permitted; Nikaitchuq North advancing slowly; no new Oooguruk wells

By ALAN BAILEY
For Petroleum News



ROBERT PROVINCE

Although Eni US Operating's activities in Alaska tend to represent a small portion of the Milan based company's worldwide activities, Eni has been expressing a positive view of its Alaska interests. That view has recently translated into the completion of new wells in the company's Nikaitchuq oil field offshore the North Slope.

In addition, drilling has continued for the NN-01 exploration well that Eni spud in late 2017 on Nikaitchuq's Spy Island drill site. The well is being directionally drilled under the Beaufort Sea into the Nikaitchuq North prospect in the federal outer continental shelf. The drilling has been proceeding intermittently since the well was spud.

In January 2019 Eni re-enforced its Alaska interests by purchasing Caelus Natural Resources Alaska's 70% interest in the offshore Oooguruk field, to the west of the Nikaitchuq field, thus making Eni the operator and sole owner of Oooguruk.

And in August 2018 Eni purchased 350,000 exploration acres from Caelus — this acreage lies on the eastern North Slope between Prudhoe Bay and Point Thomson.

Plan of development

Before the downturn in oil prices in 2014, Eni had been using a number of small drilling projects at Nikaitchuq to try to bolster production from the field. But the oil price fall resulted in those drilling activities being suspended. The activities had included the addition of multilaterals to existing wells; evaluating the potential of a sand reservoir below the producing reservoir; and drilling to the west and east of the existing well pattern.

The field has been developed by drilling from an onshore pad at Oliktok Point and from the offshore Spy Island drill site. At the time of drilling suspension in 2014 an initial Oliktok Point drilling program had been completed but a Spy Island program remained unfinished. New permitting and drilling indicate that the Spy Island program is back underway.

The Nikaitchuq plan of development, approved by the Alaska Department of Natural Resources' Division of Oil and Gas and the U.S. Bureau of Ocean Energy Management for the period through September 2019, envisaged the possibility of drilling an additional three new wells and eight lateral wells from Spy Island. Two of the wells would be injectors, while the remaining well and the laterals would be producers. In general, the concept is to convert some existing wells to multilaterals, while also drilling some new wells from the surface.

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Two laterals completed

Eni did complete two new lateral production wells, the SP33-W03L1 and SP30-W01L1 wells. The company has also permitted a new development well, the SP03-NE2, and a lateral from that well. The SP33-W03L1 well was spud May 25, 2019, and completed on June 20, while the SP30-W01L1 was spud on June 21, 2019, and completed on July 20 according to Alaska Oil and Gas Conservation Commission records.

The SP prefixes indicate that these are production wells drilled from the Nikaitchuq Spy Island drill site.

Eni has also been continuing with maintenance activities on surface facilities, and on preparing tie-ins for future wells to be drilled. And the company has conducted multiple well workovers in the field.

According to the latest Nikaitchuq plan of development, which runs through to September 2020, the company anticipates continuing with facility maintenance and well workover activities through the coming year. Depending on the timing of drilling associated with Nikaitchuq North exploration, the company also anticipates the possibility of drilling three new development wells from Spy Island: one production well and two water injectors.

Depending on the timing of drilling associated with Nikaitchuq North exploration, the company also anticipates the possibility of drilling three new development wells from Spy Island: one production well and two water injectors.

Nikaitchuq North

The Nikaitchuq North NN-01 well was started as part of an initiative to find new oil resources in federal acreage to the north of the existing field. The ultra-extended reach well is targeting Harrison Bay Block 6423, using the Doyon 15 drilling rig, the same rig that is used for development drilling from Spy Island in the existing

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ENI *continued from page 43*

Nikaitchuq field.

Clearly, the idea is to try to use Nikaitchuq North resources to bolster reserves and production for the overall field. And, with just one rig in operation, there is obviously a linkage between the timeframe for the Nikaitchuq development drilling program and the Nikaitchuq North drilling — the drilling of new 2019 development wells could not begin until after the suspension of the NN-01 drilling.

According to Eni Alaska Vice President Whitney Grande the Nikaitchuq production facility has spare capacity, with a capacity of 40,000 barrels per day, expandable to 50,000 bpd. Data published by AOGCC indicates that Nikaitchuq production in July 2019 averaged 20,175 bpd, compared with 18,545 barrels per day in July 2018 (the production increase is presumably related to the new development drilling).

In January 2019 Eni announced a goal of raising its total Alaska North Slope production to 30,000 barrels per day by drilling more wells at both Oooguruk and Nikaitchuq.

Drilling delays

Eni had originally planned to complete the NN-01 well in mid-February 2018, and then to conduct flow testing on any oil discovery. However, the drilling did not proceed to plan and was eventually suspended on Aug. 23, 2018, because of seasonal drilling restrictions. The drilling is presumably challenging, given that, with an expected measured depth of about 35,000 feet, the well would be the longest extended reach well of its type in Alaska.

According to Eni's latest plan of operations the drilling of NN-01 restarted in January 2019 but was suspended in April at a measured depth of 30,010 feet because of operational limitations. Petroleum News understands that there was a need for modifications to the drilling rig.

The plan of operations says that Eni anticipates continuing the drilling of the well in early February 2020, with the well expected to reach its target measured depth by the third quarter of the year. A reliable Petroleum News source has indicated that testing of the well is anticipated in 2020.

Eni has not publicly identified the drilling target at Nikaitchuq North. The Schrader Bluff formation that hosts the reservoir for the Nikaitchuq field is known to extend a long way north under the Beaufort Sea — it is possible that Eni is seeking a more northerly oil pool in this formation. However, there are other possibilities that, based on circumstantial evidence such as the planned drilling depth, may be more likely. One contender seems to be Jurassic Alpine sands, equivalent to reservoir sands in the Alpine oil field and deeper than the Schrader Bluff. In addition, Kerr-McGee, the previous Nikaitchuq operator, had talked about the possibility of testing the Jurassic Nuiqsut sandstone to the north of the field.

Oooguruk field

As with Nikaitchuq, the Oooguruk field saw significant impacts from the 2014 oil price downturn: In May 2016 Caelus, then the operator, suspended all drilling operations at the field. That drilling suspension continued up to the point at which Caelus sold its interests in Oooguruk to Eni. Eni became the new field operator on Aug. 1, 2019 and has thus far not announced any new development plans for the field.

Although not doing any new drilling, Caelus had been conducting some well workovers, including the replacement of some electric submersible pumps. In the summer of 2019, with the concurrence of Eni, the company carried out some maintenance work in the field's surface facilities. The field has been producing from three pools: the Kuparuk, Nuiqsut and Torok. The Torok formation contains the oil pool for the planned Nuna development that is being purchased by ConocoPhillips, separately from the Oooguruk field. However, the Torok does produce on the Oooguruk offshore production island.

The current plan of operations for the field indicates that two production wells and two injector wells are active in the Kuparuk pool, although Kuparuk production is currently shut in. Caelus had been hoping to obtain regulatory approval for commingling or alternating Kuparuk and Nuiqsut production through one of the Nuiqsut wells.

The development area for the Nuiqsut pool has 18 production wells and 10 injection wells, the plan of operations says. Caelus has been in the process of upgrading the system that supplies seawater for injection into the reservoir.

The Torok pool has three active wells — two production wells and an injector well.

Two wells drilled from the onshore Nuna drill site have been suspended.

In January 2019 Eni announced a goal of raising its total Alaska North Slope production to 30,000 barrels per day by drilling more wells at both Oooguruk and Nikaitchuq.

In July 2019 Oooguruk production averaged 8,720 bpd, compared with 9,696 bpd in July 2018. Taken together, the combined Oooguruk and Nikaitchuq production falls a bit short of that 30,000 bpd target.

With just one rig in operation, there is obviously a linkage between the timeframe for the Nikaitchuq development drilling program and the Nikaitchuq North drilling — the drilling of new 2019 development wells could not begin until after the suspension of the NN-01 drilling.

Exploration acreage

Eni has yet to announce any specific plans for exploration in the 350,000 exploration acres that it purchased from Caelus.

In 2015 Caelus acquired 175 square miles of new 3D seismic data and reprocessed another 275 square miles of existing 3D seismic, with the objective of imaging prospects in the acreage. Caelus said that, while there are multiple plays in proven stratigraphic horizons within the acreage, surrounding legacy wells confirm relatively shallow Brookian reservoirs and hydrocarbon charge, as well as deeper petroleum system elements. The company also commented that the proximity of infrastructure with available capacity reduces the resource volumes needed for viable development.

In August 2019 Eni said that it planned to apply its business model and experience to the exploration acreage, using fast-track exploration and a short time to market for potential new discoveries. ●

Contact Alan Bailey at abailey@petroleumnews.com

COURTESY EXXONMOBIL

This page and opposite page: The Central Pad in the Point Thomson unit. The process modules are connected by a line to the two re-injections wells, PTU-15 and PTU-16. Due to the high Thomson sands reservoir pressure, the PTU-17 wellhead is the largest in the Northern Hemisphere; standing more than 17 feet tall, weighing almost 14 tons and able to withstand pressures of up to 15,000 psi. The condensate from Module 103 is sent to the export pipeline. The gas from Module 103 is sent to Module 101, the gas injection compressor. The process is powered by Module 105, the power generation module, which consists of four turbines, two natural gas powered, and two dual diesel and natural gas powered. The utility Module 102 houses the nitrogen generators needed for equipment operation, the instrument air needed for the equipment and it has water for fire suppression and other heating and cooling fluids for the modules.

Exxon pursuing two fronts

Operator's ultimate goal at North Slope Point Thomson unit is marketing 8 Tcf of natural gas

By KAY CASHMAN
Petroleum News

DARLENE GATES

One of the earliest explorers in Alaska and one of the primary working interest owners on the North Slope, ExxonMobil did not embark on the $4 billion Point Thomson development just to produce 10,000 barrels of condensate a day. Production of the technically challenged condensates was the result of a settlement agreement between the state of Alaska and ExxonMobil and its minority partners to allow the companies to retain the leases. ExxonMobil's ultimate goal was to develop and market Point Thomson's 8 trillion cubic feet of stranded natural gas.

The future export of natural gas from the eastern North Slope field has always been the cornerstone of the state of Alaska's vision for a North Slope gas export project.

The Point Thomson unit condensates, a liquid hydrocarbon akin to very light oil, were particularly difficult and expensive to produce because of the exceptionally high reservoir pressure of the Thomson sands, and in part because it was a retrograde field in which condensate in the reservoir tended to liquefy as the pressure was drawn down. The need for directional drilling to reach the offshore reservoir sands from onshore drilling pads compounded the difficulties.

2012 settlement

Following efforts by the state to terminate the Point Thomson unit because of the lack of condensate field development, in 2012 the state and the field's working interest owners signed a court-approved settlement agreement, specifying terms under which the unit and its leases could be retained.

That settlement agreement spelled out a commitment by ExxonMobil and the other owners to move forward with the Point Thomson initial production system, or IPS, in which natural gas would be continuously cycled through the reservoir to enable the extraction of up to 10,000 barrels per day of condensate for export along with crude from the North Slope.

The purpose of the IPS was to test the viability of the gas cycling process. Reinjecting produced natural gas into the reservoir served to maintain pressure for future gas production

In 2016, ExxonMobil put the Point Thomson unit online, the only field the mega major operated in Alaska. (The $4 billion was invested through the end of 2015.)

The Point Thomson unit West Pad facilities were designed to eventually produce 10,000 barrels per day of condensate a day, whereas Central Pad facilities were designed to reinject 200 million cubic feet per day of recycled gas, although each began with half of that amount.

The Point Thomson startup was a long-awaited culmination of a process that began with initial leasing in 1965, oil pool discovery in 1977 (by ExxonMobil at the Point Thomson Unit No. 1 wildcat exploration well) and confirmation in 1978 and 1979 (Point Thomson Unit No. 2 and No. 3 wells), with unitization in 1977.

By 1983, ExxonMobil and other companies had drilled 17 PTU wells.

ExxonMobil

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COURTESY EXXONMOBIL

There were technical, economic, legal and regulatory challenges to development, but the issue came down to prioritizing condensate vs. prioritizing natural gas production.

For years the state deferred pressure on the Point Thomson owners to develop the field because there was no way to get condensate or natural gas to market - Prudhoe Bay and Pump Station 1 of the trans-Alaska oil pipeline were 60 miles to the west.

The Badami field came online in 1998, providing an oil pipeline covering approximately half the distance. A connecting line from Badami to Point Thomson was then built by ExxonMobil as part of its 2012 through 2017 plan of development with the state.

There was still no gas pipeline to take the field's major resource, natural gas, to market. Its problem has always been the ability to compete internationally on price given the very costly 800-mile gas pipeline that would have to be built and the easy availability of cheaper sources of gas near tidewater.

Three alternatives

The 2012 settlement had included three alternatives for expansion beyond the 10,000 bpd of condensate.

The first alternative was the sanctioning of major gas sales by June 2016, which timewise the parties agreed could not be done.

The second option was expanding liquids production to at least 30,000 bpd by 2019.

The third option was integrating Point Thomson and Prudhoe Bay operations to improve recovery, which involved building a gas line to Prudhoe for reinjection.

When ExxonMobil applied to the Alaska Oil and Gas Conservation Commission for pool rules for Point Thomson the company said it would prefer to transition from the present phase, the IPS, directly into exporting natural gas.

The company told the commission it was skeptical about increasing condensate production because of major technical challenges and the high cost of the facilities and wells.

As for integrating Point Thomson and Prudhoe Bay, ExxonMobil said while that would accelerate Point Thomson natural gas sales by two years, the acceleration would be unlikely to justify the cost of implementation.

Settlement deadline deferred

The 2012 settlement had required a plan for expansion of Point Thomson production by the end of 2019 if a major gas sale hadn't been sanctioned by June 2016.

Late in 2017, the state and ExxonMobil reached agreement on

continued on next page

EXXON *continued from page 47*

the expansion.

The settlement required either increasing production to 30,000 barrels per day of condensate or moving natural gas to Prudhoe Bay for injection there and construction of a gas pipeline between the fields. Moving natural gas to Prudhoe was ExxonMobil's choice in the 2017 agreement, but the thing that made that challenging was it would require a commercial agreement with all the Prudhoe Bay owners. Gas balancing would have been part of the challenge, especially since Point Thomson natural gas was higher quality than Prudhoe gas.

That work was deferred in the Point Thomson Unit Letter Agreement dated Sept. 10, 2018, from then-commissioner of the Alaska Department of Natural Resources Andy Mack after meetings with ExxonMobil and BP (a major Point Thomson working interest owner).

Mack said the 2019 deadline was stayed for as long as the Alaska LNG Project was progressing. The extension was to end when the Alaska LNG Project reached final investment decision or when DNR notified the parties that the project was no longer progressing.

At the end of the extension the Point Thomson owners would have 30 months to reach a final investment decision on either of the expansion projects or lose acreage in the field.

Gas sales agreement

Also Sept. 10, 2018, the Alaska Gasline Development Corp. announced that ExxonMobil and AGDC had agreed to what the state-owned corporation called "certain key terms including price and a volume basis for a Gas Sales Agreement," captured in an unbinding "Gas Sales Precedent Agreement."

The Point Thomson unit condensates, a liquid hydrocarbon akin to very light oil, were particularly difficult and expensive to produce because of the exceptionally high reservoir pressure of the Thomson sands, and in part because it was a retrograde field in which condensate in the reservoir tended to liquefy as the pressure was drawn down.

AGDC and BP, with a 32% working interest in the Point Thomson unit, had agreed to key terms of a gas sales agreement four months earlier, including price and volume.

AGDC had not reached agreement with ConocoPhillips, the other significant North Slope leaseholder with a 5% interest in Point Thomson, and a company with major natural gas interests at the BP-operated Prudhoe Bay. (ConocoPhillips, which is very focused on oil development and production farther west on the North Slope, is still trying to pull out of Point Thomson. Petroleum News sources say the unit owners are still in negotiations as of Sept. 15, 2019.)

In a Sept. 10, 2018. statement on the ExxonMobil agreement AGDC said the parties anticipated finalizing long-term gas sales agreements for ExxonMobil's share of both Prudhoe Bay and Point Thomson gas. (ExxonMobil had a 62.75% share of Point Thomson and a 36.4% share of Prudhoe Bay.)

"This precedent agreement is good for Alaska and ExxonMobil and represents a significant milestone to help advance the state-led gasline project," said ExxonMobil Alaska President Darlene Gates at the time. "As the largest holder of discovered gas resources on the North Slope, ExxonMobil has been working for decades to tackle the challenges of bringing Alaska's gas to market," she said.

Then-AGDC President Keith Meyer was equally upbeat, as was then-Alaska Gov. Bill Walker, who had made a gas export project a priority of his administration above the health of the state's oil industry.

Agreement details

The Point Thomson Unit Letter Agreement said that for purposes of the settlement agreement an Alaska LNG Project meant a fully integrated natural gas project producing LNG for export and natural gas for in-state delivery being advanced by the state, a state-owned entity such as AGDC "or an entity in which a state owned entity holds a controlling equity share."

The letter said the June 30, 2017, plan of development, or POD, for Point Thomson, as supplemented in October of that year and approved in August and December 2017, would remain in place until the effective date of a major gas sale POD, an expansion project POD or Dec. 31, 2019, "if an MGS POD or Expansion Project POD has not been submitted."

The agreement called for submittal of Point Thomson PODs on a biennial basis beginning with the 2020-21 period. Those PODs would address IPS work or other exploration or development, including activities in support of the Alaska LNG Project.

Regarding the extension period, a final investment decision was defined as "a decision by the Alaska LNG Project owners to construct the Alaska LNG Project, following securing the necessary financing arrangements to construct and operate the Alaska LNG Project."

Jade to drill Sourdough in PTU

ERIK OPSTAD

As part of the 2012 settlement between the state of Alaska and the working interest owners in the ExxonMobil operated Point Thomson unit, an East Pad and associated wells were to be drilled in the unit.

That requirement will be fulfilled through a deal between ExxonMobil and Alaska independent Jade Energy, which is planning to drill a new well in the Sourdough oil prospect on a PTU lease in first quarter 2021.

The initial well, Jade No. 1, had been planned for first quarter 2020, but because Jade was not able to get into the Point Thomson unit's service pier in summer 2019, the appraisal well had to be deferred until early 2021.

Erik Opstad, who oversees Jade's operations, is a state of Alaska certified professional geologist who has worked the North Slope for 34 years, including a stint with BP in various roles and as a principal and general manager of Savant Alaska.

By building a 70,000 barrel per day liquids export pipeline (throughput that can be expanded) at Point Thomson that connects to the Badami unit and thus moves oil and condensate to Pump Station 1 of the 800-mile trans Alaska oil pipeline, ExxonMobil improved the development economics of other oil prospects to the east. Those prospects include Yukon Gold, Stinson and any future production from the 1002 area of the Arctic National Wildlife Refuge, none of which are owned or operated by ExxonMobil.

Jade No. 1 will be drilled in state lease ADL 343112 in area F, Tract 32, of the Point Thomson unit, which is the most southeasterly in the unit and adjacent to the western border of the ANWR 1002 area.

The lease holds two mid-1990's Sourdough oil discovery wells that were drilled by BP, which estimated Sourdough held 100 million barrels of recoverable oil.

Jade holds a 95% working interest in the lease, per a farmout agreement with Point Thomson working interest owners ExxonMobil and BP, which retained a small overriding royalty interest.

The ExxonMobil and BP assignments gave both North Slope producers some skin in the game, fully aligning them in delivering a successful Sourdough development.

Opstad says he expects Jade to have 100% working interest by the end of 2019.

Drilling, development plans

Jade plans to first drill a vertical pilot hole to true vertical depth then plug it back and drill a high angle penetration into the Brookian reservoir, noting it "firmly believes … the deployment of horizontal production wells is a critical element in commercializing the PTU Brookian opportunity in Area F, as well as its adjoining areas."

Upon completion of "drilling and extended production testing, analysis of that data will be integrated into the Jade 3D Brookian seismic model," the company said in filings with the Alaska Department of Natural Resources' Division of Oil and Gas.

With those results in hand, Jade will put together a third plan of development and submit it to the division.

—Kay Cashman

In the meantime

ExxonMobil continues working on the technical challenges at Point Thomson.

From the start in April 2016, condensate output from the IPS has fluctuated from less than 100 bpd to a high of 10,725 bpd in December 2018, although something closer to 5,000 bpd is more common.

In its 2017 POD, ExxonMobil told the state that "production to date has been impacted by gas injection compressor availability and reliability," referring to the compressors as "industry-first," which likely explains their serial numbers, 001 and 002.

Development of the Point Thomson field requires handling reservoir pressures upwards of 10,000 pounds per square inch, a pressure corresponding to "the effect of an elephant standing on the end of someone's thumb," an ExxonMobil executive said right after the field came online.

Advanced technology, the company has said from early on, has been key to producing the field.

Since each compressor allows the field to produce 5,000-6,000 bpd, one is presumably often offline for maintenance.

Hans Neidig, ExxonMobil's public and government affairs manager for Alaska, told Petroleum News in late July 2018 while the field was in a warm shut down for maintenance, that the "advanced equipment at the facility requires rigorous inspection and maintenance protocols to ensure safe operation."

Without referring directly to the compressors, he said, because of "the equipment's unique nature, more time is needed to replace some components compared with standard, off-the-shelf equipment."

A state official who asked not to be identified told Petroleum News that summer, "Point Thomson would be tough for any other major to deal with, but ExxonMobil keeps whittling away at the problem. We're fortunate they're operating that field. I doubt it would ever have been developed otherwise," he said, citing "ExxonMobil's deep pockets and technical savvy." ●

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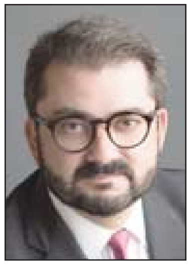
Kitchen Lights on the market

As a result of Furie's bankruptcy, the Cook Inlet natural gas producing unit's assets being sold

By KAY CASHMAN
Petroleum News


SCOTT PINSONNAULT

Owned by Texas-based Cornucopia Oil & Gas Co., which in turn is owned by Deutsche Oel and Gas, Furie Operating Alaska LLC is operator of the offshore Cook Inlet Kitchen Lights unit that began producing natural gas in 2015.

In spring 2018, lender Energy Capital Partners started foreclosure proceedings against the owners, scheduling a sale of Furie's assets, but the sale was canceled by ECP when an agreement was reached with the owners.

As a result of that deal, on March 23, 2018, Ankura Consulting Group LLC was retained to assist Furie and its affiliates with interim management and financial advisory services and Scott M. Pinsonnault, a senior managing director at Ankura, was installed as Furie's interim chief operating officer.

Delivering on commitments

Armed with a fresh round of financing from Furie's lenders, Pinsonnault set about augmenting the independent's Anchorage staff, adding a new vice president of operations, and a health, safety and environment official, as well as completing the company's planned 2018 drilling program.

With outstanding commitments, both in terms of gas supplies for a big area utility and in terms of the Kitchen Lights unit plan of development with the state of Alaska, Furie's focus was to deliver on those commitments, Pinsonnault told Petroleum News in a July 9, 2018, interview.

"It's been a tremendous effort to get where we are in 90 days, to mobilize, permit, define the operational tempo for the summer," he said.

The 2017 default, issued by the Alaska Department of Natural Resources' Division of Oil and Gas, was because Furie had failed to meet drilling and development commitments.

But, in Furie's new plan approval, issued on Dec. 11, 2018, the division said that Furie had recently complied with its commitments, curing the default.

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TOP ALASKA EXECUTIVE: Scott Pinsonnault, COO
ALASKA TELEPHONE: 907-277-3726

The terms of Furie's supply agreement with Enstar Natural Gas and its affiliate Alaska Pipeline Co. had also been met by Furie pushing drilling as hard as it could in the last half of 2018 to get a total of four wells online, which was a contractual requirement with Enstar and APC.

A later communication from Enstar to Furie said that APC had been very accommodating over the previous three years and could have terminated the contract because of Furie's failure to meet deadlines for the drilling of wells and meeting required gas production capabilities. From the outset, the utility said, Furie had to supplement its Kitchen Lights natural gas production with gas purchased from third parties, or drawn from storage, in order to meet the terms of its APC supply agreement.

Disaster strikes in January

With a vigorous year-end drilling program that both cured the 2017 default with the state and met the gas supply agreement with Enstar, Furie appeared to be headed for a successful 2019.

But then disaster struck. On Jan. 5, 2019, the company ran into problems with hydrate plugs caused by freezing water combining with gas to form solid hydrates at the unit's onshore processing facility and in the 15-mile subsea pipeline from its Julius R offshore production platform, which slowed natural gas delivery to a trickle later that month.

On Jan. 23 Furie sent a letter to Enstar affiliate APC declaring Force Majeure and saying that it could no longer meet its commitments under its gas supply agreement.

At that time Lindsay Hobson, Enstar communications manager, told Petroleum News the utility had not received any gas from Furie since Jan. 25.

Kitchen Lights gas output was a mere 1,886 thousand cubic feet in February.

On March 19, 2019, Pinsonnault said Furie had cleared the obstruction that had been blocking the subsea pipeline.

"We have safely restored utility and communication between our onshore natural gas processing plant and the Julius platform over this past weekend," Pinsonnault said, referring to the field's offshore Julius R production platform. He said Furie would spend the next few weeks making sure that the line was completely clear, functional and safe before restoring gas production.

In April 2019, natural gas output from Furie's platform rose to

347,919 mcf, according to the Alaska Oil and Gas Conservation Commission, and production continued to rise.

Furie files bankruptcy

But financial pressure on the company was rearing its head, and in April 2019 a public notice of a foreclosure sale auction was posted by EPC in the Anchorage Daily News, and in Hart Energy's Industry Voice.

Although that sale was later postponed, on Aug. 9, 2019, Furie filed a voluntary petition for Chapter 11 bankruptcy relief in the U.S. Bankruptcy Court for the District of Delaware, listing about $450 million in debt. The company said it planned to sell its assets, which it listed on its petition with an estimated value of less than $50 million, by early January 2020.

Furie petitioned the court to approve "super priority senior secured post-petition financing in the form of a multiple-draw term loan credit facility in an aggregate principal amount of up to $15 million."

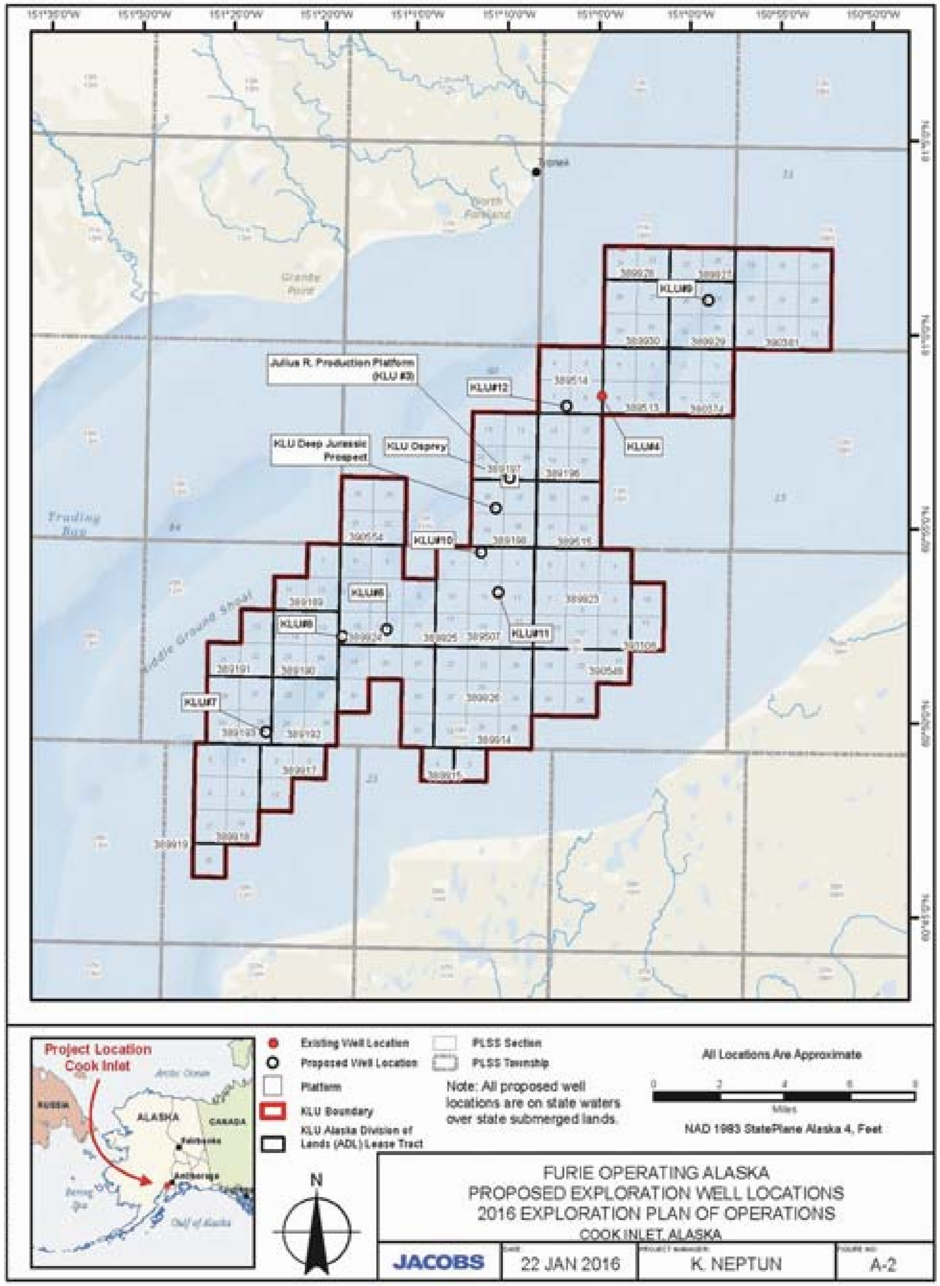
Judge Laurie Selber Silverstein granted Furie and its affiliates access to the first $7 million of the interim debtor-in-possession financing Aug. 12, clearing the way for the company to use $3 million for its interim budget needs, according to a report by Law360 and an Aug. 18 article in Petroleum News. Silverstein warned the company that key provisions of the financing remained subject to challenges, particularly provisions directing $4 million of the loan budget to pay fees incurred by prepetition lenders.

According to the petition, "after any administrative expenses are paid, no funds will be available to unsecured creditors."

Why specifically had Furie filed for bankruptcy protection?

In a first-day declaration filed by Pinsonnault with the court, Furie cited uncertainty with Alaska state tax credit reimbursements it had historically counted on receiving, years of liquidity issues and breaches of credit facilities, construction delays, and cost overruns.

In fact, in a plan of development submitted to state officials in October 2017, Furie said its failure to conduct any new development or exploration drilling at the Kitchen Lights unit in 2017 was due to "the lack of any meaningful appropriation to the oil and gas tax credit fund for the purchase of Alaska oil and gas production tax credit certificates."



As of April 5, 2019, Furie had submitted no revisions to the well locations in its 2016 map (see map in print and pdf versions of this story) but it did say that it expected the vertical well "bottom hole locations will coincide with the tophole coordinates" provided in the 2016 map.

"Furie has invested hundreds of millions of dollars in exploring and developing the KLU (Kitchen Lights unit) and has a very substantial amount of tax credit certificates in the queue awaiting purchase by the state," the company said in the plan. "These certificates are a key component to funding further exploration and development activities in the KLU and were relied on by Furie when putting together its work program and budget."

Furie's assets

As this issue of The Producers was being prepared for press in late September, a sale of Furie's assets was planned for November (see sidebar). Petroleum News will continue to follow the course of the company's bankruptcy and asset sale.

Furies' assets as reported over the last few years in Petroleum News include the following:

• Kitchen Lights unit consisting of nine state leases. The 83,394-acre unit contains three previously independent prospects that were administratively divided into four exploration blocks: Corsair, North,

continued on next page

Furie asset sale scheduled

Judge Laurie Selber Silverstein signed a bidding procedures order Sept. 26, 2019, in Furie's Chapter 11 case, setting forth a schedule for the sale of the company's assets — all the filing dates are in 2019 and all the times are at prevailing Eastern Time.

The deadline for the debtors to file a proposed form of Sale Order is 5 p.m. on Oct. 25.

Debtors shall file a Stalking Horse Supplement with the court on or before the same time and date.

The deadline to file an objection with the court to the Stalking Horse Supplement is 10 calendar days after the service of the Stalking Horse Supplement, the order said.

The deadline to file an objection with the court to the proposed assumption and assignment of an assumed contract including any objection relating to the cure claim, is 4 p.m. on Oct. 23.

The deadline to submit a qualified bid is 12 p.m. on Nov. 7.

The auction, if one is held, will commence at 10 a.m. on Nov. 12, the order said.

By no later than 12 p.m. on the first calendar day after the debtors have selected the successful bid(s) and alternate bid(s), the debtors shall file the notice of auction results with the court.

The deadline to file an objection with the court to the sale, and all objections relating to the Stalking Horse bidder (if any), the conduct of the auction or the sale is 12 p.m. on Nov. 15.

A hearing to consider the proposed sale will be held before the court at 10 a.m. on Nov. 20. or such other date as determined by the court.

—Steve Sutherlin

FURIE *continued from page 51*

Central and Southwest.

• Julius R offshore platform with six well slots that was installed in 2015, its monopod structure placed on the seafloor about 10 miles northwest of Boulder Point, near Nikiski off the Kenai Peninsula.

• Onshore natural gas processing facility near East Foreland on the Kenai Peninsula that was completed in 2015, and from which Kitchen Lights natural gas is delivered into the Kenai Peninsula gas transmission pipeline network.

• 15-mile subsea pipeline between the Julius platform and the onshore processing facility that was installed in 2015 and has a throughput capacity of 100 million cubic feet per day.

• The 10 offshore gas wells drilled to date and their status per AOGCC database as of Sept. 22, 2019: KLU A-4, development, permitted as single completion, spud 8-3-2018, completed 10-11-18, total depth 11,315 feet, into Sterling undefined gas pool, Beluga undefined gas pool, and Tyonek undefined gas pool; KLU A-A2, development, permitted as dual completion, spud 7-9-2016, completed 9-8-2016, total depth 8,160 feet, into Sterling undefined gas pool and Beluga undefined gas pool; KLU A-1, development, permitted as single completion, spud 9-27-2016,re-entered and completed 7-30-2018, total depth 8,243, into Sterling undefined gas, into Beluga undefined gas pool; KLU A-2 (plugged and abandoned), development, permitted as single completion, spud date 6-19-2016, completed 7-8-2016, total depth 7,038 feet, into Sterling undefined gas pool; KLU 5 (plugged and abandoned), exploratory, permitted as single completion, spud 9-4-2014, completed 9-28-2014, total depth 11,827 feet, unknown target; KLU 4 (suspended), exploratory, permitted as single completion, spud 7-18-23, completed date not yet reported to AOGCC but the release date was listed as 10/24/2015, total depth 9,163 feet, unknown target; KLU 3, development, permitted as single completion, spud 4-26-2013, completed 7-10-2013, total depth 10,393 feet, into Sterling undefined gas pool and Beluga undefined gas pool; KLU 2A, (suspended), exploratory, permitted as single completion, spud 10-1-2012, completed 11-5-2012, total depth 10,750 feet, unknown target; KLU 2 (plugged and abandoned), exploratory, spud 9-6-2012, completed 9-30-2012, total depth 9,106 feet, unknown target; KLU 1 (suspended), exploratory, permitted as single completion, spud 9-2-2011, completed 8-18-2012, total depth 15,298 feet (TVD the same), target unknown.

• The Kitchen wells that were in production in August 2019, were KLU A-1 (137,814 thousand cubic feet), KLU A-2A (122,566 mcf), KLU 3 (235,802 mcf). All three were producing from the Beluga gas pool.

• There is the possibility of drilling deep for oil in the Jurassic strata underlying the Tertiary rocks that host producing oil and gas fields in the Cook Inlet basin. ●

Contact Kay Cashman at publisher@petroleumnews.com

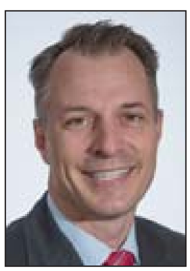
Through its subsidiary Savant Alaska, Glacier Oil and Gas drilled the B1-07 Badami exploration well with Nabors Rig 27E in early 2018 and has since announced the discovery in the Starfish prospect. In early testing the well produced 2,500 barrels per day, tapering off to a steady 1,600 bpd by 2019.

JUDY PATRICK PHOTOGRAPHY

After success, Glacier seeks investor

Focused on maintenance, well workovers and looks to do more drilling into prolific Killian sands

By KAY CASHMAN
Petroleum News



PHIL ELLIOTT

Glacier Oil and Gas Corp., which is solely focused on oil and gas fields in Alaska's Cook Inlet basin and on the North Slope, is continuing to move forward on two fronts in the state: 1. maintenance and well workovers at its four producing units, and 2. more exploration and appraisal drilling of the oil-bearing Cretaceous Killian interval in its eastern North Slope Badami unit. The formation was missed by previous operators but confirmed by Glacier in 2018 drilling.

That year the Houston independent's capital spending was about $20 million, whereas in 2019 it appears to be closer to $8-10 million. The difference is the cost of drilling the 2018 exploration well into the Killian sands in Badami's Starfish prospect.

Savant Alaska LLC, a Glacier company, drilled the Starfish B1-07 well to test the Killian interval, which is a turbidite sandstone reservoir that sits immediately above the oil source rock and below the Brookian sands that form the main reservoir for the field.

With a 15-month payout the well was promptly put online. In mid-May 2018, B1-07 produced 2,500 barrels of per day in early testing, tapering off to 1,600 bpd by January 2019.

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$200M over 3-4 years

Glacier President Phil Elliott told Petroleum News in April 2019 the company's success at Starfish called for "investing nearly $200 million (gross) to prosecute a Killian-focused drilling program over the next 3-4 years."

The value and price tag of that program impelled the small independent to begin a search for investors.

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"It makes zero economic sense to drill one well at a time except to prove a concept (e.g., the Starfish/B1-07 well). To develop the Badami field in the most thoughtful way, we need to drill several wells over several drilling seasons, which results in a fairly significant capital outlay. Given the quantum required," Glacier is seeking investors to help fund the drilling program, Elliott told PN in an Aug. 27, 2019, email.

In plans of development filed with the Alaska Department of Natural Resources' Division of Oil and Gas for Badami, Glacier describes Starfish as one of "several new target pods of interest" identified through a geologic and geophysical review of the Badami and Killian sands.

Until Glacier can bring in an investor, no new wells are expected to be drilled in 2019, per Elliott. He also said Glacier "continues to evaluate the results of B1-07, which have been positive to-date."

Glacier in Alaska

Glacier was created in early 2016 through the bankruptcy proceedings of Tennessee-based Miller Energy Resources Inc.

Unlike its predecessor, which had quickly acquired multiple oil and gas assets in Alaska and eventually became overextend when commodity prices dropped, Glacier has been taking a gradual approach by concentrating on maintenance activities to improve operations at existing wells and reserving its larger resources for targeted exploration prospects, starting with Starfish.

The four Alaska oil and gas units owned and operated by Glacier companies Savant and Cook Inlet Energy, or CIE, are as follows:

- Badami unit (Savant);
- West McArthur River (CIE);
- Redoubt Shoal (CIE);
- North Fork (CIE).

Whereas the Badami, Redoubt and West McArthur units mainly produce oil, North Fork is a natural gas field.

Badami problematic for BP

The fact that the Badami production facility and pipelines can handle 38,500 bpd is a reminder of the ambitions of the unit's previous operator, BP Exploration (Alaska) Inc.

Conoco Inc., predecessor to ConocoPhillips, discovered the Badami oil pool in 1990 and BP brought the oil field into production in August 1998.

From nearly the beginning, the complex geology involving the compartmentalization of the oil reservoir into multiple, discrete sand bodies rendered the Badami unit challenging to produce. Oil output declined severely quite early in field life — BP suspended production on three occasions, with the second suspension lasting for two years. Field suspension allowed the reservoir pressure to recharge, as subsurface oil slowly migrated between the various sand units.

Oil production peaked a month after startup at some 7,450 bpd but soon began to drop, falling as low as 876 bpd by August 2007.

Savant, ASRC enter Badami

In mid-2008, BP took a different approach. The company gave Savant and ASRC Exploration LLC a stake in Badami in return for returning the unit to operation. With Savant taking the lead with a 67.5% interest, the companies succeeded in bringing the unit to sustained production, albeit at low levels. (Later, ASRC sold small pieces of working interest to other companies, ending up with a 25% share by mid-2019.)

The partners acquired the field outright in early 2012, followed by the Badami pipeline system, which BP sold to Nutaaq Pipeline LLC, a 67.5/32.5% partnership of Savant and ASRC in 2014.

Miller closed on the purchase of Savant in December 2014, becoming majority owner of the unit. As the deal was moving toward closing, oil prices fell by more than half, which severely challenged the economics of an already complex operating environment.

Savant, and then Miller, decided to defer much of the development plan outlined for 2014 and early 2015. Miller's bankruptcy further disrupted plans and Savant and Badami became part of Glacier in 2016.

East Mikkelsen prospect

In late 2012, Savant asked the state to add seven leases, covering some 10,121 acres leases between Badami and the Point Thomson unit, to the Badami unit. The addition would have incorporated the East Mikkelsen prospect into the unit.

Instead, in March 2013, DNR agreed to include only portions of two of the seven leases, some 2,204 acres from ADL 391001 and ADL 390825.

The leases were set to expire on Jan. 31 and Feb. 29, 2012, respectively, but were extended by unitization proceedings.

The 2013 ruling also approved an exploration plan that required Savant to drill a directional well through the entire Canning formation and into the underlying Hue shale to evaluate the potential of the hydrocarbon-bearing Killian sands encountered in the East Mikkelsen Bay No. 1 well drilled in 1971 by ExxonMobil predecessor Humble Oil & Refining Co. (Humble had drilled the well to a total depth of 15,205 feet and encountered hydrocarbons in the Killian sandstone interval between 11,516 feet and 11,572 feet, measured depth, with a tested flow rate of 700 bpd of 24 degree API oil.)

Savant would have needed to complete the well, perform an extended test and present the results of the test to the state by June 30, 2014. If the drilling was successful, East Mikkelsen would be developed jointly with the existing Badami unit.

Savant appealed the ruling in April 2013, saying it needed all seven leases to effectively explore the prospect. To address the pending drilling deadline, Savant also requested a stay of its plan of exploration in August 2013.

The company said it would review all potential targets outside the Badami sands participating area, "including, but not limited to, the Killian sands on the east side of the unit" and "intends to continue exploration to fully explore the unit area as economic conditions warrant, and once the unit expansion appeal issue is resolved."

Although there has been intermittent paperwork surfacing between Savant and DNR, the unit expansion appeal has not been decided as of Sept. 27, 2019.

New pad for Badami

The latest and 16th plan of development, or POD, for the Badami unit approved by the division in June 2019, includes activities in the lease expansion area outside of the Badami sands participating area.

Glacier promised to do the following during the term of the POD, which is July 16, 2019, through July 15, 2020:

• Apply for a permit to construct a new Badami drilling pad, the "Dock Pad," which will be the surface drilling pad for additional Killian wells drilled toward the eastern side of the Badami unit.

• The B1-01 well workover will include pulling and replacing tubing; Savant also will run a casing inspection log for evaluation purposes.

• Convert the B1-14 well to a gas injection service well.

Savant said these operations would "occur during the second and third quarters of the 2019 POD period."

In the June 17 approval letter acting division Director James Beckham wrote, "The division remains encouraged by Savant's continued efforts to develop the Badami unit's resources and looks forward to further positive production development soon."

Savant production

In April 2018 Badami production had fallen to 698 bpd, but in May 2018 the field was up 203%, a difference of 1,419 bpd, to an average of 2,117 bpd because Savant had put the B1-07 Starfish exploration well online in the middle of that month.

In May 2019, the Badami unit averaged 1,721 bpd, down 26.7% from a June 2018 average of 2,180 bpd.

Glacier's other two oil fields on the west side of Cook Inlet, West McArthur River and Redoubt Shoal, respectively, averaged 553 bpd and 1,191 bpd in May 2019.

North Fork a small gas field

Standard Oil of California discovered North Fork in 1965, but the southern Kenai Peninsula field sat idle until the 1990s, when several independents attempted to develop it. An affiliate of Armstrong Energy acquired the property in 2007, brought on four partners and drilled several wells.

The Denver-based independent began delivering natural gas from the North Fork unit into the Enstar Natural Gas system in March 2011.

In 2013, CIE purchased the field.

In its current POD, which covers March 31, 2019, through March 30 of 2020, the company said it "plans to enhance production from currently producing wells through infrastructure improvements," including additional compression and separation facilities.

CIE will also continue to monitor and analyze production from existing wells and optimize production, including monitoring water volumes and converting a depleted producer for water

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GLACIER *continued from page 55*

disposal if necessary.

If data and market conditions warrant, CIE said it will continue development drilling "to fully delineate and develop all fault blocks within the current unit."

The company said it is also considering reprocessing North Fork 3D seismic "to enhance resolution for possible additional development activities."

It will also continue to evaluate drilling wells outside the current boundaries of the North Fork Gas Pool No. 1 participating area.

From December 2017 through November 2018, gas production from the field's five producing wells totaled 1.74 million mcf, with monthly production ranging from a high of 164,934 mcf to a low of 129,544 mcf.

Enhancing West McArthur output

The 28th POD for the West McArthur River unit runs from May 1, 2019, through April 30, 2020.

There are three producing wells in the unit, two in the Area No. 1 participating area and one in the Sword PA.

Activities in the 27th POD included continued analyzing of production within the 1991 WMRU No. 1 discovery well and enhancing production through perforation adds, well workovers and pump replacements.

CIE said it continues to monitor production to maximize uptime and conducted "small optimization and well maintenance operations to prolong field life" during the 27th POD, completing all operations discussed in that POD.

For the 28th POD, CIE said it will maintain an outstanding health safety and environment record at the unit and "continue to explore ways to enhance production, manage production decline, and increase total ultimate recovery from existing wells."

CIE said it has filed a permit request with the Alaska Oil and Gas Conservation Commission to dispose of produced water by converting shut-in wells to produced water disposal wells. Four shut-in wells are listed in the POD.

The company told the division it continues to permit drilling plans for the Sabre offshore exploration prospect. CIE said it was seeking partners in Sabre, although the company is more focused on Badami and the Killian sands.

CIE said it would continue to analyze production from all wells within the unit and enhance production "as appropriate through perforation adds within wells, well workovers and pump replacements."

Redoubt Shoal activities

The Redoubt unit was formed by Forcenergy Inc. in 1997. It reached sustained production in 2002, and Glacier's predecessor Miller acquired Redoubt in late 2009, undertaking redevelopment efforts between 2010 and 2013.

The latest Redoubt POD under Glacier's CIE is the 19th for the unit and covers May 1, 2019, to April 30, 2020.

Reporting on work accomplished under the 18th POD, CIE told the division it had proposed examining results of current and planned enhanced recovery waterflood and converting additional nonproducing wells to waterflood if appropriate; drilling and stimulating a sidetrack of the RU-4A well for use as waterflood injection; and changing out the failed electric submersible pump in the RU-9 well and stimulating that well as needed.

The company said it monitors Redoubt waterflood daily but did not complete the sidetrack of RU-4A, deferring that project to the second quarter of 2019. It deferred changing out the failed ESP in the RU-9 well to the third quarter of 2020.

For the 19th POD, CIE said it plans to sidetrack the RU-6 and use it as a water injection well, work which would replace the company's plan in the 18th POD to sidetrack the RU-4A.

The company said it anticipates the ESP in RU-2 will fail in 2019 and plans to replace it in conjunction with the RU-6 sidetrack.

Results of enhanced recovery waterflood efforts will be examined, CIE said, and additional nonproducing wells might be converted to water injection.

Glacier said it is working on plans for wells to evaluate oil and gas potential north of the Redoubt Northern Fault Block and would resume plans to drill when economic conditions justify that work.

In the next year the company said it plans to drill and stimulate a sidetrack to RU-6 and use that sidetrack "as a waterflood injection well to further enhance production," and is considering plans for additional produced water disposal.

"Redoubt is a mature field and we are reaching the practical limit for water disposal using currently available methods," CIE said, adding that it "is considering alternatives to allow continued production to the economic limit of the field."

The company also plans minor modifications to the Osprey platform and adding "additional space for surface ESP support equipment." ●

Contact Kay Cashman at publisher@petroleumnews.com

Hilcorp commissioned the custom-built Innovation rig, touted as the lightest modular rig on the North Slope.

COURTESY HILCORP ALASKA

Hilcorp boosts North Slope output

In August 2019, Hilcorp acquired all BP's interests in Alaska including 26% of Prudhoe Bay

By STEVE SUTHERLIN
Petroleum News

DAVE WILKINS

On the North Slope, Hilcorp operates four properties, the Milne Point unit, the Endicott field at the Duck Island unit, the Northstar unit and the Liberty project which unlike the other three is not currently in production.

The company initially acquired its positions on the North Slope from BP in 2014, and it has been adding to its positions since.

Going forward, Hilcorp is using the "buy from BP" strategy to substantially increase its North Slope position. BP is withdrawing from the state, having agreed to sell all its assets for $5.6 billion to Hilcorp. The deal includes BP's 26% interest in the giant Prudhoe Bay oil field, the major and the independent said in separate Aug. 27, 2019 press releases.

Hilcorp is already a strong producer and active developer on the North Slope; it has not been an active explorer as it is in the Cook Inlet basin.

Prior to the closing the acquisition of BP's assets in 2020,

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Hilcorp ranks as the third largest oil producer in Alaska in 2018, behind ConocoPhillips and BP.

Milne Point:

In August 2019, Ed King of King Economics Group noted

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impressive fiscal year 2019 output numbers from Milne Point oil field, based on data from the Alaska Oil and Gas Conservation Commission.

At Milne Point, King said Hilcorp had been doing a "tremendous job squeezing additional life out of this mature asset since purchasing it from BP."

A total of 8.3 million barrels were produced from Milne in FY19 — a million barrels more than in FY18. (In April, total oil production averaged 25,260 barrels per day, up 17.7% from April 2018.)

The company received authorization to install a third polymer injection facility at Milne Point, a technology Hilcorp first brought to the North Slope.

Injecting polymer and water into the field works better to coax syrupy viscous crude from the reservoir than conventional waterflood, David Wilkins, Hilcorp senior vice president for Alaska, said in November 2018.

Using polymer, Hilcorp expects to increase crude recovery from 10 to 15% of the oil in place at Milne to as much as 50%, per slides Wilkins presented at the Resource Development Council of Alaska's 2018 annual conference.

The 37th plan of development for Milne Point was approved by the Alaska Dept. of Natural Resources Division of Oil and Gas, effective Jan. 13, 2019, through Jan. 12, 2020.

The unit produces from the Kuparuk reservoir in the Kuparuk participating area, the Schrader Bluff reservoir in the Schrader Bluff PA, the Sag River reservoir in the Sag River PA, and a number of tract operations: C-15A, S-90, C-23, K033; and several Ugnu tract operations, MPS-37, MPS-39, MPS-41 and MPS-43.

Moose Pad — which came online in June 2018 — is the first new Milne pad since 2002, and can accommodate 50 to 70 wells, Wilkins said. Hilcorp is planning to build another new pad in the unit, R-Pad.

Unusually for the North Slope, Moose Pad includes processing facilities on the same pad as the wells, he said.

Pad construction began in 2017 and, with its 3-mile access road and 15-megawatt turbine generator, has cost $120 million. The Moose Pad processing facility can handle 85,000 barrels of fluid per day. Hilcorp anticipates a total price tag of some $400 million for the development, with potential recovery of some 60 million barrels of oil, a development cost of $6 to $7 per barrel, Wilkins said.

37th POD

Hilcorp anticipates drilling as many as 29 new wells during the 37th POD period, it told the division, with potential drilling candidates including 16 Moose Pad Schrader Bluff wells: two water source wells; six producers; seven injectors; and a produced fluids disposal well.

Another Schrader Bluff drilling program would be at E Pad, with as many as eight wells planned, with wells E-35 through E-42 alternating production and injection wells, with four of each planned.

Two Moose Pad Kuparuk producing wells are planned, as well as a Kuparuk producing well at L Pad.

Sag River producing wells are planned for L Pad and F Pad, one well at each pad.

Two S Pad Ugnu producing wells are also included in the 37th POD. Milne Point currently has no Ugnu production, although

AOGCC records show there was production from a single well in 2003 and 2004, peaking at 152 bpd; the pool was then shut-in. Regular production resumed for a few months in 2011, peaking at 459 bpd, and was attempted again for a few months in 2012 and again in 2013, when the pool averaged 165 bpd from a single well.

Hilcorp also anticipates as many as 16 well workovers during the 37th plan.

Duck Island

At the Duck Island unit, which holds the Endicott field and went online in 1987, Hilcorp was able to "maintain a fairly flat production rate over the last two years," King said. (Previously Hilcorp had boosted output.)

"At only 7,000 barrels per day, it's unclear how long this field will continue to produce. …. Holding it flat is about as good as we can hope for," King said.

Duck Island unit's latest approved POD is the unit's 37th. Hilcorp said production from Duck Island comes from three participating areas and one tract operation: the Endicott PA produces from the Kekiktuk reservoir; the Sag Delta North PA and the Sag River Reservoir Eider PA both produce from the Ivishak reservoir; the Minke tract operation produces from the Sag River reservoir.

Duck Island produced an average of 7,242 barrels of liquid hydrocarbons (oil plus natural gas liquids) per day from Jan. 1, 2018, through Sept. 30, the division said, and some 334.5 million cubic feet of natural gas per day.

Hilcorp drilled the SDI3-23A sidetrack during the 36th POD, the division said, but because that drilling project absorbed the majority of drilling time during the 36th POD, the company was only about to drill two additional sidetracks. Hilcorp had committed to evaluate shut-in wells and drill as many as six additional sidetracks in addition to SDI3-23A. (Alaska Oil and Gas Conservation Commission data show 14 wells at the field shut-in as of December.)

For the 37th POD, Hilcorp said it plans no new wells, but "will continue to pursue efficiencies through various well optimizations, including the evaluation of shut-in wells utility and their potential return to service." The company said it plans up to five well workover projects which "may include return to production, producer to water injection conversions, or water/gas shutoffs."

Northstar

After starting regular production in 2001, the Northstar field is already nearing the end of its economic life, currently producing about 10,000 bpd for Hilcorp, Economist Ed King said.

"However, Hilcorp has a talent for getting oil out of fields that others are ready to give up on," King noted. "In fact, the Northstar unit (in FY 19) saw an increase of 317,587 barrels of oil (a 9% increase) over FY18."

In its 15th POD for Northstar Hilcorp said the unit is jointly managed by the division and the Bureau of Safety and Environmental Enforcement of the U.S. Department of the Interior.

There are three sand accumulations at Northstar, the company said: the Ivishak sands in the Northstar PA and the Fido PA; and the Kuparuk sands in the Hooligan PA.

In its POD approval the division said Northstar produced an average of 10,361 bpd of liquid hydrocarbons (oil and NGLs) between January and the end of November 2018, and a daily average of 516.2 million cubic feet per day of natural gas.

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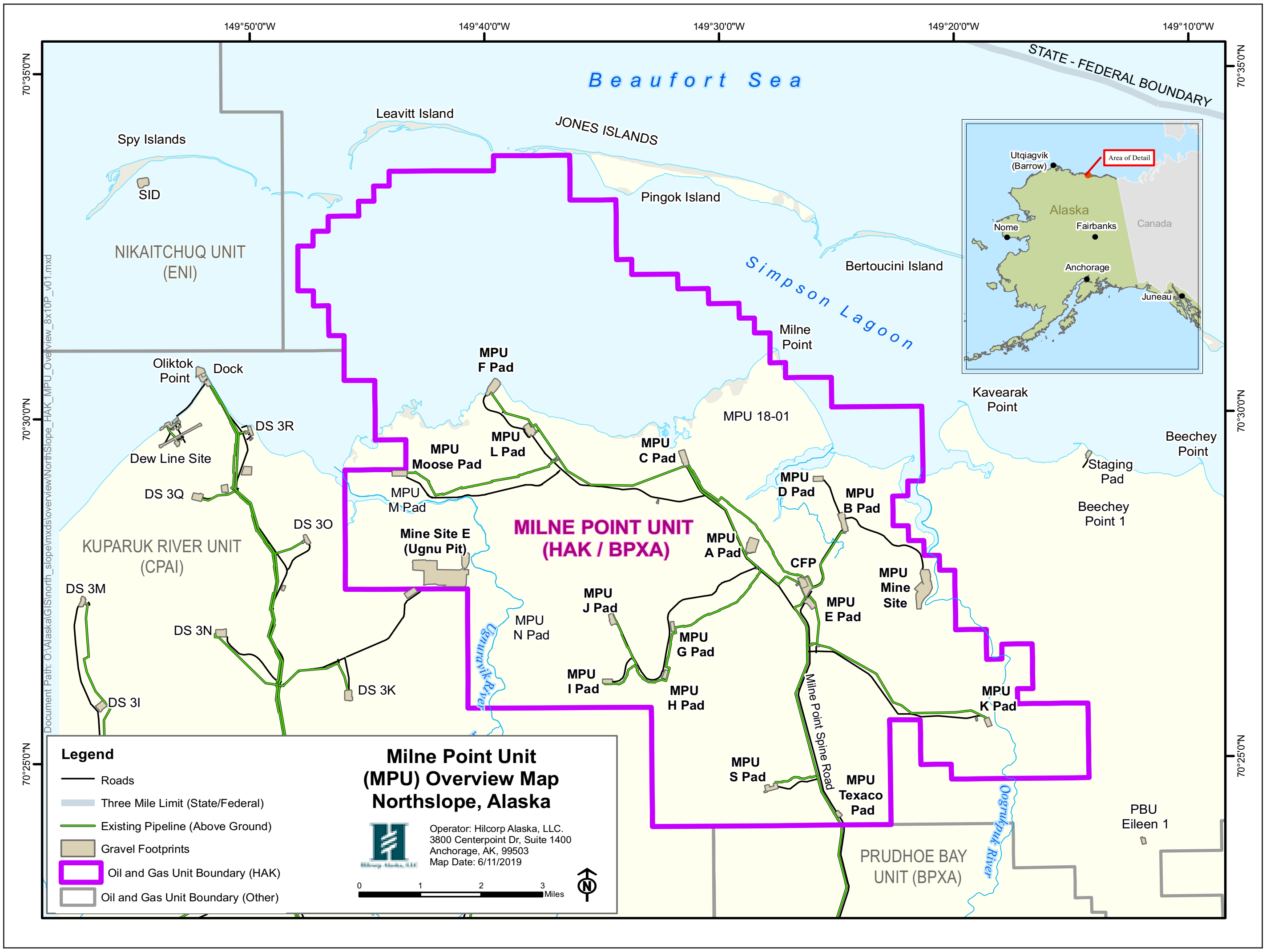

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In the just completed POD, the 14th, Hilcorp said it drilled no new grassroots wells or sidetracks, but completed various well work jobs, including two rig workovers recompleting wells from the Ivishak reservoir to the Kuparuk, and conversion of an Ivishak gas injection well to production.

In the 15th POD, which will run from February 2019 to February 2020, the company said it does not anticipate drilling any new wells, but does anticipate completing two rig well workover projects, one to recomplete an Ivishak reservoir producer to a Kuparuk C producer and one to recomplete an Ivishak reservoir gas injector to a lean gas injection well in the Kuparuk A and C reservoir.

The company said it would continue to evaluate well work opportunities as they arise and "pursue efficiencies through various well optimizations, including the evaluation of shut-in wells utility and their potential return to service." (AOGCC's December 2018 data shows four shut-in wells at Northstar.)

Facility projects that the company may undertake during the 15th Northstar POD include a feasibility study and economic analysis of the potential of a project to improve NGL recovery during warmer ambient temperatures. (Northstar, Endicott and Prudhoe Bay produce NGLs in addition to crude oil.)

Hilcorp said that if such a project were sanctioned, "the necessary infrastructure, facility modifications and tie-ins and potential module delivery could occur during the 15th POD period."

Liberty

Hilcorp expects Liberty to come online between 10,000 and 15,000 barrels per day, peaking at 60,000 to 70,000 bpd within two years. The company also expects the field to produce as much as 120 million cubic feet of natural gas per day.

The company is planning to develop the Liberty oil field from a gravel island on the federal outer continental shelf of the Beaufort Sea. Liberty will exceed a $1 billion investment for Hilcorp, with the potential to produce more than 70,000 barrels per day of oil and a field life of 20 to 30 years. In October 2018 the Bureau of Ocean Energy Management issued a record of decision, approving development of the field essentially in the manner that Hilcorp had proposed.

The development plan involves the construction of a 9.3-acre gravel island in 19 feet of water, and the laying of 5.6 miles of a pipe-within-a-pipe pipeline to deliver oil into the onshore Badami pipeline. Hilcorp has commented that the field design reflects the design of other Beaufort Sea offshore fields.

"Keep it simple and work on what's worked in the past," Wilkins said. ●

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Hilcorp: Titan of Cook Inlet producers

Active far and wide in basin, independent sees success in revitalizing production of oil and gas

By **STEVE SUTHERLIN**
Petroleum News

The Cook Inlet basin is the cradle of the modern oil and gas industry in Alaska. In 1957, Richfield Oil Corp. discovered oil when it tapped the Hemlock formation with the Swanson River No. 1 well.

The Swanson River oil field convinced a divided Congress that the oil industry could provide the economic basis for statehood and Alaska became the 49th state in 1959.

Today, the federally administered Swanson River unit is still producing oil. In fact, production is rising due to the return of shut-in wells to production, optimization of artificial lift, and other efforts by operator Hilcorp Alaska LLC, which acquired the unit in 2012.

DAVE WILKINS

The U.S Department of the Interior's Bureau of Land Management currently administers five oil and gas units in the Cook Inlet basin, and Hilcorp operates them all.

Hilcorp's "efforts to increase the oil and gas production from these mature fields have proven successful," BLM said.

The units — Beluga River unit, Birch Hill unit, Beaver Creek unit, Kenai unit and Swanson River unit — include federal, state, Cook Inlet Region Inc., and fee leases, according to BLM.

Cook Inlet revitalization

Aside from its five federally administered units, Hilcorp is active — and is increasing production — far and wide in the Cook Inlet basin.

Hilcorp Alaska, owned by privately owned Texas-based independent Hilcorp Energy Co., has a track record of entering mature hydrocarbon basins and making necessary investments to produce more oil and gas.

The company has stimulated overall Cook Inlet oil production.

Prior to the 2011 entry of Hilcorp into Alaska, the Cook Inlet basin's onshore and offshore oil production had declined to 8,900 barrels per day. At the same time, natural gas reserves were projected to soon be insufficient to meet continued local utility demand and aging platform infrastructure was considered to be nearing its functional end of life. Cook Inlet was considered a mature oil and gas province that had reached peak oil production of more than 227,000 bpd in 1970 and peak natural gas production in 1994.

Hilcorp's recent efforts have turned the tide, and production levels have begun to recover. In July of 2019, Cook Inlet production averaged 14,336 bpd. A natural gas shortage no longer looms for natural gas consumers in the region.

Hilcorp is now the dominant on and offshore oil and gas producer in the Cook Inlet basin, as of January 2019 operating about 19 fields and units — a number that fluctuates due to acquisitions, consolidations and terminations.

On the west side of Cook Inlet, Hilcorp operates the Ivan River, Lewis River, Pretty Creek and Beluga River units.

COURTESY HILCORP ALASKA

Hilcorp plans to drill development well in 2020 from the offshore Tyonek platform into a known oil pool below the North Cook Inlet gas field.

Offshore, the company operates the North Cook Inlet unit (actually in middle Cook Inlet), the Granite Point unit, the Middle Ground Shoal unit, the Trading Bay unit, and the North Trading Bay unit (middle Cook Inlet) and associated McArthur River field.

On the southern Kenai Peninsula, Hilcorp operates the Ninilchik, Deep Creek and Nikolaevsk units.

In the northern Kenai Peninsula, the company operates the Birch Hill unit, the Swanson River unit, the Beaver Creek unit, the Sterling unit, the Kenai unit and the Cannery Loop unit.

In Lower Cook Inlet, Hilcorp is moving forward to explore relatively unexplored territory.

In April through October 2020, Hilcorp Alaska hopes to drill two to four exploratory wells in the untapped federal waters of lower Cook Inlet, pending the results of a 3D seismic survey 20 miles due west of Homer halfway between Kachemak Bay in the lower Kenai Peninsula.

Granite Point unit

The Granite Point field averaged 2,541 bpd in July 2019,

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down 10.7% from a July 2018 average of 2,846 bpd.

In 2018, the Granite Point unit produced a total of about 1 million barrels of oil and about 1 billion cubic feet of gas, a significant uptick from the production of 879,000 barrels of oil and 752 million cubic feet of gas in 2017.

The Alaska Oil and Gas Conservation Commission in a May 20 order approved Hilcorp's request to commingle production, revised pool definitions for the Granite Point Middle Kenai Oil Pool and defined a new Granite Point Hemlock Oil Pool at the Granite Point unit.

The commission said retaining the vertical extent of the Granite Point Middle Kenai Oil Pool, GPMKOP, and defining the new Granite Point Hemlock Oil Pool, GPHOP, "is appropriate and will lead to better development of the field and maximization of the ultimate recovery."

In the order the commission revised the pool definition so there is no vertical gap between the oil pools, with the GPMKOP the accumulation that correlates to Mobil's Granite Point No. 1 well between 7,725 feet and 10,885 feet measured depth, and the GPHOP defined as the accumulation between 10,885 feet and 11,280 feet MD in Mobil's Granite Point No. 1 well.

Hilcorp requested elimination of inter-well spacing requirements for wells in the affected area and authorization of downhole commingling of production in wells open to both the GPMKOP and the GPHOP.

The commission's approval of commingling was subject to a production log or geochemical analysis being obtained within 30 days of beginning of commingled production. It also required periodic production logging or geochemical analysis of wells with downhole commingled production (at least every 24 months), with copies of logs and analyses used to determine allocation of production submitted to the commission within 30 days. The order eliminates well spacing restrictions for the GPMKOP and GPHOP, "except that no oil well shall be completed within 500 feet of an exterior property line where ownership or landownership is not the same on both sides of the line."

Granite Point plans

Hilcorp a indicated it would use the Spartan 151, or a similar jack-up rig, to drill as many as four sidetrack wells from existing wellbores at the Granite Point Platform. The Alaska Department of Natural Resources' Division of Oil and Gas said in an approval of the unit plan of operations dated May 16, 2019, that the proposed wells will be drilled to bottom-hole depths between 7,000 and 16,000 feet.

Rig mobilization was slated to begin by June 1, 2019, with an estimated 30 to 60 days per each well completion. Drilling activities and rig demobilization was planned to conclude by Nov. 15.

Hilcorp's most recent plan for the Granite Point unit, filed April 1, 2019, and approved May 10, 2019, said the company planned to maintain production for the period of the 2019 POD, which is effective July 1 through June 30, 2020.

Long-range Granite Point development activities included plans to delineate all underlying oil or gas reservoirs, further evaluate additional rotary development wells, and evaluate drilling of multilateral sidetracks out of existing parent bores using coiled tubing drilling technology.

Hilcorp said in the plan that it anticipates drilling two rotary sidetrack wells, GP-53 and GP-55, and said it was possible that

COURTESY POLARCUS

Polarcus source vessel for Hilcorp's offshore Cook Inlet 3-D seismic survey 20 miles due west of Homer on the lower Kenai Peninsula.

operation on the first of the wells could begin in late May.

"If timing of the ice arrival in the Cook Inlet permits, a third rotary sidetrack well, GP-52, will be drilled," the company said.

There are three platforms at the Granite Point unit: Granite Point, Anna and Bruce.

North Cook Inlet oil

Hilcorp has prepared an initial plan of development, or POD, for a known oil pool below the North Cook Inlet gas field. Drilling of the first development well from the offshore Tyonek platform should happen in 2020, the company told the division in its 2019 POD for the North Cook Inlet unit.

The Tyonek platform currently supports production from the gas field. Because the oil development well will penetrate the top of the structure of the Sterling and Beluga gas sands, the well will also enable an evaluation of remaining dry gas development in the unit, the company told the division.

In the early 1990s ARCO Alaska discovered oil in a major geologic anticline under the gas field.

In 1998 Phillips Petroleum conducted some appraisal drilling in the oil accumulation, termed Tyonek Deep. In 1999 the company put the project on hold due to low oil prices, saying that it had tested two wells in the oil pool and run completion tubing in a third well, with the wells being ready for production. The development never proceeded.

In preparation for reviving oil field development Hilcorp laid a new subsea oil pipeline from the Tyonek platform to the Inlet's west side. The line is in conjunction with a major Cook Inlet pipeline reconfiguration, conducted in 2018. The reconfiguration converted one of the twin subsea Cook Inlet Gas Gathering System pipelines from the carriage of gas to the carriage of oil.

To maintain adequate gas transportation capacity across the inlet, Hilcorp laid a new subsea gas pipeline from the Tyonek platform to the west side of the inlet, which ties up with the existing gas pipeline from the platform to the inlet's east side.

The company is replacing crew quarters on the Tyonek platform, plans to upgrade the cranes and the helideck, and to remove drilling and mud pits.

Hilcorp's POD said that in 2018 the field produced 6.2 billion cubic feet of gas, versus 7.1 billion cubic feet in 2017.

Middle Ground Shoal unit

In 2018 Hilcorp produced 520,000 barrels of oil and 111 million cubic feet of gas from the Middle Ground shoal unit. That compares with 308,649 barrels of oil and 83 million cubic feet of gas in 2017. Production in 2017 was impacted by a field shutdown due to a leak in the subsea pipeline that delivers fuel gas to the offshore platforms.

Since July 2018 Hilcorp has conducted well workover operations in the field, converting an injection well to a producer; perforating five wells; and performing coiled tubing cleanouts on two wells. The company also inspected some locations on a gas pipeline, conducted sonar surveys on all subsea pipelines and reconfigured the subsea gas pipeline manifold on one platform.

The field currently has two active platforms, Platform A and Platform C, while the Baker and Dillon platforms are dormant.

In anticipation of the potential future reactivation of the Baker and Dillon platforms, and to address issues relating to the inspection of the field's subsea gas pipeline, Hilcorp plans to install two subsea power cables to the platforms from platforms A and C, possibly during the summer of 2020. Reactivation of the dormant platforms would entail major upgrades to platform facilities, Hilcorp told the division.

Hilcorp continues to evaluate the economics of reactivating drilling rigs on the A and C platforms. Potential drilling operations would include updating the well completions, adding perforations, cleaning out wells and repairing damaged wells. There are also some potential new drilling prospects — the company is in the process of interpreting new and reprocessed seismic data, to better delineate the structure of the field and identify possible drilling targets. Drilling possibilities include infill drilling and step-out exploration tests, the company told the division.

In terms of continuing maintenance, Hilcorp plans to complete diver inspections of some subsea components of Platform A, and of the subsea gas pipeline.

Trading Bay unit

In the Trading Bay unit the McArthur River field produced 1.7 million barrels of oil and 9.7 million cubic of gas in 2018. Oil production was virtually the same as production in 2017, while gas production increased.

Since July 2018, Hilcorp had completed two new wells in the field and had started but not completed a third well as of the date of the plan of development. The company conducted workovers on four wells on the Grayling and Steelhead platforms. It also converted one well to gas lift and reperforated another well.

Hilcorp plans to continue to evaluate new rig workover opportunities in the field while also identifying new subsurface possibilities.

The Trading Bay field, the other field in the unit, produced 595,000 barrels of oil and 1.3 billion cubic feet of natural gas in 2018. That compares with 675,000 barrels of oil and 1.1 billion cubic feet of gas in 2017.

Since July 1, 2018, Hilcorp has been conducting workover operations on two wells and anticipated workover of a third well.

The company is doing a study of the field to identify rig

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HILCORP *continued from page 63*

workovers, sidetrack drilling, waterflood optimization and other activities to bolster field production.

North Trading Bay unit

Hilcorp envisions restarting production from the North Trading Bay unit, using a sidetrack well drilled from the Monopod platform that supports the adjacent Trading Bay unit.

North Trading Bay used to produce from the Spark and Spurr platforms, but oil production ceased in 1991 and gas production in 2005. The two platforms have been maintained in lighthouse mode since then — Hilcorp has in the past indicated that restarting these platforms would not be viable.

The company told the division that, following some additional seismic evaluation, it anticipates starting a sidetrack from the A-10RD well in 2019. If the sidetrack is successful, Hilcorp anticipates applying for a unit expansion to include newly producing acreage.

West Side status quo

Hilcorp filed PODs with the division for its three small onshore west side Cook Inlet gas fields, covering June 1, 2019, through May 31, 2020.

The POD for Ivan River is the 49th for that unit; the Lewis River is the 44th for that unit; and that for Pretty Creek is its 41st.

Hilcorp said Ivan River produced 184.9 million standard cubic feet of gas in 2018, while Lewis River produced 145 million cubic feet and Pretty Creek produced 54.5 million cubic feet.

At Ivan River, Hilcorp said there was no production from the Sterling-Beluga gas participating area during 2018; production from the Tyonek PA averaged 0.507 million standard cubic feet per day.

For 2019, Hilcorp said it did not have any development plans at Ivan River, but would continue production and use of the disposal wells.

There was no production from the Lewis River gas pool No. 1 participating area during 2018, and production was maintained from the Lewis River gas pool No. 2 PA.

For 2019, Hilcorp said it does not have long-range development plans, or any planned exploration or delineation plans.

The company said it will continue to produce from the No. 2 participating area during 2019.

At Pretty Creek, for 2019, Hilcorp said it plans to evaluate shut-in wells for potential return to service or utility but does not have any exploration or delineation activities planned. Production will continue from the Beluga participating area and gas storage will continue.

Kenai Peninsula gas fields

Hilcorp PODs for four Kenai Peninsula natural gas fields focus primarily on maintaining production. The gas fields — Cannery Loop, Deep Creek, Nikolaevsk and Ninilchik — account for 22% of Hilcorp's Cook Inlet gas production, some 193 million cubic feet per day in 2018.

One new well is planned at Cannery Loop. At Ninilchik, the company indicated that new drilling would probably be put off at least a year.

The PODs are for Aug. 1, 2019, through July 31, 2020.

The POD for Cannery Loop is the 40th for that field.

Hilcorp said it maintained steady production at an average of 8 million cubic feet per day at the field during the 2018 calendar year.

At Pretty Creek, for 2019, Hilcorp said it plans to evaluate shut-in wells for potential return to service or utility but does not have any exploration or delineation activities planned.

For the 2019 plan, Hilcorp is evaluating drilling the CLU No. 14 in August, a well which would primarily target the Middle Beluga with secondary targets in the Sterling sands. Hilcorp said the well would "explore farther east in the Lower Beluga and Tyonek sands than any previously drilled well at CLU," providing "more insight of the eastern flank of the Cannery Look structure," information which might "lead to additional prospects to the north of the field."

Deep Creek produced an average of 5.1 million cubic feet per day in 2018.

Hilcorp said it has completed evaluation on drilling a new HVB No. 18 well primarily targeting the Middle/Deep Tyonek sands with secondary targets in the Middle to Upper Beluga sands. The well was originally planned to be drilled in December, but is likely to be delayed, "due to bottlenecks in the KBPL gas pipeline."

A new exploratory drilling program is still planned for 2020, based on results of stratigraphic test wells, and likely targeting the Sterling and Beluga formations.

Current production at Deep Creek will be "maintained and improved throughout the 2019 POD period, primarily through implementation of efficiencies and optimization projects," the company said.

Nikolaevsk is the smallest of the fields in this group, with production from a single well averaging 500,000 cubic feet per day in 2018. This is the 12th POD for the field.

Hilcorp said in its 2019 POD that it did not have any planned exploration or delineation project at the field and plans to continue production from the Red Well No. 1

Ninilchik is the largest field in this group, averaging 27.9 million cubic feet per day in calendar year 2018. This is the 15th POD for the field.

In its 2019 POD Hilcorp said that the six identified prospects in the Grassim Oskolkoff PA will not likely be drilled in the 2019 POD period unless market conditions change but will most likely be drilled in the 2020 or 2021 POD periods.

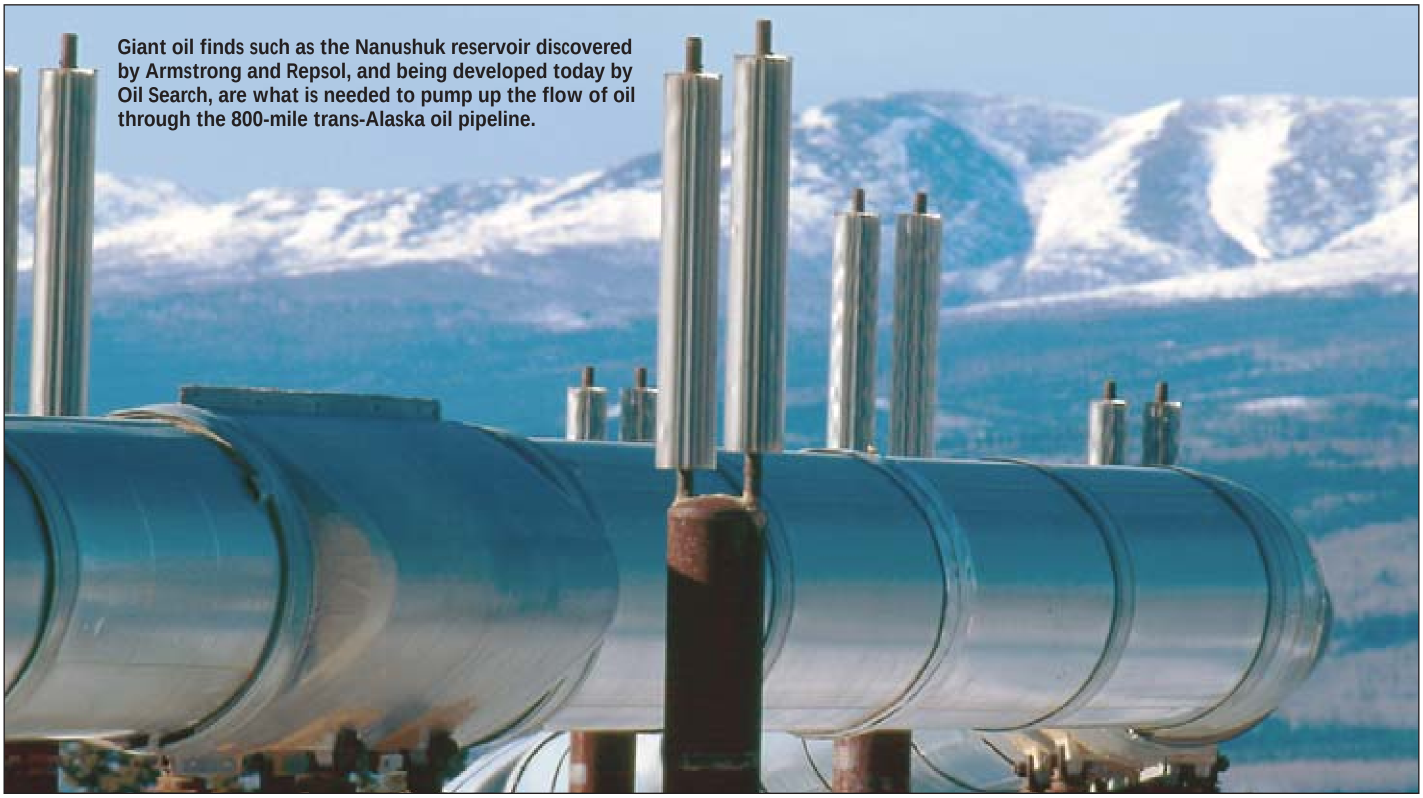
Hilcorp said the Pearl No. 2A may be drilled in the late 2019 POD period, "contingent on market conditions, but will most likely extend beyond the 2019 POD period."

The Blossom No. 1 may be sidetracked, based on market demand and economic conditions, but will most likely be drilled in the 2020 or 2021 POD periods.

March data from the Alaska Oil and Gas Conservation Commission show 26 producing wells at Ninilchik. Hilcorp said that during 2019 it would evaluate adding "velocity strings and/or other artificial lift options in various wellbores to enhance production."

The company has a workover program planned during the 2019 POD for several wells and plans to install an additional high-pressure heater-separator unit at the Paxton pad to allow for additional throughput from the Paxton No. 8 wells. It may install additional dehydration facilities on the Susan Dionne pad to allow for additional throughput from Kalotsa pad. It plans to add a water injection module at Susan Dionne pad for produced water disposal. ●

Contact Steve Sutherlin at ssutherlin@petroleumnews.com



JUDY PATRICK PHOTOGRAPHY

Giant oil finds such as the Nanushuk reservoir discovered by Armstrong and Repsol, and being developed today by Oil Search, are what is needed to pump up the flow of oil through the 800-mile trans-Alaska oil pipeline.

Oil Search's Pikka project evolving, improving

First oil in mid-2022 via Kuparuk, working to bump early output to 50,000 bpd; Horseshoe next project?

By KAY CASHMAN
Petroleum News

BRUCE DINGEMAN

Oil Search announced its entry into Alaska on Nov. 1, 2017, when it cut a deal with Armstrong Energy and a minority partner to buy a working interest in leases in and near the Pikka unit and Horseshoe block west of the central North Slope. Taking over as operator from Armstrong, the Australia company's Alaska arm, headed by Keiran Wulff, was at the front of the North Slope exploration and development renaissance, which stemmed from Armstrong and Repsol's discovery of a huge Nanushuk oil reservoir.

Since that time Oil Search has increased its working interest in the leases, bought out Armstrong and continued to pick up other North Slope acreage, including a block with Armstrong as a 50-50 partner on the eastern North Slope.

A flurry of new stakeholder documents and a filing with the state of Alaska toward the end of September 2019 paint a picture of continuous evolution in Oil Search's first North Slope development in the Pikka unit.

NAME OF COMPANY: Oil Search
COMPANY HEADQUARTERS: Perth and Sydney, Australia
ALASKA SUBSIDIARY: Oil Search (Alaska) LLC
ANCHORAGE OFFICE: Two floors in BP building, 900 E Benson Blvd., Anchorage, AK 99508
TOP ALASKA EXECUTIVE: Bruce Dingeman, president, Oil Search Alaska
TELEPHONE: 907-375-6900
WEBSITE: www.oilsearch.com

Pikka will consist of three drill sites, a processing facility, an operations pad, a tie-in pad, infield pipelines, export and import pipelines, an access road, infield roads, a boat ramp and a potable water system.

continued on next page

Wulff promoted, leaving Alaska

After serving as Oil Search's managing director for 25 years, Peter Botten is retiring and Keiran Wulff, president of Oil Search Alaska, is taking his place.

In an interview with Petroleum News in late September 2019, Wulff said Bruce Dingeman, currently chief operating officer of the Alaska business unit, will take over his role as president, and Matt Elmer, senior vice president of production and operations, will assume the role of acting COO.


KEIRAN WULFF

Wulff estimates that after the transition to his new position is complete, he will be spending about 20% of his time in Alaska.

What do the changes mean for the state?

"Alaska has a champion at the very top of the company," was Wulff's response, noting the leadership change has been internally progressing for about two years.

To ensure a smooth transition of responsibilities Wulff was appointed chief executive officer designate on Sept. 30, 2019. He will retain his Alaska responsibilities until mid-December to help oversee the company's entry into front-end engineering and design for the North Slope Pikka development, while also engaging with stakeholders and being involved in budget and planning for 2020 and beyond.

"The transition is a very measured … well thought out … process. Nothing has been rushed," he said.

"We have three fantastic projects we have to develop, including Alaska, and the beauty of it is we have the time to do so in an economically sound and environmentally sensitive manner," Wulff said.

He will move from Anchorage to Sydney in mid-December, assuming his role as managing director and joining the Oil Search board on Feb. 25, 2000.

Alaska team, ConocoPhillips rapport

Wulff, a geologist with a Ph.D., spoke highly of the Alaska leadership team, mentioning individuals by name and offering background on most of them.

For example, when talking about Oil Search Alaska's vice president of exploration and new ventures and former geoscientist with the state, Wulff said "there is no doubt Joe Chmielowski is very knowledgeable and has a deep understanding of the geology of the North Slope, but Joe is also genuinely a good person … a great leader … someone who empowers his staff."

Currently the Oil Search Alaska group numbers 151 — 36 contractors and 115 employees.

The Alaska leadership team, which has several people with extensive North Slope experience, Wulff said, includes Dingeman, Elmer, Senior Vice President External Affairs Joe Balash, Executive Advisor Cindy Bailey, Vice President Commercial and Strategy Patrick Flood, Vice President Exploration and New Ventures Josef (Joe) Chmielowski, Vice President People and Culture Wanda Lewis, Vice President Finance and Project Services Jonathan Boyce, Senior Vice President Projects Bob Writt, Vice President Supply Chain and Ops Support Lea Souliotis, Senior Vice President Drilling and Completions Steve Robinson, Senior Vice President HSES James Robinson, Senior Vice President Subsurface Mark Ireland and IT and Data Management Manager Stephanie Kreibich.

When asked whether his experience as a Phillips Petroleum employee in the early years of his career had anything to do with his success in building a good relationship with North Slope neighbor ConocoPhillips, Wulff said no.

"Our playmates elsewhere are the majors, so I think it's more a matter of we were taken seriously" by the bigger company, he said, making the relationship easier to establish.

—Kay Cashman

OIL SEARCH *continued from page 65*

Pikka changes

The most recent major project change in late September is that Pikka will start production early, in mid-2022, with 30,000 barrels of oil per day processed at ConocoPhillips's nearby Kuparuk River unit.

Once Oil Search's processing facility "is operational in 2023 or 2024," the early production phase will end and the Nanushuk export pipeline will transition from carrying sales quality oil to Kuparuk central processing facility 2 and instead begin transporting it to the Nanushuk facility, which will have a capacity of handling 120,000 barrels of oil per day.

Note, the Pikka unit development is referred to as the Nanushuk development or project in state and federal paperwork, even though it will initially target oil deposits in both the Nanushuk and Alpine C reservoirs — two of six stacked plays in the unit that might eventually be tapped. This explains the pad names, which begin with ND, as well as the names of other project components, such as the Nanushuk processing facility, or NPF.

Data released during in late September 2019 during an Oil Search investor tour of its Anchorage office and the North Slope reveal that the company's Alaska team through a value engineering process is looking to increase early production to 50,000 bpd, as well as increase the nameplate size of the Pikka project to 135,000 bpd. (The process of value engineering involves brainstorming ways to reduce initial or lifecycle costs while still maximizing function and maintaining safety and environmental standards. When the information was released the team had evaluated 86 different ideas.)

Once Oil Search's processing facility "is operational in 2023 or 2024," the early production phase will end and the Nanushuk export pipeline will transition from carrying sales quality oil to Kuparuk … and instead begin transporting it to the Nanushuk facility, which will have a capacity of handling 120,000 barrels of oil per day.

Primary modifications

Sept. 26, 2019, modifications to the Pikka plan of development filed with the Alaska Department of Natural Resources' Division of

Oil and Gas say early production will come from the ND-B pad.

"Multi-phase fluids from ND-B will be transported for processing at Kuparuk CPF2 via the 24-inch multiphase pipeline to the NPF, and the 18-inch Nanushuk export pipeline from the NPF to Kuparuk CPF2."

The changes requested in the filing are "based on local community input" and "enhance engineering operational efficiency," Oil Search says.

Other project alterations proposed by the company involve the following:

1. Modify the ND-B pad layout.
2. Relocate the tie-in pad and modify its layout.
3. Modify the water source access road and pump house pad.
4. Update road and pad footprint and fill volumes by about 0.2 acre and a net increase in total fill volume of approximately 5,000 cubic yards.
5. Relocate the boat ramp and associated boat ramp access road.
6. Implement early production.

COURTESY ARMSTRONG

Drilling the Horseshoe wildcat well.

ND-B pad alterations

Regarding the ND-B pad modifications, Oil Search wants to change its size and layout to accommodate the newly designed grind and inject facility, which will reduce the gravel footprint on the west and south sides of the pad and increase it on the east side.

The modified pad will be 20.8 acres, an increase of 1.3 acres from the previously proposed 19.5-acre pad.

Oil Search originally planned to construct underground injection control, or UIC, wells at each drill site within the well row. These wells were only capable of handling waste generated from the respective well pad. In October 2018 Oil Search reduced the overall number and location of UIC wells and relocated them to ND-B. In order to maintain disposal well sustainability with the reduced number of UIC wells, the company designed the grind and inject facility at ND-B to handle all drilling and operational wastes, including waste deliveries from ND-A and ND-C; hence the changes to ND-B.

The increased gravel footprint on the east side of ND-B will allow the grind and inject facility to be moved away from drilling and production operations to separate traffic having to do with processing and fracturing equipment, pipelines, and drill rigs "as recommended by detailed facility siting reviews and advanced en-

continued on next page

JUDY PATRICK PHOTOGRAPHY

The Nabors 105 rig drilled for Oil Search last winter in the Pikka unit.

OIL SEARCH *continued from page 67*

gineering," all of which will reduce overall drill site congestion and enhance safety, Oil Search says.

Tie-in pad, boat ramp changes

The tie-in pad relocation from near the Kuparuk River unit 2C pad to northeast of the Kuparuk central processing facility 2, or CPF2, is based on a request from ConocoPhillips, Oil Search says.

The new location will reduce the project pipeline length by 1 mile, including re-routing the pipeline "north of Lake K213/M8103 and eliminating two pipeline-road crossings."

The tie-in pad size will increase from 0.8 to 0.9 acre to accommodate access to existing powerlines, a telecom tower, and space for additional equipment during project development and production.

Oil Search's proposal to move the boat ramp and its access road from the permitted location on the Kachemach River, west of ND-B, to north of ND-B on the Colville River was requested by the Nuiqsut community, who will be using both to launch and retrieve boats. The new location will give subsistence users direct access to the east channel of the Colville.

Water source, pump house

Oil Search also proposes to change the permitted pump house pad location and realign the water source access road.

The modification will result in an overall increase in footprint from 2.2 acres (1.1- acre pad and 1.1-acre road) to 2.5 acres (1.1-acre pad and 1.4-acre road), an increase of approximately 0.3 acre, the company says.

The new pad location, approximately 500 feet west of the original site, will "improve access to a deeper portion of Lake MC7903 and provide more consistent access to unfrozen water during the winter," Oil Search says.

The location and configuration of the water source access road intersection with the access road will also change, the first increasing from 24 to 32 feet surface width, which will allow the company "to maintain consistency with all roads and pipeline/road crossings on the project."

Oil Search says it will also "allow for construction and maintenance equipment to gain access to the north side of the pipeline; and allow straight-line removal and replacement of pumps year-round."

Finally, the pipelines near the pump house pad will be realigned to cross the water source access road south of the pump house pad, which will change the pipeline length but won't alter the overall estimate of total vertical support members, the company says.

Horseshoe next?

With more oil potential in the Nanushuk formation to the north and south of the Pikka development, Oil Search sees Pikka as the first of a series of potential developments in a fairway between the Colville River and Kuparuk River units, Richard D'Ardenne, Oil Search senior vice president of development, said Jan. 18, 2019.

The Nanushuk reservoir for Pikka actually extends more than 60 miles north to south. And, while the company has not explored the more northerly end of that trend, there is promising acreage to the south, in the area of the successful Horseshoe exploration wells, he said.

The idea was to repeat that success many times in the fairway over the next 10 years, with more projects coming down behind Pikka, D'Ardenne said.

The investor tour slides from late September 2019 identified two exploration prospects Oil Search will be drilling this winter, Mitquq and Stirrup, to test Nanushuk analogues (see story with map in the Sept. 29, 2019, edition of Petroleum News).

The Stirrup prospect is adjacent to the Horseshoe Block and "could de-risk additional fairways to underpin a possible stand-alone" Horseshoe development, the company says, noting Stirrup is a direct analogue to the Horseshoe 1 Nanushuk discovery drilled by Armstrong in 2015. ●

The Pikka unit development is referred to as the Nanushuk development or project in state and federal paperwork, even though it will initially target oil deposits in both the Nanushuk and Alpine C reservoirs — two of six stacked plays in the unit that might eventually be tapped.

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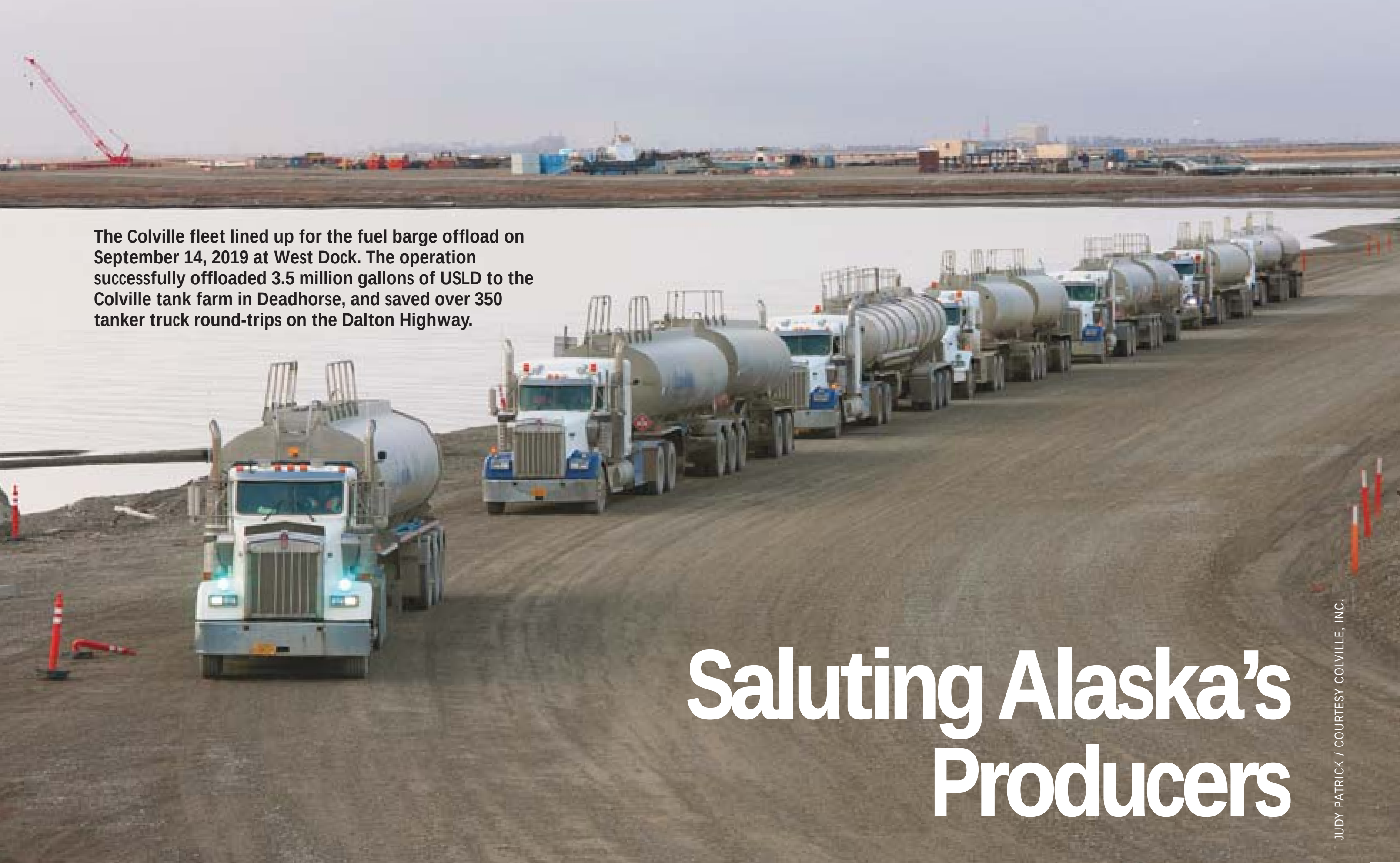

The Colville fleet lined up for the fuel barge offload on September 14, 2019 at West Dock. The operation successfully offloaded 3.5 million gallons of USLD to the Colville tank farm in Deadhorse, and saved over 350 tanker truck round-trips on the Dalton Highway.

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Saluting Alaska's Producers

A

B-F

G-M

N-P

Q-Z


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