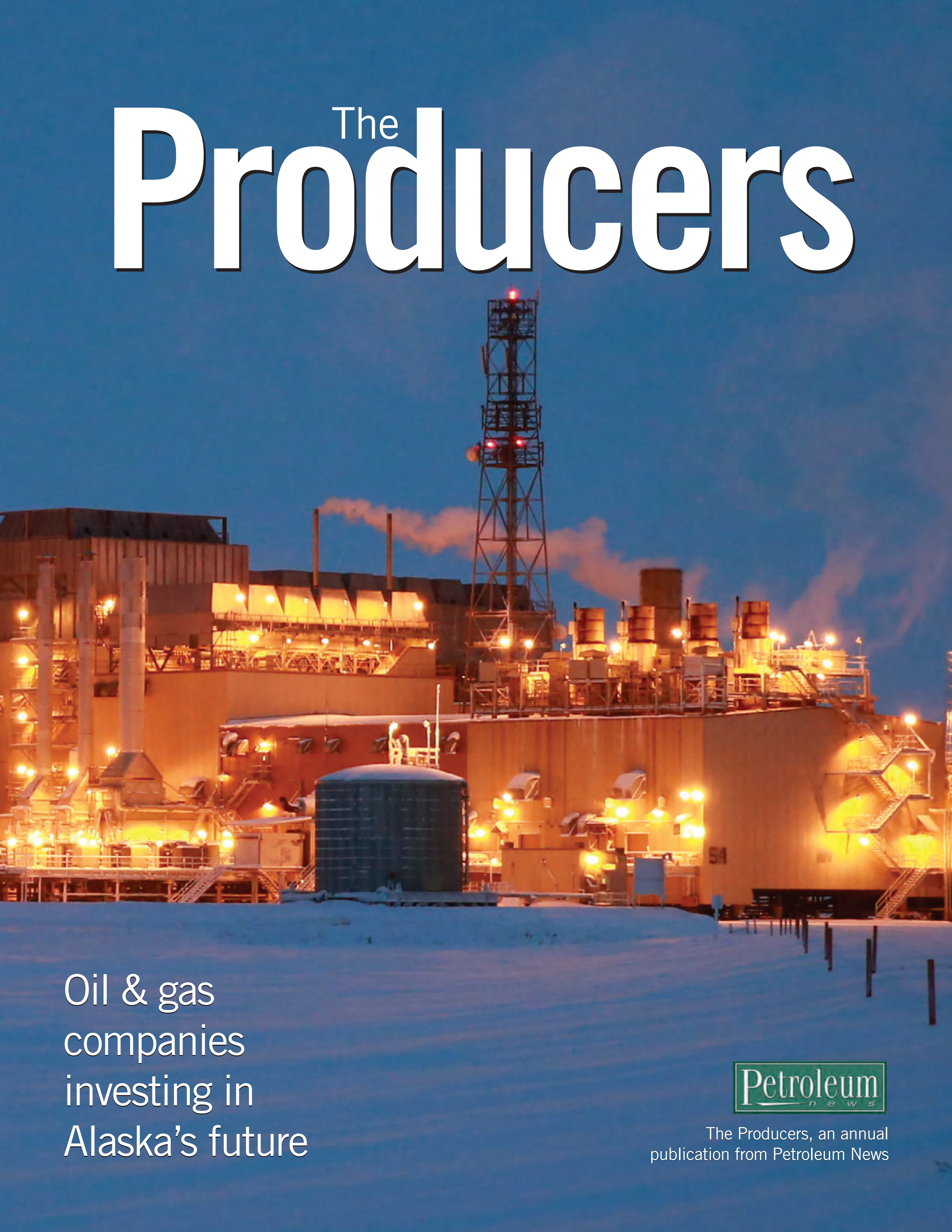

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The Producers

Released Dec. 19, 2021

The Producers is a special annual supplement to Petroleum News, which is owned by Petroleum Newspapers of Alaska LLC.

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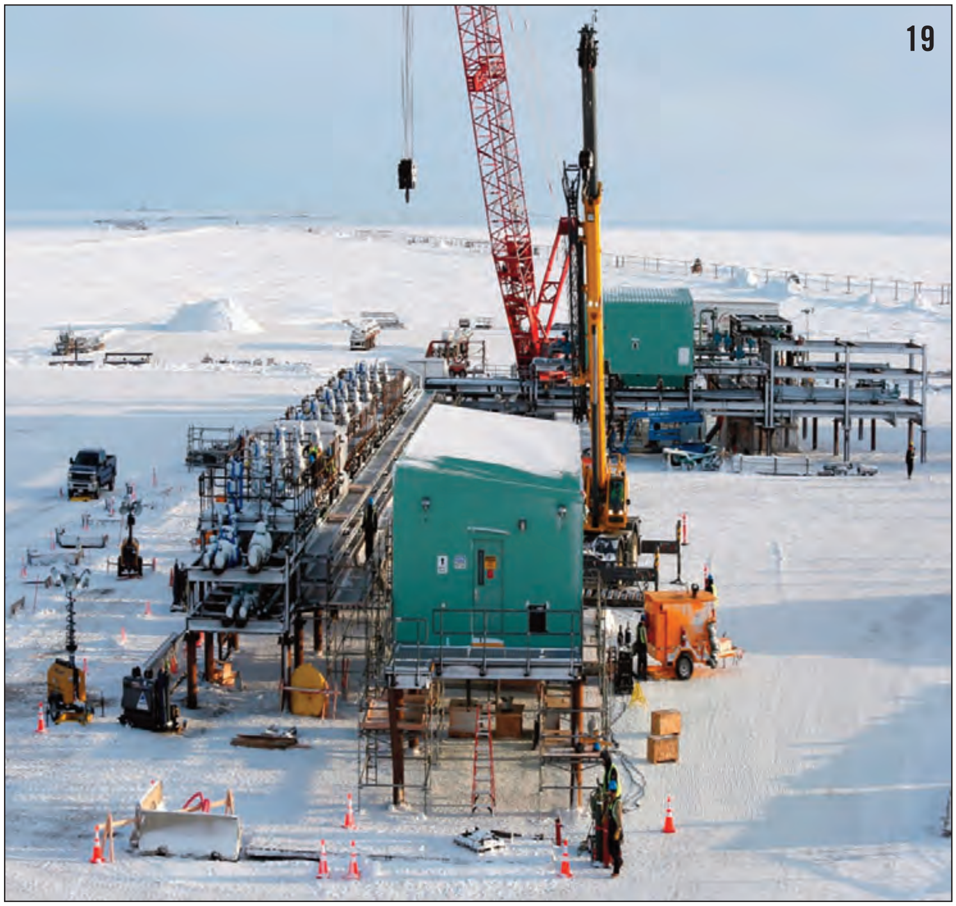
On the cover:
The Lisburne field was discovered in early 1968 with the drilling of the Prudhoe Bay State #1 well by ARCO/Exxon. Development drilling started in 1985, and the field came on-line in December 1986. Today, the field is operated by Hilcorp.

Photo by Judy Patrick, courtesy of Hilcorp Alaska LLC

Printed by Century Publishing, Post Falls, Idaho



Alaska energy investment advances ESG principles

BY CORRI A. FEIGE
Commissioner, Alaska Department of Natural Resources

Those opposed to development of oil and gas on Alaska's North Slope have employed a variety of creative opposition tactics over the years, everything from unfurling slogan-bearing banners, to harassing offshore drilling ships, to dressing up as polar bears and mugging for the cameras. And now, emboldened by the climate policies of the new federal administration, they have begun using a new approach: claiming that Alaska developments cannot meet "ESG" investment principles.

"ESG" is shorthand for "Environmental, Social, and Governance," a set of concepts that financiers and investors are increasingly applying in deciding where to invest their dollars, in hopes their money will help protect the environment, improve society, and encourage enlightened governance.


CORRI FEIGE

Those who work and live in Alaska know we pioneered environmental best practices, robust community engagement and good governance practices long before they got trendy names. However, those hoping to hobble the oil industry by choking off its capital are telling bankers and financiers that investing in Alaska inevitably violates ESG principles

It is time to climb up on our soap box and proclaim the truth: investing in Alaska's energy sector fulfills ESG principles as much as or more than investing anywhere else in the world.

Environment

Consider the "E" in ESG: environment, the idea that investment in development should provide for the highest possible protection of nature. On the North Slope, the heart of Alaska's oil patch, we have three tiers of stringent governmental environmental permitting that work collaboratively to shrink project footprints, schedule activities to preserve natural cycles, and minimize and mitigate ecological impacts. The North Slope Borough, the State of Alaska, and the U.S. federal government have overlapping permitting, monitoring and compliance programs that keep a close eye on operators, which have helped the North Slope build a decades-long record of environmental success.

The "E" is often read as "C," for climate, denoting the carbon dioxide emissions associated with most energy projects. Like every other jurisdiction in the world, Alaska is looking at how to measure and reduce these emissions. Long ago Alaska specifically prohibited "wasting" of our natural resources — like flaring natural gas — that has occurred for decades in other jurisdictions. Companies here continue to push the envelope, deploying the latest equipment and technology to reduce project emissions. The benefits of shipping Alaska crude to West Coast refineries, instead of importing Middle East oil from halfway around the world by tanker, are also clear.

Social

The "S" in ESG stands for social, the idea that investment in a project should bring positive social impacts for those living nearby, help people escape poverty and raise their standard of living. I believe Alaska's energy industry sets the gold standard for following this principle, providing tremendous benefits both to the Alaska Native people most closely affected by development, and to Alaskans throughout the state.

I mentioned that the North Slope Borough has its own regulatory agencies working diligently to protect the region's resources, wildlife and environment. These local officials are highly effective in making sure those wanting to do business in their backyard keep the concerns of their community uppermost in mind. The borough also collects property taxes on industry infrastructure to fund the education, healthcare, internet and other modern services needed to meet the challenges of living in the Arctic. The borough has dramatically raised citizens' standard of living in just a generation and has built a $1 billion Permanent Fund endowment to provide for the needs of future generations.

The 1971 federal Alaska Native Claims Settlement Act that settled aboriginal land claims created a system of Alaska Native regional and village corporations, some of which have grown into the state's largest enterprises, operating for the benefit of their Alaska Native shareholders. These companies facilitate grassroots decisions about control of their own lands and resources, and provide a unique share-the-wealth program ensuring that the prosperity of any one company benefits Alaska Natives across the state. Native corporations own as many modern office buildings and sponsor as many youth sports programs and arenas as any oil company in Alaska.

The state also collects royalties and taxes on oil production, which provide essential public services in every corner of the nation's largest state, including some of the smallest, most remote and poorest villages anywhere in the country. Alaska leaders also wisely decided to use a portion of this wealth to establish the Alaska Permanent Fund — an $80 billion public endowment fund whose investment earnings both fund public services and provide an annual dividend to every qualified resident.

Governance

The "G" in ESG stands for governance, the idea that investment should be used to support effective, accountable companies and public institutions. Once again, Alaska has an impressive record in this regard, attracting some of the most socially conscious energy companies in the world — companies that manage risk, follow strict ethics standards in their business dealings, and give back to their communities through impactful health, art and charitable programs.

As members of a far-flung but close-knit human community, Alaskans have a strong tradition of social licensing. Any company hoping to operate successfully here must embrace a value system that respects and protects subsistence rights and practices, honors and works in good faith with Alaska Native landowners, hires Alaska companies and workers, employs a local workforce that knows how to operate safely in our unique environment, and engenders the highest possible compliance with the state's regulatory regime. Those that fail to respect this social compact simply don't last long up North.

Those who work and live in Alaska know we pioneered environmental best practices, robust community engagement and good governance practices long before they got trendy names.

The ESG boxes

So, for thoughtful institutional investors considering whether putting money into Alaska advances ESG principles, the answer is a resounding "Yes!" But too many others may not understand the facts. Worse, they might give credence to fanciful horror stories from those who would prefer to keep Alaska untouched in a snow globe, and Alaskans frozen in an economic icefield.

What can we do? It is up to us to tell our story — to both tell and show that Alaskans are ESG pioneers, and that investing here will advance the ESG metrics of any forward-looking investment portfolio. As Natural Resources commissioner, I invite everyone to join me in that mission. We may not have the polar bear costumes or TikTok trendiness of the environmental movement, but we have the facts on our side, and facts matter.

What if banks and financiers ignore these facts and decide not to invest here? If a lack of investment reduces oil production from Alaska, the continuing global market's demand for oil will be met with oil produced from Russia, the Middle East or other regions. These foreign jurisdictions have far weaker environmental standards, so their energy production will cause greater damage to our global environment. The economic benefits of development in these regions seldom go to the people, but too often accumulate in the hands of government officials and economic elites. And it is no coincidence they are more likely to be led by strong-man, authoritarian governments than by democratic institutions founded on citizen involvement.

So, enlightened investors hoping to check their ESG boxes can look to Alaska with confidence.

*Environment? Check. Alaska has strong legal and regulatory institutions that protect local and global environments.

*Social? Check. Alaskans support responsible development whose benefits are shared broadly for the common good.

*Governance? Check. Alaska demands companies have the qualifications and capabilities to operate safely and responsibly in this challenging location, and in full, transparent compliance with the world's most rigorous regulatory programs.

Even the most progressive financiers can invest in Alaska with confidence that they will not only be meeting ESG investment principles, but also banking on a world-class oil province with tremendous resources and almost unlimited upside potential. That should be as reassuring to the conscience as it is rewarding for the bottom line. ●

AIX perseveres with Kenai Loop production

Small natural gas field went into production in 2012; company said in 2020 it had an estimated 5 years of remaining economic life

BY KRISTEN NELSON
Petroleum News

AIX Energy acquired the Kenai Loop natural gas field after Buccaneer Energy went bankrupt in 2014. AIX was Buccaneer's largest secured creditor and agreed to be the stalking horse bidder in the 2014 bankruptcy sale, setting the lowest acceptable price and assuring that the field did not fall prey to an unreasonably low bidder in the bankruptcy sale.

In the seventh plan of development and operations for Kenai Loop, effective May 7, 2021, through May 6, 2022, AIX said it became field operator on Nov. 10, 2014, retroactively effective to Oct. 1 of that year. AIX finalized lease agreements with the stakeholders in the field — the Alaska Department of Natural Resources, Cook Inlet Region Inc. and the Mental Health Trust Land Office — in February 2015.

In August, the latest month for which production by field data was available from the Alaska Oil and Gas Conservation Commission, Kenai Loop averaged 1,567 thousand cubic feet, mcf, of natural gas, down 69.2% from an August 2020 average of 5,087 mcf per day.

The August volume was down 66.3% from a July average of 4,646 mcf per day, so the August volume may reflect work at the field.

Production in both 2020 and 2021 was from two wells.

AOGCC data show the field, east of the Kenai Airport in the Kenai Industrial Park, had cumulatively produced 24.98 million mcf of natural gas, 2,815 barrels of condensate and 10,400 barrels of water as of the end of August 2021.

The field produces from a single drill pad, KL-1. A second pad was constructed in 2012, AIX said, but was never used in operations, and AIX decommissioned that pad in June 2017, returning the surface lease to the Trust Land Office.

Drilling by Buccaneer

There are four wells at the field, AIX said in its seventh plan of development and operations, all drilled by Buccaneer: KL 1-1 (the field discovery well; drilled in 2011 it flowed 10 million cubic feet per day from the 9,700-foot Tyonek sand) is an active producer; KL 1-2 (drilled in 2011 and reported as a dry hole) is temporarily suspended and has possible future use as a disposal well; KL 1-3 (drilled in 2012, a 9,700-foot sand producer, 300 feet structurally deeper than the KL 1-1 discovery well) is an active producer; and KL 1-4 (drilled in 2013, in 9,700-foot sand, 100 feet shallower than KL 1-1; tested at 2.5 million cubic feet per day, but was determined to be in the same reservoir as KL 1-1 and KL 1-3; has been used to monitor reservoir pressure), a shut-in producer which is not tied into the production system.

Buccaneer completed a 23 square mile 3D survey at Kenai Loop in 2012.

A field production chart from startup in 2012 indicates that field production peaked in 2016 at more than 11,000 mcf per day.

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Current plans

AIX said its marketing goal is to continue to pursue gas sales opportunities, aligning with existing and future production, while maintaining price discipline. It said that on April 1, 2021, it "will begin selling all gas volumes to a single purchaser under a one year 'Firm as Available' contract."

The company said it will evaluate tying KL 1-4 to the production system for increased deliverability and to provide redundancy to meet firm gas sales obligations "and to possibly increase ultimate recovery." This is the well, determined to be in the same reservoir as current producers KL 1-1 and KL 1-3, which is currently a shut-in producer used to monitor reservoir pressure.

AIX also is evaluating recompleting wells for additional deliverability.

The company said it plans to obtain static reservoir pressures on KL 1-1 and KL 1-3 during this plan year to "update the material balance estimates of gas in place and reserves." It requires a 72-hour field shutdown and AIX said it "will attempt to shelter the work during planned pipeline or facility maintenance."

The company will be doing a workover, planned for the second quarter of 2021, on KL 1-1 to replace the subsurface safety value as required by AOGCC.

AIX said it has not identified any drilling opportunities at the field.

In 2013 DNR's Division of Oil and Gas denied a request by then-operator Buccaneer to unitize Kenai Loop and the field remains un-unitized.

Reserves data for Kenai Loop is confidential, but in February 2020 testimony to AOGCC on bonding requirements, Wendy Sheasby, the company's chief financial officer, said the remaining economic life of the field is five years. ●

Contact Kristen Nelson at knelson@petroleumnews.com


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Increased gas focus for Amaroq Resources

Nicolai Creek natural gas production up 43% year-over-year; NCU 10 well back online following conversion of NCU 1B to disposal well

BY KRISTEN NELSON
Petroleum News

Amaroq Resources LLC, operator of the Nicolai Creek unit on the west side of Cook Inlet, is working to increase natural gas production from the field, one of the inlet's smaller gas producers, while hoping for upside potential including the possibility of deeper oil at the field.

Amaroq, a small, privately funded company, is also fighting the Alaska Oil and Gas Conservation Commission's new bonding requirements in court.

Nicolai Creek natural gas is the company's only production.

Amaroq filed a 47th plan of development for Nicolai Creek in September 2020 with the Alaska Division of Oil and Gas and on Oct. 11, 2021, the company filed a progress report on that POD, reviewing work at the unit and reporting on the status of its legal challenge to AOGCC's new bonding requirements.


SCOTT PFOFF

A 48th POD had not been filed when this story went to press.

In its November 2020 approval of the 47th POD, the division said the field first produced in 1968, with many years between production.

AOGCC data show regular production at the field from 1968 through 1977, with production starting up again in 2001.

Aurora Gas succeeded Union Oil of California as operator in 2000, the division said, and after Aurora Gas filed for reorganization in federal bankruptcy court, Aurora Exploration (which later changed its name to Amaroq Resources) acquired Nicolai Creek out of bankruptcy effective Jan. 1, 2018.

In the 47th POD, filed Sept. 28, 2020, Amaroq President G. Scott Pfoff said production from the unit totaled 92,881 thousand cubic feet, mcf, for the 12 months from Sept. 1, 2019, through Aug. 31, 2020. This was a decrease from the same period in the previous year, when the field produced 145,391 mcf of gas, although water production 2,966 barrels

AOGCC data show that from Sept. 1, 2020, to Aug. 31, 2021, the field produced 133,067 mcf of gas, up 43% from the previous year.

But another volume grew faster: water produced at the field along with the gas totaled 297 barrels from Sept. 1, 2019, through Aug. 31, 2020, but the most recent year, September 2020 through August 2021, saw 8,756 barrels of water produced, an increase of 2,848%.

Comparing natural gas production for the most recent month, August 2021, for which AOGCC data were available when this story when to press, the field averaged 530 mcf per day, up 33.7% from an August 2020 average of 397 mcf per day.

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Disposal well

Nicolai Creek formerly had access to a nearby disposal well for water which was produced with natural gas, but that well was plugged and abandoned.

In 2019, Amaroq applied to AOGCC for underground disposal of Class II oil field waste fluids into the Nicolai Creek unit 1B well, which would allow the company to bring the Nicolai Creek unit No. 10 well, considered to have the most production potential, back online.

Following commission approval, in the spring and early summer of 2020 Amaroq converted the 1B well for oil field waste fluids disposal.

In its October 2021 progress report to the division, the company said it used a portable rental pump to inject produced water until completion of permanent injection facilities in the fourth quarter of 2020. Freezing temperatures and poor road conditions prevented permanent startup of the injection well until the second quarter of 2021.

Injection rates are some 250 barrels per day, Amaroq reported in October 2021.

Nicolai Creek unit No. 10 well

AOGCC data show 2020 production from three wells, Nicolai Creek unit Nos. 2, 9 and 11; in August 2021, production was from two wells, Nicolai Creek unit Nos. 9 and 10.

In the 47th POD Amaroq reported the Nicolai Creek unit No. 10 well remained shut-in until the 1B disposal well could be completed to handle water disposal. The company said it would continue to evaluate the economics of a gravel pack and/or rig workover at NCU 10, "which would facilitate production at much higher rates."

In 2019 filings related to its application for disposal at the NCU 1B well, Amaroq said it estimated that proved reserves at Nicolai Creek were on the order of 1.8 billion cubic feet, with some 1 bcf of those proved reserves allocated to the NCU 10, which the company said was expected to produce 100 to 200 barrels per day of water when on production.

Pfoff said in the Oct. 11, 2021, progress report that the company wasn't able to put the NCU 10 well into production until May 2021. "The well has produced sporadically since and is producing quantities of water higher than originally anticipated," he said.

AOGCC data show NCU 10 produced for a single day in May, 124 mcf. In July it produced 1,184 mcf of gas for the month and 1,552 barrels of water; in August, gas production was 1,924 mcf and water production 7,013 barrels.

The highest historic rate for the NCU 10 reported in AOGCC data was in March 2012, when it produced 99,167 mcf for the month.

Field purchase and upside potential

Pfoff discussed the acquisition of Nicolai Creek in a Feb. 18, 2020, AOGCC public hearing on the company's request for reconsideration of bonding requirements.

He said the field was purchased out of bankruptcy for $100,000 cash and the owners have since put half a million into well workover expenses and about $100,000 into needed compressor repairs and overhaul.

The owners see significant upside potential at the unit, both in proved, developed gas reserves and in probable reserves.

Additional conventional development includes oil prospects under the current gas producing zones and unconventional coalbed methane potential.

Amaroq Resources is owned 66.66% by Trading Bay Oil & Gas LLC and 33.34% by Aurora Power Resources Inc. Trading Bay is 100% owned by Paul Craig; Aurora Power Resources is 85% owned by G. Scott Pfoff and 7.5% by David Boelens.

The bonding issue

Amaroq's dispute with AOGCC over the commission's new bonding requirements is now in Superior Court.

In its October 2021 progress report Amaroq said it appealed AOGCC's final order on its reconsideration request of the required bonding amount to Superior Court on Dec. 9, 2020, and as of June 1, 2021, the company said, it had filed its initial brief and awaited AOGCC's response.

The commission's original bonding requirement was $2.4 million for the field's six wells, less the $200,000 bonding Amaroq already had in place with AOGCC. The commission reduced the amount of additional bonding to $700,000 based on costs for plugging and abandoning wells in the area.

Amaroq is contesting that amount, which the company says is more than double estimates it has received to P&A the wells. The company also says AOGCC is ignoring a DR&R — dismantle, remove and restore — agreement Amaroq has with the Department of Natural Resources. Amaroq says the AOGCC bonding requirement duplicates its DR&R agreement with DNR. That agreement includes P&A of the wells, the company has said, while the commission has said the DR&R agreement does not include a specific amount dedicated to P&A of the wells. ●

Contact Kristen Nelson at knelson@petroleumnews.com

BlueCrest progressing offshore gas plans

New oil drilling in Cook Inlet Cosmopolitan unit on hold until market conditions improve

BY KAY CASHMAN
Petroleum News

BlueCrest Alaska Operating LLC, the local subsidiary of the Dallas-based independent BlueCrest Energy Inc., brought the Cook Inlet Cosmopolitan unit's Hansen field into production in early 2016 from an oil well drilled by former operator (and former partner) Buccaneer Energy. The unit's oil was, and continues to be, trucked to Marathon Petroleum Co.'s refinery at Nikiski on the southern Kenai Peninsula.

The Hansen field is an offshore accumulation accessed from an onshore pad using directional drilling.

Utilizing its custom-built BlueCrest Rig No. 1, BlueCrest launched a solo development effort in November 2016.

J. BENJAMIN JOHNSON

The program began with the H-16 and H-14 wells. Even those initial wells were complex by normal Cook Inlet standards.

BlueCrest Rig No. 1 accommodated wells extending three miles out and then a mile-and-a-half down to the reservoir and an additional mile-and-a-half horizontally through the sands, according to the company.

JOHN M. MARTINECK

The H-16 well, for example, was a 22,810-foot well targeting the Hemlock formation at 7,089 feet.

The company suspended the rest of its five-well program proposed in early 2017, in response to the state withholding between $75 million and $100 million exploration tax credits.

In the interim, BlueCrest re-evaluated its approach.

Drilling resumed in 2018

The following summer, in late July 2018, BlueCrest completed the H-12 well in a fishbone design, which is a "spine" well running through the Hemlock with seven lateral "ribs" drilled every 800 feet up through the Hemlock and Starichkof horizons.

These ribs drained to the spine well, which then flowed back to shore, where the oil is trucked to market.

The company repeated the fishbone design later in the year by re-drilling the H-16 well. The H-16A well also used the eight-well design mimicking an 800-foot spacing array.

According to BlueCrest, the fishbone wells are particularly suited for the rock formation at the unit. The consolidated nature of the geology allows wellbores to remain open after drilling, making hydraulic fracturing less effective than the multilateral approach. The fishbone wells have been very effective in maximizing the production from a given area.

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2019 oil drilling

The H-16A well came online in December 2018 and accounted for 29% of oil production and 10% of gas production at the field as of October 2019.

Pleased with those results, BlueCrest drilled the H-04 well into the southern end of the reservoir in early 2019. The well also had the one-well/seven-lateral fishbone pattern.

The company brought the H-04 well online in March 2019. The well accounted for 26% of oil production and 7% of gas production at the field as of October 2019.

Crunching the numbers reveals the cumulative benefits of this approach. Three of four wells now producing oil in the Hansen field for BlueCrest incorporate the company's fishbone concept — they are producing from 20 supplemental laterals. And, seen another way, the company has only used five of the 20 slots at its drilling pad.

The company's 2021 plan was to maintain production through well maintenance and, depending on market conditions, drill their first trident fishbone well. (Market conditions is not only oil prices.)

In its previous plan of development, submitted late September 2019, BlueCrest proposed a trident well design to further improve efficiency at the unit.

In the trident well, BlueCrest would drill one main wellbore from the surface that would then split into three subsurface fishbone wells. Each trident well would provide the same amount of reservoir contact as 21-27 individual wells (see sidebar to this story).

continued on page 16

BLUECREST *continued from page 14*

Eighth plan filed

On Sept. 29, 2021, BlueCrest filed the eighth plan of development for the Cosmopolitan unit with Alaska's Division of Oil and Gas. Operator of the Hansen field in the Cosmopolitan unit, the company said it will continue to suspend its drilling program "as long as the Covid pandemic, and the current market environment persist."

The Hansen field produces primarily oil, but BlueCrest said it will continue to advance engineering and permitting for its Offshore Gas Development in the eighth POD period, which runs from Jan. 1, 2022, through Dec. 31, 2022.

"There is a tremendous amount of uncertainty around investors/lenders extending funding to the oil and gas industry in Alaska considering the treatment the state of Alaska has given to the industry in its current obligation to pay the tax credits earned," John Martineck, president and COO of BlueCrest, wrote in the POD.

"We have run into increasing obstacles with existing and potential investors/lenders with the uncertainty of potential regulation changes midstream in the process," he said, likely referring to the bonding increases imposed retroactively by AOGCC, resulting in the company currently owing the agency $1.5 million (see full story in the March 21, 2021, Petroleum News titled "AOGCC denies BlueCrest request for reconsideration on bonding").

"Investor/lenders like stability and follow through," Martineck added.

Some new work proposed

During the eighth POD period the company said it will "evaluate options on all its wells to extend their lives" and perform hot oil treatments on the Hansen 1AL1, H-04, H-12, H-14 and H-16A wells to maintain production rates.

In the long-term, BlueCrest "plans to continue to develop the Starichkof/Hemlock oil reservoir as Covid and market condition dictates," Martineck wrote.

During the seventh POD period in 2021, the company's drilling program was on hold.

Nonetheless, BlueCrest completed the workover on the Hansen 1AL1 well and installed a gas lift system into the well to bring it back into production and extend its life.

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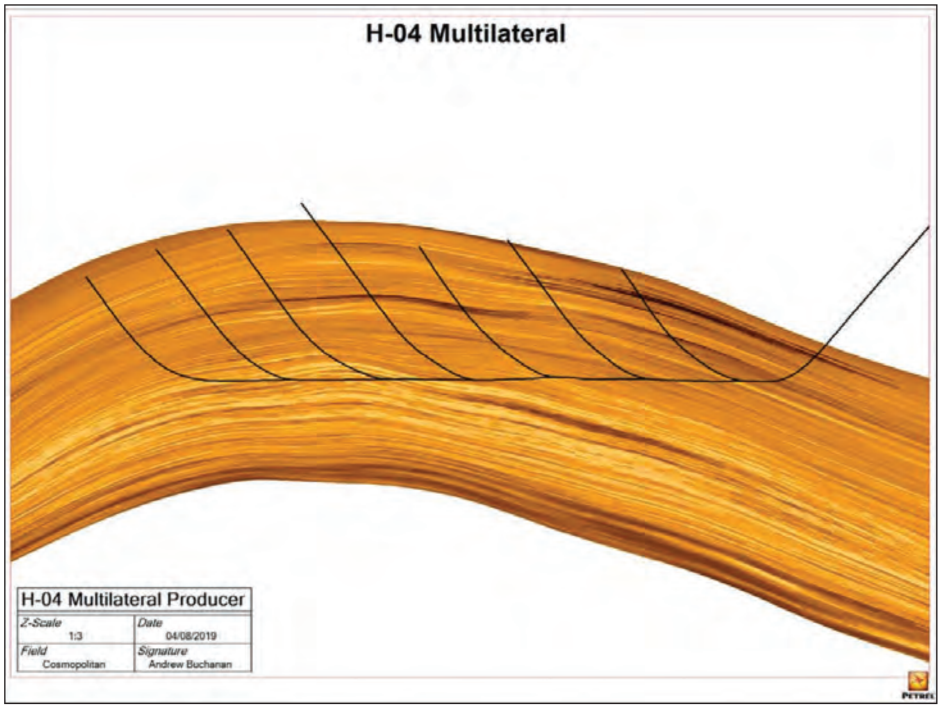
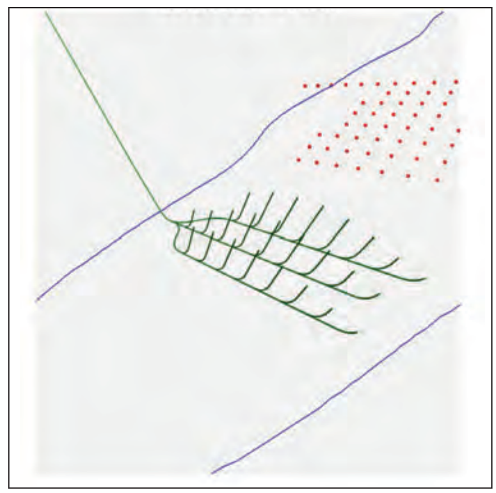


BLUECREST ALASKA OPERATING LLC

Trident project complexity worth it



BLUECREST ALASKA OPERATING LLC

In its proposed "trident" well, BlueCrest Alaska Operating will drill one main wellbore from the surface that will then split into three subsurface "fishbone" wells.

The project is as much a regulatory challenge as a technical one. BlueCrest needs to obtain 24 separate drilling permits from the Alaska Oil and Gas Conservation Commission, not to mention a field-wide development plan intended to obviate the need for requesting a series of spacing exemptions for each of the individual lateral wells.

In its 2020 plan of development, BlueCrest proposed drilling at least one and possibly two of the trident wells in 2020, but then the COVID pandemic hit, which among other things reduced the demand for, and price of, oil.

In its 2021 POD BlueCrest said that it was continuing to delay the trident project in response to economic conditions brought on by the pandemic.

Despite the challenges, BlueCrest believes that the complex trident design is worth it, especially given the inherent complexities of the Cosmopolitan unit's Hansen field — an offshore accumulation accessed from an onshore pad using directional drilling.

"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, so, each trident well provides the same amount of reservoir contact as 21-27 individual wells," BlueCrest CEO and President J. Benjamin Johnson previously told Petroleum News.

—Kay Cashman

BLUECREST *continued from page 16*

Natural gas development

As mentioned, BlueCrest intends to continue to advance the engineering of its offshore gas development in the eighth POD period, including work on permitting.

Its pause in oil drilling has allowed BlueCrest to "advance the evaluation of developing the offshore gas reserves," the company told the division in its 2021 POD filed in September 2020.

"We have a large gas resource, proven; it's been tested, but it's expensive to develop," Johnson said, noting the gas is coalbed methane that has migrated onto the sands of the Tyonek formation, which lies above all the oil zones in the unit.

"Cook Inlet needs this gas, and especially if any of the mines come online or if there's any new demand for the gas," he said.

According to BlueCrest, the fishbone wells are particularly suited for the rock formation at the unit. The consolidated nature of the geology allows wellbores to remain open after drilling, making hydraulic fracturing less effective than the multilateral approach.

In the meantime, the company has made strides to better handle and commercialize associated gas produced from its existing and future oil wells.

BlueCrest said in September 2020 that it had completed the commissioning of a new mechanical refrigeration unit capable of processing up to 35 million feet per day of natural gas, adding that the MRU will reduce the hydrocarbon dew point in the natural gas stream to meet strict pipeline quality specifications, while also allowing the company to process a much higher level of gas production.

"The gas that is with the oil contains natural gas liquids, and the MRU is basically a gas plant and the gas plant removes the natural gas liquids — the propane, butane, and that type of material," Johnson said. "In the Lower 48, the gas pipelines want the NGLs in the gas; in Alaska they don't want it."

"We're not sure exactly what its origin is, but it's intermixed within the oil zones, and so, one way or another it has absorbed natural gas liquids," he said. "There are two possibilities: one is that it is gas that has evolved off of the oil — most likely it's probably coalbed methane that has migrated and been trapped inside one of the oil zones."

"Some of our oil wells initially will produce a lot of gas," Johnson said. "We have one well that … we were never able to open it up because we didn't have a MRU that could handle its gas rate — it probably would have made 17 million a day."

The oil well was producing gas from a gas zone inside the oil reservoir, he said, adding, "it's mostly been depleted; we do expect we will have a few more of those as we drill more … oil wells."

The MRU is expected to handle as much gas as BlueCrest will ever produce from the oil zones, Johnson said.

If BlueCrest does develop its offshore natural gas, that gas is extremely dry, he said.

"There really won't be any natural gas liquids to worry about," Johnson said, adding that the MRU still may aid in cleaning up the gas from the offshore in some way in the future. ●

Contact Kay Cashman at publisher@petroleumnews.com

ConocoPhillips still moving west

Big independent's commitment to Alaska remains strong despite delays in NPR-A development

BY KAY CASHMAN
Petroleum News

ConocoPhillips is Alaska's largest oil producer and its most prolific North Slope explorer.

With a history of more than 60 years in the state, the Alaska unit of the Houston-based independent has diligently pushed westward beyond its Kuparuk River unit.

ConocoPhillips' primary operated assets on the North Slope include the Kuparuk River unit and Colville River unit, including the Alpine field.


EREC ISAACSON

By expanding its Alpine field across a channel of the Colville River, ConocoPhillips was the first company to build an oil development in the National Petroleum Reserve-Alaska.

Additionally, the company has significant interest in the Prudhoe Bay field and the Trans-Alaska Pipeline System.

Every year, ConocoPhillips works to further develop the oil and gas fields it operates and, in some years, explore for new ones. The company has drilled more than 60 exploration wells since 2000, including more than 20 in NPR-A.

The big independent holds 1.2 million acres in state and federal exploration leases. These leases represent a major asset and are tangible proof of ConocoPhillips' commitment to Alaska's future.

Kuparuk River unit

ConocoPhillips owns 94.5% of North America's second-largest oil field, the Kuparuk River field, which was discovered in 1969 by Sinclair Oil Corp., and acquired that year by ARCO.

ConocoPhillips operates the field, which is part of a major unit, and continues to develop it.

The Kuparuk River unit, or KRU, was formed effective Dec. 1, 1981, and is located immediately west of the Prudhoe Bay unit and southwest of the Milne Point unit.

The KRU includes five participating areas: Kuparuk, Meltwater, Tabasco, Tarn, and West Sak. As of July 23, 2021, there were

continued on next page

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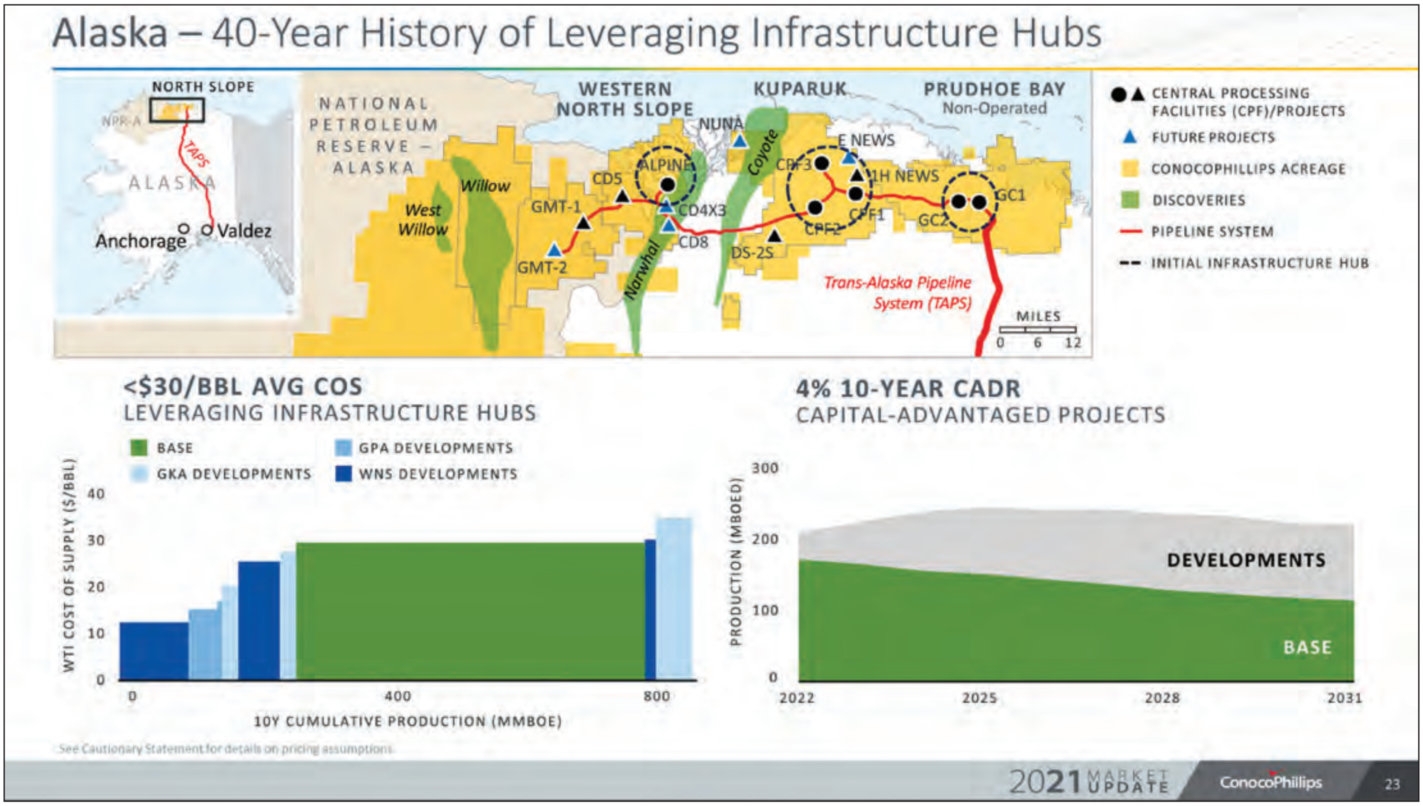

CONOCOPHILLIPS ALASKA INC.

CONOCOPHILLIPS *continued from page 19*

798 active wells within the KRU — "active" being defined as having produced or injected fluid in calendar year 2020.

As the field matures, reservoir management strategies and associated operational activities continue to change in addition to locating and drilling additional oil targets.

Maximizing production from the KRU relies on maintaining and upgrading facilities, increasing well work to keep existing wells online, employing new technologies, and optimizing current and future enhanced oil recovery, or EOR, programs to recover the remaining oil.

COVID-19 impact

ConocoPhillips publicly announced in March of 2020 the cessation of KRU drilling activity due to COVID-19 public health concerns. In April 2020, the company announced its plan to curtail oil production of approximately 100,000 barrels per day for the month of June 2020 from the KRU and Western North Slope units.

The ramp down to reduce production in Alaska began in late May 2020 and was part of broader curtailments by ConocoPhillips in the Lower 48 and other areas. The company's decision to curtail production was made in response to unacceptably low oil prices stemming from global oil demand reduction following both the impacts of the COVID-19 pandemic and global oversupply of oil.

Production was ramped up back to normal in July 2020. In July 2021 ConocoPhillips forecast that about 50% of the production deferred by the curtailment would be recovered over the next three years with the remainder recovered over the life of the field.

Restarting Kuparuk drilling

Normal drilling operations at the KRU began the process of ramping back up to pre-COVID-19 levels with plans to restart a workover rig in the third quarter 2021, followed by the coiled tubing rig in the fourth quarter and rotary rig drilling in the second quarter of 2022.

In calendar year 2020 the KRU produced an average rate of 91.4 thousand barrels of oil per day, a decrease from the 2019 average rate of 104.7 MBOPD.

Cumulative oil production from the KRU (including satellites) at year-end 2020 was 2.80 billion stock tank barrels of oil compared to 2.77 billion stock barrels of oil at year-end 2019.

The average gas production rate for 2020 was 136.4 million standard cubic feet per day, down from 173.2 MMSCFD in 2019.

Natural gas liquids imports from the Prudhoe Bay unit were resumed in September 2018 for blending miscible injectant, or MI, as part of ongoing EOR efforts at the KRU to increase production.

In July 2021 the KRU was operating under full field miscible injection with approximately half being imported and half being indigenous.

Kuparuk 2020 POD

The following activities took place within the KRU during the calendar year Jan. 1, 2020, to Jan. 1, 2021.

In the Kuparuk PA the company successfully completed two rotary wells (one producer and one injector), as well as implemented a three-well coil tubing drilling program under which two producers were brought back online and one well (1R-23A) was returned to injection service.

Successful execution of non-rig well work activity that included slickline, electric line, and service coiled tubing jobs also took place in the Kuparuk PA, adding an incremental oil rate of approximately 9 MBOPD in 2020 compared to 8 MBOPD in 2019.

A successful turnaround was also executed in the Kuparuk PA in 2020 at Central Processing Facility 1.

In 2020, the Kuparuk PA received 66 MMSCFD of miscible injectant on average. The incremental oil rate from enhanced oil recovery was estimated to be approximately 4.9 MBOPD.

Satellite Tabasco PA

The following activities also took place at the KRU satellite Tabasco PA during the 2020 calendar year:

The process of converting the 2T-209 producer well into an injector well began in 2018 and was completed in 2019 to provide more pressure support and improve the sweep efficiency of the 2T-201 and 2T-217A producing wells in the periphery area.

In 2020, however, the 2T-209 was shut-in when a high shut-in bottomhole pressure was measured in the well that suggested inadequate offtake from the 2T-209 pattern. The injector therefore was shut-in as a cautionary measure to prevent any out-of-zone injection.

Satellite Tarn PA

The following activities took place at the KRU satellite Tarn PA during the 2020 calendar year:

Similar to 2019, routine paraffin scrapes and hot diesel flushes were conducted throughout 2020 on many Tarn wells to maintain production.

The producer 2L-311 was converted to gas lift from jet pump service.

The producer 2N-315 was shut-in after developing an annular communication and was shut-in after securing it downhole.

Both 2L-317 and 2L-301 (injectors) were shut-in at the 2L drill site but brought back on again following successful wellwork.

Routine paraffin scrapes and hot diesel flushes also were conducted throughout 2020 on many Tarn wells to maintain production.

By expanding its Alpine field across a channel of the Colville River, ConocoPhillips was the first company to build an oil development in the National Petroleum Reserve-Alaska.

Satellite Meltwater PA

Two producers (2P-406 and 2P-443) were converted to jet pump operations in the Meltwater PA in 2020. Although the former continued to produce uninterruptedly after conversion, the latter had to be shut down due to low productivity.

All other Meltwater producers continued operation in 2020 without any artificial lift mechanism.

West Sak & NEWS PAs

The following activities also took place at the KRU satellite West Sak and NEWS PAs during the 2020 calendar year:

- One new MBE1 developed between the 1E-1-2 and 1E-121, while the 1E-121 was shut-in.
- Continued evaluation of two MBE treatments attempted in injectors 1C-190 and 1J-105 to reestablish injection support and pattern sweep.
- Injectors 1C-150, 1C-152, 1C-154, 1D-142, 1H-119, and 1J-118 received viscosity reducing injection during 2020, suggested positive benefits and pattern-level surveillance efforts are continuing.
- Field trials of through tubing conveyed ESP motor and pump systems (rig-less ESP) continue and are currently installed

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in six wells. According to CPAI, the continued running of these systems shows increasing potential of this technology to improve overall uptime and improved drawdown of West Sak producers (additional systems may be considered for future wells upon a showing of continued success with rig-less ESP field trials).

2021 POD activities

Although the Aug. 1, 2021-July 31, 2022, POD, approved July 23, 2021, "assumes a return to regular operating condition following the significant impacts of COVID-19 and market conditions in 2020," this POD, like its 2020 predecessor, contains a disclaimer saying that "future investment decisions include evaluation of all factors affecting economic assessment including cost, production, technical, regulatory environment, and fiscal framework."

Several sections of the 2021 POD also repeat ConocoPhillips' commitment "to a safe and environmentally sound operation, meeting or exceeding the standards specified by applicable state or national codes," and so on.

That said, in addition to indicating planned wells that are expected to be drilled in the Kuparuk PA during the approved unit POD period of Aug. 1, 2021-July 31, 2022, the plan lists the following activities at the KRU and its satellite PAs.

In addition to restarting rig activity, the company will continue monitoring two existing Moraine-Torok horizontal producer/injector well pairs at drill site 3S, a new well pair will be drilled in Q2 2022.

In the Kuparuk PA, existing wells "currently shut-in due to mechanical problems or low production rates may be sidetracked to new bottom-hole locations; both rotary and coiled tubing drilling rigs may be utilized over the plan period to access new resources."

Furthermore, operations and support infrastructure will be assessed for upgrade or replacement to target continued production from the Kuparuk; and a facility turnaround for field maintenance is tentatively planned for the summer of 2022.

Meltwater is a non-contiguous PA, lying south, southwest of the KRU unit. It was discovered by exploratory drilling in 2000 some 9 miles south of the existing Tarn oil pool. Development at Meltwater began in 2001 and was completed in 2004 after two phases of development drilling. Production began in November 2001 and AOGCC shows that cumulative crude oil production from Meltwater was 20.3 million barrels as of June 2021.

After analyses of Meltwater PA operations, low production, and associated impacts (back-out) on other production, ConocoPhillips said it plans to indefinitely shut-in Meltwater production, drill site 2P, to eliminate backout of production at Central Processing Facility 2.

The company cited an average of some 300 barrels per day of production in 2020, and back-out issues at CPF-2 which were estimated to cost some 600 bpd of production due to water cycling requirements to keep the Meltwater crude oil pipeline warm.

At the Tabasco PA, a study of waterflood optimization strategies in order to maintain or improve current field performance is the goal both over the next five years, as well as the long term.

And ConocoPhillips plans to replace the progressive cavity pump at Tabasco, an assisted lift mechanism for producing wells, in 2T-215 and bring the well online.

Although there are no current plans for drilling activity within the Tarn PA during the 2021-2022 POD period, ConocoPhillips is considering the "feasibility of fracking or refracking Tarn wells, along with process of history matching a new full field model for Tarn" for the purpose of identifying drilling opportunities.

COURTESY CONOCOPHILLIPS

Greater Mooses Tooth 1, or GMT1, in NPR-A.

In addition to continuing to evaluate other opportunities within the KRU for West Sak development and various wells planned to be drilled in the West Sak PA during the plan period, ConocoPhillips committed to the following through mid-2022:

• Drill two CTD sidetrack wells at DS-2Z using abandoned Kuparuk wells as donor wellbores.

• Evaluate future West Sak development wells, which would include four rotary wells at DS-3R to complete nine well program.

As with the Kuparuk PA, the company says operations and support infrastructure will be assessed for upgrade or replacement to target continued production from the KRU satellite fields.

West to Colville River unit

The Colville River unit was formed in 1998 and included 37 leases consisting of state, Arctic Slope Regional Corp. and joint state and ASRC lands.

The CRU has been expanded nine times since 1998 and as of May 2021 covered more than 134,000 acres of state, ASRC, joint and federal lands.

The CRU currently covers seven participating areas and eight distinct oil reservoirs. Production from the unit averaged 53,230 barrels of oil per day during the 2019 calendar year and declined to an average 45,990 barrels of oil per day during the 2020 calendar year.

Recent CRU development plans

When the 22nd POD was filed for the period of May 16, 2020, through May 15, 2021, ConocoPhillips planned to drill 21 wells premised on a plan involving multiple rigs drilling within the CRU, including the startup of Doyon 26, the giant extended reach drilling rig.

Due to the COVID-19 pandemic, drilling activity did not resume at CRU until December 2020. Consequently, only six of the 21 planned wells were drilled. Two wells each were drilled into the Alpine and Nanuq PAs, and one in the Fiord West Kuparuk and Qannik PAs.

In its 23rd POD, which was approved by the division for the period of May 16, 2021, through May 15, 2022, ConocoPhillips said it plans to drill seven wells in the CRU during the period.

These wells include three Alpine PA wells, one Narwhal reservoir well, and one disposal well at drill site CD 1.

The company said planning for development of a new drill site called CD 8 will continue during 2021. This new drill site will develop the Narwhal reservoir (Nanushuk formation) in the Fifth Expansion area of the CRU and depending on modeling could support 20-40 wells.

Approval of the Fifth Expansion of the CRU required specific benchmarks be met to bring the area into production. In its approval letter, the division said ConocoPhillips has met the benchmarks set out to date, however, estimated first production would be delayed from 2025 to 2028.

West into NPR-A

After beginning exploration drilling in the National Petroleum Reserve-Alaska in 2000, ConocoPhillips had one unit, Greater Mooses Tooth, in production as of Oct. 1, 2021, and development of a second unit, Bear Tooth, on hold for development.

In a ConocoPhillips plan update for its work in NPR-A, submitted to the Bureau of Land Management March 1, 2021, the company described plans for the Bear Tooth unit, which contains the giant Willow accumulation.

The Bear Tooth unit was approved in 2009 and the Greater Mooses Tooth unit was approved in 2008. ConocoPhillips holds 168 NPR-A tracts, 1,103,540 acres, according to BLM records current as of June 2021.

Bear Tooth plan

ConocoPhillips told BLM March 1,2021, that under the previous continuing development obligation plan it constructed ice roads and completed the Tinmiaq 20 and Tinmiaq 18 appraisal wells during the 2019-20 winter drilling season.

The company said it had planned to drill up to two additional wells, but "due to the extenuating circumstances surrounding the COVID-19 pandemic," it suspended drilling operations in March 2020.

ConocoPhillips said it continued to advance Willow project permitting during 2020, receiving "key project approvals" including the BLM Willow Master Development Plan Record of Decision, the BLM right-of-way grant, BLM permits to drill on leases AA081807, AA081808 and AA081787, U.S. Army Corps of Engineers Record of Decision and Department of the Army permit POA-2008-00190 and North Slope Borough Willow Project

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Master Plan and Rezone Approval.

ConocoPhillips said it and BLM also executed a material sales contract for gravel from the Willow mine site.

Based on those authorizations, the company said, it mobilized the camps and personnel needed for Willow construction and began building ice roads and pads, 4.47 miles of ice roads and 0.39 acres of ice pads.

Then lawsuits were filed challenging the BLM and U.S. Fish and Wildlife permitting process, eventually resulting in a preliminary injunction preventing gravel mining and gravel road construction from the 9th Circuit Court of Appeals "during the pendency of the appeal."

That injunction caused the company to miss the ice road season and it won't be able to begin gravel work until the 2022 ice road season, "assuming favorable litigation status by that time."

ConocoPhillips said the injunction cost it "several million dollars" because it mobilized camps and personnel that were not used, made non-refundable contractual commitments and paid for ice roads and pads to be constructed, which were never used.

ConocoPhillips told BLM it does not believe that further appraisal drilling is required for Willow and said it had hoped to be in construction by the date of the plan, March 2021. "The lawsuits challenging federal permits now present considerable uncertainty as to whether construction will be permitted to commence in the next ice road season."

Disappointing news on Willow

On Aug. 18, 2021, a ruling by the federal District Court in Alaska upheld litigation challenging the legal validity of the environmental impact statement for ConocoPhillips' development of the Willow oil field.

Neither ConocoPhillips nor the Department of the Interior elected to appeal the decision to the U.S. Court of Appeals for the 9th Circuit.

Meanwhile, in the absence of a legally valid EIS, the Willow development remains on hold.

Rebecca Boys, ConocoPhillips Alaska's director of media and advertising, told Petroleum News that ConocoPhillips was not appealing the court's decision because the company believes that the best path forward is to engage directly with the relevant agencies to address the matters raised in the decision.

"We and many important stakeholders remain committed to Willow as the next significant North Slope project," Boys wrote in an Oct. 25, 2021, email. "The merits of the project represent a strong example of environmentally responsible, low cost of supply development that offers extensive benefit to the public and to the residents of the North Slope, including significant employment of Alaskan skilled labor from union and non-union trade associations and revenue for federal, state, borough, and local governments."

BLM under the Biden administration had accepted the results of the Willow EIS. But since the 30-day deadline for appealing to the 9th Circuit has passed, Interior is also not appealing the District Court decision.

"The matter has now been remanded to the BLM. In light of the court's decision, we are reviewing to determine next steps," Melissa Schwartz, communications director, Office of the Secretary, Department of the Interior, told Petroleum News in an Oct. 26, 2021, email.

Oil production at Willow was projected at 160,000 bpd, with the field having potential production capacity of 200,000 bpd. Total cumulative production over 30 years was projected to be 586 million barrels.

Willow field development would involve the construction of up to five drill sites, a central processing facility, an operations center pad, up to 37 miles of gravel roads and an airstrip, as well as the installation of necessary pipelines.

Committed to Alaska, to Willow

What do the top executives at ConocoPhillips Alaska parent in Houston think about Alaska and Willow? On Sept. 21, 2021, Phil Gresh, senior equity analyst at JPMorgan Chase & Co's Research Division, asked them in a conference call: "I know your plan has not changed as a result of this transaction (ConocoPhillips' $9.5 billion cash purchase of Shell's Permian assets). But I'm curious if it makes you think differently at all about projects like Willow, which would obviously still have a lot of upfront capital and has regulatory uncertainty. Does that become a bit more of a back burner option now that you have the Shell acquisition to integrate?"

Ryan Lance, ConocoPhillips' chairman and CEO, responded: "No, it doesn't change our perspective at all about Willow," he said, turning to Nick Olds, ConocoPhillips, executive VP of global operations, to provide a Willow update.

"As we laid out in June 30 in the market update, Willow remains very competitive in the portfolio, even with the Shell assets," Olds said. "We're continuing the front-end engineering, engineering design work in service of FID (final investment decision). Currently, we won't FID the project based on the Alaska District Court litigation."

Olds added: "We're working closely, Phil, with the BLM and just working through the cited key attributes with the BLM. We'll keep you posted. But Willow clearly remains competitive in the portfolio."

Lance added: "And arguably, (Willow) probably has moved a little bit to the right given the litigation, but we're still focused on moving the project forward when we have the ability to go do that."

In a Bloomberg Markets interview, also on Sept. 21, 2021, questions arose about the company's commitment to Alaska, including "is the deal in the Permian against what you guys are doing in Alaska?"

"No, we strongly believe in a global diversified portfolio," Lance said. "It's one of the strengths of our company. … It lowers the capital intensity by having these large legacy places, like Alaska, Norway and Canada, the Far East, Qatar. Those things just add to the capability of the company, they lower the decline rate of the company. … We strongly believe in maintaining global diversity, but we've got to make sure it's low cost of supply where we're at. And the things we are doing up in Alaska compete favorably in the portfolio."

When asked about his level of confidence in getting to do what he wants to do in Alaska, Lance replied: "We expect to do what we want to do in Alaska. … We do it right in Alaska and it's really important to the state. All our stakeholders are supportive and behind what we're doing. A federal judge on the Willow project asked a few questions. There's remedies, there's solutions to those and we're working through those. And we expect to work through those in a way that will satisfy any questions the judge has — and make a more robust permitting process that we've already been through on the projects we're developing up there."

Lance called attention to GMT2, a project ConocoPhillips "has coming online at the end of this year in Alaska. We've reinstituted a number of rigs that are drilling up there, and we're still operating and investing capital up there."

Alaska "is very, very competitive" in ConocoPhillips' portfolio, Lance said.

Greater Mooses Tooth

The most recent continuing development obligation plan, or CDO plan, for Greater Mooses Tooth, provided a summary of work in NPR-A through the end of 2020. It illustrates the lengthy timeline for development in the reserve, with exploration wells drilled in 2000 through 2004, followed by BLM's approval of an Alpine satellite development plan in 2004, which included GMT1 and GMT2, formerly called CD6 and CD7.

Alpine satellites came online at CD3 and CD4 in 2006; CD5 was delayed by permit denial, but finally came online in 2015. Additional NPR-A exploration wells were drilled in 2008, 2009 and 2014, followed by the first Tinmiaq wells in 2016.

A record of decision for Greater Mooses Tooth 1 was received in 2015, with 80 square miles of Lookout 3D seismic shot that same year, followed by 470 square miles of 3D at GMT2 and Willow in 2017, also the first winter season of GMT1 construction.

2018 saw the startup at GMT1 Oct. 5, following Lookout participating area approval in March of that year.

In 2019, merged processing began for 810 square miles of seismic, and a geologic, geophysical and reservoir engineering, or GGRE, model was updated with new processed data.

Drilling continued at GMT1, and road and pad gravel 2020 saw additional work on the 810 square miles of seismic, and the GGRE model was updated with newly processed data.

Gravel work was completed at GMT2. ConocoPhillips said the seismic data set covered 88% of Greater Mooses Tooth and was being used to update GGRE models to evaluate future opportunities in the unit, "including models for GMT1, GMT2, Spark, exploration leads and other prospects within GMTU."

For 2020-21, at the Lookout GMT1 development, ConocoPhillips said it would continue the water alternating gas injection program, with further development planning to be evaluated with the revised GMT1 GGRE model and field performance data.

GMT1 production averaged some 2,500 bpd in June 2021, down from a peak of more than 12,000 bpd in early 2019, per the Alaska Oil and Gas Conservation Commission.

GMT2 will produce from the Rendezvous oil pool, which also extends into the Bear Tooth unit to the west. The $1.4 billion GMT2 project is expected to produce 35,000 to 40,000 barrels per day at its peak.

Other recent CRU news

On Sept. 27, the division approved an Aug. 2, 2021, ConocoPhillips CRU Miscible Injection Gas Injection, Pad Expansion Unit Plan of Operations Amendment application.

Basically, the company wanted to expand the Miscible Injection/Gas Injection, or MIGI, pad, in the CRU.

ConocoPhillips was given permission to place 8,000 cubic yards of gravel onto roughly 0.7 acres of tundra and jurisdictional wetlands to expand the northeast side of the pad.

The expanded area would be used to install new infrastructure necessary to advance the Western North Slope Service Pipeline Replacement project. All project work will occur using existing gravel pads and roads.

Unfortunately, due to the Aug. 18 court decision that effectively put Willow on hold, in early October 2021 ConocoPhillips confirmed that it had paused its Western North Slope Service Pipeline Replacement project, on which the company planned to start work in November in preparation for new oil coming from Willow in 2025.

"However, the ADOG permit provides COPA flexibility should the project be redefined and progressed at a later date," Boys told Petroleum News in an Oct. 5, 2021, email.

Bright spots

Given the level of activity on the North Slope by ConocoPhillips in its legacy fields as well as in its advancement into NPR-A, it's not surprising that a snippet of information about a new oil discovery makes its way into the public eye ahead of an official announcement by the company.

In 2021 that was the Coyote discovery just west of Kuparuk.

It was first mentioned — and no more than that — by ConocoPhillips executives Lance and Olds in a June 30, 2021, Market Update conference call.

At the Resource Development Council's annual luncheon in Anchorage later that morning ConocoPhillips Alaska President Erec Isaacson said Coyote was in the Brookian topset above the Nuna Torok discovery. He described Coyote as shallow.

In other words, Coyote appears to be another in a long line of Nanushuk discoveries.

North Slope geologists that Petroleum News spoke to all said they thought Coyote was an extension of Oil Search's Mitquq Nanushuk discovery; a younger, shallower interval than Nuna.

A ConocoPhillips' map titled Advancing Alaska shows Coyote parallel to the Narwhal trend, which is the name the company uses to describe the Pikka-Nanushuk trend and their own adjacent Narwhal trend.

Two 2020 Mitquq exploration penetrations discovered a separate reservoir lying to the east and parallel with the Pikka Nanushuk reservoir, its tentative length and width similar to that of Pikka — and west of Kuparuk.

It appears, however, that most of the leases around the area that do not belong to Oil Search are controlled by ConocoPhillips.

Isaacson said, "we will be taking a look at developing" Coyote, which he said could be developed using Kuparuk infrastructure. ●

Contact Kay Cashman at publisher@petroleumnews.com

Eni focus on facilities, maintenance

Drops eastern North Slope acreage, but Nikaitchuq and Oooguruk facilities work, drilling picking up

BY KAY CASHMAN
Petroleum News

The fates of the North Slope Nikaitchuq and Oooguruk units have been intertwined for two decades.

Bill Armstrong, who ran a small independent, entered Alaska in 2001 to pursue smaller oil prospects overlooked by ExxonMobil, BP and ConocoPhillips, the last two the only producer-operators on the North Slope at the time.

For example, the Exxon-operated Thetis Island exploration drilling program in the Beaufort Sea west of Oliktok Point found oil in the prospect. Development was not pursued at that time, but it proved a lead to Oooguruk and in 2007 the Thetis lease became part of an expanded Oooguruk oil field.


ROBERT PROVINCE

Because Armstrong preferred to operate without debt, he took a novel approach to exploring the complex and expensive world of the North Slope — attracting partners that were large independents and super-majors not yet active in the state. Because the prospects Armstrong identified were small in comparison to northern Alaska giants Prudhoe Bay and Kuparuk, they proved less risky and therefore attractive to these companies.

Through his partnering efforts, Armstrong brought Pioneer Natural Resources, Kerr-McGee and Eni Petroleum to Alaska by proving up the Northwest Kuparuk (now called Oooguruk), Nikaitchuq and Tuvaaq prospects in the nearshore waters of the Beaufort Sea. (Eni eventually merged the Nikaitchuq and Tuvaaq prospects into a single unit.)

In addition to stemming production declines, the Oooguruk and Nikaitchuq units helped diversify the historically small world of northern Alaska oil developments. Pioneer became the first independent operator in North Slope history, and Eni became the first company on the North Slope to operate production facilities independent of BP and ConocoPhillips.

The Nikaitchuq and Oooguruk units are now more intertwined than at any point in their producing lives. After being a minority partner at Oooguruk for its entire existence as a producing field, Eni US Operating Co., the American subsidiary of the Italian major Eni Petroleum, is wrapping up its second year as the operator and 100% working interest owner of both the units.

Nikaitchuq 14th POD

Fifty-seven development wells have been drilled and completed in the Nikaitchuq unit as of June 28, 2021. They included two Class I disposal wells, three Ivishak source water wells, a N-

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sands test well, 29 Shrader Bluff OA Sands oil production wells and 22 Schrader Bluff OA Sands water injection wells. Of the 29 OA Sands oil producer wells, 24 have been twinned into dual lateral producers.

The primary cause for well shut-ins and workovers in the unit are electrical submersible pump, or ESP, failures and tubing corrosion. To mitigate the corrosion risk, all workovers and new drills incorporate coated tubing.

The 14th plan of development for the Nikaitchuq unit runs from Oct. 1, 2021, through Sept. 30, 2022, and was approved by Alaska's Division of Oil and Gas on Aug. 25, 2021.

In its 14th POD application Eni said that facility upgrades will be completed to support the planned Nikaitchuq North exploration well (NN-02), as well as drilling the two remaining Spy Island Drillsite injection wells and the "potential" of six new wells discovered from the SP03-NE2 pilot-hole analysis from the 12th POD. (The work will include completing internal piping and electrical tie-ins for the new six-slot well containment shelter installed during that time.)

The Nikaitchuq unit consists of 11 state leases encompassing some 21,200 acres north of the Kuparuk unit. It produces from the Schrader Bluff formation with drilling from two locations — the Oliktok Point Pad, or OPP, and the Spy Island Drillsite, or SID, which is a man-made gravel island in shallow state waters off Oliktok Point where Nikaitchuq's onshore production and processing facilities are located.

Nordic Calista Rig No. 4 is scheduled to conduct workover activities on OPP in Q4 of 2021 and Q1 2022, as needed. Workovers are planned on OI15-S4, OI13-03, OP16-03, OI20-07, OI06-05, OP09-S1.

Eni currently has plans to drill five wells (four grassroots and one sidetrack) during the 14th POD period. The injector SI02-SE6 of the original development plan is scheduled to be drilled Q4 2021 and will help support the SP01-SE7 and SP04-SE5 producers, Eni said in its 14th POD application.

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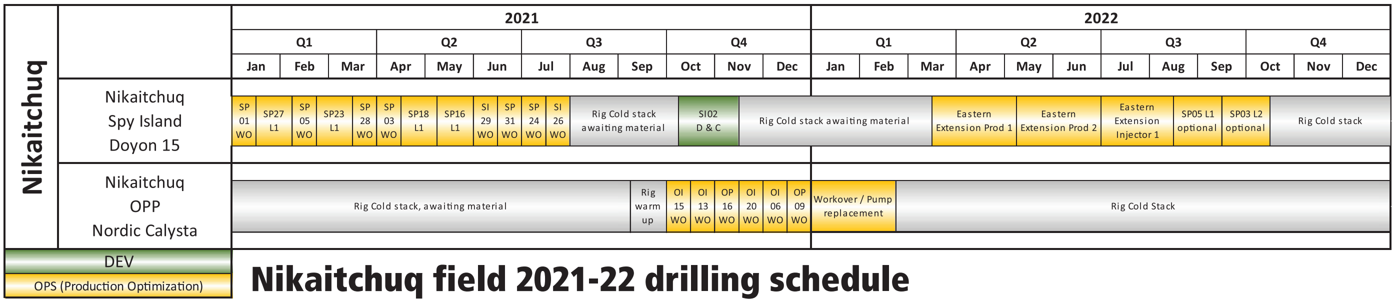

Nikaitchuq field 2021-22 drilling schedule

ENI *continued from page 26*

Two new production wells and an injection well are also planned to be completed as part of the northeast extension during the 14th POD period. A second lateral is tentatively planned to be added to SP05-FN7.

Plant maintenance shutdown

Well operations were planned to continue until late July 2021 when all rig operations were suspended in preparation for the production plant's scheduled 10-year maintenance turnaround and the arrival of materials to continue workover and drilling operations. The Nikaitchuq turnaround occurred over 23 days in August and September 2021.

Reservoir management plans

Eni said that reservoir management activities will continue in the Schrader Bluff participating area, or SBPA, with the following objectives:

- Maximize daily volumes and value by optimizing hydrocarbon production.
- Minimize risk exposure to key producing wells and maintain well integrity.
- Continue the polymer injection test at OPP through Q1 2022.
- Tracer sampling and interpretation in the OP-I2 polymer pilot area.
- Proactively define and develop mitigation plans related to water production.
- Proactively acquire reservoir performance data critical to reservoir management and overall recoverable volumes determination.
- Ensure timely execution of reservoir surveillance plans, workovers, re-completions and infill drilling.
- Update current reservoir simulations and studies to reproduce the field behavior.
- Find cost-effective solutions to optimize production.

Eni also said that a simulation model will continue to be maintained and updated to support the ongoing operations and future development of the Schrader Bluff OA reservoir. (The company has said the top of the Schrader Bluff pool is the Cretaceous shale below the Ugnu formation and the bottom of the pool is some 45 feet below the base of the Schrader Bluff OA sand.)

Other facilities work

In addition to the Nikaitchuq facilities upgrades previously mentioned, during the 14th POD period, Eni said it will perform routine maintenance and mechanical integrity inspection of piping, equipment, vessels, tanks and other safety systems. The company has several planned minor facility upgrades at OPP and SID.

For example, process hazard analysis revalidation action items from the 11th POD will continue to be addressed and mitigated and cleaning and replacing inlet heat exchanger bundles will continue to add more heat to the processing system. Actions will be based on the heat exchanger analysis performed in the 12th POD.

An alarm management and rationalization study will be performed to reduce nuisance alarms in the OPP control room.

Financial approval is expected on the electrical power sharing, or EPS, project to connect the Nikaitchuq power infrastructure with the Oooguruk power infrastructure. Eni said it will allow more robust and efficient power system sharing between the two development projects.

Detailed design and fabrication will also occur during the 14th POD. Once approved, EPS startup is scheduled for 2023.

Exploration outside PA

Eni drilled the Nikaitchuq North extended reach exploration well, NN-01 outside the Nikaitchuq unit's participating area from SID into the Harrison Bay Block 6423 federal unit north of the Nikaitchuq state unit boundary.

The NN-01 well was first spud at SID on Dec. 25, 2017, but drilling did not get underway until February 2018 because of what Eni said were "unforeseen impacts to the drilling schedule."

The well was drilled to a measured depth of 30,010 feet and suspended in August 2018, but not fully logged as it was short of its target which seismic showed to be at approximately 34,150 feet. NN-01 drilling was done with Doyon Rig 15, which had been specially modified for the well.

Drilling operations resumed in mid-January 2019, but due to the "drilling complications" at NN-01 that had plagued it from the start, Eni said it suspended the well in April of that year.

The U.S. Bureau of Ocean Energy Management said Eni's NN-02 well would be "targeting the same seismic anomaly" as the first well.

Like the first ultra-extended reach well, NN-02 will be an S-shape wellbore into the target reservoir.

Eni had planned to drill NN-02 in Q2 2020 during the winter drilling season and complete it in Q3 2020. However, the company's working interest partner in the Nikaitchuq North leases elected to go non-consent (not participate) in the drilling of NN-02, resulting in Eni temporarily postponing its drilling plans.

Eni applied for and received from the U.S. Bureau of Safety and Environmental Enforcement, or BSEE, a suspension of operations for an additional 2-year period, or until April 2022, to drill NN-02.

One of the reasons Eni gave for stepping out north of the Nikaitchuq unit to test the Nikaitchuq North prospect was it wanted new oil to take advantage of significant spare capacity in the standalone Nikaitchuq unit production facility, which can currently handle 40,000 barrels per day and can easily be expanded to 50,000 bpd, according to Eni.

May 2021 production from Nikaitchuq averaged 17,250 bpd.

Unit contraction delayed

Low oil prices, reduced oil demand and impacts of the COVID-19 pandemic prompted Eni to request a delay in unit contraction on state leases for the Nikaitchuq unit.

The division approved the Nikaitchuq deferral on Feb. 17, 2021.

Unit agreements stipulate that 10 years after sustained unit production begins, the unit area must be contracted to include only lands included in an approved participating area, lands included in an approved unit plan of exploration or development, and lands that facilitate production including the immediately adjacent lands necessary for secondary or tertiary recovery, pressure maintenance, reinjection, or cycling operations. The agency may delay contraction of the unit area if the circumstances of a particular unit warrant.

The leases affected by the request — ADL 388571, ADL 388572, ADL 388575, ADL 388577, ADL 388581 and ADL 388582 — lie in the vicinity of Spy Island, approximately 3 miles north of Oliktok Point. They were added to the Nikaitchuq unit in an October 2007 unit expansion.

In approving the 2007 expansion request, DNR said that within the proposed expanded unit, potentially commercially recoverable reserves had been tested in the Cretaceous Schrader Bluff and the Triassic Sag River formations.

In granting the deferral, division Director Tom Stokes said Eni provided "evidence that the Schrader Bluff reservoir extends outside the current participating area and has described long-term plans to drill wells in this area."

If the wells are drilled, and prove productive, that area would likely be included in the existing Schrader Bluff PA, he said.

Without a contraction delay, Eni might have lost the right to drill there, and if the Nikaitchuq unit was contracted, Stokes said, "the resources outside the unit are unlikely large enough to justify development by another lessee who might acquire the area in a future lease sale."

The area would also likely require "duplicative facilities to develop."

If the area was contracted from the Nikaitchuq unit, Stokes said, "then the relatively small resource size and difficult development options could prevent development and thus strand state resources."

Financial approval is expected on the electrical power sharing, or EPS, project to connect the Nikaitchuq power infrastructure with the Oooguruk power infrastructure. Eni said it will allow more robust and efficient power system sharing between the two development projects.

Contraction of the Nikaitchuq unit was deferred through Sept. 30, 2022, which corresponds with the expiration of the unit's next plan of development, the 14th.

Drops eastern North Slope

Eni surrendered its remaining 42 leases on Alaska's eastern North Slope in July 2021; leases that were adjacent to acreage held by Oil Search and Bill Armstrong's Lagniappe Alaska.

When asked why Eni relinquished the leases, the company told Petroleum News: "Eni completed its exploration studies on the area the leases covered and the prospectivity of the area didn't meet Eni's economic metrics."

Oooguruk focus on facilities, workovers

Eni submitted its 15th plan of development for the Oooguruk unit to the division on June 28, 2021; it was approved by the agency on Aug. 25.

The 15th POD covers Oct. 1, 2021, through Sept. 30, 2022.

The Oooguruk unit has16 state leases encompassing some 35,271 acres, with cumulative production from three participating

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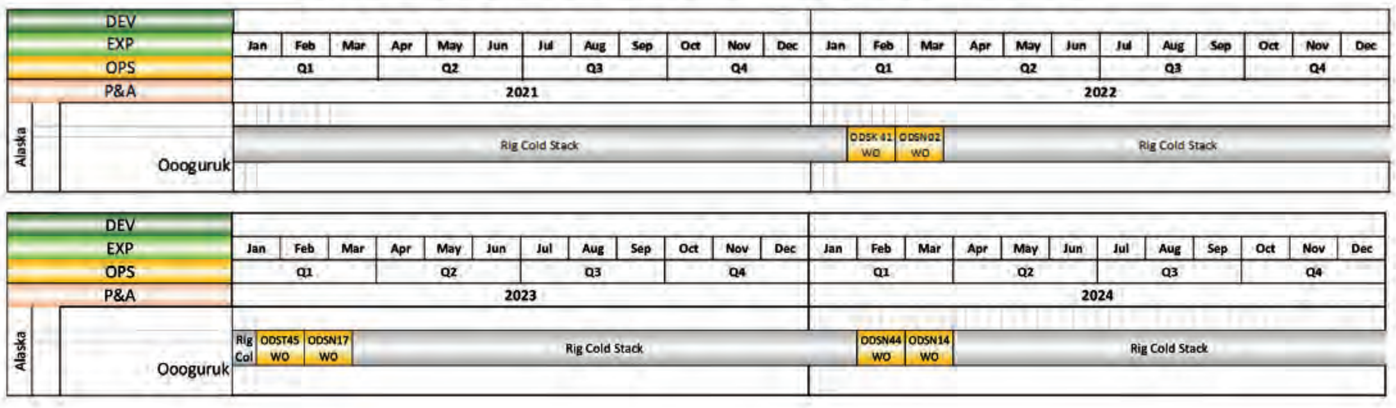
Table 1. Proposed four-year plan drilling schedule 2021 – 2024



ENI *continued from page 29*

areas through May 2021 totaling 43.8 million barrels of oil. Oooguruk production averaged 7,020 barrels per day from January through May 31, 2021.

Eni said the automatic 10-year contraction (to just areas under production) for Oooguruk has been revised by the division, delaying that date to Sept. 30, 2022.

Review of first year

In its first year (under the 13th POD) as operator of Oooguruk, Eni was hampered by a series of external factors, mostly arising from the impact of the coronavirus pandemic on the Alaska oil industry.

The proration of the trans-Alaska oil pipeline and the curtailment of the gas handling capacity at the Kuparuk River unit created secondary problems at Oooguruk.

Prompted by those infrastructure challenges and by the broader economic conditions of falling oil prices and declining demand, Eni deferred its original plans to perform 15 maintenance and repair projects on 10 wells in 2020 in advance of resuming the drilling of new wells at the unit in 2021.

The company also undertook a range of other maintenance activities, including a gas debottlenecking project responsible for "several hundred" barrels per day of production.

Second year

Eni said that during Oooguruk's 14th POD capital investment and development activities continued to be affected by the low crude oil prices, lack of demand for oil, and the logistical interference of the coronavirus pandemic resulting in budget cuts, production curtailments and project deferrals.

In the three participating areas at Oooguruk — the Oooguruk Nuiqsut PA, Oooguruk Kuparuk PA and Oooguruk Torok PA — there are 37 development wells and a disposal well. There are also four well completions outside of existing Oooguruk PAs, two appraisal wells (one plugged and abandoned), and a Kuparuk test and an exploration well, Sikumi 1 (plugged and abandoned).

Eni said active development wells include 23 oil producers (18 Nuiqsut, three Kuparuk and two Torok), 13 injectors (10 Nuiqsut, two Kuparuk and one Torok) and the one disposal well, with the producers — with one exception — requiring gas lift to produce, limited to some 15 million cubic feet per day.

There is also some 10 million cubic feet per day in formation gas.

The back-out cost at the Kuparuk River unit (Oooguruk crude is processed at Kuparuk's Central Processing Facility 3) is significant, Eni said, describing KRU as "primarily constrained by gas compression capacity," so KRU fluid production is backed out when then high total gas oil ratio Oooguruk unit fluids enter the system.

The high gas lift rate and Oooguruk formation gas increase flowline pressure, and that, combined with KRU back-out, means all Oooguruk wells cannot be produced at the same time using gas lift. During 2020, an average of 12 of the producing 23 Oooguruk wells were online with total gas oil ratio ranking typically determining which wells are produced, the company said.

Eni discussed plans for additional wells at only one of the PAs, Nuiqsut. The company said future development plans include 12 additional Nuiqsut PA wells, with eight from available well slots and four from reclaimed well slots.

The company said it had planned several workovers "to recomplete shut-in or low performing wells prior to drilling planned new wells in 2021" in the 14th POD but those plans were deferred due to low crude oil prices, lack of demand for oil and COVID-19 logistical interference.

The company did do a number of rigless well interventions and maintenance operations.

Eni said routine operations during the 14th POD included general maintenance and replacement of critical oil, water and gas piping and valves, along with field-wide maintenance and routine maintenance on the three power generation turbines and two gas injection compressors at the onshore Oooguruk Tie-in Pad. Cathodic protections inspections were completed on the sub-sea production flowline from the offshore Oooguruk Drill Site to the tie-in pad, along with a mandatory U.S. Department of Transportation hydrotest.

In addition to some minor capital projects, major capital projects included finalizing commissioning and startup of the seawater injection system booster pump upgrade at the drill site.

An engineering feasibility study was completed for 20 million standard cubic feet per day partial gas procession, or PGP, at the tie-in "to mitigate gas processing constraints and reduce associated costs from KRU CPF-3." That project received final Eni approval with detailed engineering beginning in June 2021 and startup forecast for 2023.

15th POD operations

Eni said there will be no significant maintenance turnaround at Oooguruk during the 15th POD period from Oct. 1, 2021, through Sept. 30, 2022.

Similar routine maintenance will be performed on facilities as in all past years, including replacement of worn piping and valves and general mechanical integrity inspections of piping and other safety systems.

Engineering and operational efforts will continue in optimizing and debottlenecking existing equipment, including separator control system performance, proportional fluid sampling upgrades and measurement system accuracy.

A complete 5-year revalidation of the facilities Process Hazard Analysis was to be completed in November of 2021.

Minor capital facilities projects being evaluated include: "ODS and OTP control room relocation efforts, installing an access platform on the flowline shore crossing support structure, additional upgrades to the ODS polar bear camera system, upgrades to the compressor lubrication system and installation of a chemical injection system for the new Seawater Injection pipeline."

Major capital projects include engineering and fabrication work on the PGP project.

Financial approval is also expected on the EPS project to connect the Nikaitchuq power infrastructure with the Oooguruk power infrastructure, allowing more robust and efficient power system sharing between the two development projects. Detailed design and fabrication will occur during the 15th POD period.

Reservoir management

During the 15th POD period, Eni plans to further optimize the OKPA waterflood and the ONPA under-saturated water-alternating-gas flood and reestablish the OTPA enhanced recovery operation by repairing ODST-46i.

All OU floods will be managed to maximize voidage replacement.

Individual well and pattern surveillance data will be collected in all reservoirs to monitor performance versus expectations.

Simulation models will be updated to assist in reservoir and flood management decision.

Drilling plans

Based on the four-year plan, Eni has approved two rig workovers to be executed during the 15th POD.

The proposed drilling schedule for the next four years is subject to changes depending on global economic environment and company investment objectives, Eni said.

"Drilling activities have been forecasted to be reactivated after the year 2025 based on the maturity of Partial Gas Processing Project," Eni told the division in its 15th POD application. The company listed eight new wells plus reclaims for drilling between Sept. 1, 2025, and Sept. 1, 2028.

The reclaims were ERD-NO1, ERD-NO2, RC-47, RC-45, RC-40 and RC-35.

Exploration outside PAs

Its plan of exploration for outside the existing participating area, Eni said it targets maximizing OU oil production, managing producing gas oil ratios, or GORs, and maximizing long term reservoir performance and value.

Consistent with these objectives, the company said it is evaluating two appraisal wells targeting the northern Nuiqsut reservoir. The wells, "ERD-N01 and ERD-N02 are within the proven drilling radius from ODS (~22,000 ft)," the company said.

Eni's primary objective is to test the productivity and oil quality of the oil on leases ADL-379301, ADL-389953 and ADL 389949 in several horizons. ●

Contact Kay Cashman at publisher@petroleumnews.com

Major gas sale remains Point Thomson focus

ExxonMobil tells state in 2-year development plan it continues to work with Alaska Gas Development Corp., Qilak LNG on projects

BY KRISTEN NELSON
Petroleum News

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Dropping operatorship in 2022

BREAKING NEWS

ExxonMobil has said Hilcorp Alaska will become the operator at Point Thomson, a change expected to be effective early next year.

In an email to PN, the company said it is not giving up acreage. It will remain the largest working interest owner at Point Thomson — a position it already holds at Prudhoe Bay, where Hilcorp operates, having acquired BP's share of Prudhoe in a sale which closed in 2020. ExxonMobil will also retain its interest in the trans-Alaska pipeline system.

ExxonMobil said an Oct. 19 agreement between the companies to transfer operatorship is expected to become effective, subject to regulatory approvals, in early 2022.

Luke Saugier, Hilcorp's senior vice president, Alaska, said in a statement: "Hilcorp is excited about our continued commitment to Alaska. We welcome the opportunity to apply our proven record of enhancing legacy conventional assets to Point Thomson."

—Kristen Nelson

ExxonMobil is a major player on Alaska's North Slope, holding the largest working interest ownership, WIO, share at Prudhoe Bay, the Slope's largest oil field, and the majority interest at Point Thomson, where ExxonMobil Alaska Production is the operator. The company opened its first Alaska field office in 1921 and drilled its first Alaska well in 1926.

ExxonMobil was instrumental in the discovery of Prudhoe Bay and Point Thomson and operates Point Thomson. It helped discover the Kuparuk River and Duck Island unit and holds small working interests in both Duck Island and Kuparuk.

The company was involved in early Cook Inlet discoveries, although its last involvement in the inlet was when it merged with XTO in 2010. XTO had interests there acquired by Hilcorp in 2015.

Point Thomson

ExxonMobil submitted the current two-year plan of development for Point Thomson to the Alaska Division of Oil and Gas on Oct. 1, 2021, with focus of the POD continuing on condensate production and providing information as needed for major gas sales projects.

ExxonMobil and Hilcorp North Slope are the major working interest owners at Point Thomson, with the Hilcorp interest one of two ownership changes ExxonMobil noted during the 2020-21 two-year POD:

•ConocoPhillips Alaska's interest in the PTU was transferred to BP Exploration (Alaska) effective Nov. 1, 2019.

•Effective June 30, 2020, Hilcorp Alaska acquired the shares of BPXA and the name of that entity was changed to Hilcorp North Slope.

The new POD covers Jan. 1, 2022, through Dec. 31, 2023, and provides a summary of work under the 2020-21 POD and plans for future development, including planning for a major gas sale.

Agreement, settlement with state

The 2022-23 POD, the company said, is consistent with the Sept. 10, 2018, letter of agreement between the state and the PTU working interest owners (major WIOs in 2018 were ExxonMobil, BPXA and ConocoPhillips Alaska), and the March 29, 2012, settlement agreement between the state and the WIOs (major owners the same as in the 2018 letter of agreement).

The 2012 settlement agreement was the result of the state's insistence that the Point Thomson WIOs move ahead with Point Thomson development — or give up the leases.

The leaseholders, led by ExxonMobil, had long demurred, citing lack of a means to transport production. As a result of the settlement, ExxonMobil built a sales oil pipeline, linking Point Thomson to a pipeline previously built by BP to take Badami oil to connect with North Slope lines taking oil to the trans-Alaska oil pipeline.

ExxonMobil said the primary resource at Point Thomson is "natural gas with entrained condensate, contained within high pressure sands of the Thomson reservoir," with the field primarily lying offshore under state water and land.

There have been 22 wells drilled in and around the PTU since the early 1970s, the company said, with the Thomson reservoir representing some 25% of known and recoverable natural gas resources

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EXXONMOBIL *continued from page 32*

on the North Slope.

Initial production system

ExxonMobil constructed the initial production system, IPS, at Point Thomson in 2012-16. The IPS is a high pressure, 10,000 psi, gas cycling project, the company said, using "industry-first reciprocal injection compressors" with condensate delivered for sale.

Once condensate is removed from the gas, gas is compressed and injected back into the reservoir.

IPS infrastructure, wells and facilities were designed to cycle 200 million standard cubic feet of gas per day and deliver up to 10,000 barrels per day of condensate to the trans-Alaska oil pipeline through the Point Thomson Export Pipeline.

Three wells are active, two injectors on the Central Pad and a production well on the West Pad. There is also a class 1 disposal well used for produced water and grey water disposal, the company said.

For Jan. 1, 2020, through July 31, 2021, condensate production averaged 8,300 barrels per day, ExxonMobil said, with a maximum monthly average of 9,600 bpd achieved in May 2020 and a total of 4.8 million barrels of condensate delivered to the trans-Alaska oil pipeline. Gas production averaged 151.2 million standard cubic feet per day, with 147.2 million standard cubic feet per day reinjected and the remaining gas used as fuel gas in unit operations. In May 2020 a maximum monthly average production of 179.6 million standard cubic feet per day was achieved.

IPS reliability

In earlier years at Point Thomson, where production began in April 2016, there were reliability issues related to the gas injection equipment.

In the 2020-21 POD ExxonMobil said Point Thomson had "experienced issues related to its gas injection equipment, which is based on leading edge technology designed to handle gas reinjection at the high pressures of the Point Thomson reservoir," and said the unit worked with the equipment manufacturer to identify potential reliability improvements and modifications. The unit "designed and procured a modified component for use in its gas injection system," with the first of the new components installed in July 2019 and remaining equipment ordered for installation during the 2020-21 POD period.

ExxonMobil also said the unit "is upgrading the lubrication systems and continuing to optimize operations and maintenance practices to further increase reliability and reduce downtime."

In its current POD, for 2022-23, ExxonMobil said the new components which were installed starting in 2019 "enabled significant reliability improvements in 2020 and 2021."

Major gas sales

ExxonMobil said in its 2022-23 POD that as described in the 2018 letter agreement with the state, the preferred development at Point Thomson is as a major gas sales project, "such as the Alaska LNG Project or the Qilak LNG Project," and said the unit plans to continue evaluating "facility modifications and development activities necessary to support any viable MGS project."

The company said that as PTU operator it has engaged in confidential discussions with the Alaska Gasline Development Corp. on the Alaska LNG Project, "to share knowledge in support of AGDC's efforts to identify potentially viable commercial structures for the project and to identify further opportunities to improve the competitiveness of the project," has provided support for Federal Energy Regulatory Commission permitting for the project and AGDC cost reduction studies and continues evaluating "the technical feasibility of required PTU facility modifications, including study of a potential option under which Alaska LNG would initially construct a pipeline from PTU to Fairbanks."

ExxonMobil also said that as PTU operator it has engaged in confidential discussions with Qilak LNG "to discuss advancing mutual objectives under the Heads of Agreement signed by the parties in October 2019," received periodic updates on the status of the Qilak LNG project feasibility studies and provided technical support and "conducted evaluations of the technical feasibility of various development scenarios, including assessments of PTU facility modifications and upgrades that would be necessary to supply the PTU gas to the project."

ExxonMobil provided a list of long-range activities that would be required "to ensure continued alignment with either MGS project."

Point Thomson expansion planning, required under the 2012 settlement, was suspended under the September 2018 letter agreement.

The company said no additional wells are planned during the 2022-23 POD period.

Reservoir management, facilities

ExxonMobil said reservoir management to date has met expectations, with no indications of reduced reservoir connectivity or capacity. No enhanced oil recovery efforts are planned through 2023.

Central Pad processing facilities have achieved production greater than the 200 million standard cubic feet per day of cycled gas and 10,000 bpd of condensate, the company said, and gas injection compressors have demonstrated "the ability to operate at maximum design capacity based on facility performance rates."

The 2012 settlement agreement required a debottlenecking program after IPS project startup, the company said, and debottlenecking opportunities have been reviewed "with the assistance of an independent engineering contractor," evaluating "operating parameters such as separator pressures and hydraulic limits, but no significant debottlenecking opportunities were identified to increase capacity." ●

Contact Kristen Nelson at knelson@petroleumnews.com

Vision's G&G team seeks more gas at North Fork

Once RCA approval issued, Vision will officially operate the 16-mile North Fork Pipeline

BY KAY CASHMAN
Petroleum News

BOB GARDES

MARK LANDT

Gardes Holdings entered Alaska in November 2020 with the acquisition of the southern Kenai Peninsula North Fork unit from Cook Inlet Energy, a Glacier Oil and Gas company. The 2,602-acre unit produces natural gas from a single participating area, Gas Pool No. 1, covering 800 acres.

Unlike every other hydrocarbon producer that has entered Alaska, Lafayette, Louisiana-based Robert "Bob" Gardes is first and foremost looking for natural gas, not oil. He told Petroleum News that he views the Cook Inlet basin as one of four top gas regions in the world.

"We think the future in the U.S. is gas. It burns 98% cleaner than oil and coal. It is a transformational resource," Gardes said. "There is a lot of bypassed gas here because the deposits weren't big enough" for companies to bother with them.

Gardes Holdings' operating entity in Alaska is Vision Operating and its lease owner is Vision Resources.

Mark Landt, VP of land and business development for Vision Operating, told PN that the company will not thumb its nose at an oil discovery, but gas is most important to it.

Right now, Bob Gardes and his team are "98% focused on North Fork," Landt told PN Oct. 19, 2021. "We see a lot of opportunities to pursue there."

In a March 10, 2021, interview, Landt said the company has a "full geologic and geophysical team" working on North Fork. "Now that we have our plan of development for the unit approved with the Division of Oil and Gas and have purchased 3D seismic … we are going to be working the 3D data and generating our own ideas going forward."

Landt said Vision sees "additional gas to be recovered" at North Fork, mentioning the possibility of "additional sands" in the field and more workovers.

In its approval the division wrote that the operator "has no specific plans for exploration or delineation," but will continue to evaluate opportunities to drill outside the existing PA, as well as "analyzing and optimizing" current production from the unit.

Originally 58,113-acre unit

The North Fork unit was formed as a federal unit on May 27, 1965, with Standard Oil Company of California as the original operator. The U.S. Department of Interior, Bureau of Land Management and the State of Alaska co-managed North Fork which was originally comprised of two state and two federal leases totaling 58,113.40 acres, until 2006 when BLM waived its administration rights and transferred its North Fork leas leases to the state. As it currently stands, the North Fork unit is comprised of five state leases.

Gardes Holdings, Inc.

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Armstrong brought inline

North Fork was first brought online in 2011 by a Bill Armstrong joint venture.

The North Fork Pipeline was built in the winter of 2011 and consists of dual pipelines and their related facilities. It is unique among pipelines in Alaska in that the majority of it is a glass-fiber reinforced epoxy pipe instead of the standard steel pipe.

In a nearly $65 million deal Armstrong sold the gas field to Cook Inlet Energy's original parent in 2014.

Through the end of 2020, North Fork had cumulative production of 21.46 billion cubic feet of natural gas and 27,414 barrels of

continued on next page

VISION *continued from page 35*

water, all from the original PA.

First 13 months

In the 13 months since it signed the acquisition agreement with CIE, Gardes/Vision has gotten the North Fork unit leases transferred from CIE by Alaska's Division of Oil and Gas, effective Jan. 1, 2021. That's the same date the division used when it approved a change in operatorship in May 2021.

The working interest, along with operatorship, were first transferred to Gardes Holdings and then from Gardes to Vision Resources and Vision Operating.

In February 2021 Vision entered into a five-year natural gas sales and purchase contract with Alaska Pipeline Co. that resulted in APC's utility affiliate Enstar Natural Gas continuing to purchase gas from Vision Resources after CIE's contract expired on May 10, 2021.

In March 2021, the division approved a one-year delay in unit contraction; requested on behalf of Gardes by CIE because it would allow the new owner time to assess opportunities for additional drilling targets outside the PA and other methods to enhance production from the North Fork unit.

Contraction of a unit is required after a unit has been in production for 10 years, at which point it is contracted to areas that are producing.

With North Fork having only one 800-acre PA, the contraction was a logical step; until Gardes came into the picture, that is.

On Oct. 13, 2021, Glacier received conditional approval from the division's State Pipeline Coordinator's Section to transfer its interest in the Anchor Point Energy (the North Fork Pipeline company) right-of-way lease, ADL 230928, to Gardes Holdings.

Gardes received an analysis of the transfer of interest that carried conditions the company must sign off on before approval is final, but Landt told Petroleum News Oct. 19, 2021, that the company will accept the terms.

"It was what we expected, and fair," he said. "There were no obligations that we did not expect."

Once the Regulatory Commission of Alaska approval has been issued Vision Operating will officially operate the pipeline.

Vision's North Fork unit averaged 3,135 mcf per day in August, up 0.5% from a July average of 3,119 mcf per day but down 6.2% from an August 2020 average of 3,341 mcf per day.

Gardes/Vision model

Under "Natural Gas Solutions" on the shared Gardes Holdings/Vision Resources website it says Vision is committed to providing clean natural gas and power to Alaska communities.

"We are committed supplying natural gas to utilities and other off-takers in the Interior and rural communities of Alaska without access to clean affordable natural gas. Vision … brings extensive upstream experience to its Alaskan assets, including patented drilling technologies that mitigate negative impacts of operations."

The website refers to Vision's model as simple. It is "acquiring and developing natural gas reserves" in Alaska's Cook Inlet basin, as well as "securing additional future supply of natural gas with CNG and LNG."

Similar to most oil and gas companies in Alaska, Vision said it is committed to minimizing environmental impacts in all its operations.

Vision's model also includes "securing off-take commitments to sell natural gas to Alaskan utilities and large industrial end-users on a long term basis," as well as developing, building and operating gas and power infrastructure that supports the use of clean burning natural gas.

Vision's team, expertise

Vision has assembled a lead team of 11 experienced professionals in the following fields: drilling; production; engineering; geology; geophysics; land management; asset acquisitions; power generation; sales and marketing; asset management; price risk management; governmental affairs; regulatory management; infrastructure development; planning and operations; LNG and logistics; environmental and regulatory.

Founder and CEO Bob Gardes has more than 40 years of engineering, drilling and completions in the oil and gas industry. He is a pioneer in lateral drilling and completions and coalbed methane development worldwide with more than 3,000 wells drilled under his management and supervision. His companies own multiple drilling patented methodologies related to lateral drilling and completions.

Doug Wight is president of Gardes Holdings and Vision. Doug has more than 40 years' experience as a senior geologist/geophysicist, leading to numerous successful roles as vice president, exploration, acquisitions and divestitures across the oil and gas industry worldwide. He has conducted robust scientific due diligence and evaluation of hundreds of oil and gas field acquisitions, deals, leases, farm-ins and other transactions similar to the North Fork unit acquisition.

In its approval (of the 56th plan of development) the division wrote that the operator "has no specific plans for exploration or delineation," but will continue to evaluate opportunities to drill outside the existing PA, as well as "analyzing and optimizing" current production from the unit.

Institutional experience

Stephen Hennigan is president of Vision Operating. He is the company's lead on engineering, drilling and completions with a 48-year track record in the oil and gas industry throughout the Lower 48 and, importantly, the Cook Inlet.

Hennigan has been directly engaged in successful drilling and development of North Fork unit and other Cook Inlet fields since 2007 for previous operators and owners.

Hennigan has a Master of Science Degree in Engineering Management.

Landt, who is well known in Alaska's oil patch, began his career with ARCO, where he spent 25 years in various land, negotiation, acquisition, business development, marketing and senior management positions in their Denver, Lafayette, Dallas, Houston, Anchorage, Bakersfield and Plano offices.

He has more than 25 years of direct experience in Alaska and was based in Anchorage for five years. After leaving the company, Landt co-founded Prodigy Alaska, Renaissance Alaska, Buccaneer Alaska and Stellar Oil & Gas, all focused on E&P in Alaska. He holds a Bachelor of Business Administration in Petroleum Land Management from the University of Oklahoma.

Landt has previously worked with Hennigan. ●

Contact Kay Cashman at publisher@petroleumnews.com

Glacier Oil sells North Fork, restarts Redoubt unit

Subsidiary Cook Inlet Energy plans to restart offshore West McArthur River unit in November 2021

BY KAY CASHMAN
Petroleum News

STEPHEN RATCLIFF

Glacier Oil & Gas operates the offshore West McArthur River and Redoubt units on the west side of Cook Inlet through its subsidiary Cook Inlet Energy, or CIE, and operates the Badami unit on the North Slope via its subsidiary Savant Alaska (see Glacier profile in North Slope section of this magazine).

Glacier recently sold its interest in the Cook Inlet North Fork unit to Gardes Holdings (see Gardes/Vision Resources profile).

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The Redoubt and West McArthur River units make Glacier one of only two companies operating production in both of the major Alaska hydrocarbon provinces: North Slope and Cook Inlet. The other company, Hilcorp, operates a substantial number of fields in both areas.

As of Oct. 23, 2021, the most recent news about CIE was that on Oct. 20 the Alaska Oil and Gas Conservation Commission, or AOGCC, reduced CIE's bond requirement, based on an EPA bond.

But the most important recent news is that Glacier put the Redoubt unit back online Sept. 28, 2021, with output at 1,200 barrels a day, company President Stephen Ratcliff told Petroleum News Oct. 7, 2021. The field, which is north of Kalgin Island, had been shut down since May 2020.

Ratcliff also said Glacier would "hopefully have the Cook Inlet West McArthur River unit back online sometime in November."

The company expects West McArthur production will give Glacier's Cook Inlet oil output a "300-500 bpd uptick," Ratcliff said.

Glacier was created in early 2016, as a result of the bankruptcy proceedings of the Tennessee-based Miller Energy Resources.

The Redoubt unit was formed in April 1997 and prior to the early June 2020 suspension of operations had cumulatively produced some 5.3 million barrels of oil and 2.6 billion cubic feet of gas.

The West McArthur River unit was formed in 1990 and prior to the early June 2020 suspension cumulative production was 15.65 million barrels of oil and 3.975 billion cubic feet of natural gas.

West McArthur history

The West McArthur River unit was formed on July 27, 1990, with Stewart Petroleum Co. as the original unit operator. CIE took over as unit operator effective Dec. 15, 2009.

On May 29, 2020, Alaska's Division of Oil and Gas received the initial suspension of operations, or SOP, application from CIE, citing the global condition of low crude oil prices combined with the lack of demand as justification for the SOP.

On June 4, 2020, the division approved CIE's initial SOP application subject to modifications, which included:

- Quarterly updates to the division.
- Written request to the division no later than 45 days from the expiration of the plan of development, or POD, period, should the SOP extend beyond the currently approved period.
- Immediate written notice from CIE no later than 30 days prior to the time CIE intends to resume operations and production.
- Submission to the division of a new POD no later than 60 days after resumption of operations and production.

On Sept. 29, 2020, the division received notice from CIE that it downgraded the shutdown status at the West McArthur River unit from a "warm-shutdown" to a "cold-shutdown and unmanned," due to longer-term global economic conditions that negatively impacted operations.

Redoubt unit history

The Redoubt unit (initially referred to as Redoubt Shoal) was formed in April 1997, and brought online in December 2002 by then-operator Forest Oil Corp.

On May 29, 2020, the division received the initial SOP application from CIE, citing the global condition of low crude oil prices combined with the lack of demand as justification for the SOP.

On June 4, 2020, the division approved CIE's initial SOP application subject to modifications, which were identical to those for the West McArthur River unit.

On Sept. 29, 2020, the division received notice from CIE that it downgraded the shutdown status at Redoubt from a "warm-shutdown" to a "cold-shutdown and unmanned," due to longer-term global economic conditions that negatively impacted operations for the Redoubt unit.

RU, WMRU interdependence

In a March 16, 2021, request from CIE to the division, the

But the most important recent news is that Glacier put the Redoubt unit back online Sept. 28, 2021, with output at 1,200 barrels a day, company President Stephen Ratcliff told Petroleum News Oct. 7, 2021.

company asked for an extension to the SOP for a period of one year for the West McArthur River unit and the Redoubt unit, along with an extension of the respective PODs for each unit.

CIE explained that production from Redoubt via the Osprey Platform and production from West McArthur are commingled and processed through the Kustatan Production Facility, located on the West Side of Cook Inlet. The facility provides power and essential operations to realize production from both the units, CIE told the division.

Lease operating expenses incurred at the Kustatan Production Facility are also shared between the units. Due to high fixed costs associated with these operations and low production; operating either the Redoubt or the West McArthur River units independently was not a financially feasible solution.

Furthermore, CIE said, the asset footprints are remote, extensive and span over 10 miles. This includes a platform, production facilities, 100-plus miles of pipeline, and associated infrastructure that support oil and gas drilling and production operations.

Wells producing from the two units were also dependent upon artificial lift operations, involving electronic submersible pumps (ESP) that have limited run lives and

The division said CIE provided a technical presentation to the division on April 7, 2021.

West McArthur decision

On April 21, 2021, the division issued a decision conditionally approving the request from CIE for the West MacArthur River unit SOP and POD extensions due to "the economic instability and state of uncertainty."

The time, CIE said, would give the company time to "assess all options before making final determinations. The company cited "three pathways" for the future of both its West McArthur and Redoubt units:

1. Investment with restart;
2. Divestment through asset sales; or
3. Abandonment of wells and facilities.

CIE said it had been aggressively marketing its assets since July 2020 and although there had been significant interest from other entities in the asset, "the process is tedious, time consuming and is taking its due course."

Because of the uncertainty as to whether the West McArthur River unit (and the Redoubt unit) would receive the investment necessary for restart, CIE had been working on both a plan to restart, and a plan to abandon.

Lastly, in its extension request, CIE requested an extension of the 29th POD period for the West McArthur River unit.

The division approved the extension request, subject to CIE's agreement on the following modifications, which were accepted by the company:

• The SOP and 29th West McArthur River unit POD will be extended for six months;

• CIE will provide an update to the division as to the status of unit by July 31, 2021; and

• CIE will submit its proposed 30th POD to the division no later than 30 days after the resumption of production at West McArthur.

The period approved for the SOP and the POD extensions would be from May 1, 2021, through Oct. 31, 2021.

Redoubt unit decision

On April 23, 2021, the division responded separately on CIE's request for one year SOP and POD extensions for the Redoubt unit, approving them for six months with identical modifications to those of the West McArthur unit.

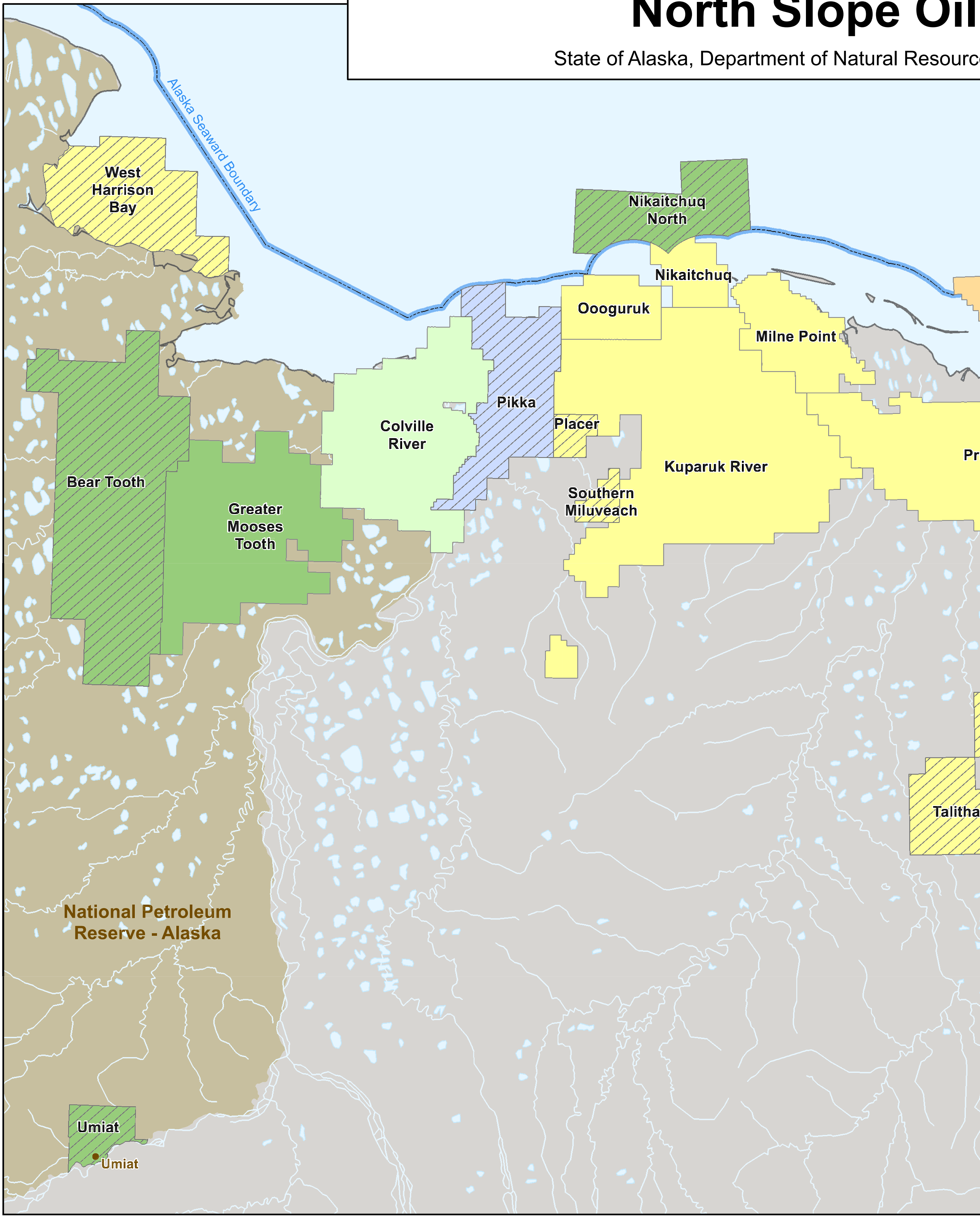
Even the SOP and POD extension periods were identical — May 1, 2021, through Oct. 31, 2021.

Obviously, the path chosen by Glacier-CIE was to retain and invest in the assets, restarting production from both units. ●

Contact Kay Cashman at publisher@petroleumnews.com

North Slope Oil

State of Alaska, Department of Natural Resourc



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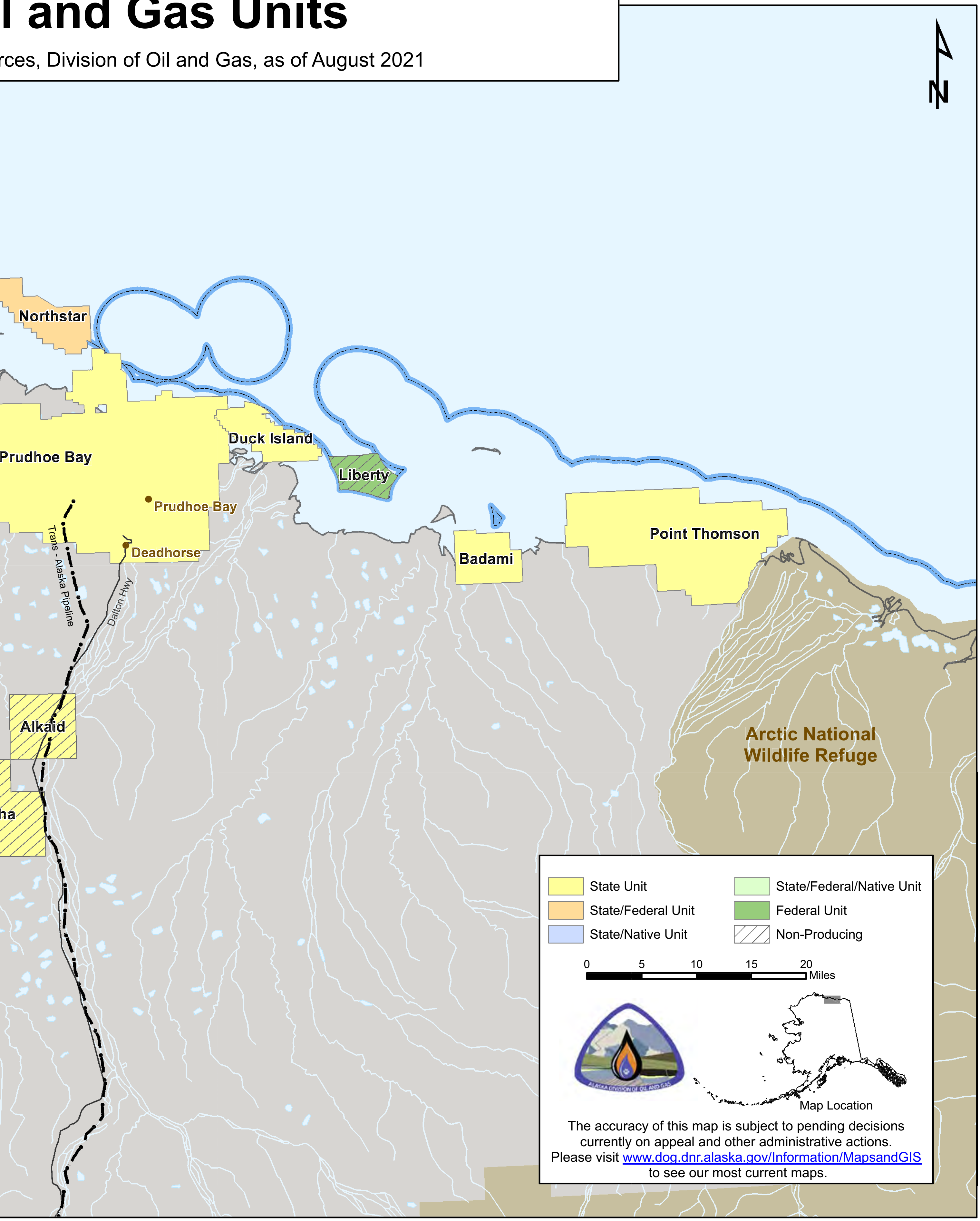
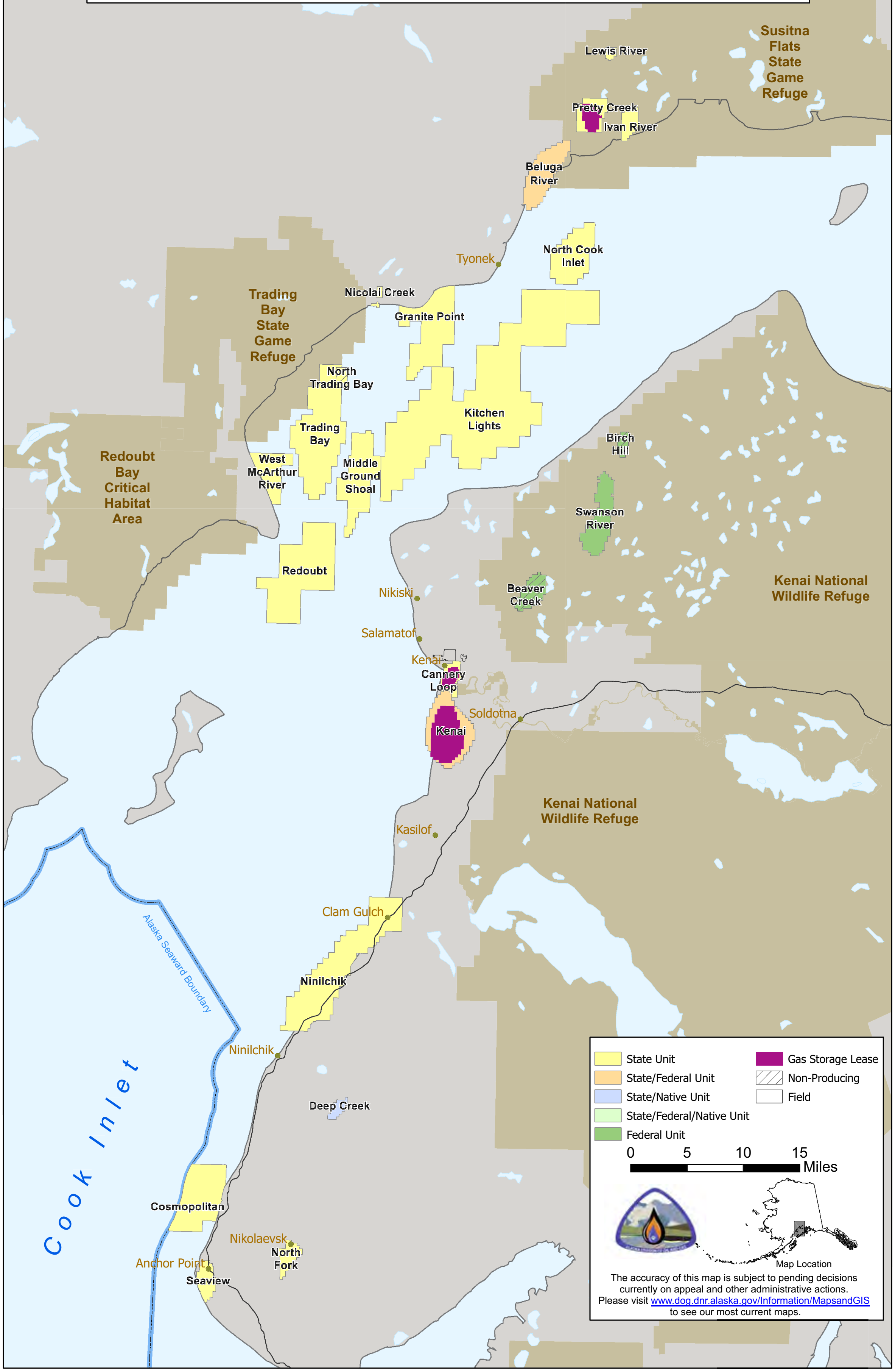


Cook Inlet Oil and Gas Units

State of Alaska, Department of Natural Resources, Division of Oil and Gas, as of August 2021



Heckuva bunch of work done, but obstacles remain

Under ownership of HEX, Furie Operating worked on all its Kitchen Lights production wells & much more since taking over

BY KAY CASHMAN
Petroleum News

JOHN L. HENDRIX

HEX Cook Inlet LLC became the newest producer in Alaska in the summer of 2020 when it closed on a deal to acquire the assets of Furie Operating Alaska LLC and related companies.

HEX CI is the only producer in the state that is owned by Alaskans.

The independent's $5 million acquisition was the culmination of the intense bankruptcy proceedings of Furie and its partners Cornucopia Oil & Gas Company LLC and Corsair Oil & Gas LLC.

The centerpiece of the purchase was the offshore Kitchen Lights unit, which is the largest unit in Cook Inlet by acreage and which has been seen as a source of growth for the basin. The field is operated by HEX CI's Furie Operating.

HEX CI is a joint venture between HEX LLC (80%) and Rogue Wave AK LLC (20%), which were founded by John Hendrix, who was raised in Homer and is an engineer. He has close to four decades of experience in the energy industry in Alaska, the Lower 48 and internationally with Apache, BP and Schlumberger.

Fixing what it bought

At the time HEX CI acquired Furie Operating, Kitchen Lights was an undeforming field in need of fixing, but with considerable potential.

In a Dec. 18, 2020, presentation in Anchorage to Commonwealth North, Hendrix said, "When we took over (July 1, 2020), we basically had to go in and fix everything."

Furthermore, "there was not one Alaska person working in our field (including contractor personnel). There was only one person in the Anchorage office. … Well files were in boxes. … We're going to have to go back and work all of the wells over to have access to all the original reserves because in a lot of it you have tubing inside the well covering up the flow," he said.

Among the accomplishments Hendrix mentioned in that presentation were:

- Majority of field operations contracting had been turned over to Alaska-based Udelhoven Oilfield Services, which was founded in Kenai in 1970 by Jim Udelhoven who Hendrix said was "one of those men whose word you can trust with a handshake."
- Hired Alaskan Kevin Smith (first employee ever for Furie in the field), who had retired from BP after a 25 year-plus career on the North Slope to take the position.
- Brought in production safety management coach Daryl Leech.
- Functioning Anchorage office vs. a Houston office.
- Anchorage local employees up 500%, field employees up 1000%.
- Established data management control.
- Performing well surveys on two production wells.

Hex Cook Inlet LLC

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"It was a journey, it was a challenge to get where we are today," Hendrix said in the presentation.

More than once he thanked the Alaska Industrial Development and Export Authority for providing financing to acquire Furie Operating and its Kitchen Lights infrastructure, as well as loan some of the money needed to help develop the Beluga and Sterling formations within the Kitchen Lights unit.

"It was the only financial institution at the time in the state that would help us — even across the United States and North America it was very tough to get financial backing for a project in Alaska," Hendrix said.

History of unit formation

Following a series of battles over work commitments involving several small players in Cook Inlet, the state formed the 83,394-acre Kitchen Lights unit in 2009 to prevent a legal battle and encourage exploration and development activities at a time of dwindling local supplies.

The unit combined the Escopeta Oil & Gas Co.-operated Kitchen unit, the Renaissance Alaska LLC-operated Northern Lights prospect and the Pacific Energy Resources Ltd.-operated Corsair prospect.

So, the state took three previously distinct prospects that were unitized and then administratively divided into four exploration blocks: Corsair, North, Central and Southwest.

A corporate shuffle in 2011 put Furie in charge of the project.

Early plans of exploration for Kitchen Lights required Furie to drill at least one well in each exploration block. The company drilled exploration wells across the unit between 2011 and 2014 before shifting to development, but it left the North and Central blocks underexplored and the Southwest block undrilled.

All development activities to date — October 2021 — have occurred within the Corsair block.

Early development work had involved construction of the Julius

continued on next page

HEX COOK INLET *continued from page 43*

R platform, which was the newest platform in Cook Inlet and structured to have six wells online.

Another piece of the infrastructure building was the subsea pipeline between the field's onshore facility at Nikiski and the platform. It's 16 miles long and 16 inches in diameter.

The third piece of infrastructure was construction of the onshore gas processing facility, which can reportedly handle five times what it is handling today — an average of 11,285 thousand cubic feet per day in August 2021, per the Alaska Oil and Gas Conservation Commission.

Furie under its previous owners brought the unit into production from a single well in July 2013 and subsequently drilled three more production wells, with the last being the KLU A-4 well in October 2018.

By the time HEX CI took control, one of the four wells was offline, awaiting upgrades and repairs. And the three other producing wells were underperforming.

HEX CI's goal was, and continues to be, having all four existing wells producing natural gas from both the Beluga and the Sterling formations, with much of the upside in the Sterling.

Eighth POD work planned

Fast forward to Oct. 15, 2021, when HEX's Furie Operating filed its eighth plan of development for the northern Cook Inlet Kitchen Lights unit with Alaska's Division of Oil and Gas. The eighth POD period will run from Jan. 3, 2022, through Dec. 31, 2022.

Although Hendrix, told Petroleum News Oct. 19 that Furie Operating would be filing an addendum to the eighth POD listing more well work the company hoped to do in the unit, Furie Operating did commit to some things in the Oct. 15 filing, as well as describe an appreciable amount of work accomplished so far in 2021 under the seventh POD.

Furie Operating said it planned to continue ongoing efforts from the seventh POD, which would end Jan. 2, 2022, along with evaluating development options for the state leases it won in the June 2021 Cook Inlet areawide lease sale. Specifically, in its eighth POD period Furie Operating would:

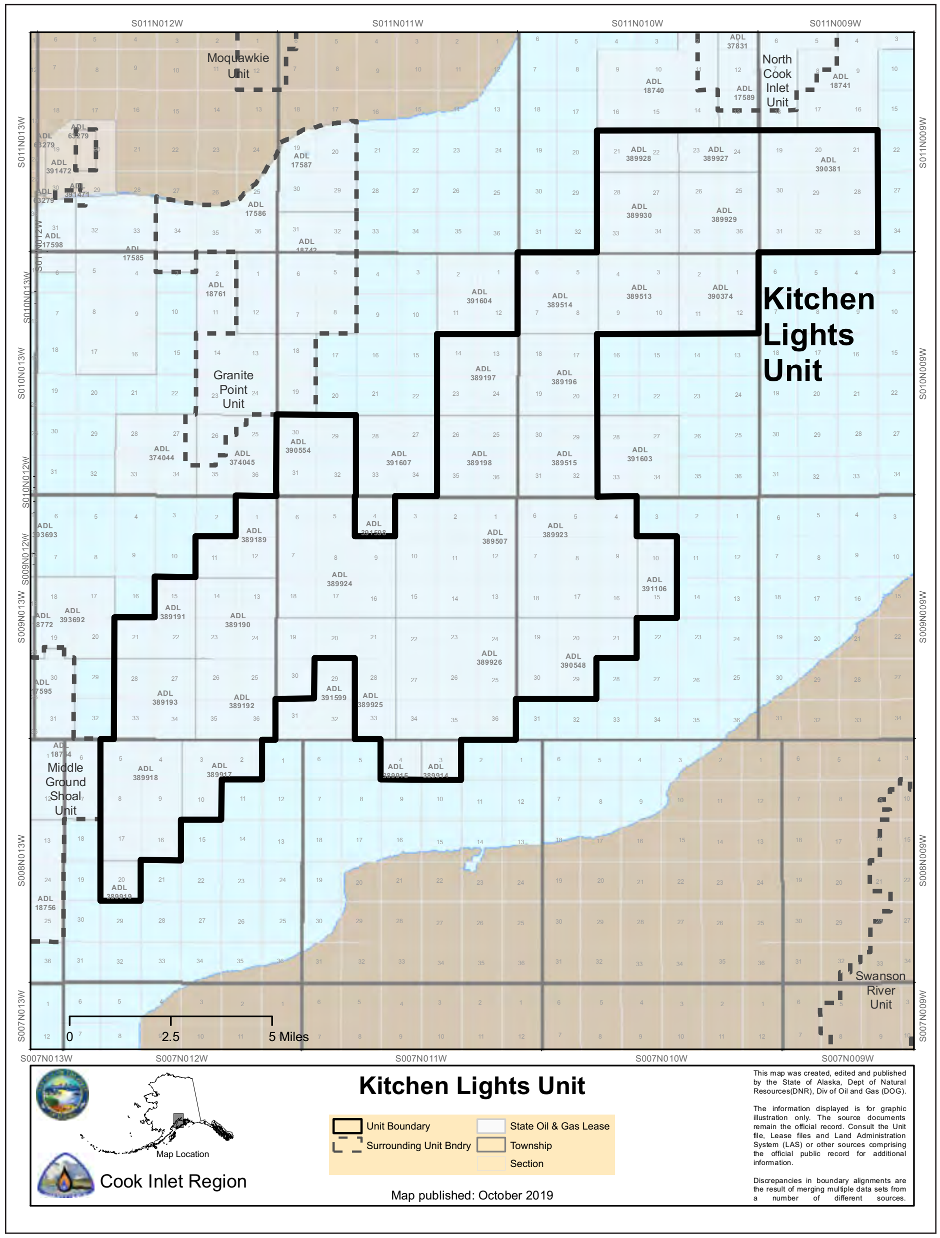
• Continue development of proven gas reserves in the KLU. The 2021 well intervention campaign was still in progress; results or new information were coming in almost daily. The specific activities planned for individual wells in 2022 would be determined after the 2021 intervention campaign was complete and sustained production results were available.

• Continue efforts to optimize production, enhance safety and minimize environmental footprint of KLU related infrastructure.

• Continue progress on establishing a participating area along with a possible unit expansion.

• Evaluate drilling of additional wells on existing lease acreage and new acreage acquired in the state's June 2021 lease sale.

"At this time, we are trying to bring all wells back online," Hendrix told PN, noting KLU A-1 was giving them some difficulties.



The above Kitchen Lights unit map is accurate as of October 2019. But HEX LLC's Furie Operating Alaska LLC acquired four additional leases for the unit in the state's June 2021 Cook Inlet areawide lease sale: Two of the tracts, CI0348 and CI0349, are adjacent to Furie's offshore northern Cook Inlet Kitchen Lights unit, and two of the leases are adjacent to CI0348.

Lots of work already done

In its review of work promised for the seventh POD period from July 1, 2020, through Jan. 2, 2022, Furie Operating had committed to doing the following, noting in the eighth POD whether it had met its commitments:

• Met — Continue development of proven gas reserves in the KLU.

• Met — Continue and increase production of natural gas on the Julius R platform.

• Met — Continue exploration of the KLU, including the new analysis of seismic data and offset wells to identify specific targets for exploration outside of the Corsair block.

• In progress — Update joint operating agreement to reflect the realities of operating in Cook Inlet.

Furie Operating said all four wells on the Julius R. platform have had one or more downhole interventions completed, or intervention work was in progress to continue development and increase production from the KLU.

Well KLU A-1 had dozens of feet of fill bailed from the tubing to allow access for reperforations and additional perforations in the Beluga interval. The perforations were successfully executed. The well was incapable of sustained flow during the initial post intervention startup attempt. Further diagnostics were performed and another attempt to initiate flow was in progress. (The old Furie, prior to HEX's ownership, had never produced this well from the Beluga formation.)

Well KLU A-2 had additional perforations added in the Beluga interval.

Well KLU 3 had two sliding sleeves shifted to the open position to allow additional Beluga formation production.

Well KLU A-4 had never produced from the Beluga formation due to a plug in the tailpipe with several feet of solids above it, along with multiple wireline tool strings and wireline in the well. The tubing tailpipe was perforated above the fish to allow production from the Beluga.

Well KLU A-4 also had a wireline tool string fish retrieved from the well, several dozen feet of slickline recovered, and several

continued on next page

HEX COOK INLET LLC

The Julius R platform offshore in the Cook Inlet produces gas from the Kitchen Lights field.

HEX COOK INLET *continued from page 45*

dozen feet of solids bailed out of the tubing tailpipe. Bailing and fishing efforts were ongoing. The objective was to allow access to the liner below the tailpipe for additional Beluga perforations.

A produced water handling system was installed primarily for the Sterling formation, and appropriate permits obtained to allow production of gas zones with higher water content. This may result in increased gas recovery once the formation is brought on production.

A detailed assessment of the KLU area and adjacent acreage was completed and led to Furie Operating being the high bidder on adjoining leases at the June 2021 lease sale.

An amendment to the joint operating agreement was submitted to the working interest owners. No agreement had been reached regarding this amendment.

PA, technical presentation

The division had also wanted Furie Operating to complete its existing participating area applications or submit a new PA application on or before Dec. 31, 2020. Furie said in its eighth POD that was continuing to evaluate available data to submit a draft PA application for review.

In an August 2021 meeting with the division, agency staff suggested that Furie consider unit expansion prior to finalizing the draft PA application.

During the seventh POD period the division also wanted a technical presentation from Furie to the division by July 1, 2021, detailing with specificity the progress made on the subsurface description of the KLU along with any other activities undertaken by Furie Operating related to further development of the KLU and exploration activities.

"If a number of obstacles are reduced Furie believes there is potential development opportunity within the Kitchen Lights unit and adjacent acreage to provide clean, reliable energy for Alaskan residents for many years."
—John Hendrix

The company said its personnel spent much of the first half of 2021 analyzing all available data in preparation for the June Cook Inlet lease sale. Due to confidentiality concerns prior to the sale, Furie Operating told the division that it "preferred not to provide specificity regarding progress on the subsurface description."

During its August 2021 meeting with the division the company offered to provide a technical presentation at its Anchorage office for division personnel. As of October 2021, this presentation had not yet been scheduled, but there were ongoing conversations between the agency and Furie Operating staff.

Development obstacles

"If a number of obstacles are reduced Furie believes there is potential development opportunity within the Kitchen Lights unit and adjacent acreage to provide clean, reliable energy for Alaskan residents for many years. Furie's participation in the June 2021 Cook Inlet lease sale provides clear evidence of this premise," Hendrix told the division and PN.

The company's high bids at that lease sale totaled $325,605.23.

"Unfortunately, enthusiasm for development must be tempered with the reality of the unfavorable economic climate in the state of Alaska," Hendrix told PN and expressed in his remarks to the division

"The delay in paying earned tax credits and excessive tax valuation of the KLU infrastructure are a couple of examples that conspire to limit both internal and external capital availability for development," he said.

The previous owners of the Kitchen Lights assets are still owed $103 million by the state of Alaska for tax credits that would flow through a HEX company to them. If the state doesn't pay the $103 million by 2025, HEX is on the hook to pay a $15 million penalty to the previous owners.

Furthermore, the Alaska Department of Revenue imposed a property tax on the fixed assets and related infrastructure of Kitchen Lights, assessing its value at $81.2 million, even though its value in bankruptcy court was the $5 million paid by HEX CI.

That DOR assessment earned Furie a $1.6 million tax bill, which Hendrix told PN was "unfair and excessive." It is money that should be allocated for well work, he said.

The COVID-19 pandemic also had "significant impacts on KLU activity over the last year and may continue into 2022," Hendrix told the division in his concluding remarks.

"I took a gamble on buying Kitchen Lights; I know that. But I figured I should be able to trust my state government to treat me fairly," he told PN. "Obviously, that's not what's happening at this time. The state agencies need to quit operating in silos and start cooperating and working with each other." ●

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Extended life for mature fields: Hilcorp in Cook Inlet

Company operates majority of fields in Southcentral, from small gas fields to existing major oil, gas fields, is major inlet producer

BY KRISTEN NELSON
Petroleum News

LUKE SAUGIER

Alaska's modern oil and gas production began in Cook Inlet in the 1950s and the area was the focus of exploration and development in the state until the discovery of Prudhoe Bay in the late 1960s drew companies — and investment — to the North Slope. Cook Inlet oil production peaked in 1970 at more than 227,000 barrels per day, and natural gas production peaked in the mid-1990s at more than 850,000 thousand cubic feet, mcf, per day. Alaska Oil and Gas Conservation Commission data for August, the most recent available when this publication went to press, show Cook Inlet crude oil averaging 8,464 bpd and natural gas averaging 187,410 mcf per day.

In 2021, Hilcorp Alaska is the dominant oil and gas producer in Cook Inlet.

The company began operating in Southcentral Alaska in 2012 after acquiring Chevron's properties in Southcentral; in 2013 it also began operating properties acquired from Marathon Oil; it added inlet acreage previously operated by XTO Energy in 2015; and in late 2016 it acquired ConocoPhillips' North Cook Inlet field and minority interests ConocoPhillips held in and around the North Trading Bay, as well as small interests ConocoPhillips held in the West McArthur River unit and the Nicolai Creek unit.

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Hilcorp's forte is extending the life of mature fields.

Its properties in Cook Inlet can be grouped into four broad areas: the west side; the northern Kenai Peninsula — primarily fields in the Kenai National Wildlife Refuge; the southern Kenai Peninsula, home of Cook Inlet's newest fields; and offshore, fields produced from platforms. Each area includes at least one major field — Beluga on the west side, Kenai and Swanson on the upper Kenai, Ninilchik on the lower Kenai and McArthur River in Cook Inlet. There are also numerous smaller fields, and at last count, Hilcorp operates 17 Cook Inlet fields, including all of the large fields.

continued on next page

HILCORP *continued from page 47*

Its properties in Cook Inlet can be grouped into four broad areas: the west side; the northern Kenai Peninsula — primarily fields in the Kenai National Wildlife Refuge; the southern Kenai Peninsula, home of Cook Inlet's newest fields; and offshore, fields produced from platforms.

The west side

BELUGA RIVER

Of the four fields on the west side of Cook Inlet, all producing gas, Beluga is by far the largest. That field, 66.67% owned by Chugach Electric Association, is operated by Hilcorp, which holds a 33.33% interest.

In August Beluga averaged 22,917 mcf per day, 12.2% of inlet gas production, and an increase of 4.5% from an August 2020 average of 21,940 mcf per day.

AOGCC describes Beluga as a shallow, 7-mile by 2.5-mile gas accumulation, discovered in December 1962 by Standard Oil Company of California in a search for deeper oil. Regular gas production began in March 1968, AOGCC said, and peaked in 2004 at an average rate of 157,433 mcf per day.

In its most recent plan of development and operations, filed with the federal Bureau of Land Management March 1, 2021, Hilcorp said that in the previous plan year it drilled three grassroots wells with Hilcorp Rig 169, each targeting Sterling and Beluga gas sands and executed three workovers, two with Rig 169 and the other with a coil unit.

For the 2021 plan period, Hilcorp said it anticipated drilling one grassroots well with Rig 147 targeting Sterling and Beluga sands. It does not anticipate any workovers with Rig 401 but through-tubing workovers to add perforations or do eline work are being evaluated for 2021.

Produced water line tie-ins are planned for D and F pads.

In a June 29, 2021, amendment to the current plan, Hilcorp said it has signed a farmout agreement with Chugach Electric Association under which Hilcorp will drill a well within the unit to target and test formations at depths below 7,000 feet. Chugach Electric owns 100% working interest at depths below 7,000 feet and upon completion of the well Hilcorp would acquire a 33.33% working interest ownership below 7,000 feet, "resulting in an alignment of ownership interests at all depths."

The well would be drilled in the fourth quarter of 2021 from K Pad.

Hilcorp told AOGCC in a Sept. 13, 2021, request that the target of that well is the Tyonek Undefined Gas Pool within the Beluga River field and said the BRU 223-24 well would target "undrained reserves within the Undefined Sterling/Beluga and Undefined Tyonek." The Beluga field is currently producing only from the Undefined Sterling/Beluga. Hilcorp said it would initially perforate and test the Tyonek and if the deeper sands are unsuccessful, would then move up hole and perforate and test additional Tyonek and Sterling/Beluga sands.

IVAN RIVER

Hilcorp has been working to increase natural gas production from the west side Ivan River field for more than a year. The Ivan River unit was formed in 1967 by Standard Oil Company of California and Hilcorp took over as operator from Union Oil Company of California on Jan. 1, 2012, the Alaska Division of Oil and Gas said in an Aug. 25 decision approving an amendment to the Ivan River plan of development.

When Hilcorp took over, the field was producing some 3,000 mcf per day and gradually declined to less than 400 mcf per day by January 2019. But by January 2021, Hilcorp had increased production to more than 6,200 mcf per day.

In its proposed 2021 plan of development, the company planned to continue producing from the Sterling-Beluga and Tyonek participating areas and was evaluating delineation well opportunities within both PA. It was also evaluating a rig workover at the IRU 11-06.

But by August the company told the division in a proposed amendment that it had identified sufficient natural gas reserves in the Sterling and Beluga formations to support drilling of a grassroots well in the 2021 POD period. The well is planned for the fourth quarter of the year.

As of August of this year, Ivan River was producing from two wells, with production averaging 5,980 mcf per day.

In its 2019 POD the company said that during the 2018 POD it "worked on a comprehensive field study that would lead to possibly enhanced production." The field study "evaluated the Sterling, Beluga and Tyonek reservoirs for further development," the company said, and "included pursuing efficiencies through various well infrastructure and facility repairs, including evaluation of shut-in wells for potential return to service or utility."

LEWIS RIVER

The Lewis River unit, three state leases on 620 acres, was formed in 1977 with Cities Service Oil Co. as operator, the division said in an April 26, 2021, approval of the unit's 46th plan of development. Lewis River has two participating areas, LRU Gas Pool No. 1 and LRU Gas Pool No. 2, with all current production from the LRU Gas Pool No. 2 PA.

Hilcorp took over as operator from Union Oil Company of California effective Jan. 1, 2012, the division said.

AOGCC data show the field was producing 1,564 mcf per day in January 2012 and 1,126 mcf per day in August 2021.

When it filed its current POD in March, Hilcorp told the division it was "evaluating delineation drill well opportunities at Lewis River" but said it had no long-range development activities planned for the 2021 POD period, and no planned exploration or delineation activities.

The company said that during the 2020 POD it "pursued efficiencies through various well, infrastructure and facility repairs, including evaluation of shut-in wells for potential return to service or utility."

PRETTY CREEK

Of the four west side fields Hilcorp operates, Pretty Creek is the only one not currently in production.

In an April plan of development approval the division said the Pretty Creek unit was formed in 1977 by Union Oil Company of California and currently covers some 4,660 acres, 12 tracts, within the Beluga participating area.

There is only one producing well at Pretty Creek and Hilcorp told the division in its 43rd POD that there was no native gas production from the Beluga PA during the 2020 POD period after the only producing well, PC-02, stopped producing in August 2019 after several months of increasing water production. The company said attempts to unload the well of water were unsuccessful. "It is predicted that the well is currently filled with a combination of water and sand," Hilcorp said.

The company said a regional study on the Sterling sands in the westside satellite fields — Pretty Creek, Ivan River and Lewis River — was done in 2020, with the first Sterling perforations from the study done at Ivan River in the second half of 2020. Those perforations, the company said, were very successful.

The same Sterling sands have been correlated to Pretty Creek and Lewis River and the next phase of the study is to begin with additional Sterling sands perforations in Lewis River A1 and Pretty Creek No. 2, both scheduled for 2021.

The company said the PC-4 well, currently used for gas storage, appears to have commercial Sterling sands with commercial potential; a twin well to access the Sterling is being evaluated — either a sidetrack of PC-2 or a grassroots well, with a potential timeline of the 2022-23 winter months. Hilcorp said it is planning a coiled tubing fill cleanout on PC-2, which could allow access to two additional Sterling sands above current producing sands, following by wireline perforation, work planned for the third quarter of 2021.

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PHOTO BY JUDY PATRICK, COURTESY OF HILCORP ALASKA LLC

Hilcorp's Steelhead Platform (at the McArthur River field), first operated by Marathon Oil in 1986, rests atop four giant legs that house multiple wells. It's topped with a 150-foot derrick.

Northern Kenai Peninsula

BEAVER CREEK

Beaver Creek, discovered by Marathon Oil Co. in 1967, is southwest of the Swanson River unit on federal leases in the Kenai National Wildlife Refuge. It is the smallest of the northern Kenai Peninsula fields operated by Hilcorp, which took over in 2013 after it bought out Marathon's oil and gas assets in Cook Inlet.

The field produces both oil and natural gas. AOGCC data show the field averaged 644 bpd of oil in August 2021, up 311.3% from 151 bpd in August 2020, and 8,202 mcf per day of natural gas, down 33.9% from 12,413 per day in August 2020.

In Hilcorp's most recent plan of development and operations for the unit, submitted to the federal Bureau of Land Management in March 2021, the company said it drilled a sidetrack to the BCU-19 well targeting the Tyonek/Beluga sands during the 2019 plan period, and, also in that plan period, attempted to work over BCU-04RD, a Tyonek oil sand producer which failed in August 2019. A 2020 attempt to work over the well also failed, and Hilcorp said there is a new plan in place for 2021.

Under the 2020 plan, Hilcorp said it restaged the sales compressor as a booster compressor and routed the BC-05 flowline through a process heater. Also during the 2020 plan period, the company completed well work on two wells previously shut-in, returning them to production: BCU-14A and BCU-09 were both perforated in the Sterling gas pool and brought online in August, 2020.

Hilcorp said 2021 planned work includes working over BCU-04RD, the Tyonek oil sand producer which failed mechanically in 2019, as well as evaluating the implementing additional well repairs and/or workover projects as they arise.

SWANSON RIVER

Swanson River in the Kenai National Wildlife Refuge was discovered in 1957 by Richfield Oil Corp.

Initially an oil discovery, the field now produces both oil and gas. AOGCC data for August show the field averaged 907 barrels per day of oil, up 17.4% from August 2020 when the field averaged 773 bpd, and 15,770 mcf per day of natural gas, down 32.4% from an average of 23,334 mcf pr day in August 2020.

Hilcorp, which took over operatorship at Swanson in 2012, told BLM in its latest plan for the field that during 2020 cumulative gas production was 3,513 million standard cubic feet and cumulative oil production was 326,000 barrels.

In 2020 the company said, it did work on gas wells to stem decline, including two successful perforation additions, one rig workover and one return to production of a long-term shut-in well which had been slated to be plugged and abandoned.

"The non-continuous Sterling B6U gas sand accessed in SRU 213-15 was mapped in SRU 12-15, providing a new future offtake point" in the field, Hilcorp said.

The company had successful Tyonek G2 perforations in two oil wells and said a handful of wells with those oil zones would be perforated in 2021, including a well on the P&A list.

Also in 2020, a gas storage well was drilled to provide additional deliverability from the Tyonek 77-3 gas storage reservoir and Hilcorp said the plan for that grassroots well is to serve only as a gas producer, although it could serve as a gas injector if needed. A second gas storage well targeted the Tyonek 64-5 storage sand as an injector and producer.

Hilcorp did a number of workovers targeting shallow gas sands, including on two wells that were returned to service, and while perforations were successfully added on one well, they were unsuccessful on the second.

"Hilcorp quantified remaining Sterling and Upper Beluga gas reserves in the North Block" of the field through a field study, identifying several opportunities to add perforations and an opportunity for a grassroots well.

Hilcorp also did a workover targeting gas sands at one well and planned a workover at another well which was pushed into the 2020 plan period "due to market conditions and other unforeseen factors."

The company said it did not perform any P&A work during the 2020 plan period.

Wells on the P&A list in the 2020 plan "have been reevaluated and it has been determined that these wells have future potential production," the company said, with no plans to P&A other Swanson River wells at this time.

Hilcorp said it has a new subsurface team in place for the

2021 plan period and will continue to review the Swanson River unit "to identify remaining Sterling, Upper Beluga, and Tyonek gas in Blocks 3, 4, and 5; remaining oil reserves across the field in the Tyonek G-Zone; and potential oil prospects to target with CTD drilling."

Six workover opportunities are either planned or under review, and there will also be routine facilities repair and replacement during the 2021 plan period, the company said.

CANNERY LOOP

The small Cannery Loop unit north of Kenai was formed in 1978 with Union Oil Company of California as operator, the Division of Oil and Gas said in a June approval of the 42nd plan of operations.

Hilcorp took over as operator in 2012.

Production from Cannery Loop averaged 3,795 mcf per day of natural gas in August 2021, the latest month for which data is available by field from AOGCC, a 27.4% drop from August 2020, when the field averaged 5,230 mcf per day.

Hilcorp told the division that during the 2020 POD period it reperforated the UT-5A sand in CLU 1RD, increasing production by some 160 mcf per day; executed a rig workover on CLU 14 which increased production by some 2,200 mcf per day, with additional perforations planned; did a rig workover on CLU 5RD which have so far failed to produce sustained gas production, but work on that well was to continue; Upper Beluga perforations planned on the CLU 11; and a recompletion of the CLU 1RD to the Beluga sands.

In work beyond that in the 2020 POD, Hilcorp drilled and completed the CLU 6RD in the Sterling A and B sands, with perforations producing water and sand. The future utility of CLU 6RD is under evaluation, the company said.

Hilcorp reactivated CLU Pad 3 o allow for maintaining and increasing production from Cannery Loop. A plan to install a sales compressor on CLU Pad 1 did not go forward as it was found to be unnecessary.

Additional wells are being evaluated in the 2021 POD period, the company said; one potential is a sidetrack to CLU 10 targeting the Deep Tyonek sands. Timing of this drilling "is dependent upon current risked resource and economics, market demand, pipeline capacity, and competitiveness within Hilcorp's gas project portfolio," the company said.

The company said it is evaluating new information and production results from the CLU 6RRD along with ongoing interventions/recompletions, with information to aid in evaluation of future exploration/delineation prospects.

Evaluation and execution of additional well work will be evaluated and executed as opportunities arise.

KENAI

Hilcorp's Kenai unit is currently Cook Inlet's largest natural gas producer, accounting for more than 16% of inlet gas production, averaging 30,688 mcf per day in August 2021, based on AOGCC data, down 19.4% from an August 2020 average of 38,079 mcf per day.

In the 63rd plan of development and operations for the unit, filed in March, Hilcorp told the Bureau of Land Management

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that during the 2020 POD period it drilled the KU 24-32 well from Kenai Unit Pad 34-31, completing the well in the Sterling formation. The company said 28 projects during the 2020 period included converting 10 wells from shut-in to producing and including uphole recompletions, additions of perforations and rig workovers to existing wells.

Hilcorp said it also drilled two grassroots wells not in the 2020 POD — the KU 42-12 from the Kenai Unit 14-06 Pad and the KU 44-08 from the Kenai Unit 41-18 Pad.

The company also conducted routine repairs and facility replacements.

For the 2021 POD Hilcorp said it plans “several uphole recompletes, perforation adds and rig workovers to existing wells” to maintain and increase production, as well as routine facilities repairs and replacement: 24-inch low pressure and 20-inch medium pressure flowline installation; new compressor installations; Saturn building HVAC upgrade; and 20-inch sales pig launcher/receiver installation.

The company also said it would continue to operate and do routine repairs to the Kenai gas field grind and injection facilities.

Hilcorp also operates a gas storage lease in Pool 6 at the Kenai gas field.

In a June 17, 2021, approval of the POD for the gas storage lease, the Alaska Division of Oil and Gas said Kenai Pool 6 was formed in 2006. Hilcorp took over from Marathon Oil Co. Feb. 1, 2013.

In its proposed 2021 POD Hilcorp committed to recompleting KDU-01 to the Kenai Pool 6 storage reservoir and KU 31-07X from the Kenai Pool 6 storage reservoir to other native gas sands in the KU. The division said KDU-01 is a shut-in KU well that last produced from the Tyonek sands in 2008; KU 31-07X is a currently shut-in Kenai Pool 6 injector and producer.

Hilcorp told the division that recompletion of KU 31-07X is dependent on the success of the recompletion of KDU-01. The division said the company’s intention is that the wells would swap functions, improving deliverability of Kenai Pool 6 through recompletion of KDU-01 while increasing native gas production in the Kenai unit through completion of the KU 31-07X well.

Southern Kenai Peninsula

NINILCHIK

Hilcorp’s Ninilchik is the newest of the large gas fields in Cook Inlet.

The Ninilchik unit was formed in 2001 and contains three participating areas, Falls Creek, Grassim Oskolkoff and Susan Dionne-Paxton, the Alaska Division of Oil and Gas said in a June 10 approval of Hilcorp’s current plan of development for the unit.

Hilcorp acquired Ninilchik in 2013 from Marathon Oil.

Expansions of the Ninilchik unit and the Falls Creek PA were approved March and May 2017, the division said, with the Falls Creek PA expansion currently pending appeal before the commissioner of the Department of Natural Resources. Mandatory contraction of the unit has been delayed from Dec. 12, 2013, to May 31, 2017, 2018, 2020 and most recently to May 31, 2022.

In August, the most recent month for which production data is available by field from AOGCC, Ninilchik averaged 30,483 mcf per day, down 4.2% from an August 2020 average of 31,833 mcf per day. Ninilchik is currently the second most prolific natural gas field in Cook Inlet.

In the POD covering 2020, Hilcorp told the division a rig workover was completed on the Frances 1 well, recompleting it to the Beluga sands, after which several Beluga intervals were perforated, but “did not sustain commercial production” and the well was shut-in for evaluation of future utility.

The Kalotsa 5 was drilled and completed in the Middle and Upper Beluga sands and began production at some 1,400 mcf per day in October 2020.

Perforations were added at the Grassim Oskolkoff 8, addition some 700 mcf per day of production in April 2020.

A rig workover pulled velocity string at Ninilchik State 1; after perforations, Tyonek T-19 was found depleted; the well loaded up after additional Tyonek perforations; after additional work production returned to some 220 mcf per day.

A plunger lift was installed in Susan Dionne 5, but the project was unsuccessful and the plunger lift was removed.

Perforations were added to Paxton 3 and Paxton 4, adding some 400 mcf per day (October 2020) and some 1,450 mcf per day (November 2020) respectively.

Work at Falls Creek 3 to perforate the Beluga sands was not successful.

A rig workover at Paxton 2 resulted in initial production of some 2,200 mcf per day (March 2021).

Kalotsa 2 came online at some 1,050 mcf per day (April 2021) after work and perforations in the Upper Tyonek.

Perforations at the Paxton 9 added some 1,200 mcf per day (July 2020), but the well loaded up and was recompleted to the Middle Beluga in March 2021, with the project ongoing in April.

Production began falling off in Kalotsa 1 in January 2021; a coil fill clean out was performed and production was increased to some 850 mcf per day, with reperforations planned.

Perforations are planned in the Susan Dionne 5.

Two wells were drilled under the 2020 POD: Paxton 10 targeted the Beluga reservoir with production beginning at some 3,300 mcf per day. The Kalotsa 7 targeted the Tyonek reservoir and began production at 3,900 mcf per day in January. Hilcorp said the wells were required to follow the 2020 POD and maintain/increase unit production.

An additional compressor was installed on the Susan Dionne pad to allow for additional throughput from the Kalotsa and Susan Dionne pads; conversion of the SD 8 Class II disposal well in progress.

Hilcorp said it has no plans for additional development wells at Ninilchik but there are proposals for exploration/delineation wells: Pearl 2A from a new pad on private land outside the unit; a sidetrack is being considered from the Blossom 1, most likely in the 2022 or 2023 POD periods; and Abalone has been identified as a potential prospect just north of the Falls Creek PA. Hilcorp said this well needs to be drilled before the unit contracts, but said it is unknown when the project would be completed due to market conditions.

DEEP CREEK

The Deep Creek unit, jointly managed by the Division of Oil and Gas and Cook Inlet Region Inc., was formed in 2001, the division said in a June 9 approval of Hilcorp’s 2021 POD for the unit.

Deep Creek is on the southern Kenai Peninsula, south, southwest of the Ninilchik unit.

The division said sustained production began from the Happy Valley participating area in November 2004. Hilcorp took over as operator in January 2012 and Deep Creek was contracted to the PA in July 2019; there are currently 1,240 acres in the unit.

Deep Creek is one of the smaller Cook Inlet gas fields, averaging 3,933 mcf per day in August 2021, the latest month for which AOGCC's data by field is available, up 2.7% from an August 2020 average of 3,831 mcf per day.

The division said the unit produced 1.41 billion cubic feet of gas in 2020, 0.25 bcf less than calendar year 2019.

In the 2020 POD, Hilcorp said workovers at three wells, HVA-01, HVA-09 and HVA-10 were unsuccessful in sustaining or increasing rate.

After several perforations at HVB-17 failed to improve production, perforations added in March and April added some 1,200 mcf per day to production.

A rig workover planned for HVB-16 and additional perforations in HVB-13 in the 2020 POD were not performed due to other Deep Creek projects taking precedence, the company said.

Hilcorp is evaluating drilling the HVB 18 well in the 2021 POD period; it would target Tyonek sands. "The potential timing of this drill well is dependent upon current risked resource and economics, market demand, pipeline capacity, and competitiveness within Hilcorp's gas project portfolio," the company said.

Additional wells targeting the Middle/Deep Tyonek are dependent on HVB 18 results.

The company said it continues to evaluate a Deep Creek exploratory drilling program, with the current focus on Sterling and Beluga formations within the unit and said contraction of the unit has limited its "ability to explore and drill outside the unit, due to leases being contracted out of the unit and expiring."

A rig workover at HVB-16 is being evaluated, along with a recompletion of the Sterling C in the HVB-14 and other well optimizations, including evaluation of whether shut-in wells could be returned to service.

NIKOLAEVSK

Nikolaevsk is on the southern Kenai Peninsula north of the North Fork field.

Hilcorp in April 2021 requested termination of the unit; the Division of Oil and Gas approved the termination request and the company will continue to operate natural gas production from the Red 1 well as a tract operation.

The division said the Nikolaevsk unit was formed in 2004 and following completion of the Red 1 well the unit was contracted several times. Hilcorp assumed operatorship in January 2012 and completed pipeline and surface infrastructure by December 2012 and production began from the Red 1 well.

Nikolaevsk production averaged 331 mcf of natural gas in August 2021, the most recent month for which AOGCC field production data is available, down 15% from an August 2020 average of 389 mcf per day.

In its application for unit termination Hilcorp said Red 1 was completed in the Tyonek formation and had no sustained production although there were indications of resource potential in the area surrounding the wells. Red 2 was drilled and completed

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in September 2004 and test results indicated no measurable hydrocarbons in that well.

A mandatory 10-year contraction of the Nikolaevsk unit is coming up, Hilcorp said, proposing to terminate the unit and continue production from Red 1 on a tract operation basis. The company said there were no changes from its 2020 POD, which proposed continuing production from Red 1 but no additional work at Nikolaevsk.

SEAVIEW

Seaview, a gas field at Anchor Point on the southern Kenai Peninsula, is a Hilcorp discovery, and the newest field to come online in the Cook Inlet basin. Production began from the field in June from a single well, Seaview 8; the company completed a second well, Seaview 9, in early August, AOGCC drilling records show.

The most recent AOGCC production data by field, for August, shows production for the first well averaging 600 mcf per day.

Hilcorp submitted a second plan of exploration for Seaview to the Division of Oil and Gas at the end of April 2021. The company noted that formation of the Seaview unit and the first plan of development and operations were approved by the state in October 2020.

During the 2020 plan, Hilcorp began permitting for a gas pipeline at the unit and planned a second well, Seaview 9. That well, the company said, was to be drilled to a measured depth of 6,685 feet.

The company said it began installation of a gas pipeline to carry Seaview gas during the 2020 plan, but there were delays in the installation process with final sections of the pipeline not planned to be completed until the spring of 2021. Those sections required horizontal directional drilling.

Work was completed on the pipeline and AOGCC field production records show that Seaview came online in June.

Processing and production facilities were installed on Seaview Pad 1 during the 2020 plan period, the company said, with the Seaview 9 well scheduled to spud June 15, 2021.

In other work on the southern Kenai, Hilcorp told the division it would drill the Whiskey Gulch 1, an oil and gas exploration well, from the new Whiskey Gulch Pad 1, north of the Seaview pad and outside the Seaview unit boundary.

PHOTO BY JUDY PATRICK, COURTESY HILCORP ALASKA LLC

The Lisburne L4 pad was reinstated and resumed production on March 23, 2021, after having been shut-in since 2014. As of June 1, 2021, L4 pad production was approximately 1,200 BOPD.

Whiskey 1 has a spud date of July 1, 2021, the company said, and is planned to be drilled to a measured depth of 10,126 feet targeting potential gas targets in the Sterling, Beluga and Tyonek formations and potential deeper oil targets.

The company said that although Whiskey Gulch is outside the Seaview unit, "the results from the exploration well may trigger a Seaview Unit expansion to include the oil/and or gas bearing zones found in the Whiskey Gulch No. 1 well."

Offshore Cook Inlet

Luke Saugier, senior vice president of Hilcorp Alaska, told the Cook Inlet Regional Citizens Advisory Council board of directors Sept. 10 that the company's efforts going forward will be on delivering natural gas to local markets, particularly from two platforms, Steelhead (at the McArthur River field) and Tyonek (at North Cook Inlet), where he said the company will be drilling wells for years to come.

He said Hilcorp intends to extend the life of its Cook Inlet assets, particularly the platforms, as long as possible.

He described the platforms as remarkable from both a historical and technical perspective and said they would be very difficult to replace.

NORTH COOK INLET

The North Cook Inlet unit, one of Cook Inlet's largest natural gas producers, has been in production since 1969 and has produced a total of 1.921 trillion cubic feet of gas through Jan. 31, 2020, the Alaska Division of Oil and Gas said May 20 in approving Hilcorp Alaska's 2021 unit plan of development.

The field, in northern Cook Inlet, is operated from the Tyonek Platform, installed in 1968.

Hilcorp acquired North Cook Inlet from ConocoPhillips in late 2016.

In August, the most recent month for which AOGCC production data by field is available, North Cook Inlet averaged 20,191 mcf per day, up 12.3% from an August 2020 average of 17,976 mcf and up from an average of 12, 394 mcf per day in August 2016, the last August prior to Hilcorp's acquisition of the field.

In its 2021 POD submittal to the division, Hilcorp reviewed a number of non-rig wellwork projects accomplished during its 2020 POD, and said additional rig workovers and non-rig related wellwork projects were expected to be completed during the remainder of the 2020 POD period, which ended June 30: Work on NCI-B-01A and NCI-B-03 included adding perforations in the Beluga A and B sands; a rig workover recompleted the suspended NCI-B-02 well; and additional rig/rigless wellwork was in preparation for potential sidetracks in the 2021 POD.

The company did work on surface facilities on the Tyonek Platform, including piping work, subsea galvanic anode installation and annual tank and other regulatory inspections as required.

A planned workover at the NCI-A-04 well was found not to be required after successfully completion of a workover at the NCI-A-07.

For its 2021 POD Hilcorp said a NCIU field study identified four sidetrack well prospects but said it was likely some of the wells would not be drilled in the 2021 POD period, but most likely in future POD periods, 2022 and later. Hilcorp said it would further review gas potential in the Beluga and Sterling accessible by right workover or sidetracks of existing wells,

"Due to commodity price volatility, and large capital necessary, the potential development plans for the deep oil prospect has been deferred," the company said.

In Sept. 10 remarks to the Cook Inlet Regional Citizens Advisory Council, Paul Mazzolini, a drilling engineering advisor for Hilcorp, said that in conjunction with plugging and abandonment of a 1960s well, using the Spartan 151 jack-up, the rig on the jack-up was moved to the Tyonek platform and one well drilled, a second in process and a third likely.

AOGCC drilling records show three sidetrack wells permitted at North Cook Inlet: NCIU A-01A, A-03A and A-04A.

In its May 20, 2021, approval of Hilcorp's 2021 POD for North Cook Inlet, the division said: "In the 2021 POD period, Hilcorp plans to maintain production by completing sidetracks of up to three shut-in wells, recompleting wells, well clean outs and adding perforations. Longer term, sidetrack drilling is planned beyond the 2021 POD period."

GRANITE POINT

The Alaska Division of Oil and Gas approved Hilcorp Alaska's 2021 plan of development for the Granite Point unit on May 26.

The Granite Point unit name dates from 2015 when the South Granite Point unit was expanded to include the Granite Point field, the division said. There are six offshore state oil and gas leases in the unit, some 15,411 acres, and two participating areas, the Hemlock PA and the Granite Point Sands PA, with operations from the Granite Point, Anna and Bruce platforms and production processing at the Granite Point Production Facility east of Nicolai Creek on the west side of Cook Inlet. The Bruce Platform was installed in 1965, the Anna and Granite Point platforms in 1966. The division said production at Granite Point began in 1967.

Hilcorp took over as operator in 2012.

AOGCC production data for August, the latest month available, show Granite Point averaged 2,654 bpd of oil, down 9.9% from an August 2020 average of 2,944 bpd, and 3,689 mcf of natural gas, up 2.3% from an August 2020 average of 3,605 mcf per day. A relatively small gas producer by inlet standards, Granite Point is the inlet's second largest oil producer, behind only McArthur River, accounting for 31.4% of inlet production in August.

In its 2021 POD, Hilcorp said that during the 2020 POD it did no grassroots or sidetrack drilling at Granite Point but did complete workover operations: installing a coil tubing inner string in Granite Pt. St. 18742 20RD and returning that well to production and unsuccessfully re-perforating an undefined gas zone in the Granite Pt. St. 18742 46.

For the 2021 POD Hilcorp said it will further evaluate additional rotary development wells, perform mud acid jobs to further enhance later wellbore injectivity and test the feasibility of

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multilateral coil tubing drilling and identifying future candidates.

The company said it doesn't have any grassroots wells planned for 2021 but anticipates sidetracking the GPP 031-23. No workover operations are planned, but workovers will be done as need to maintain and enhance production.

TRADING BAY

There are two fields in the Trading Bay unit — McArthur River and Trading Bay — and the unit has both oil and gas production.

In its May 25, 2021, approval of Hilcorp's 2021 TBU plan of development, the Alaska Division of Oil and Gas said the Trading Bay unit was formed in 1967 with sustained production that same year. The unit produces from four participating areas in the McArthur River field — the Hemlock Oil Pool PA, the West Foreland Oil Pool PA, the Middle Kenai "G" Oil Pool PA and the Grayling Gas Sands PA.

There are four platforms at McArthur River: Dolly Varden, Grayling, King Salmon and Steelhead.

Earlier in the year the division approved a reduction to 5% of the royalty for oil from the Grayling Platform, as "due to a reservoir condition" in the mature waterflood reservoir, production from the platform has dropped below 1,200 bpd.

Hilcorp was approved as the successor unit operator Jan. 3, 2012, the division said, and on Aug. 23, 2013, the division approved the second expansion of the Trading Bay unit to include the 5,280-acre Trading Bay field. Trading Bay produces from the Monopod.

McArthur River is the inlet's largest oil producer, averaging 3,224 bpd in August, the most recent month for which AOGCC data by field is available, down 14.9% from an August 2020 average of 3,787 bpd. McArthur River also averaged 21,407 mcf of natural gas in August, down 17.2% from an August 2020 average of 25,846 mcf per day.

Trading Bay averaged 169 bpd of oil in August, down 87.1% from an August 2020 average of 1,311 bpd, and 293 mcf of natural gas, down 90.2% from an August 2020 average of 2,981 mcf per day.

In its 2021 POD for the TBU Hilcorp said that in the 2020 POD period it did no grassroots drilling but did two rig workovers, replacing a failed ESP completion in the D-12RD and converting from ESP to gas lift completion in the D-43RD; a third rig workover, replacing ESP at the G-01RD, was planned before the end of the 2020 POD period (that plan ran through June 30).

The company said it also did 17 rig and non-rig wellwork projects, including adding perforations and recompleting shut-in gas wells.

The Monopod oil pipeline was replaced this summer, Tasha Bacher, Hilcorp's project manager for the work, told the Cook Inlet Regional Citizens Advisory Council earlier in September. That work involved assembly of 4,100 feet of pipe on the beach at Trading Bay and then pulling the string of pipe from the beach to the Monopod. Once sections were in place on the seafloor, divers completed the work and after hydrotesting at the end of August, the line was restarted, Bacher said.

The Monopod oil pipeline was replaced this summer, Tasha Bacher, Hilcorp's project manager for the work, told the Cook Inlet Regional Citizens Advisory Council earlier in September. That work involved assembly of 4,100 feet of pipe on the beach at Trading Bay and then pulling the string of pipe from the beach to the Monopod.

The company said additional ESP repairs or replacements on all McArthur River platforms could be executed before the end of the 2020 POD and additional perforations added in active or shut-in wells.

Facility work included cathodic protection repair on the rectifier at the Trading Bay Production Facility, and two in-line inspections anticipated by June 2021 — the first on oil and gas pipelines on the Dolly Varden and the second on the gas pipeline at the Steelhead Platform.

Hilcorp said an in-line inspection of the Grayling gas pipeline, scheduled for the 2020 POD, was postponed to 2024.

In Trading Bay, the company did no drilling, sidetracks or workovers, but performed in-line inspections on oil and gas pipelines.

The company had anticipated a workover of the A-15RD2 wells but said that work was not performed.

In the 2021 POD for McArthur River, Hilcorp said it would continue evaluating existing completions for rig workover opportunities to optimize drawdown and lift mechanism of wells and continue working on a field study to identify additional opportunities.

No exploration or delineation activities are planned at McArthur River and Hilcorp also does not plan any grassroots or sidetrack drilling, but does plan various rig and non-rig well projects

Proposed facility work at McArthur River includes in-line inspections of the oil and gas pipelines at the King Salmon Platform and an in-line inspection on the gas pipeline at the Steelhead Platform.

Hilcorp said it is working on a Trading Bay field study "to identify additional rig workover, rotary sidetrack, perforation adds, fill cleanouts, and waterflood reactivation opportunities."

No wells or sidetracks are planned, but the company said it is evaluation potential wellwork which may include ESP repairs or replacements, coil cleanout operations, well gaslift optimizations and adding perforations.

MIDDLE GROUND SHOAL

Operations are currently suspended at the Middle Ground Shoal unit pending completion of a replacement for the fuel gas pipeline.

In a July 28 decision approving a request for suspension of operations and production, the division provided background on Middle Ground Shoal, the first offshore discovery in Alaska and in Cook Inlet, made by Amoco Production Co. in 1963.

The Middle Ground Shoal unit was formed in 1967, first as the South Middle Ground Shoal unit; it was renamed Middle Ground Shoal in 2016 when the division approved an application by Hilcorp to include two leases the company acquired from XTO Energy in 2015 in the unit. Hilcorp had taken over as operator at the Baker and Dillon platforms in 2012 when it acquired Chevron's Cook Inlet oil and gas assets.

There are four platforms in the unit: Baker and Dillon, on the original Hilcorp acreage; and A and C on the XTO tracts. Dillon was lighthoused in 2003 and Baker in 2013.

All recent production has come from the A and C platforms, the division said.

In March, prior to discovery of the leak from the fuel gas line in April which resulted in production being shut-in, AOGCC records show the field averaged 1,226 barrels per day of oil and 218 thousand cubic feet per day of natural gas.

Dan Polito, Hilcorp's project manager for the Middle Ground Shoal pipeline replacement, told the Cook Inlet Regional Citizens Advisory Board in September that the company would be replacing two 8-inch lines, the fuel line and an oil line, next summer, using a lay barge for the work, which is planned for as early next year as the ice moves out. The pipe laying work is expected to take three to four weeks, Polito said, and then some two months will be required to finish the work and commission the line, which the platforms expected to be back online by September 2022.

In a POD for Middle Ground Shoal predating the fuel gas leak, Hilcorp said it performed multiple workover operations during the 2020 POD and did work on Platform A—a leg wrap inspection/repair, subsea flange inspection and a close interval survey on the A1 and B1 pipelines, expected to be completed by July 1.

On the Baker Platform the company cleaned and temporarily abandoned in place the B gas pipeline and did a subsea platform brace joint inspection. On the Dillon Platform the company cleaned and temporarily abandoned in place the A gas pipeline.

The company also did coil tubing cleanouts and safe acid soaks on four wells.

In the 2021 plan proposed before the shut-in, Hilcorp said it "is continuing to pursue rate add opportunities off both A and C platforms," and if economic hurdles are met, plans to update completion designs for wells at the platforms and is "looking to drill several rotary drill wells along with some coil tubing drilling wells."

The company plans safe acid soaks on six wells and said it would do ESP repairs or replacements as required.

NORTH TRADING BAY

The North Trading Bay unit is not in production.

There are three state oil and gas leases in the unit, the Division of Oil and Gas said in a Sept. 7, 2021, POD approval. Two platforms, Spark and Spurr, were installed in 1967 by Marathon Oil Co. Production from the unit ceased in 2005 and the platforms have been in lighthouse mode, with crane and helidecks functional but no wells active.

In 2008, Marathon set out a conceptual abandonment plan but that was not implemented.

Hilcorp took over as operator in 2013.

In 2017 Hilcorp said it wasn't feasible to return the platforms to production but proposed to restore NTBU production by drilling from the Monopod during the 2018 POD period.

That well, the division said, was not drilled.

Hilcorp proposed in its 2019 POD drilling from the Monopod into acreage outside the NTBU and, if successful, petitioning to have that acreage added to the NTBU.

The division denied the 2019 POD and administratively terminated the unit, a decision reversed by the commission of the Department of Natural Resources, who invited the company to submit a new POD allowing it 16 months to identify drill targets which it would then be required to drill in the subsequent POD.

In a 2020 POD, Hilcorp proposed to identify targets and drill during the 2021 POD.

The division said Hilcorp identified Tyonek reservoir targets and candidates which could be sidetracked to reach those targets.

For the 2021 POD, the division said, Hilcorp proposes to sidetrack the A-10RD into the Tyonek gas sands inside the NTBU boundary, and, if successful, return the unit to production. ●

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PHOTO BY JUDY PATRICK, COURTESY HILCORP ALASKA LLC

In late January 2020, total production at Milne Point reached 34,000 barrels of oil per day for the first time since May 2008.

Hilcorp a major North Slope player

Company came to Slope in 2014, acquired BP's remaining assets in deal that closed in 2020

BY KRISTEN NELSON
Petroleum News

Hilcorp Alaska, a subsidiary of Hilcorp Energy, came to Alaska in 2011 with initial Cook Inlet basin purchases and began operating in that basin in 2012.

In 2014 it acquired some of BP Exploration (Alaska)'s interests in that company's smaller North Slope fields, taking over as operator at Duck Island, Northstar and Milne Point.

Then, in a sale announced in 2019 and finalized in mid-2020, Hilcorp took over BP's remaining Alaska assets, including its share of Prudhoe Bay, Alaska's largest oil field.

Hilcorp took over as operator at Prudhoe July 1, 2020, after closing June 30 on the purchase of Standard Oil Co.'s stock in BP Exploration Alaska. The BPXA name was then changed to Hilcorp North Slope.

Hilcorp has pursued in Alaska what it is known for in the Lower 48, acquiring and bringing new life to mature fields.

The company's optimism for its Cook Inlet purchases was expressed by Hilcorp Energy CEO Greg Lalicker when he told the Resource Development Council in November 2013, "The fields in the Cook Inlet aren't dying. They're just middle aged. There's another 20, 30, 40 years of activity to be done out there."

What does Hilcorp do to extend field life?

"There's nothing magic about what we do," Lalicker said. "It's just we're willing to chase smaller and more challenging projects than what other people were and put the time and effort into really understanding and re-interpreting the fields."

The North Slope presents somewhat different challenges than those the company has encountered in Cook Inlet, not least of which is that while Hilcorp is the majority working interest owner at all but one of the Cook Inlet fields it operates, that isn't always the case on the North Slope, particularly at Prudhoe, where Hilcorp's working interest ownership share is smaller than either ExxonMobil or ConocoPhillips, the other two major WIOs.

PRUDHOE IPA

Activities at Prudhoe are reported to the Alaska Division of Oil and Gas in three segments — the initial participating area, greater Point McIntyre and the western satellites.

And the initial message Hilcorp delivered to the division was grim — no new drilling at Prudhoe in 2021.

In January 2021 the company said the field's working interest owners had not approved a 2021 drilling program for the Prudhoe Bay satellite fields.

In its 2021 proposed plan of development for the main Prudhoe reservoirs — the initial participating areas — dated March 30, 2021, Hilcorp delivered the same message — no new drilling in 2021.

"Due to the challenging economic conditions related to the COVID-19 global pandemic, the PBU working interest owners did not approve a drilling program for 2021," Hilcorp told the division in its March 30 filing. "The resumption of drilling activity in 2022 will depend on market conditions and approval from working interest owners. Hilcorp North Slope will continue to evaluate drilling projects for future years."

Drilling at the field was shut down in April 2020 due to the coronavirus pandemic.

There are 12 participating areas in the Prudhoe Bay unit, including the initial participating areas (the Oil Rim PA and Gas Cap PA), the western satellites and the Point McIntyre PA.

In its June 1 approval of the POD for the IPA, the division said the Prudhoe Bay unit was formed in 1977. Currently there are 254,235 acres in the unit with average ownership of 26.36% Hilcorp North Slope, 36.4% ExxonMobil Alaska Production, 36.08% ConocoPhillips Alaska and 1.16% Chevron U.S.A.

Hilcorp told the division that average production from the IPA in 2020 was 166,578 barrels per day of oil and condensate, up from an average of 165,030 bpd in 2019.

IPA proposed activities

The 2021 POD, covering July 1, 2021, through June 30, 2022, includes as many as 15 workovers or well completions in the IPA, Hilcorp said, drawn primarily from wells that have failed mechanically, but which could also include profile modifications or injector/producer conversions.

Hilcorp said that during the 2021 POD period it "anticipates flat to increasing well intervention activity," with focus on maintaining existing well stock, "returning wells to service or increasing existing production through non rig rate enhancement work."

On the facilities side, Hilcorp said it anticipates several projects:

•Seawater Treatment Plant maintenance and upgrades including inlet dredging, retrofitting cathodic protection, sea ice trenching, chemical tank reinstatement and repair and reinstatement of deaerator tower.

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PHOTO BY JUDY PATRICK, COURTESY HILCORP ALASKA LLC

For the 2021 POD period Hilcorp said it anticipates drilling up to four new wells at the GMPA, with potential candidates including two coil tubing drilling sidetracks within the Lisburne and Point McIntyre PAs.

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•At Gathering Center 2, reinstating the B slug catcher sand jetting system to improve solids and water handling capabilities.

•A turnaround at Flow Station 2 to include tank inspection, valve replacements and crude cooler install.

•Continuing the power upgrade to increase field wide power reliability.

•Pig launch/receiver valve installations for common lines 12B and 9A to improve pigging operations.

•Continued subsidence related repairs and improvements to pipelines and facilities.

IPA long-range activities

Under the category of long-range activities Hilcorp said it continues to evaluate future drilling opportunities "and plans to continue to evaluate potential undeveloped resources."

In 2019 BP, then the Prudhoe operator, acquired new seismic data across most of the Greater Prudhoe Bay area. That 3D data was merged with the 2015 North Prudhoe Bay survey.

Hilcorp said interpretation of the recently acquired seismic would be completed prior to June 30, "and will be utilized to guide post-2021 development drilling as well as reservoir characterization and management studies."

Hilcorp said it also plans to continue to monitor SWOP, the Sea Water Optimization Plan, performance and complete evaluation of PAVE, Pressure and Vaporization Enhancement, working toward a sanction decision for PAVE.

SWOP ends seawater injection at two Prudhoe drill sites and increases seawater injection in the gas cap (see story in Feb. 16, 2020, issue of Petroleum News titled "Fine tuning Prudhoe: Seawater injection switch to add barrels").

IPA 2020 POD review

In its summary of the 2020 POD for the IPA, Hilcorp included a summary of calendar year 2020 production, which for the IPA was some 2.728 trillion cubic feet of natural gas and 60.668 million barrels of oil, for an average of 166,587 barrels per day in 2020.

The company said 798 producers and 220 injectors contributed to production or injected water and gas into the IPA.

"A focus on returning idle wells to service, optimizing production through the existing surface infrastructure and improved operational efficiency led to an increase in fluid handling from calendar year 2019 to calendar year 2020," Hilcorp said.

The efforts offset decline and increased the 2020 oil rate above that for 2019, with gas production for 2020 up by 422 million cubic feet per day over 2019 rates and water production up 164,000 bpd.

Alaska Oil and Gas Conservation data show Prudhoe crude oil production (for the entire field, not just the IPA) for 2020 at 78,550,002 total barrels, up by more than 2 million barrels from a 2019 total of 76,385,711 barrels.

Hilcorp said the efforts "increased IPA online well count by an average of 35 wells a day from calendar year 2019 to 2020."

Gas cap water injection was increased significantly in 2020, with 166,000 bpd of water injected over 2019 rates. Factors contributing were facility maintenance which increased plant reliability and implementation of SWOP seawater injection in August of 2020.

"The intent of the SWOP program is to increase ultimate recovery by improving the gas vaporization process within the IPA," Hilcorp said.

The 2020 POD drilling program saw two rotary wells drilled, a producer and an injector, and six coil tubing sidetracks, one injector and five producers.

Hilcorp said the 2020 drilling program was primarily focused on the miscible injectant sidetrack program at drill site 3.

"The 2020 rig program was successful at adding additional oil rate at the IPA," the company said.

In April 2020 drilling activity was halted due to COVID-19 and Hilcorp said it "is not expected to resume during the remaining 2020 POD period."

Two wells, an injector and a producer, were worked over during the 2020 POD, allowing both wells to return to service.

"Hilcorp North Slope plans to start a workover campaign in the IPA in Q2 2021," the company said.

While well work activity was slowed in April due to COVID, Hilcorp did increase the pace of well work when it took over operatorship on July 1, with some 730 well interventions executed at Prudhoe, including all the participating areas, 461 of those jobs at the IPA. The work "included well stock sustainment, rate enhancement and well surveillance work."

Major facility projects completed in 2020 included:

- Maintenance activities at the Sea Water Treatment Plant.
- New transformer, line relays and insulators installed on the Central Power Station, Central Gathering Facility and Central Compression Plant.
- All required integrity inspections completed.
- Water injection line pig launcher replacement at drill site 14 completed.
- Compressor controller upgrades at CGF.

PRUDHOE GREATER POINT MCINTYRE

In a June 25, 2021, proposed plan of development, Hilcorp North Slope told the Alaska Division of Oil and Gas it may drill as many as four new wells in the Greater Point McIntyre Area at Prudhoe Bay in the 2021 plan of development period, from Oct. 1, 2021, through Sept. 30, 2022.

The Greater Point McIntyre Area at Prudhoe includes several participating areas, a designation for areas where production occurs.

Development at the Niakuk reservoir began in 1994 from the Niakuk PA; West Niakuk PA production began in 1995; in 2007 the two PAs were combined into the Combined Niakuk PA. Waterflood began in 1995 and continues.

The Lisburne field was discovered in 1968 at the Prudhoe Bay State No. 1; development drilling began in 1985 along with long-term testing of wells in the pilot waterflood area. The field came online in late 1986, ramping up production in 1987 to 45,000 barrels per day. The Lisburne PA was formed in 1986. Lisburne gas cap water injection began as a pilot in 2008 and continues. Since the end of 1986 production is primarily processed at the Lisburne

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Production Center.

North Prudhoe Bay is a small field north of the Prudhoe Bay field and south of the Point McIntyre field. The North Prudhoe Bay PA, formed in 1995, produces from the Sag River and Ivishak formations.

The Point McIntyre PA was formed in 1993 with reservoirs at Point McIntyre and Stump Island and has been developed from two drill sites, PM1 and PM2.

The Raven PA was formed in late 2007 with reservoirs in the Sag River formation and the Ivishak sandstone member of the Sadlerochit group; production is processed at LPC.

The West Beach PA was formed in early 1993 and production began later that year with water injection from 2000 through 2003. The last production occurred in 2009. "Surface facilities remediation is needed prior to returning the PA to production," Hilcorp said.

Greater Point McIntyre 2020 POD

From April 1, 2020, through March 31, 2021, the GPMA PAs produced some 146 billion cubic feet of gas, 9.461 million barrels of oil, 1.362 million barrels of natural gas liquids and some 52 million barrels of water, Hilcorp said. Average oil equivalent production was 29,651 barrels per day (146 bcf of gas; 9,461 bpd of oil and 1,362 bpd of NGL).

A table showing production by PA shows the majority of combined oil, gas and NGL production (barrels of oil equivalent) coming from the Point McIntyre (15,745 bpd) and Lisburne PAs (11,612 bpd), with other PAs trailing far behind: Combined Niakuk 825 bpd and Raven 715 bpd. There was no production during the period from North Prudhoe Bay and West Beach.

There was also oil, NGL and natural gas production from three tract operations (NK-14B, NK-08B and P1-09) totaling 754 bpd.

Hilcorp said that since taking over as operator it has "focused on returning idle wells to service, optimizing production through the existing surface infrastructure, targeting reservoirs that had been under-developed, improving voidage replacement, and improving operational efficiency, which together led to a 2.7% (289 Mbbl) year-on-year increase in overall oil production rate from GPMA from the period April 1, 2019-March 31, 2020 to April 1, 2020-March 31, 2021."

The company said no new wells were planned for the 2020 POD and it does not anticipate drilling any new wells during the remainder of the 2020 POD.

No workovers were proposed in the 2020 POD, and none have been completed, but Hilcorp said it plans to complete as many as four workovers during the remainder of the 2020 POD (which ends Sept. 30), with two workovers in the Lisburne PA, one at the Niakuk PA and one at the Point McIntyre PA.

Two facility expansion projects were completed: L4 pad was reinstated and resumed production at the Lisburne PA, after having been shut-in since 2014, with production of some 1,200 bpd as of June 1; on-pad three-phase piping at Drill Site PM2 at the Point McIntyre PA was re-engineered to reduce vibration, allowing more throughput, with work completed May 27 and production from PM2 expected to increase 2,000-3,000 bpd due to the project.

Hilcorp said it is evaluating two additional major facility projects, the LPC Rich Gas to the Central Gas Facility and the L5 Pipeline Replacement Project, both of which would improve the production capacity of the GMPA PAs.

Greater Point McIntyre 2021 POD

For the 2021 POD period Hilcorp said it anticipates drilling up to four new wells at the GMPA, with potential candidates including two coil tubing drilling sidetracks within the Lisburne and Point McIntyre PAs. No new wells are planned in the Combined Niakuk, North Prudhoe Bay, Ran or West Beach PAs.

Up to three wells workovers with the Thunderbird 1 workover rig are proposed, with candidates including two rig workovers in the Lisburne PA and one rig workover in the Point McIntyre PA. No well workovers are planned for the Combined Niakuk, North Prudhoe Bay, Raven or West Beach PAs.

Major facility projects may include: LPC Rich Gas to CGF and L5 pipeline replacement.

Greater Point McIntyre long-range activities

Hilcorp said it continues to evaluate future drilling opportunities and potential undeveloped resources, with the following planned during the 2021 POD period:

- Evaluate and execute additional facility expansions.
- Evaluate development potential in Lisburne L4/L5 area.
- Evaluate development potential in Niakuk Kuparuk.
- Evaluate development potential at West Beach and North Prudhoe Bay.
- Evaluate development potential of existing tract operations — NK-14B, NK-08B and P1-09.

WESTERN SATELLITES

In its proposed 2021 plan of development for the Prudhoe Bay western satellites, filed Jan. 27, 2021, Hilcorp told the division that no wells were planned for 2021, citing — as the company had for the IPA at Prudhoe — challenging economic conditions due to the COVID-19 pandemic, with resumption of drilling in 2022 dependent on market conditions and WIO approval.

Circumstances changed.

In mid-July 2021, Hilcorp told the division it now anticipated completing as many as six wells within the Orion participating area in the Western Satellites during the 2021 POD period, including up to three producers and one injector from L pad and up to one producer and one injector from Z pad.

The division approved the POD amendment July 28.

Drilling proposed for the 2022 POD period, Jan. 1, 2022, through Dec. 31, 2022, includes up to 10 new wells, Hilcorp said. The company listed more than 10 candidates to be evaluated, and said the potential candidates were not limited to those named.

- Aurora PA, up to one S pad producer.
- Borealis PA, up to three L pad producers and up to one V pad injector.
- Midnight Sun PA, no planned drilling activity.
- Orion PA, up to four producers and two injectors at Z pad and up to two producers and two injectors at V pad.
- Polaris PA, up to two producers and one injector at W pad and up to one producer and one injector at M pad.

Hilcorp said it anticipates up to three workovers or recompletions during the 2022 POD, with candidates including, but not limited to:

- Aurora PA, no planned workovers or recompletes, but Hilcorp said it is "continuing to evaluate well-stock."

•Borealis PA, as with Aurora, no workovers or recompletes planed, but continued evaluation of well stock.

•Midnight Sun PA, no planned workovers or recompletes.

•Orion PA, one rig workover to install sand control in V-205.

•Polaris PA, two rig workovers to add additional injection.

On the facilities side, Hilcorp said it is "evaluating additional sand jetting improvement projects at GC-2 in the C and D slug catchers, similar to the project executed for the B slug catcher in 2021."

L pad expansion is also being evaluated, work which would provide space for future drilling.

The company said it "plans to continue evaluating opportunities to improve the western area gathering infrastructure."

Long term, future drilling opportunities are being evaluated along with evaluation of potential undeveloped resources. New pad development options will be evaluated, along with polymer injection and expansion of L pad.

A reservoir engineering and geologic study of I pad development will start in the fourth quarter of 2021, with detailed pad options and facility layouts to be evaluated during the 2022 POD period, Hilcorp said.

Starting in the fourth quarter of 2021, Hilcorp will do a six-month, three-well polymer pilot in the Polaris PA. "This pilot will determine polymer's impact on injectivity, MI utility, oil rate, and reserves. Hilcorp North Slope will use this data to determine whether polymer expansion is economic in Orion and Polaris PAs."

The company is conducting front-end engineering studies on L pad expansion and V pad gas separation to determine whether those projects are economic.

Western Satellites 2021 POD review

Hilcorp told the division in its proposed 2022 POD, submitted Sept. 30, 2021, that its focus with the Western Satellites has been "on returning idle wells to service, optimizing production through the existing surface infrastructure, targeting reservoirs that had been under-developed, improving voidage replacement, maximizing MI utility, and improving operational efficiency."

Those things combined, the company said, led to a 43% year-over-year increase in oil production from the Western Satellites for the 12 months from July 1, 2020, to June 30, 2021, compared to July 1, 2019, through June 30, 2020.

Hilcorp North Slope took over as operator at Prudhoe on July 1, 2020, after the sale of BP's upstream assets was finalized effective June 30, 2020.

The company said the Western Satellite PAs produced some 9.417 million barrels of oil and 24.6 billion cubic feet of gas between July 1, 2020, and June 30, 2021, an increase of 2.837 million barrels of oil. The daily average for the 2020-21 period was 25,801 bpd of oil.

For the July 1, 2020, through June 30, 2021, period, Aurora averaged 5,968 bpd, Borealis 7,094 bpd, Midnight Sun 1,263 bpd, Orion 4,056 bpd and Polaris 7,420 bpd.

2021 POD activity

The Prudhoe working interest owners agreed to drilling in the Western Satellites and the division approved an amendment to Hilcorp's 2021 POD for the Western Satellites.

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The division said the Aurora, Borealis and Midnight Sun PAs produce primarily from the Kuparuk River formation while Orion and Polaris "produce oil with higher viscosity from the Schrader Bluff formation."

In its 2022 POD, Hilcorp said it mobilized a drilling rig to the Orion PA in September 2021 and spud the L-206 well. The company told the division it plans to drill five wells from L pad and two from Z pad during the remainder of the 2021 POD period, and said one of the wells, the Z-221i is expected to spud in late December but will not be completed until 2022. Z-220, a Z pad producer, will likely move into the 2022 POD period "due to operational timing," the company said.

A number of workovers were completed or are planned to be completed during the 2021 POD.

At the Borealis PA, Hilcorp recompleted two Z pad wells from the Ivishak to the Kuparuk formation: Z-31, recompleted and put on injection June 2, is currently on MI; Z-11A was recompleted and put on production June 18, with an initial stabilized production rate of some 350 barrels per day of oil.

In the Midnight Sun PA, a rig workover was proposed, but not executed. Hilcorp said an alternative procedure was found to achieve the work.

At Orion, Hilcorp said two rig workovers were scheduled to repair mechanically failed wells. L-203, following repairs, tested at some 1,000 bpd. At V-205, a rig workover on the 2021 list was moved to 2022 "due to long lead tangible order timing."

Two rig workovers were done to add injection: V-137 was completed into the Schrader and put on injection; a rig workover at V-120 was "delayed into 2022 POD period due to workover scheduling."

At the Polaris PA, three workovers were proposed to add injection, with work completed at S-216 and W-212, and a scheduled rig workover to convert S-15 to injection scheduled for the third quarter 2021.

Major facility projects in the 2021 POD period included completion of reinstating the Gathering Center 2 "slug catcher sand jetting system to improve solids and water handling capabilities."

Hilcorp said it "continues to generate and evaluate opportunities to improve the western area gathering infrastructure."

Western Satellite PAs

Hilcorp included background on the Western Satellite reservoirs, here supplemented with data from the Alaska Oil and Gas Conservation Commission, which provides profiles on oil and gas pools in the state, as well as monthly production by field and well.

Development of the Aurora reservoir began in July 2000, Hilcorp said, with production startup in November 2000 and water injection beginning in December 2001. Prudhoe Bay miscible gas for water-alternating-gas injection, WAG, was used for tertiary recovery at Aurora beginning in December 2003. AOGCC information on the Aurora oil pool describes it as within the Kuparuk River formation and defined by the 1969 Mobil Oil Corp. Mobil-Phillips North Kuparuk State No. 26-12-12 discovery well with the structure between 6,450 and 6,850 feet true vertical depth. AOGCC data shows Aurora production from S pad.

Hilcorp said development at the Borealis reservoir began in July 2021. Production startup was in November 2001, with water injection starting in June 2002. A pilot project using Prudhoe Bay miscible injectant, MI, for WAG for tertiary recovery began at Borealis in June 2007. AOGCC information on the Borealis oil pool says it is in the Kuparuk River formation and is produced from the L, V and Z pads. The hydrocarbon accumulation correlates with the interval between 6,534 and 6,952 feet measured depths in the West Kuparuk State 3-11-11 well.

PHOTO BY JUDY PATRICK, COURTESY HILCORP ALASKA LLC

Lisburne gas cap water injection began as a pilot in 2008 and continues. Since the end of 1986 production is primarily processed at the Lisburne Production Center.

Development of the Midnight Sun reservoir began in 1997, Hilcorp said, with production beginning in October 1998, water injection in October 2000 and MI in 2016. In AOGCC data on the Midnight Sun oil pool, the discovery well is listed as the 1997 Sambuca No. 1, later renamed PBU MDS E-100. The discovery was confirmed in 1998 by the Midnight Sun No. 1 delineation well, later renamed PBU MDS E-101. Midnight Sun is a Kuparuk River formation accumulation which correlates with the interval from 11,662 to 11,805 feet measured depth in the Sambuca No. 1. AOGCC production records show two wells in production at Midnight Sun in the 2021 calendar year through August, with production from E pad.

Hilcorp said development began at the Orion reservoir in December 2001, with production beginning in April 2002 and water injection in December 2003. Prudhoe Bay MI for WAG has been used since October 2006 for tertiary recovery. Orion is in the Schrader Bluff formation, and AOGCC information on the pool says Orion represents the PBU portion of the formation, which is also present in the Milne Point and Kuparuk River units. The accumulation at Orion was discovered in 1968 by the Kuparuk State No. 1 exploratory well and confirmed in 1998 by Northwest Eileen 2-01 and is defined as the hydrocarbons correlating with the interval from 4,549 to 5,106 feet measured depth in PBU V-201. AOGCC said the pool produces from the V and L pads with horizontal well drilling technology used extensively in the pool's development.

The Polaris PA also produces from the Schrader Bluff formation. Hilcorp said development at the pool began in November 1997 with production beginning in November 1999 and water injection in May 2003. Prudhoe Bay MI was used in 2006 for WAG and then beginning again in 2009 for tertiary recovery. AOGCC said the Polaris oil pool is an accumulation correlating with the interval between 5,544 and 6,012 feet measured depths in the PBU S-200PB1 well, with production from the S and W pads.

MILNE POINT

Milne Point is one of the North Slope's smaller fields, currently accounting for less than 7% of Slope production. Following initial development in the 1980s, the field has seen two surges of development, the first after BP took over operation in 1994 and the second 20 years later, after Hilcorp Alaska became a 50% working interest owner and operator in late 2014.

In 2020, as part of its acquisition of the remainder of BP's Alaska assets, Hilcorp became 100% WIO at Milne.

Milne Point produced 7.1 million barrels of oil in calendar year 2014; in 2020 it produced 12.2 million barrels.

Production at Milne Point was some 14,000 barrels per day in 2014, and Hilcorp's goal was to reach 40,000 bpd by the end of 2020. While the average is still below 40,000 bpd, Hilcorp has made progress in adding to Milne volumes.

For August 2021, the most recent month for which Alaska Oil and Gas Conservation Commission production data by field was available when this publication went to press, the monthly average at Milne was 37,062 bpd, a 12% increase from August 2020, when it averaged 33,069 bpd.

The company's recent plans of development show how it is achieving this increase, with drilling — both new wells and sidetracks — and expansion of polymer injection into the Schrader Bluff reservoir.

In the 40th proposed Milne Point POD, dated Oct. 14, 2021, Hilcorp said there are three participating areas, each representing a reservoir: the Kuparuk participating area, the Schrader Bluff PA and the Sag River PA. There are also tract operations: C-15A, S-90, C-23, K-33, B-30, C-46 and S-203.

Cumulative production from the Milne Point accumulations is: Kuparuk — 271,973,907 barrels; Schrader Bluff — 105,661,423 barrels; Sag River — 3,915,851 barrels; and Ugnu — 285,985 barrels.

The four accumulations were all discovered in 1969, in post-Prudhoe discovery drilling, at Standard Oil of California's Kavearak Point 32-25 exploratory well, AOGCC said in its pool descriptions.

The unit was formed in 1979.

The first Milne pool to be delineated and then developed was the Kuparuk River, which Conoco delineated and then developed

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beginning in 1980, with regular production beginning in 1985. Conoco also delineated the Schrader Bluff pool beginning in 1989 and brought the pool into production in 1991. Conoco tested the Sag River pool in 1980.

BP took over as operator at Milne Point in early 1994 and began an aggressive development program, and it was that company that began production of the Sag River pool in 1995. In 2003 AOGCC approved a request from BP for a three-year pilot for Ugnu injection. Ugnu production occurred sporadically beginning in 2003.

The biggest difference since Hilcorp took over at Milne Point is not only the increase in production, but the difference in the source of the production, comparing January through August volumes from 2014 with those from 2021.

*There was no Ugnu production in 2014; in 2021, Ugnu, at 51,399 barrels, accounted for 0.6% of Milne production.

*Sag River, 2.4% of production in 2014 (112,405 barrels), had dropped to 1.2% (99,151 barrels) in 2021.

*Kuparuk, which at 3,122,982 barrels, was 65.7% of Milne production in 2014, had dropped to 2,576,690 barrels in 2021, 30% of the field's production.

*Schrader Bluff, 32% of the field's production in 2014 at 1,520,679 barrels, had grown to 5,879,383 barrels in 2021, 68.3% of Milne volume.

Summary of 39th POD

Hilcorp said it anticipated drilling as many as 22 new wells under the 39th POD, which covers January 2020 through January 2021, but to date has only drilled 12 new wells.

All anticipated new wells were drilled at S pad (three horizontal injectors and two horizontal injectors, all Nb Sand completions).

At I pad, where 14 wells were planned (six injectors and eight producers), five wells were completed (a vertical injector to the Schrader Bluff Sands; a Schrader Bluff Oba Sand horizontal producer and horizontal injector; a Schrader Bluff Oa Sand horizontal producer and horizontal injector). Hilcorp said the remaining nine wells were on hold "due to completion equipment availability and desire to observe results from the first two producer/injection patterns in each sand."

At J pad, three wells were anticipated (two injectors, one producer) and two wells were drilled, a horizontal producer and a horizontal injector to Schrader Bluff Nb Sand.

As many as 31 workovers were anticipated in the 39th POD, Hilcorp said, and as of Oct. 14, 12 had been completed, 11 with the ASR1 workover rig and one with the Doyon 14 workover rig. Hilcorp attributed the reduced workovers with the ASR1 to budgetary constraints, "as well as fewer electric submersible pump (ESP) failures." As many as 11 workovers had been anticipated using Doyon 14, and Hilcorp said the first workover operation was unsuccessful and "the remainder of the planned workovers were cut from the schedule."

Coiled tubing sidetracks had been anticipated on seven wells and two wells on C pad were successfully sidetracked. On F pad, where four sidetracks were anticipated, two sidetracks were completed, with one of the remaining "deferred due to complexity issues" and the other "deferred dur to prior well results."

Major facility projects completed during the 39th POD included polymer facility installation and startup at Moose pad, I pad and E pad. Hilcorp said it upgraded L pad polymer systems. At S pad it did polymer engineering/procurement and header expansion and polymer facility project.

40th POD

Under the 40th POD, submitted Oct. 14 and covering Jan. 13, 2022, through Jan. 12, 2023, Hilcorp said it "anticipates drilling up to 17 new wells" including 10 I pad Schrader Bluff wells — six producers and four injectors — and seven M pad or B pad Schrader Bluff wells — four producers and three injectors.

Six coiled tubing sidetracks are proposed — one at B pad, two at C pad, one at E pad and two at K pad.

Hilcorp said it does not anticipate any workovers but said they will "be executed to maintain and enhance production as needed."

As was the case in the 39th POD, 40th POD facility projects include polymer — a B pad polymer unit installation, an M pad upgraded polymer unit installation and installation of a water softening system at J pad related to that pad's polymer system. Other projects include power fluid separation system installation at F pad; multiphase meter replacement at S pad; production header replacement at E pad; installation of new produced water treatment equipment at the central facilities pad and Solar Titan 130 power generator engineering/procurement.

Hilcorp also listed other projects which may occur during the 40th POD, among them a second polymer unit installation at L pad.

Long-range activities include future drilling on undeveloped acreage in the northwest of the unit, "particularly in the Net Profit Share Leases" and in previously developed acreage in the Schrader Bluff PA at L, H and S Pads; continued evaluation performance of Ugnu horizontal producing well S-203 "to help determine future Ugnu development strategy" and continuing evaluation of infill drilling opportunities in the Kuparuk sands using conventional and coiled tubing drilling.

Polymer injection

Hilcorp has made use of polymer injection to increase Schrader Bluff production and has proposals for expansion of facilities supporting that process.

In August 2020 the division approved three amendments to plans of operations for polymer injection facilities — one at Moose pad, one at S pad and conversion of a temporary polymer injection facility at I pad to a permanent facility.

A $9.7 million project led by the University of Alaska Fairbanks and involving Hilcorp, New Mexico Tech, Missouri S&T and the University of North Dakota, has been researching the effectiveness of polymer injection for enhanced heavy oil recovery at Milne (see story in April 4, 2021, issue of Petroleum News).

Water has a significantly lower viscosity than Schrader Bluff oil, and the addition of polymer to water makes it more viscous, slowing down the movement of water and making it more effective in pushing oil through the rock formation.

Northstar

Northstar is a small offshore field north of Prudhoe Bay with four state and two federal leases jointly managed by the Alaska Division of Oil and Gas and the Department of the Interior's Bureau of Safety and Environmental Enforcement.

Alaska Oil and Gas Conservation Commission pool data describe Northstar Island as a 5-acre, manmade island in the Beaufort

Sea northwest of Prudhoe Bay and 6 miles offshore.

The Northstar oil pool was discovered by Shell in 1984. BP began construction of the island in the winter of 1999-2000. Regular production began in 2001.

There is also production from the Northstar Kuparuk oil pool.

Hilcorp became operator at Northstar in 2014 when it acquired BP's interest in the field.

In a January approval of an amended 17th plan of development for the field, the division said the unit, some 20,135 acres, was formed in January 1990. There are three participating areas: Northstar, Fido and Hooligan.

In an initial POD, filed in November, Hilcorp reviewed work completed under the 16th POD, which included surface casing repair to the NS-25 well and a number of surface facility operations, including an ice road for chiller module deliveries, installation of support frames, setting the chiller modules and installing associated piping and commissioning the chiller for improved natural gas liquids recovery during warmer ambient temperatures. (In recent months some 60% of Northstar production has been NGLs.)

As initially filed, the 17th POD called for exploring the opportunity to import gas from the Prudhoe Bay unit using the existing Northstar Island gas pipeline, confirming the existence of the Kuparuk oil rim and exploring opportunities to target any existing reserves and workover operations at two wells, NS-20 (conversion from Ivishak producer to Kuparuk gas injector) and replacing corroded tubing on the NS-10. That work would require an ice road.

The company said a summer 2021 outage of eight to 10 days was planned for maintenance activities.

In an amended plan, submitted in January 2021, the company said it did not anticipate performing any workover operations.

In its approval of the amended plan, the division said that while Hilcorp cancelled workover plans, in the amended plan it committed "to converting the NS-15 well from a producer to an injector to increase gas injection and maintain production at the NSU."

AOGCC data for August show Northstar production averaging 7,817 bpd of liquids (4,635 bpd of oil, 59.3% of total and 3,182 bpd of NGLs, 40.7%), down 14.3% from an August 2020 average of 9,116 bpd (5,648 bpd of oil and 3,468 bpd of NGLs).

Northstar has the highest percentage of NGL production of any North Slope field.

DUCK ISLAND

Duck Island is a small offshore North Slope field east of Prudhoe Bay.

The Duck Island unit is in the Beaufort Sea, east of Prudhoe. Alaska Oil and Gas Conservation Commission pool data show discovery of the Endicott oil pool by Sohio Alaska Petroleum Co. in 1978. The pool was developed from two artificial, gravel islands some 4 miles offshore. The islands are connected by a 1-1/2-mile gravel causeway. There is also production from the Endicott Ivishak oil pool, discovered in 1982, and from Sag Ivishak undefined oil, a pool discovered in 2009. There is a fourth pool, the Endicott Eider oil pool, discovered in 1998, but that pool is no longer in production.

Hilcorp acquired BP's interest in Duck Island in 2014, along with BP's interest in Northstar, and a 50% interest in Milne Point and Liberty — and became operator at all those fields.

In its January 2021 approval of Hilcorp's plan of development for Duck Island, the Alaska Division of Oil and Gas said the unit was formed in 1978 and currently has some 17,588 acres, with three participating areas: Endicott, Sag Delta and Eider.

PHOTO BY JUDY PATRICK, COURTESY HILCORP ALASKA LLC

Hilcorp's Innovation Rig drilling Milne Point Unit – S Pad.

In its POD for Duck Island, the 39th for the unit, filed in November 2020, Hilcorp said that during the previous POD it did not complete any workover operations but did complete non-rig wellwork operations. The company said anticipated workover operations were not performed during the 38th POD "as the rig and capital allocated for those projects were diverted elsewhere."

The company did complete several non-rig wellwork operations which, it said, optimized the unit's well stock.

In its plans for the 39th POD, Hilcorp said it planned a "tracer study to understand injector/producer response to target potential future drilling targets," but said it had no drilling planned.

The company listed several workover operations and said a facility turnaround was planned for the summer of 2021 for various maintenance activities.

AOGCC data for August show Endicott — the commission's designation for production from the Duck Island unit — averaged 4,231 bpd of oil and 445 bpd of natural gas liquids, a total of 4,676 bpd of liquids, down 34.6% from August 2020 averages of 6,153 bpd of oil and 991 bpd of NGLs, a total of 7,144 bpd of liquids. ●

Contact Kristen Nelson at knelson@petroleumnews.com

North Slope Borough's unique gas fields

The three Barrow gas fields power Utqiagvik, the northernmost city in the U.S.

BY KAY CASHMAN
Petroleum News

HARRY K. BROWER, JR.

Near Point Barrow in northern Alaska, natural gas has accumulated in Jurassic-aged sandstone reservoirs that lie along the western and eastern margins of a buried, ancient meteorite impact crater, which is on the northern flank of the east-trending Barrow High.

In the aftermath of World War II, the federal government sponsored exploration in the National Petroleum Reserve-Alaska in a bid to improve domestic energy security. Drilling by U.S. Navy contractors began in the winter of 1948 and continued through 1987.

One impact of that activity was the discovery of three gas fields — South Barrow, East Barrow and Walakpa — near the community of Barrow (renamed Utqiaġvik in 2016), the North Slope's biggest economic hub and population center (4,383 in 2017 Census).

According to the U.S. Department of Energy's National Energy Technology Laboratory, the Barrow Gas Fields Hydrate Study provided very strong evidence for the existence of hydrates updip of the East Barrow and Walakpa gas fields.

The South Barrow and East Barrow reservoirs have a stratigraphic setting similar to the Alpine oil field.

Walakpa, the most productive of the Barrow gas fields, is in the Pebble shale unit, a major North Slope source rock.

North Slope Borough

HEADQUARTERS: P.O. Box 69 Barrow, Alaska 99723
TELEPHONE: 907-852-2611
TOP ALASKA EXECUTIVE: Mayor Harry K. Brower, Jr.

Walakpa has been proven to be methane-bearing at depths of 2,000-2,550 feet below sea level. The producing formation is a laterally continuous, south-dipping, Lower Cretaceous shelf sandstone.

Minimal investment

The Barrow gas fields are unique in Alaska's oil and gas industry because they are operated by a public entity — and because they are the only fields on the North Slope where natural gas is being used for something other than oil field operations.

The Barrow Gas Field Transfer Act of 1984 directed the secretary of the Interior to convey subsurface estates of the South Barrow and East Barrow gas fields and the Walakpa gas discovery site, related support facilities, funds and other surrounding land interests to the North Slope Borough. This subsurface land transfer gave the borough ownership of and authorization for exploration and harvesting of oil and gas within 320 acres of land.

Entitlements to energy transportation easements were provided within the transfer act, allowing easements for all purposes associated with the operation, maintenance, development, production, operation or transport of energy (including electricity) from the Barrow gas fields and Walakpa discovery site to Utqiaġvik, Wainwright and Atqasuk.

The North Slope Borough has operated the gas fields for decades. The fields have generally required minimal development work, aside from a $92 million rejuvenation program launched in 2011 to combat declining production.

With that effort, the borough commissioned three wells at the East Barrow field and three wells at the Walakpa field. By improving deliverability, the city of Utqiagvik could rely on natural gas for its energy needs even during cold snaps or during maintenance activities, instead of switching to diesel as an alternative.

Walakpa improvements

Other improvements were also made, such as in 2017, NSB selected Taku Engineering to develop the design and construction bid package for work at the Walakpa gas field.

The design included the replacement of the three generators, gas turbine heat recovery, fuel gas process improvements, supervisory control and data acquisition, remote operator controls and all other ancillary systems.

Taku also provided construction administration services for the project including owner representation and fulltime on-site construction oversight.

The design was completed in early 2018 and construction was completed in April 2019.

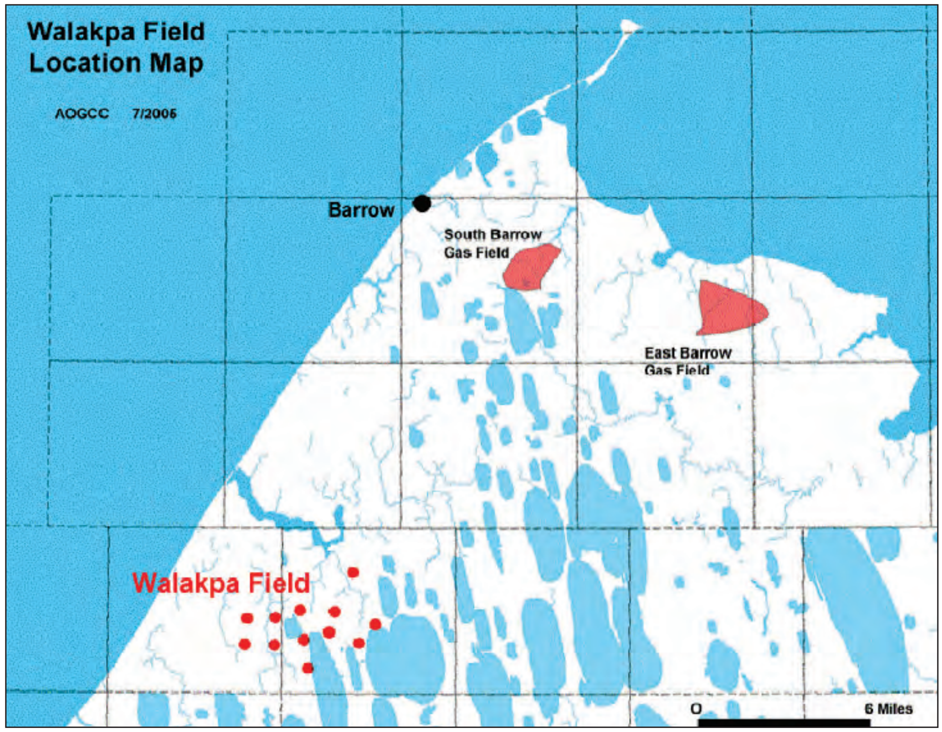
South Barrow gas field

The accumulation on the western margin of the meteorite impact crater is named the South Barrow gas pool, per the Alaska Oil and Gas Conservation Commission, or AOGCC. The South Barrow field was discovered by the Navy with the 2,505-foot South Barrow No. 2 well in 1949.

From 1948 through 1987, the commission reported that 13 wells were drilled, and one well, South Barrow 7, was subsequently deepened approximately 64 feet.

The South Barrow gas field's main natural gas reservoir is the Barrow sandstone, an informal member of the Kingak formation. This sandstone lies between the measured depths of 1,900 feet and 2,150 feet.

According to AOGCC's records, regular production from the pool began in August 1949, peaked at 3.6 million cubic feet of gas per day in November 1981, and began to decline.



ALASKA OIL & GAS CONSERVATION COMMISSION (AOGCC)

Although dated, this map is still accurate except for the fact that it refers to the city of Utqiagvik as Barrow. (Barrow was its name from 1901 to 2016.) Utqiagvik, Alaska is the northernmost city in the United States, the borough seat and the largest community in the North Slope Borough. The Barrow gas fields — South Barrow, East Barrow and Walakpa — are operated by the North Slope Borough.

In 1990, the borough began to sporadically suspend production at South Barrow.

For the first half of 2011, the pool produced an average of 1.1 million cubic feet of gas per day from five wells.

Since July 2012, the pool produced only during winter months.

In November 2015, South Barrow averaged 461 thousand cubic feet, mcf, of gas per day from three wells.

After nearly six years of inconsistent production, South Barrow has now been producing regularly since May 2018 because of the $92 million rejuvenation program that started in 2011 and spanned several years.

During the first six months of 2019, AOGCC data show the pool averaging 330 mcf per day.

Cumulative production from South Barrow through 2020 was 24.0 billion cubic feet, according to AOGCC.

East Barrow gas field

The Navy discovered the East Barrow field with the South Barrow No. 2 well in 1949 at a measured and true vertical depth of 2,505 feet.

According to AOGCC, the main gas reservoir for the East Barrow field is the Barrow sandstone, an informal member of the Kingak formation. In South Barrow No. 12 well this sandstone lies between the measured depths of 1,940 feet and 2,132 feet.

It deposited in a marine environment, and it consists of silty, very fine to fine grained, moderately sorted sandstone that contains pyrite, siderite, glauconite and calcite and is commonly interbedded with siltstone and shale.

In the East Barrow field, porosity for the Barrow sandstone ranges from 2% to 28%, averages 18% and has a median value of 18%. Permeability for the sandstone ranges from 0.01 to 3295 millidarcies, averages 133 millidarcies, and has a median value of 13 millidarcies.

Reservoir quality rock also occurs within the Walakpa sandstone, Pebble shale, Torok formation, and the Sag River sandstone.

Drilling and testing of the East Barrow gas field began in 1974 and continued through 1990, the commission reported. During this time eight wells were drilled in the field: South Barrow 12, 14, 15, 17, 18, 19, 20, and East Barrow 21, per AOGCC.

Regular gas production from the pool

continued on page 72

Maintaining output at eastern North Slope Badami unit

Glacier's Savant Alaska committed to conduct gas lift optimization on Badami B1-07, and more

BY KAY CASHMAN
Petroleum News

STEPHEN RATCLIFF

On Oct. 7, 2021, Stephen Ratcliff, president of Glacier Oil and Gas, told Petroleum News that progress at the eastern North Slope Badami unit is "steady," in terms of the company's Badami team doing a good job maintaining output.

Operated by Savant Alaska, a Glacier company, Badami averaged 1,065 barrels of oil per day in August 2021.

Production in the warmer months on the North Slope is normally lower for all fields. In comparison, Badami averaged 1,466 bpd in February 2021.

For BP, the field's original operator, by August 2007 production had fallen to 876 barrels a day.

BP brought the Badami oil field into production in August 1998. It was first in a "string of pearls," or new pipelines between undeveloped oil discoveries on Alaska's North Slope, to make their way east from Pump Station 1 of the trans-Alaska oil pipeline at Prudhoe Bay to the border of the ANWR 1002 area, a total of about 70 miles as a goose flies.

From nearly the beginning, the Badami sands reservoir's complex geology — compartmentalized into multiple, discrete sand bodies — rendered the Badami unit challenging to produce.

BP first brought the Badami field online in 1998.

Starting early in the field's life, oil output declined so severely that the major suspended production on several occasions, with one suspension lasting for two years. Field suspension allowed the Badami sands reservoir pressure to recharge, as subsurface oil slowly migrated between the various sand units.

A disappointment for BP, which had built a 38,500 barrel-a-day capacity Badami processing plant, in mid-2008, BP brought in Savant as a partner and operator, eventually selling out to the small independent.

While Savant has been much more successful with oil production from the Badami sands with only one multi-month shutdown (due to the 2020 oil price crash), the company has also looked outside the Badami participating area for new sources of oil.

B1-38 and Starfish discoveries

Savant's first discovery was in early 2010 with the B1-38 well, followed by the Starfish prospect's B1-07 well which was drilled after Savant became part of Glacier.

Both the discoveries were in the shallow Cretaceous Killian sands, a Brookian interval, although B1-38 in the Red Wolf prospect also had oil in the deeper Kekiktuk formation that contains the oil reservoir for the Endicott field to the west.

As a result of these successes and well work, Savant has been able to keep Badami producing.

For several months Glacier had Badami up for sale. But on Aug. 23, 2021, Ratcliff told Petroleum News that the oil field was no longer on the market.

E. North Slope hot spot

Successful North Slope explorer Bill Armstrong thinks the future of the eastern North Slope is promising.

Armstrong's company, Lagniappe Alaska, and 50-50 partner Oil Search, hold some 275,000 acres south of Badami, which they expect to be drilling in the next year or two.

That alone will increase Badami's value, especially if they find what they expect to. And so far, their track record for finding oil on the North Slope has been excellent.

But a potential merger between Oil Search and Santos could slow things down.

Still, in spring-2021, Armstrong told PN in a series of texts that he was very excited "about our Lagniappe play. … We are essentially taking our learnings from the Pikka/Horseshoe/Mitquq/Stirrup play (all significant discoveries) in the west to east of Prudhoe Bay."

The play concept "is very similar. Multiple zones, onshore, good gravity oil, reasonably close to infrastructure," he said.

"The targeted objectives are slightly younger than what we have at Pikka et al but with better reservoir qualities — porosity and permeability — even though they are slightly deeper," Armstrong said.

There have been very few wells drilled in the Lagniappe area, he continued, "and the few wells that have been drilled were not pursuing the zones that we are. Yet almost all wells had good oil and gas shows. We are using 3D seismic. We know what we are looking for due to our big success to the west."

Glacier Oil & Gas Corp.

GLACIER

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JUDY PATRICK

Glacier's Savant Alaska drilled the B1-07 exploration well with Nabors Rig 27E and made its second Killian oil discovery.

Armstrong said Lagniappe and its partner "are pursuing stratigraphic traps, which are subtle, but now that we know what they look like, they are identifiable on 3D seismic. Real big targets."

Plus, all the Lagniappe acreage is on state leases, he noted more than once.

That is true for the Badami unit and area leases as well.

Proposed 18th POD

On June 14, 2021, Alaska's Division of Oil and Gas approved the 18th plan of development for the Badami unit.

The application was signed April 27 by David Pascal, Glacier's chief operating officer.

As of April 30, 2021, the Badami unit had cumulatively produced 9.667million barrels of oil, 34.981billion cubic feet of gas and 16,651 barrels of water.

For its 18th Badami POD period, Savant committed to the following:

* Conduct gas lift optimization on the Badami B1-07 well (was part of the Starfish drilling program);

* Conduct production logging on the Badami B1-36 well;

* Continue compliance work and further engineering work related to infrastructure, tie-in and additional processing requirements for the Badami East Pad; and

* Continue well and facility maintenance, optimization, and explore options to enhance production "as appropriate."

In addition to Badami leases, its production facility and related lines, Glacier owns and operates the 12-inch, 25-mile Nutaaq pipeline that connects Point Thompson to the east and Endicott to the west, with Badami in the middle. Nutaaq is a common carrier line.

17th Badami unit POD

In May 2020, with the approval of the division, Savant suspended operations and production at Badami.

The suspension ended on Oct. 7, 2020, when Savant was able to fully restart production.

Due to the production suspension, the 17th Badami POD period was shortened from 12 months to nine months. During this shortened period, Savant committed to progressing its compliance and engineering work for the Badami East Pad and maintaining its current unit infrastructure while exploring for options to optimize and enhance Badami production.

The Badami East Pad is expected to become the base of operations for drilling at the eastern edge of the unit.

continued on next page

GLACIER *continued from page 71*

Savant told the division that it has permits in place to extract gravel and build the pad but did not proceed with detailed engineering work. The company said it will delay construction until a multi-well development project for the Badami East Pad is approved.

Nonetheless, from December 2020 through April 2021, daily production from Badami averaged 1,463.25 barrels of oil per day and 1.302 million cubic feet of gas per day.

Ratcliff steps up

In June 2020 Stephen Ratcliff replaced Phil Elliott as president of Glacier.

Ratcliff, a petroleum engineer, had been Glacier's vice president of drilling, having served in that position since 2013.

Prior to joining Glacier, he spent his career in operating and engineering roles in the oil and gas industry — the most recent with Hess Corp. — and has worked on both the service and operator side, as well as in various consulting roles.

At one time Glacier was looking for an investment partner in Badami to help fund a three-to-four-year drilling program in the Killian oil discoveries on its leases outside the Badami Sands participating area.

The company wanted such a partner to invest $200 million in the program. ●

Contact Kay Cashman at publisher@petroleumnews.com

NORTH SLOPE BOROUGH *continued from page 69*

began in December 1981, peaked at about 2.75 million cubic feet of gas per day in early 1983, and then began to decline, AOGCC said.

During the first quarter of 2011, the East Barrow gas pool produced an average of 448 mcf of gas per day, and for 2015 the pool averaged 442 mcf per day. During the first six months of 2019, the pool averaged 392 mcf of gas per day.

In the year ending June 1, 2021, the East Barrow gas field was producing an average of 334 mcf per day.

Through the end of 2020, cumulative production from the field was 9.8 billion cubic feet, AOGCC reported.

Walakpa gas field

Working under a U.S. Navy contract, Husky Oil discovered the Walakpa field with the 3,666-foot Walakpa No. 1 well in the 1980s.

Southwest of Utqiaġvik, Walakpa has peaked above 5 million cubic feet per day numerous times in the decades since it went online in late 1992.

In the year ending June 1, 2020, the field produced 1.3 billion cubic feet, bcf, or nearly 3.6 million cubic feet per day, according to AOGCC, up from 12.8 bcf or more than 3.5 million cubic feet per day in the year prior.

In the year ending June 1, 2021, the Walakpa gas field produced an average of 3.7 million cubic feet per day, per AOGCC.

Cumulative production from Walakpa was 35.1 bcf through the end of 2020. ●

Contact Kay Cashman at publisher@petroleumnews.com

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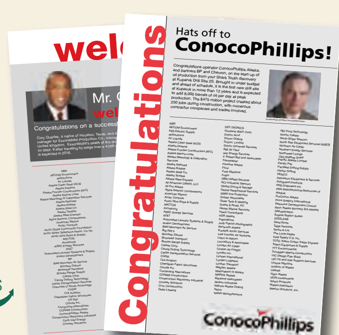

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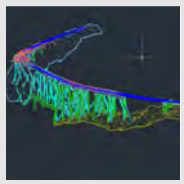

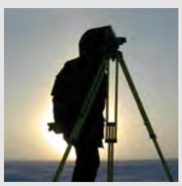

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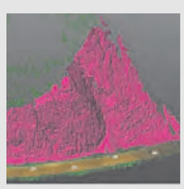

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